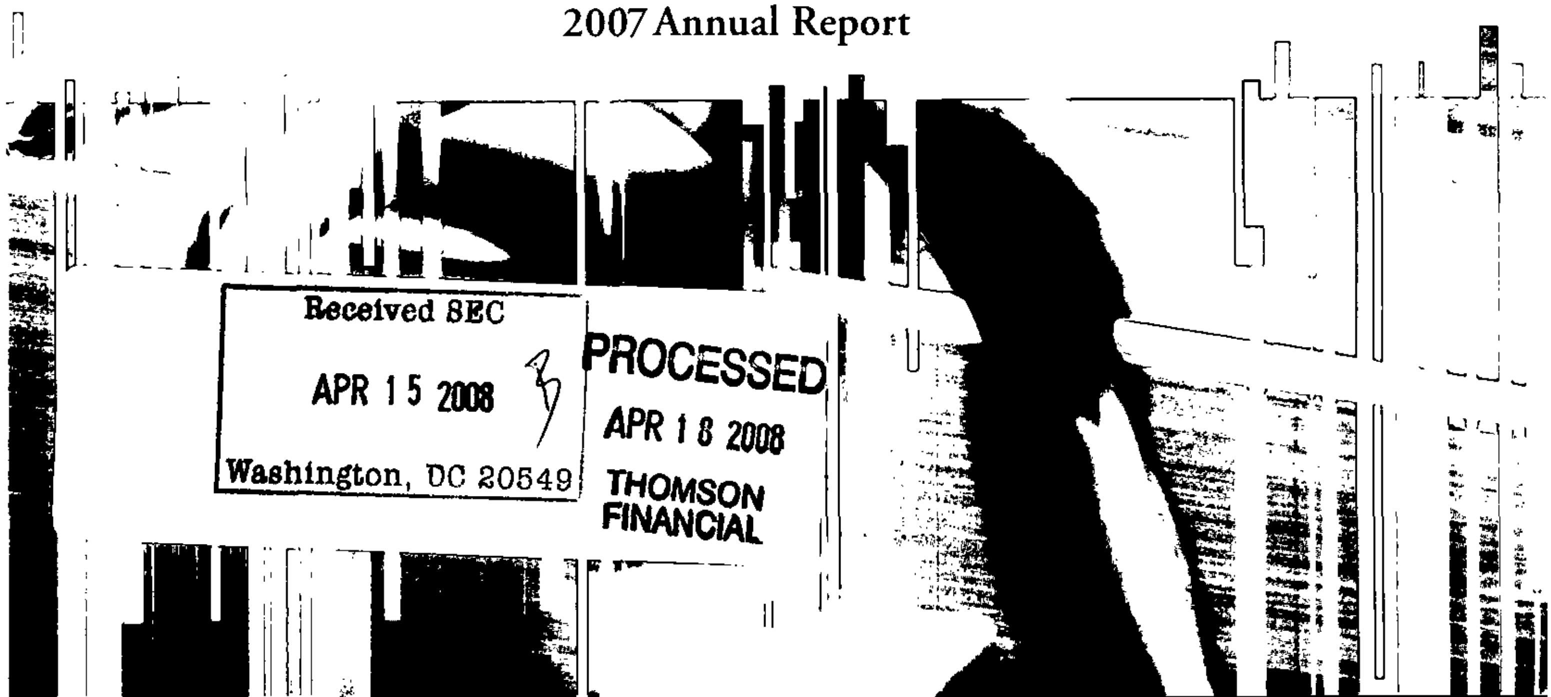
VENOCO, INC.

2007 Annual Report



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Selected Financial and Operating Data

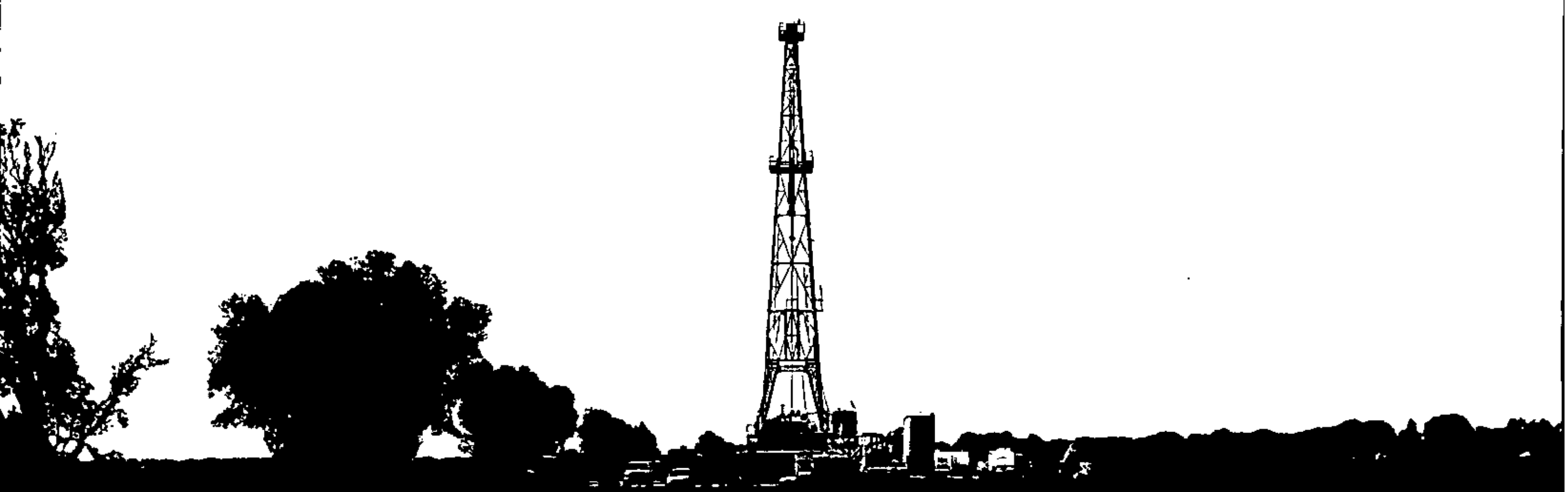
(amounts obtained from 2007 Form 10-K for years 2007 and 2006 data and from 2006 10-K for 2005 data)

Years Ended December 31 ($ in thousands)	**2005**	**2006**	**2007**
Production Volumes (MBOE)	4,218	5,797	7,130
Daily Average Production Volume (BOE/Day)	11,555	17,349	19,535
Proved Reserves (MMBOE)	47.6	87.9	99.9
Standardized Measure of Discounted Future Net Cash Flows	$ 565,385	$ 819,302	$ 1,655,641
Oil and Natural Gas Revenue	$ 191,092	$ 274,813	$ 377,871
Total Revenue	$ 137,953	$ 277,918	$ 233,860
Income (Loss) from Operations	$ 41,880	$ 92,762	$ (26,020)
Net Income (Loss)	$ 16,110	$ 23,951	$ (73,372)
Earnings Per Share - Basic	$ 0.49	$ 0.71	$ (1.58)
Earnings Per Shared - Diluted	$ 0.49	$ 0.69	$ (1.58)
Current Assets	$ 61,443	$ 86,168	$ 116,572
Net Property Equipment	$ 233,776	$ 774,253	$ 1,131,032
Other Long Term Assets	$ 7,339	$ 32,772	$ 17,881
Total Assets	$ 302,558	$ 893,193	$ 1,265,485
Current Liabilities	$ 60,532	$ 86,761	$ 172,436
Long-Term Debt	$ 178,943	$ 529,616	$ 691,896
Other Liabilities	$ 58,749	$ 86,500	$ 155,551
Stockholders' Equity	$ 4,334	$ 190,316	$ 245,602
Total Liabilities and Stockholders' Equity	$ 302,558	$ 893,193	$ 1,265,485

Adjusted EBITDA Reconciliations

Years Ended December 31 ($ in thousands), **Unaudited**	**2005**	**2006**	**2007**
Net Income	$ 16,110	$ 23,951	$ (73,372)
Interest, Net	$ 13,673	$ 48,795	$ 60,115
Income Taxes	$ 10,300	$ 15,650	$ (46,200)
DD&A	$ 21,680	$ 63,259	$ 98,814
Amortization of Deferred Loan Costs	$ 1,755	$ 3,776	$ 4,197
Loss on Extinguishment of Debt	$ -	$ -	$ 12,063
Pre-tax Share-based Payments	$ -	$ 3,050	$ 4,680
Amortization of Derivative Premiums	$ 4,701	$ 8,181	$ 11,546
Pre-tax Unrealized Commodity Derivative (Gains) Losses	$ 32,236	$ (21,079)	$ 122,778
Pre-tax Unrealized Interest Rate Derivative (Gains) Losses	$ -	$ 495	$ 17,312
Adjusted EBITDA	$ 100,455	$ 146,078	$ 211,933

LETTER TO STOCKHOLDERS



We started Venoco in 1992 with the plan to build an oil and gas company to grow production, reserves and, most important, shareholder value. Over the past 15 years we have accomplished many of the goals set out in our five and 10 year plans. Venoco entered a new phase when we became a publicly held company in November of 2006. When I think about our corporate evolution, I see a direct analogy to something I am very familiar with – the early stages of a marathon. In 1992, we started at the back of the pack of energy companies – with just $3,000 of "capital" and a $50-a-month office. Our vision was to grow by acquiring undervalued and under-exploited assets from the majors and then applying our technical expertise to reinvigorate these fields. Since 1992, we have passed by many of our early competitors, have grown significantly and ended 2007 with proved reserves having a PV-10 value of $2.4 billion[1]. Though this is a considerable achievement, we realize we have barely started the race.

Fifteen years after our start, Venoco has the strengths required to succeed – a solid base of assets in prolific hydrocarbon-rich basins, requisite engineering and geoscience expertise, experienced and knowledgeable operating staff, financial strength to support continued growth, a dynamic "can-do" corporate culture, as well as a proven track record of regulatory understanding and corporate citizenship. Together, these advantages will help us continue to acquire, develop, explore and exploit oil and gas resources in California and Texas.

In a race, there are definitely times when others tire, when the unconditioned fall back, when the undisciplined burn out. As a company, we have come through 2007 with a stronger core base of long-lived assets having large volumes of hydrocarbons in place that are ripe for the application of simple technology to take them to the next level. Here are a few achievements from the past year:

- Increased adjusted EBITDA by 45% to a company-record of $211.9 million, second consecutive year of growth of 45% or greater[2].
- Increased Operating Cash Flow by 81% to a company-record of $160.9 million.
- Increased total production by 23% to 7.1 million barrels of oil equivalent (BOE), 19,535 BOE per day, the second consecutive year of greater than 20% production growth.
- Replaced 269% of production and grew proved reserves by 14% to 99.9 million BOE, 64% of which is oil.
- Drilled 136 wells, nearly doubling the number drilled in 2006, with an 82% success rate.
- Acquired 11.9 million BOE of proved reserves for $139.9 million, or approximately $11.76 per BOE.

Our definition of PV 10, and a reconciliation of a standardized measure of discounted future net cash flows to PV 10, is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation PV 10 Value and Reserve Replacement Costs" in the enclosed Form 10 K.

See previous page for definition of adjusted EBITDA and a reconciliation to net income.

Strategy for Long-Term Value Creation

Our three-pronged strategy is comprised of selective acquisitions, aggressive development and exploitation, and focused exploration. We prefer negotiated acquisitions and target properties offering large upside potential, operational control and an ability to enhance our existing areas of operation and knowledge. Our existing assets contain significant organic growth potential from redevelopment opportunities and application of new technology. This strategy has helped us build a valuable competitive niche in California and establish a solid growth platform in onshore Texas. The expertise and skill sets of our technical staff, operating personnel and management team are well matched for successful execution of our strategy. At this time, we have 99.9 million BOE of proved reserves to produce and several times more in our existing assets to prove up. We have about a five-year inventory of 620 drilling locations and operate approximately 95% of our properties, giving us control over our future.

Visible Long-Term Organic Growth

The Sacramento Basin continues to be a key growth driver for the company and we continue to expand our presence in this area. We have 520 identified drilling locations, giving us about a 5-year drilling inventory at current activity rates and each with multiple producing zones. Since 2004, we have expanded our acreage position from about 35,000 to almost 200,000 net acres.

Unlocking New Value in Proven Assets

A significant mile-marker in creating value in our Hastings complex was increasing fluid handling capacity. The project was one of the largest of its kind in the lower 48 states and, coupled with our planned injection well capacity increase, will remove constraints to returning wells to production and completing workovers. Additional upside exists from our active workover and recompletion program and potential CO_2 flooding. Our option agreement to sell the Hastings field to Denbury Resources could provide Venoco with significant liquidity while allowing it to participate in the field's growth.

In April 2007 we acquired the nearby Manvel field, which is geologically similar to Hastings. We have been revitalizing the field by applying the experience we developed at Hastings. Manvel also presents CO_2 potential that we are evaluating.

Strategic Acquisitions for Leveraging Our Expertise

We continue to look for ways to leverage our technical expertise in under-exploited areas. In addition to the Manvel field, we also acquired the West Montalvo field in Coastal California in the second quarter of 2007. Both of these fields trend with existing Venoco operations, giving us efficiencies and opportunities for applying our knowledge and technical expertise.

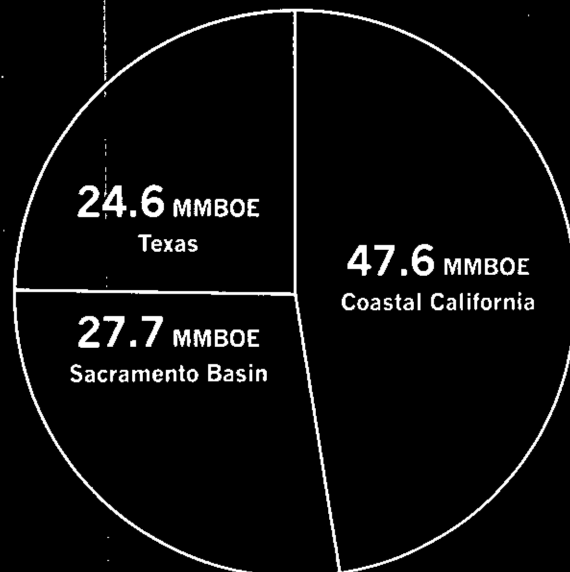
Through the combined acquisition of the Manvel-Texas assets and the West Montalvo field, we increased our proved reserves by approximately 9.8 million BOE for approximately $106 million, or $10.79 per BOE. In February 2007, we closed on the last of three small Sacramento Basin acquisitions, adding 0.9 million BOE at a cost of $11.04 per BOE (or $1.84 per thousand cubic feet equivalent). Finally, in the second half of 2007 we closed three negotiated transactions and added 1.2 million BOE of proved reserves for about $6.02 per BOE. As a point of reference, John S. Herold notes that the average acquisition cost for proved reserves in 2006 was $12.40 per BOE. The value-based acquisitions of 2007 complement our existing operations and will provide production growth that leverages our engineering expertise for years to come.

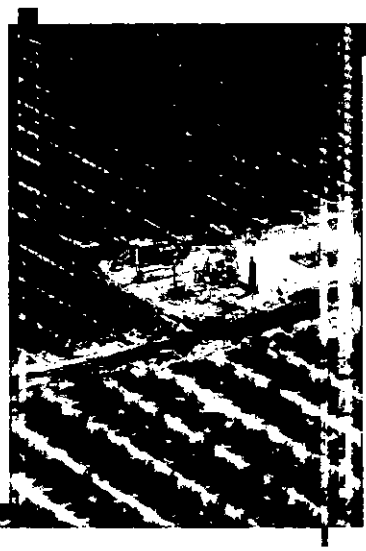
Investing for Growth and Value Creation

We invested $310 million during 2007 in development drilling, facilities expansion and exploration. Of the total, about 50% was invested in drilling 122 wells and performing 113 workovers and recompletions in the Sacramento Basin. The majority of our remaining capital (about 40% of total) went into redevelopment activities to enhance our oil assets at Hastings, West Montalvo and the Santa Clara Unit with approximately $43 million for improved facilities at these fields.

"we buy big fields and make them bigger"

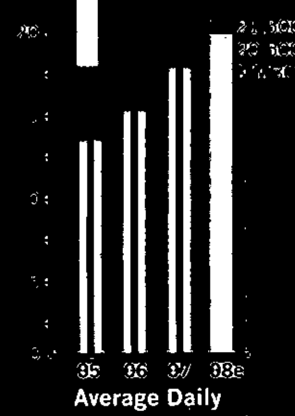
99.9 MMBOE Proved Reserves (December 31, 2007)





Our long-lived reserves provide stable and predictable production volumes and we have hedged 70-80% of our estimated proved developed producing volumes through the year 2011, primarily through the use of collars. Protecting cash flow preserves our ability to execute our capital investment plan and provides dry powder for making opportunistic acquisitions that fit our business strategy. These actions will help us maintain adjusted EBITDA growth.

Letter to Stockholders continued on page 10...



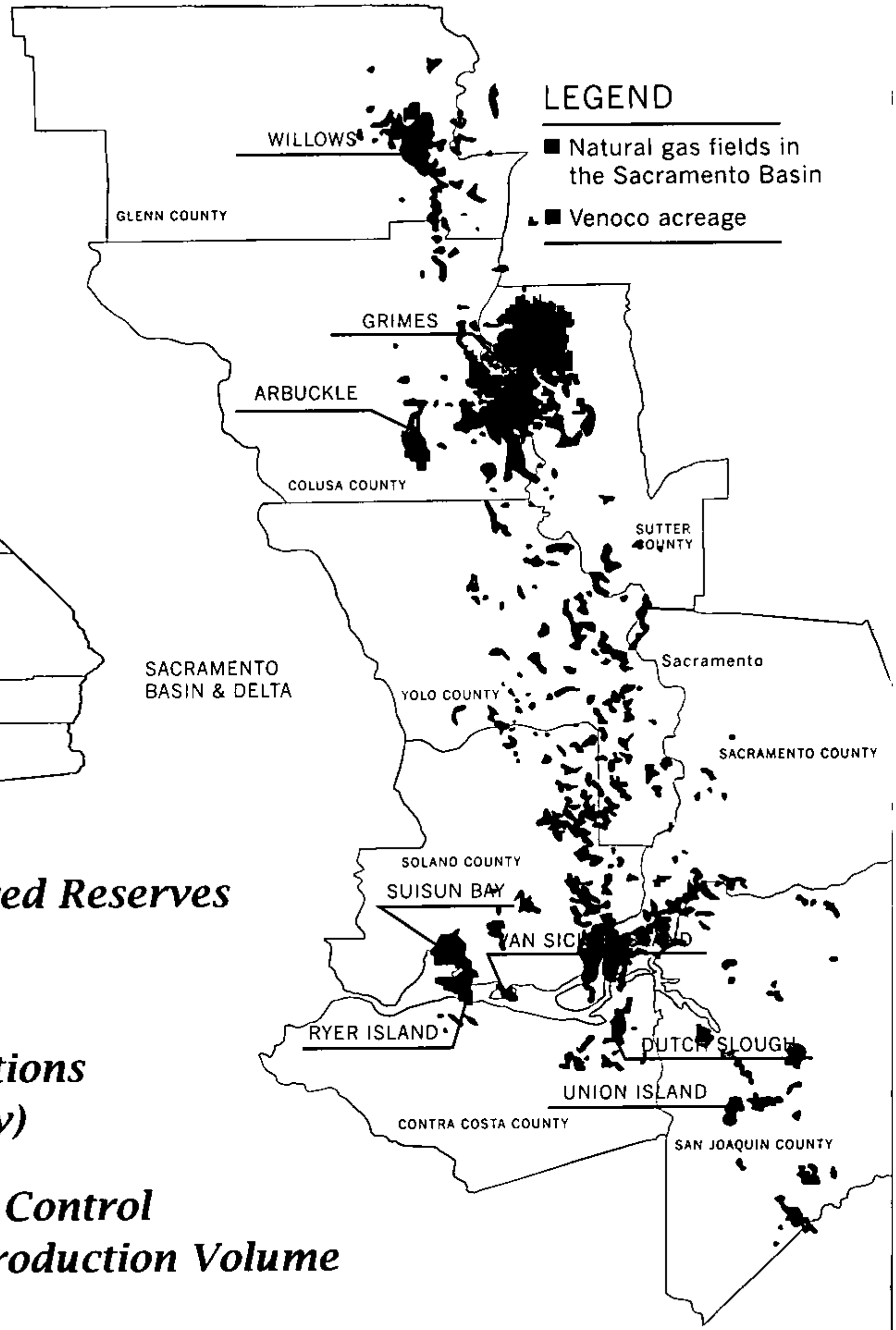
OPERATIONS: SACRAMENTO BASIN

Venoco is one of the largest operators in the Sacramento Basin. Since 2004, we have drilled 198 wells in the Willows and Grimes fields with a success rate of 86%. The Willows and Grimes Fields have been Venoco's primary area of activity in the region with five to six rigs running for most of 2007. We doubled the number of wells drilled in 2007 (122) and performed 113 workovers and recompletions in the Basin. In addition, our drilling became more efficient and we were able to reduce drilling days, allowing us to release a rig and still achieve our drilling activity goals.

Historically, nearly all of the wells in the Sacramento Basin have been completed with conventional techniques – setting casing and then perforating the pipe. In late 2007 we initiated a pilot program to complete wells using hydraulic fracture techniques. The initial results from the program have been very encouraging and we plan to fracture 20 to 50 wells in 2008. Besides completing new wells with frac'ing, we plan to use fracturing to recomplete existing wells.

In addition to our Greater Willows and Grimes fields, our Sacramento Delta, Dutch Slough and Union Island fields continue to factor into our production growth. These fields produced 5.5 million cubic feet per day (MMcf/d) during the fourth quarter. Average daily production from the Sacramento Basin during 2007 was 44.5 MMcf/d, a 38% increase over 2006.

Looking ahead to 2008, we have allocated $130 million (55% of our capital budget) to continued development of the Sacramento Basin. We see the basin as a significant driver of organic growth in the coming year. In addition to pursuing our fracturing program, we plan to drill 110+ new wells this year. Our drilling inventory of 520 locations represents about a five-year inventory at our current pace of low-risk development drilling and exploration stepouts. With more than 400 workover and recompletion opportunities we also have extensive behind-pipe growth upside. In 2008 we plan to drill as many as 10 "higher impact" exploration wells in the basin, which will test the known limits of the producing areas and could extend and further delineate the fields.



- *27.7 MMBOE Proved Reserves*
- *99% Natural Gas*
- *520 Drilling Locations (~5-year Inventory)*
- *High Operational Control Operate 98% of Production Volume*

"The Sacramento Basin is a key growth driver for the company."

OPERATIONS: COASTAL CALIFORNIA

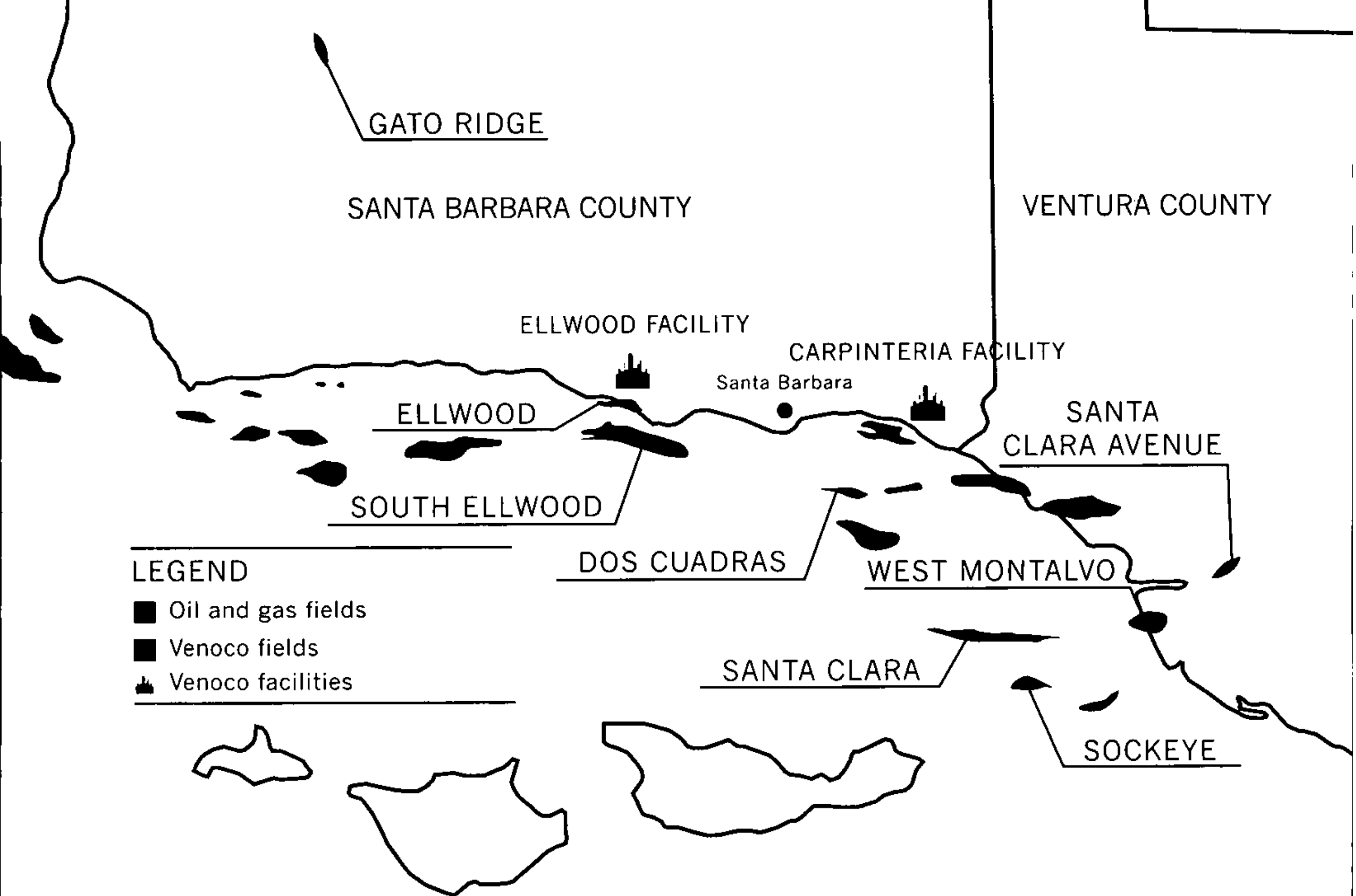
Venoco focuses on building long-term value from assets it believes have been overlooked or underfunded. The company's expertise in enhanced oil recovery, ability to employ new technology, and knowledge of its operational and regulatory environments, forms the platform for this strategy. In the Coastal California region, we produce oil and gas from the prolific and unconventional Monterey Shale formation. Our team possesses extensive knowledge of this formation. Venoco holds interests in massive fields estimated to have 3.6 billion barrels of original oil in place with very low recoveries to date.

In 1997, Venoco acquired Mobil Oil's interest in the South Ellwood field, which has been producing since the late 1970s, but only from the western portion of the field. Since we acquired the field, we have produced 13.4 million barrels of oil equivalent (MMBOE), with 2007 production averaging 3,083 BOE per day. We are in the process of extending the boundaries of the lease on the field through an application to the California State Lands Commission. The project review and approval process is expected to continue through 2008 and into 2009. Our proposed development program will extend the lease to fully encompass the Eastern portion of the field.

With today's technology, this previously untapped portion of the field can be developed using extended-reach drilling from our existing Platform Holly. We have not booked reserves for the lease boundary extension. That portion of the field is estimated to have more than 1 billion barrels of original oil in place.

The project to extend the lease boundary also includes replacing the current barging operation that transports the produced oil to Long Beach area refineries. A new, 10-mile long pipeline would replace the barge and tie into All-American Pipeline's existing transportation pipeline near Los Flores Canyon.

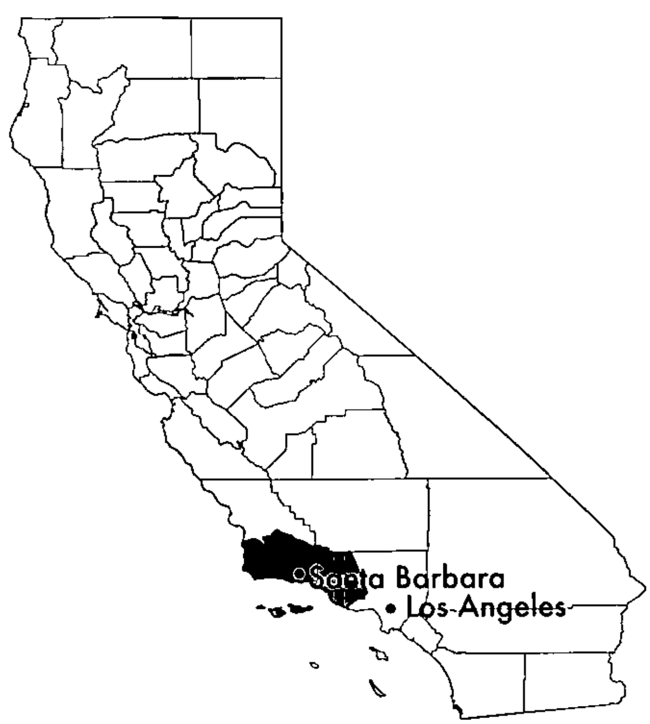
Average daily production from the Sockeye field, produced from Platform Gail, had virtually no decline in 2007, in part due to the success of our water flood project commenced in 2005. We are evaluating the potential to expand the water flood into other portions of the field. Our technical staff continues to look for ways to improve field performance and our geoscientists are studying ways to increase the recovery factor from the extensive Monterey formation.



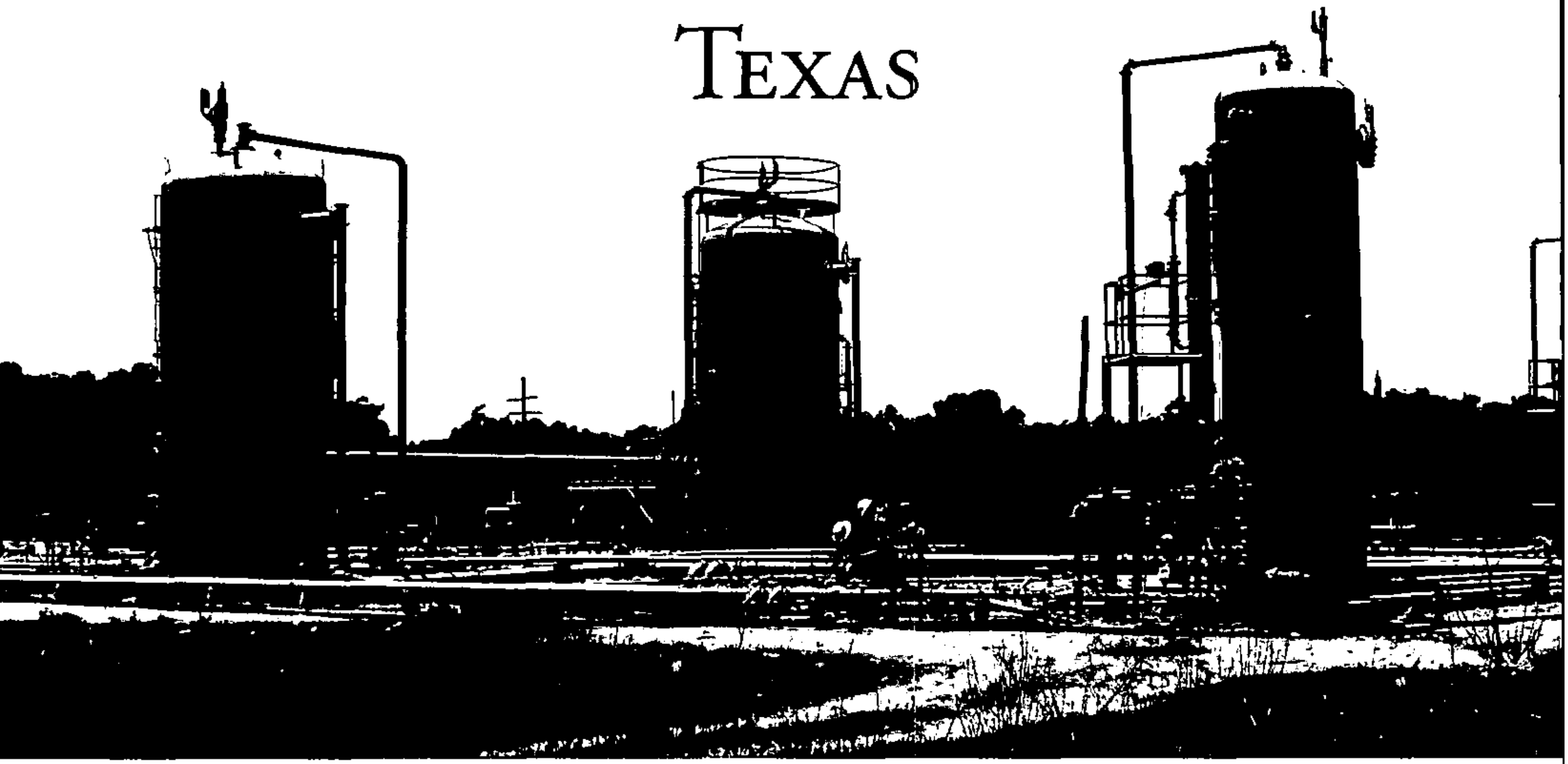
The West Montalvo field was acquired in the second quarter of 2007. The onshore portion of the field is largely developed and is characterized by a shallow production decline rate and long-lived reserves. The offshore portion of the field is largely undeveloped and undelineated, and therefore represents upside that we believe we can realize in the coming years thanks to the knowledge of the reservoir we've developed from other nearby projects. We are pursuing an aggressive redevelopment program for the field, which includes working over existing wells, returning idle wells to production, reactivating injection wells and expanding fluid processing capabilities. Shortly after acquiring the field, we drilled and completed our first new well from an onshore pad to an offshore location. The well successfully extended the boundary of the field. We have completed extensive tests and evaluations of the various geological horizons the well encountered and the well is now on production. An additional well targeting the offshore portion of the field is planned for 2008.

In 2008 we expect to invest up to $70 million (30% of our capital budget) in Coastal California for drilling six new wells (including three "higher impact" wells), improving infrastructure and expanding facilities.

- ***47.6 MMBOE Proved Reserves***
- ***90%+ Oil***
- ***51 Drilling Locations***



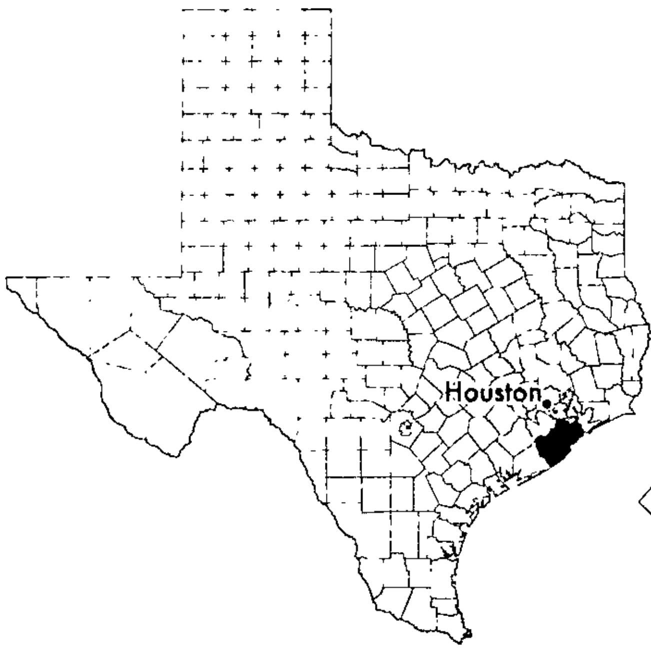
OPERATIONS:
TEXAS

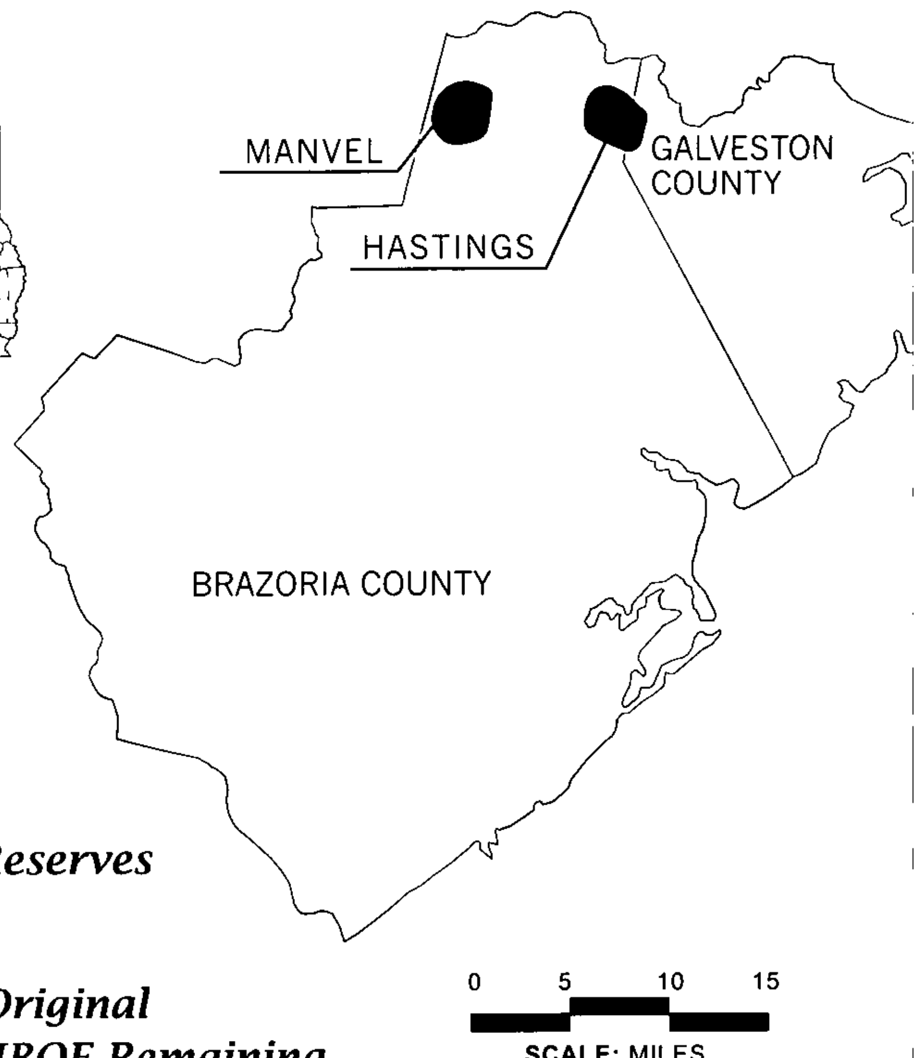


The Hastings complex in Texas is a set of mature fields with long-lived, stable production where we continue to extract long-term value. Venoco controls 4,648 net acres and operates the entire complex. Approximately 42% of the estimated 1.2 billion barrels of original oil in place remain in the reservoir. Since the acquisition from TexCal in March 2006, we have increased daily production approximately 55% and proved reserves 24% through an aggressive recompletion and workover program. Our exploitation program includes converting gas lift wells to electric submersible wells and adding fluid processing and injection capacity. Proved reserves grew 12% to 14.4 MMBoe in 2007 and further upside exists. Significant opportunities to increase recovery in Hastings still remain. At the time of acquisition, only 95 of the 374 wellbores in the complex were active. At the end of 2007, that number had grown to 131. Since we acquired the property, we have expanded our fluid processing capacity from 150,000 barrels per day to about 500,000 barrels per day. This additional fluid processing capacity will allow us to return many of the remaining 243 idle wells in the field to production.

The Manvel field, acquired in the second quarter of 2007, is located less than five miles away from our Hastings complex and is considered analogous in structure, having similar geology in the same Frio sands. Our focus has been on returning idle wells to production, recompleting existing wells as well as increasing fluid processing and injection capacity in the field. In the nine months following acquisition, production has risen more than 15%. The Manvel field is a natural addition to our South Texas asset portfolio and we believe it holds upside similar to our Hastings complex.

In November 2006 Venoco entered into an option agreement to sell part of the Hastings complex to Denbury Resources for implementation of a CO_2 flood of the field. The option can be exercised on November 1, 2008 or November 1, 2009. If Denbury elects to exercise its option, Denbury will pay Venoco the PV-10 value of the proved reserves in cash or a volumetric production payment, at Venoco's discretion. Venoco will retain upside in the project with a 2% overriding royalty and the option to back into a 22.3% working interest after Denbury recoups certain of their investment costs. Current estimates indicate that a CO_2 flood could recover between 120 and 240 million barrels of oil. Phase I of the CO_2 flood could potentially net Venoco between 15 and 30 million barrels. To date, no reserves have been booked for this project.





TOTAL TEXAS:

- *24.6 MMBOE Proved Reserves*

HASTINGS COMPLEX:

- *1.2 Billion Barrels of Original Oil in Place - ~500 MMBOE Remaining*
- *374 Wellbores - 95 Active at Acquisition, 131 Active as of December 31, 2007*
- *CO_2 Flood Potential for Capturing up to 60 MMBOE*

"We have established a solid growth platform in onshore Texas."

Closing Words

...Continued from page 3

Our Commitments

We are mindful of the impact our business can have on the communities and sensitive environments in which we operate. Although 2007 was a very active year for Venoco, we maintained a watchful eye on safety and a genuine concern for habitat preservation.

Nearly everyone has a story about a teacher who made a difference in his or her life. I know two teachers made a big impact on me – my parents. I believe teaching is a profession that does not get the recognition and respect it deserves, especially considering the amount of trust we place in our teachers to help educate our children. We reached a milestone in 2007, awarding the Venoco Crystal Apple Awards for the 10th year to outstanding teachers, administrators and staff in the Santa Barbara County School District, recognizing them for making a difference in children's lives and helping build strong and successful communities.

A Word of Thanks

We worked hard in 2007 to grow Venoco during its first full-year as a public company. Since our initial public offering in November 2006, our employees and management team have focused on growing reserves, production and cash flow. I also want to thank the members of our Board of Directors for their ongoing contributions and commitment. Our acquire-and-exploit business model is a cost-effective strategy to build net asset value over the long-run and we believe significant upside exists from applying our technical expertise to unlock the value from assets we know well. In 2008, we will continue our marathon of creating long-term value for all of our stockholders.

Thank you for your support.

Timothy Marquez

Chairman and Chief Executive Officer

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 333-123711

VENOCO, INC.
(Exact Name of Registrant as Specified in its Charter)

Delaware (State or other jurisdiction of incorporation or organization)	**77-0323555** (I.R.S. Employer Identification No.)
370 17th Street, Suite 3900 **Denver, Colorado** (Address of principal executive offices)	**80202-1370** (Zip Code)

(303) 626-8300
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant on June 30, 2007 was $259,089,191, based on the closing price as reported on the New York Stock Exchange (treating, for this purpose, all executive officers and directors of the registrant, and a charitable foundation associated with the registrant's chief executive officer, as affiliates). There were 50,867,872 shares of common stock outstanding as of March 10, 2008.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

VENOCO, INC. 2007 ANNUAL REPORT ON FORM 10-K
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FORWARD-LOOKING STATEMENTS

This report on Form 10-K, including information incorporated herein by reference, contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. The use of any statements containing the words "anticipate," "intend," "believe," "estimate," "project," "expect," "plan," "should," "could" or similar expressions are intended to identify such statements. Forward-looking statements may relate to, among other things:

- our future financial position, including cash flow and anticipated liquidity;
- our proposed master limited partnership;
- amounts and nature of future capital expenditures;
- acquisitions and other business opportunities, including those relating to the proposed full-field development project in the South Ellwood field and our option agreement with Denbury Resources Inc.;
- operating costs and other expenses;
- wells to be drilled, reworked or recompleted and the results of those activities;
- oil and natural gas prices and demand;
- exploitation, development and exploration prospects;
- asset retirement obligations;
- estimates of proved oil and natural gas reserves, PV-10 values and related cash flows;
- reserve potential;
- development and infill drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- business strategy;
- future production of oil and natural gas;
- transportation of the oil and natural gas we produce;
- planned or possible asset sales or dispositions; and
- expansion and growth of our business and operations.

The expectations reflected in such forward-looking statements may prove to be incorrect. Disclosure of important factors that could cause actual results to differ materially from our expectations, or cautionary statements, are included under the heading "Risk Factors" and elsewhere in this report, including, without limitation, in conjunction with the forward-looking statements. All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

Factors that could cause actual results to differ materially from our expectations include, among others, such things as:

- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us;
- competition for available properties and the effect of such competition on the price of those properties;
- oil and natural gas prices;

- conditions in financial markets that affect capital raising activities;
- risks related to our level of indebtedness;
- our ability to replace oil and natural gas reserves;
- loss of senior management or technical personnel;
- risks arising out of our hedging transactions;
- our inability to access oil and natural gas markets due to operational impediments;
- uninsured or underinsured losses in, or operational problems affecting, our oil and natural gas operations;
- inaccuracy in reserve estimates and expected production rates;
- exploitation, development and exploration results, including from enhanced recovery activities;
- costs related to asset retirement obligations;
- a lack of available capital and financing;
- the potential unavailability of drilling rigs and other field equipment and services;
- the existence of unanticipated liabilities or problems relating to acquired businesses or properties;
- difficulties involved in the integration of operations we have acquired or may acquire in the future;
- general economic, market or business conditions;
- factors affecting the nature and timing of our capital expenditures, including the availability of service contractors and equipment, permitting issues, weather and limits on the number of activities that can be conducted at any one time on our offshore platforms;
- the impact and costs related to compliance with or changes in laws or regulations governing our oil and natural gas operations;
- environmental liabilities;
- risk factors discussed in this report; and
- other factors, many of which are beyond our control.

GLOSSARY OF TECHNICAL TERMS

3D and 2D seismic	3D seismic data is geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional, or 2D, seismic data.
Anticline	An arch-shaped fold in rock in which rock layers are upwardly convex.
Bbl	One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbon.
Bcf	One billion cubic feet of natural gas.
Bcfe	One billion cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.
BOE	One stock tank barrel of oil equivalent, using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.
Btu	British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The installation of permanent equipment for the production of oil or natural gas.
Condensate	Hydrocarbons which are in a gaseous state under reservoir conditions but which become liquid at the surface and may be recovered by conventional separators.
/d	Per day.
Developed acreage	The number of acres which are allocated or assignable to producing wells or wells capable of production.
Development drilling or development wells	Drilling or wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry well	A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of the well.
Exploitation and development activities	Drilling, facilities and/or production-related activities performed with respect to proved and probable reserves.
Exploration activities	The initial phase of oil and natural gas operations that includes the generation of a prospect and/or play and the drilling of an exploration well.

Exploration well	Means "exploratory well" as defined in Rule 4-10(a)(10) of SEC Regulation S-X and refers to a well drilled to find and produce oil or natural gas reserves in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.
Finding and development costs	Capital costs incurred in the acquisition, exploration, development and revision of proved oil and natural gas reserves divided by proved reserve additions.
Gross acres or gross wells	The total acres or wells, as applicable, in which a working interest is owned.
Infill drilling	Drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.
Injection well	A well in which water is injected, the primary objective typically being to maintain reservoir pressure.
MBbl	One thousand barrels.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas. For the purposes of this report, this volume is stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.
Mcfe	One thousand cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
MMcf	One million cubic feet of natural gas. For the purposes of this report, this volume is stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.
MMBbl	One million barrels.
MMBOE	One million BOEs.
MMBtu	One million British thermal units.
Natural gas liquids	Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.
Net acres or net wells	The gross acres or wells, as applicable, multiplied by the working interests owned.
NYMEX	The New York Mercantile Exchange.
Oil	Crude oil, condensate and natural gas liquids.
Pay zone	A geological deposit in which oil and natural gas is found in commercial quantities.

Producing well or productive well . . .	A well that is producing oil or natural gas or that is capable of production in sufficient quantities to justify completion, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.
Proved developed non-producing reserves	Proved developed reserves that do not qualify as proved developed producing reserves, including reserves that are expected to be recovered from (i) completion intervals that are open at the time of the estimate, but have not started producing, (ii) wells that are shut in because pipeline connections are unavailable or (iii) wells not capable of production for mechanical reasons.
Proved developed reserves	This term means "proved developed oil and gas reserves" as defined in Rule 4-10(a)(3) of SEC Regulation S-X, and refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved developed reserves to production ratio	The ratio of proved developed reserves to total net production for the preceding 12 months or other specified period.
Proved developed producing reserves .	Reserves that are being recovered through existing wells with existing equipment and operating methods.
Proved reserves or proved oil and natural gas reserves	This term means "proved oil and gas reserves" as defined in Rule 4-10(a)(2) of SEC Regulation S-X and refers to the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved reserves to production ratio . .	The ratio of total proved reserves to total net production for the preceding 12 months or other specified period.
Proved undeveloped reserves	This term is defined in Rule 4-10(a)(4) of SEC Regulation S-X and refers to reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
PV-10	The PV-10 value of reserves is the present value of estimated future revenues to be generated from the production of the reserves net of estimated production and future development costs and future plugging and abandonment costs, using prices and costs as of the date of estimate without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%.

Recompletion	The completion for production of an existing wellbore in a different formulation or producing horizon, either deeper or shallower, from that in which the well was previously completed.
Secondary recovery	The second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore.
Shut in	A well suspended from production or injection but not abandoned.
Undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether the acreage contains proved oil and natural gas reserves.
Waterflood	A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil.
Working interest	The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production, subject to all royalties, overriding royalties and other burdens, all costs of exploration, development and operations and all risks in connection therewith.
Workover	Remedial operations on a well conducted with the intention of restoring or increasing production from the same zone, including by plugging back, squeeze cementing, reperforating, cleanout and acidizing.

PART I

ITEM 1. AND ITEM 2. Business and Properties

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. Since our founding in 1992, our core areas of focus have been offshore and onshore California. Our principal properties are located offshore southern California, onshore in California's Sacramento Basin and onshore along the Gulf Coast of Texas, and are characterized by long reserve lives, predictable production profiles and substantial opportunities for further exploitation and development.

We are one of the largest independent oil and natural gas companies in California based on production volumes. According to a reserve report prepared by DeGolyer & MacNaughton, we had proved reserves of approximately 99.9 MMBOE as of December 31, 2007, of which 64% were oil and 61% were proved developed. The PV-10 value of our proved reserves as of that date was approximately $2.4 billion. Our definition of PV-10, and a reconciliation of a standardized measure of discounted future net cash flows to PV-10, is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation—PV-10 Value and Reserve Replacement Costs." Our average net production in the fourth quarter of 2007 was 20,098 BOE/d, implying a proved reserves to production ratio of 13.6 years. The following table summarizes certain information concerning our production in 2007 and our reserves and inventory of drilling locations as of December 31, 2007.

	2007 Net Production			Proved Reserves			
	Oil (MBbl)	Gas (MMCF)	(MBOE)	Total (MMBOE)	% Oil	PV-10 Value ($MM)(1)	Drilling Locations(2)
Coastal California(3)	2,825	1,195	3,024	47.6	91.7	1,374.7	51
Sacramento Basin	2	16,235	2,708	27.7	0.1	384.4	520
Texas	1,154	1,465	1,398	24.6	83.2	600.2	49
Total	3,981	18,895	7,130	99.9	64.2	2,359.3	620

(1) Based on unescalated prices of $95.97 per Bbl for oil and natural gas liquids and $7.48 per MMBtu for natural gas, in each case adjusted for regional price differentials and similar factors.

(2) Represents total gross drilling locations identified by management as of December 31, 2007. Of the total, 292 locations are classified as proved.

(3) Includes properties offshore and onshore southern California.

Our Strengths

We believe that the following strengths provide us with significant competitive advantages:

High quality asset base with a long reserve life. Most of our reserves are located in fields that have large volumes of hydrocarbons in place in multiple geologic horizons. One of our primary objectives is to use our engineering expertise to improve recovery rates from these fields and thereby increase our production and reserves. Our offshore California fields and our Texas Gulf Coast fields generally have well-established production histories and exhibit relatively moderate production declines. As of December 31, 2007, our proved reserves to production ratio was 13.6 years and our proved developed reserves to production ratio was 8.3 years, in each case based on production during the fourth quarter of 2007. We believe that this relatively stable base of long-lived production is a strong platform to support further growth in our reserves and production.

Significant drilling inventory and growth potential. We believe that the continued exploitation and development of our properties will allow us to increase our proved reserves and our average net daily production even if we do not make additional acquisitions. Growth projects that we expect to pursue include a full-field development project, including an extension of the lease area, in our South Ellwood field and a hydraulic fracturing program in the Sacramento Basin. We have also entered into an agreement with Denbury Resources Inc. relating to a potential CO_2 enhanced recovery project at the Hastings complex in Texas. See "—Description of Properties" for more information regarding each of these projects. As of December 31, 2007, we had identified 620 drilling locations on our properties, and we anticipate identifying additional locations on those properties as we pursue our exploitation and development activities.

Attractive reserve replacement costs. From our inception in 1992 through December 31, 2007, we made approximately $1.5 billion in capital expenditures to acquire, develop and/or discover 161.5 MMBOE of proved reserves at an average reserve replacement cost (including reserve revisions) of $9.30 per BOE. These capital expenditures consisted of $732.2 million used to complete 45 acquisitions and $769.5 million used for exploitation, development and exploration projects. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—PV-10 Value and Reserve Replacement Costs" for a description of how we calculate reserve replacement cost.

Strong position in the Sacramento Basin. We have considerable expertise in the exploration, exploitation and development of properties in the Sacramento Basin, where we have operated since 1996 and are currently one of the largest producers. We believe that our experience, expertise and substantial presence in the basin will allow us to take advantage of attractive acquisition, exploration, exploitation and development opportunities there. In addition, we believe that the basin's proximity to northern California natural gas markets, its substantial gathering infrastructure and pipeline capacity and the relatively small differential to NYMEX prices received for natural gas produced there contribute to the value of our position.

Extensive knowledge of the Monterey shale formation. A substantial portion of our production consists of offshore production from an unconventional reservoir, the fractured Monterey shale formation in California. Our technical team has extensive offshore experience with the evaluation and exploitation of this reservoir. We believe that there are significant exploration, exploitation and development opportunities relating to the Monterey formation onshore as well, and that our offshore expertise will help us take advantage of those opportunities.

Experienced, proven management and operations team. The members of our management team have an average of over 25 years of experience in the oil and natural gas industry. Prior to founding our company in 1992, our CEO, Timothy Marquez, worked for Unocal for 13 years in both engineering and managerial positions. Our operations team has significant experience in the California and Texas oil and natural gas industry across a broad range of disciplines, including geology, drilling and operations, and regulatory and environmental matters. Our team includes 48 engineers and geoscientists as of December 31, 2007. We believe that our experience and knowledge of the California oil and natural gas industry, including the unconventional Monterey reservoir, are important competitive advantages for us.

High percentage of operated properties. We have operating control of substantially all of our properties, operating approximately 95% of our production in the fourth quarter of 2007. Maintaining control of our properties allows us to use our technical and operational expertise to manage overhead, production and drilling costs and capital expenditures and to control the timing of exploration, exploitation and development activities.

Reputation for environmental, safety and regulatory compliance. We believe that we have established a reputation among regulators and other oil and natural gas companies as having a commitment to safe environmental practices. For example, the state of California has presented us with awards for outstanding lease maintenance at our Beverly Hills and Santa Clara Avenue fields. We believe that our reputation is an important advantage for us when we are competing to acquire properties, particularly those in environmentally sensitive areas, because sellers are often concerned that they could be held responsible for environmental problems caused by the purchaser.

Good relationships with local communities. We have devoted substantial effort towards establishing and maintaining good relationships with the communities in which we operate, and have won several awards for our community service and outreach programs. We believe that maintaining strong community ties can, among other things, help to facilitate the process of obtaining the governmental approvals needed to expand our operations.

Our Strategy

We intend to continue to use our competitive strengths to advance our corporate strategy. The following are key elements of that strategy:

Grow through relatively low-risk exploration, exploitation and development projects. We operate properties with substantial volumes of remaining hydrocarbons. We believe that we can expand reserves and increase production from these properties on a cost-effective basis with relatively limited risk. We expect that our exploration, exploitation and development capital expenditures in 2008 will be approximately $235.0 million.

Make opportunistic acquisitions of underdeveloped properties. We pursue acquisitions that we believe will expand our reserves and production on a cost-effective basis. Our primary focus is on operated interests in large, mature fields that are located in our core operating regions and have significant production histories, established proved reserves and potential for further exploitation and development. Historically, we have had success acquiring offshore California properties from major oil companies, including Chevron and ExxonMobil. We believe that we have established a strong reputation as a reliable and safe operator and that this will lead to future opportunities to acquire properties from major oil companies. In addition, many large properties in California are held by smaller independent companies that lack the resources to exploit them fully. We intend to pursue these opportunities to selectively expand our portfolio of properties.

Actively grow in the Sacramento Basin. We intend to continue to pursue an active drilling and acreage acquisition program in the Sacramento Basin. In 2007, our net production in the basin was 2,708 MBOE, up 38% from our net production there in 2006. We expect to continue our growth in this area, which we believe has significant exploration, exploitation and development opportunities. As one of the largest operators in the basin, we believe that we are well positioned to identify and exploit these opportunities. In particular, as discussed above, we have initiated a hydraulic fracturing program targeting the Forbes and deeper formations, a program that could result in significant reserve and production growth in the basin.

Exploration and exploitation of unconventional reservoirs. We plan to use the expertise we have developed with the fractured Monterey shale formation and other complex, unconventional reservoirs in our acquisition, exploration, exploitation and development of properties with similar characteristics. As of December 31, 2007, we controlled approximately 50,000 net acres with proven, probable and possible Monterey reserves and are actively seeking additional acreage.

Continue to focus on the California market. Historically, we have focused primarily on properties onshore and offshore California. We believe the California market will continue to provide us with attractive growth opportunities. Many properties in California are characterized by significant hydrocarbons in place with multiple pay zones and long reserve lives—characteristics that our technical expertise makes us well-suited to exploit. In addition, competition for the acquisition of properties in California is limited relative to many other markets because of the state's unique operational and regulatory environment. We believe that our technical capabilities, environmental record and experience with California regulatory requirements will allow us to grow in the California market.

Reduce per-unit production expenses. We expect our production expenses to decrease on a per BOE basis for 2008 as a whole as a result of production volume increases in the Sacramento Basin, the West Montalvo and Manvel fields and the Hastings complex, and a reduction in activity at the Hastings complex. We continue to focus on our operating cost structure in order to improve production and processing efficiencies and reduce operational downtime.

Maintain financial flexibility. We believe that maintaining both financial flexibility and a disciplined capital expenditure program are integral to the successful execution of our business strategy. Our cash flow from operations is supported by the hedges we have in place from 2008 through 2011. Using primarily purchased floors and collars, we maintain a balanced oil and natural gas derivative position intended to limit downside price risk. We will continue to pursue our hedging strategy in order to protect our ability to execute our capital expenditure plan. See "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our derivative/hedging activity.

Description of Properties

The following table summarizes our proved reserves by area and related information as of December 31, 2007, as derived from a reserve report prepared by DeGolyer & MacNaughton.

	Proved Reserves (MMBOE)	% of Total Reserves	% Oil	PV-10 Value ($MM)	% of Total PV-10
Coastal California					
South Ellwood	22.9	22.9	91.0	592.0	25.1
Santa Clara Federal Unit	12.3	12.3	93.8	419.8	17.8
West Montalvo	6.9	6.9	92.7	207.3	8.8
Dos Cuadras	3.0	3.0	83.4	81.6	3.5
Onshore	2.5	2.5	95.1	74.0	3.1
Sacramento Basin					
Greater Grimes	20.7	20.7	—	267.4	11.3
Willows	3.8	3.8	—	63.1	2.7
Other	3.2	3.3	0.6	53.9	2.3
Texas					
Hastings Complex	14.4	14.4	100.0	310.9	13.2
Constitution	1.6	1.6	44.4	67.8	2.9
Manvel	3.8	3.8	99.3	121.3	5.1
Other	4.8	4.8	33.1	100.2	4.2
Total	99.9	100.0	64.2	2,359.3	100.0

Coastal California

South Ellwood Field. The South Ellwood field is located in state waters approximately two miles offshore California in the Santa Barbara channel. We conduct our operations in the field from platform Holly and own related onshore processing facilities. We acquired our interest in the field from Mobil Oil Corporation in 1997. Since that time, we have made numerous operational enhancements to the field, including redrills, sidetracks and reworks of existing wells and upgrades at the platform and the onshore treatment facility. We operate the field and have a 100% working interest.

The South Ellwood field is approximately seven miles long and is part of a regional east-west trend of similar geologic structures running along the northern flank of the Santa Barbara channel and extending to the Ventura basin. This trend encompasses several fields that, over their respective lifetimes, are each expected to produce over 100 million barrels of oil, according to the California Division of Oil, Gas, and Geothermal Resources. The Monterey formation is the primary oil reservoir in the field, producing sour oil with a gravity of approximately 21 degrees. As of December 31, 2007, there were 18 producing wells and three injection wells in the field. During the fourth quarter of 2007, average net production at the field was 2,587 Bbl/d of oil and 1,351 Mcf/d of natural gas.

We are currently pursuing the permits necessary for a full-field development project at South Ellwood, including an extension of the current field area. The project is expected to include new wells to be drilled to the proposed lease extension area, the installation of a crude oil pipeline and workovers and redrills within the existing lease area. All drilling activities would be conducted from the existing platform. We expect to receive a draft of the environmental impact report relating to the project in the first half of 2008 and, subject to the receipt of final approvals, to commence work in 2009.

Our processing and transportation facilities at South Ellwood include a common carrier pipeline, an onshore facility, a pier and a marine terminal. We conduct two-phase separation on the drilling platform and the oil/water emulsion is transported by pipeline to the onshore facility for further separation. The oil is then transported to the marine terminal via the common carrier pipeline. From the marine terminal, the oil is transported by barge. Title to the oil is transferred when the barge completes delivery. At this time, the barge is the only means available to us for delivery of oil produced from the field. The barge is owned and operated by a third party with whom we have a long-term service contract. We sell oil production from the field to the operator of a refinery in Long Beach, California pursuant to a contract that provides for a price based on a fixed differential to the NYMEX price for light sweet crude. Pursuant to the agreement, we expect to have access to an alternate barge to make deliveries of oil production from the field when the barge we currently use is out of service and are currently in the process of obtaining the consents and approvals required prior to our use of the alternate barge. Natural gas produced at the field is transported by common carrier pipeline.

Santa Clara Federal Unit. The Santa Clara Federal Unit is located approximately ten miles offshore in the Santa Barbara channel near Oxnard, California. Our operations in the unit are conducted from two platforms, platform Gail in the Sockeye field and platform Grace in the Santa Clara field. We acquired our interest in the unit and the associated facilities from Chevron in February 1999. Production is transported via pipeline to Los Angeles, California. We operate the unit and have a 100% working interest.

The Sockeye field structure is a northwest/southeast trending anticline bounded to the north and south by fault systems. The field produces from multiple stacked reservoirs ranging from the Monterey, at about 4,000 feet, to the Upper Juncal at approximately 12,000 feet. Other formations include the Upper Topanga, Lower Topanga and Sespe. As of December 31, 2007, there were 17 producing wells and eight injection wells in the field. The oil produced from the Monterey and Upper Topanga is sour with gravities ranging from 12 to 18 degrees. The Lower Topanga and Sespe horizons produce sweet crude with gravities of 26 to 30 degrees. During the fourth quarter of 2007, average net production at the field was 3,561 Bbl/d of oil.

Chevron shut in production at platform Grace in 1997, and we currently use it as a launching and receiving facility for pipeline cleaning devices and as an interconnecting pipeline to transport oil and natural gas produced from platform Gail to our onshore plant. In 2007, we pursued a program to return platform Grace to production but had limited success with the three wells we redrilled there. We have currently suspended drilling on the platform pending further geologic and engineering review.

A third party has an option to purchase or lease platform Grace for use as a liquid natural gas, or LNG, terminal. The option became exercisable on January 1, 2008 and will expire on March 1, 2012. If the option is exercised, we will cease any exploration, exploitation and development activities then conducted from the platform and the option holder will commence construction of its LNG facility. The option holder's right to exercise the option is subject to, among other things, its receipt of certain regulatory approvals relating to the construction and operation of its LNG facility and the satisfaction of certain financial requirements. If the option is exercised, the option holder will pay us an annual fee during the period in which the LNG facility is being constructed. This annual fee will initially be $6.0 million, and will increase over time to a potential maximum of $10.0 million. Following the commencement of operations at the facility, the option holder will pay us an annual fee based on the amount of LNG processed, produced or stored at the facility. The fee will be equal to approximately $12.0 million for the first 800,000 MMBtu/d and $0.04 per MMBtu for volumes in excess of 800,000 MMBtu/d on an average annual basis.

West Montalvo. We acquired the West Montalvo field in Ventura County, California in May 2007. We operate the field and have a 100% working interest. The field, which includes an offshore portion that is reachable from onshore locations, produces from the Sespe formation. As of December 31, 2007, there were 27 producing wells in the field. During the fourth quarter of 2007, average net production at the field was 649 Bbl/d of oil and 342 Mcf/d of natural gas. Since acquiring the field, our activities have focused on returning idle wells to production, working over and recompleting existing wells, and upgrading well lift systems and processing facilities. We believe this field provides us with significant development opportunities. During 2008, we anticipate drilling two to three development wells and continuing the field reactivation program. We also expect to commission a seismic survey for the field that will assist us in designing and optimizing what we anticipate may be a significant infill development drilling program.

Dos Cuadras Field. The Dos Cuadras field is located in federal waters approximately five miles offshore California in the Santa Barbara channel. We acquired our 25% non-operated working interest in the western two-thirds of the field from Chevron in February 1999. We have working interests ranging from approximately 17.5% to 25% in the associated onshore facility and pipelines. The field is operated by an unaffiliated third party. Production is transported via pipeline to Los Angeles, California. As of December 31, 2007, there were 97 producing wells and 16 injection wells in the field. During the fourth quarter of 2007, average net production at the field was 591 Bbl/d of oil and 694 Mcf/d of natural gas.

Onshore Coastal California. Our onshore properties in the coastal California region include the Beverly Hills West field, the Santa Clara Avenue field and the Cat Canyon field. The Beverly Hills West field is located in Beverly Hills, California. All drilling and production operations at the field are conducted from a 0.6 acre surface location adjacent to the campus of Beverly Hills high school. We acquired our interest in the field in 1995. We operate the field and have a 100% working interest. The Santa Clara Avenue field is located in Ventura County, California. We acquired our interest in this field in 1994 and 1996. We operate the field and have working interests ranging from 43% to 100%. The Cat Canyon field, which we acquired in December 2007, is located in Santa Barbara County, California. We operate the field and have a 100% working interest. During the fourth quarter of 2007, aggregate average net production from our onshore coastal California properties was 430 Bbl/d of oil and 338 Mcf/d of natural gas.

Sacramento Basin

In terms of historical production, the Sacramento Basin is one of California's most prolific onshore natural gas producing areas not associated with oil production. It is approximately 210 miles long and 60 miles wide and contains a variety of different geologic plays. We own 3D seismic data covering approximately 1,000 square miles in the basin, and 2D seismic data covering approximately 20,000 line miles. We continue to analyze this data to identify additional exploration, exploitation and development opportunities on our properties. We believe this data will also help us assess acquisition opportunities in the basin.

Willows and Greater Grimes Fields. The Willows and Greater Grimes fields are located in Colusa, Glenn and Sutter Counties north of Sacramento, California. Our combined lease position in these fields was approximately 142,000 net acres as of December 31, 2007. We operate substantially all of the fields and have a volume-weighted average working interest of 71.0% (based on production during the fourth quarter of 2007).

Natural gas production in the Greater Grimes field is from the Forbes, Kione and Guinda formations and production in the Willows field is from the Forbes and Kione formations. Depths range from 2,800 feet in the Willows field to 8,900 feet in the Greater Grimes field. There were 368 producing wells in the fields as of December 31, 2007. We have been engaged in an aggressive drilling program in these fields for the past two years. During 2007, we spudded 114 wells in these fields and completed 88 productive wells. We also completed 111 workovers and recompletions. This activity led to a 17.8% increase in production from the fields in the fourth quarter of 2007 relative to the same period in 2006. During the fourth quarter of 2007, average net production at the Willows and Greater Grimes fields was 41,882 Mcf/d of natural gas. We have identified 494 drilling locations in these fields as of December 31, 2007, of which 239 are classified as proved. In 2007, we initiated a hydraulic fracturing program in the fields targeting the Forbes and deeper formations. We tested the fracturing process on three wells in 2007, and intend to pursue the program on a larger scale in 2008.

Other Sacramento Basin. We own interests in a number of other fields in Solano, Contra Costa, San Joaquin and Colusa Counties. We operate substantially all of these fields and have a volume-weighted average working interest of 62.0% (based on production during the fourth quarter of 2007). As of December 31, 2007, there were a total of 42 producing wells in these fields. We believe that the fields will provide us with exploration, exploitation and development opportunities that are similar to those found in the Willows and Greater Grimes fields. Total average net production from these fields was approximately 9 Bbl/d of oil and 5,446 Mcf/d of natural gas during the fourth quarter of 2007.

Texas

Hastings Complex. Our largest property in Texas is the Hastings complex, which encompasses approximately 4,600 net acres located 30 miles south of Houston in Brazoria County. The Hastings complex is comprised of the West Hastings Unit, the East Hastings field and the Hastings field. We have an 89% working interest in the West Hastings Unit and 100% working interests in the East Hastings and Hastings fields. We operate the entire complex.

The Hastings complex produces light, sweet crude oil with a gravity of approximately 30 degrees and is characterized by long-life, stable production. The fields in the complex produce from multiple Miocene and Frio reservoirs at depths ranging from 2,000 to 6,100 feet. As of December 31, 2007, there were 131 producing wells in the complex. Average net production from the complex was 2,517 Bbl/d of oil and 32 Mcf/d of natural gas during the fourth quarter of 2007. In 2007, we continued our aggressive field reactivation program in the complex by returning idle wells to production, increasing the lift capacity of existing wells using larger, more efficient pumps, working over and recompleting existing wells in different producing sands, significantly upgrading surface facility fluid handling capacity and increasing water injection capabilities. In 2008, we plan to focus our efforts on additional workovers and recompletions in order to further increase production and reserves.

In November 2006, we entered into an option agreement with a subsidiary of Denbury Resources Inc. relating to a potential CO_2 enhanced recovery project in the Hastings complex. Pursuant to the agreement, Denbury will pay us a non-refundable fee of $50.0 million ($45.0 million of which has been received) for an option to acquire our interest in the West Hastings Unit, the East Hastings field and certain related property for use in an enhanced recovery project in which we will have a continuing interest. Denbury may not exercise the option until September 2008. The initial exercise period will end in October 2009, subject to Denbury's right to extend it for successive one-year periods until 2016 for an annual extension fee of $30.0 million.

Following the exercise of the option, Denbury will either purchase the properties subject to the option or, if we so elect, enter into a volumetric production payment or similar arrangement with us with respect to the properties. The purchase price or volumetric production payment will be based on the value of the properties as determined with reference to the net proved reserves associated with the properties based on then-existing operations and NYMEX forward strip pricing, subject to certain adjustments. The $50.0 million option payment will not be deducted from the purchase price or payment amount. Contemporaneously with its exercise of the option, Denbury will commit to a development plan for the properties that will call for it to make capital expenditures of at least $178.7 million over five years. As part of the plan, Denbury will be responsible for providing the necessary CO_2. Following the exercise of the option, we will retain an overriding royalty interest of 2.0% in production from the properties. We will also have the right to back in to a working interest of approximately 22.3% in the CO_2 project after Denbury recoups (i) its operating costs relating to the project and a portion of the purchase price and (ii) 130% of its capital expenditures made on the project. Denbury will either resell the properties to us at a discount or make additional payments to us if recovery operations do not meet certain development milestones by the third anniversary of the date the option exercise is given effect. During the term of the option, we will not enter into or amend any agreement in a manner that would have a material adverse effect on Denbury's rights under the option agreement. Each of us and Denbury will have a right of first refusal with respect to any proposed sale or transfer by the other of its interests under the option agreement. The option agreement also establishes an area of mutual interest with respect to us and Denbury in specified areas adjacent to the properties. We will continue our operations on the properties until the option is exercised. We cannot assure you that Denbury will exercise the option or that any CO_2 enhanced recovery project will be pursued. The success of any CO_2 enhanced recovery project that may be pursued will be subject to numerous risks and uncertainties, including those relating to the geologic suitability of the properties for such a project and the availability of an economic and reliable supply of CO_2.

Manvel. We acquired the Manvel field in Brazoria County, Texas, and certain related properties, in April 2007. We operate the field and have a 100% working interest. The field produces from the Frio sands. As of December 31, 2007, there were 35 producing wells in the field. During the fourth quarter of 2007, average net production at the field was 548 Bbl/d of oil and 193 Mcf/d of natural gas. We believe that the field provides us with exploitation and development opportunities that are similar to those in the Hastings complex, which is nearby and geologically similar.

Constitution Field. The Constitution field is located in Jefferson County, Texas. We operate part of the field and have working interests ranging from 25% to 100%. The field produces oil with a gravity of 47.8 degrees and natural gas from the Yegua reservoir at depths ranging from 13,500 feet to 15,300 feet. As of December 31, 2007, there were three producing wells in the field. During the fourth quarter of 2007, average net production from the field was approximately 17 Bbl/d of oil and 74 Mcf/d of natural gas. In 2008, we plan to drill at least one development well in this field.

Other. Our other Texas properties encompass approximately 17,700 net acres in the southern Gulf Coast region. We operate substantially all of our production in these fields and have a volume-weighted average working interest of 75.6% (based on production during the fourth quarter of 2007). As of December 31, 2007, there were a total of 58 producing wells in these fields. Total average net production from the fields in the fourth quarter of 2007 was 189 Bbl/d of oil and 3,713 Mcf/d of natural gas. In 2007, we drilled four productive development wells in these fields (two in our AWP field, one in our Barbers Hill field and one in our Giddings field).

Oil and Natural Gas Reserves

The following table sets forth our net proved reserves as of the dates indicated. Our reserve estimates as of December 31, 2005 are based on a reserve report prepared by Netherland, Sewell & Associates, Inc., or NSAI, our reserve estimates as of December 31, 2006 are based on reserve reports prepared by NSAI and DeGolyer & MacNaughton, and our reserve estimates as of December 31, 2007 are based on a reserve report prepared by DeGolyer & MacNaughton. Proved reserves as of each date indicated reflect all acquisitions and dispositions completed as of that date. The reserve estimates were based upon the review by the relevant engineering firm(s) of production histories and other geological, economic, ownership and engineering data.

	December 31,		
	2005	2006	2007
Net proved reserves (end of period)			
Oil (MBbl)			
Developed	24,154	37,497	44,730
Undeveloped	11,146	12,110	19,446
Total	35,300	49,607	64,176
Natural gas (MMcf)			
Developed	53,390	79,796	96,522
Undeveloped	20,663	150,156	118,083
Total	74,053	229,952	214,605
Total proved reserves (MBOE)	47,642	87,932	99,944

As of December 31, 2007, our proved reserves totaled 99.9 MMBOE (61% proved developed), comprised of 64,176 MBbl of oil (64% of the total) and 214,605 MMcf of natural gas, and our estimated proved reserves to production ratio was 13.6 years. See "Glossary of Technical Terms" for an explanation of the terms "proved reserves," "proved developed reserves," "proved undeveloped reserves" and related terms. You should not place undue reliance on estimates of proved reserves. See "Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves." We have not filed any estimates of our total net proved oil or natural gas reserves with any federal authority or agency other than the Securities and Exchange Commission, or SEC, since January 1, 2007.

Production, Prices and Costs

The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and natural gas for the periods indicated. We urge you to read this information in conjunction with the information contained in our financial statements and related notes included elsewhere in this report. The information set forth below is not necessarily indicative of future results.

	Years ended December 31,		
	2005	2006(1)	2007
Production Volume			
Oil (MBbls)	2,953	3,411	3,981
Natural gas (MMcf)	7,588	14,314	18,895
MBOE	4,218	5,797	7,130
Daily Average Production Volume			
Oil (Bbls/d)	8,090	9,958	10,907
Natural gas (Mcf/d)	20,789	44,346	51,767
BOE/d	11,555	17,349	19,535
Oil Price per Bbl Produced (in dollars)			
Realized price	$45.66	$55.92	$64.06
Realized commodity derivative loss and amortization of commodity derivative premiums	(7.46)	(8.38)	(4.35)
Net realized price	$38.20	$47.54	$59.71
Natural Gas Price per Mcf Produced (in dollars)			
Realized price	$ 7.45	$ 6.04	$ 6.61
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	(0.11)	0.36	0.23
Net realized price	$ 7.34	$ 6.40	$ 6.84
Average Sale Price per BOE(2)	$39.55	$44.13	$50.24
Expense per BOE			
Production expenses(3)	$12.81	$15.09	$16.74
Transportation expenses	$ 0.62	$ 0.61	$ 0.85
Depletion, depreciation and amortization	$ 5.14	$10.91	$13.86
General and administrative expense, net(4)	$ 3.79	$ 4.88	$ 4.46
Interest expense	$ 3.24	$ 8.52	$ 8.43

(1) Includes information for TexCal Energy (LP) LLC ("TexCal") from March 31, 2006, the date of acquisition. Daily average production volumes shown represent (i) second, third and fourth quarter 2006 production from TexCal properties divided by 275 days plus (ii) production from other Venoco properties for the full year 2006 divided by 365 days. Total net production for 2006 divided by 365 days results in average net production of 15,882 BOE/d.

(2) Amounts shown are based on oil and natural gas sales, net of inventory changes, realized commodity derivative gains (losses), and amortization of commodity derivative premiums, divided by sales volumes.

(3) Production expenses are comprised of oil and natural gas production expenses and property and production taxes.

(4) Net of amounts capitalized.

Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2005 through December 31, 2007. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross wells.

	Development Wells Drilled		
	2005	2006	2007
Producing			
Gross	16.0	17.0	45.0
Net	7.9	12.4	41.0
Dry			
Gross	1.0	1.0	9.0
Net	0.2	0.7	6.8

	Exploration Wells Drilled		
	2005	2006	2007
Producing			
Gross	3.0	42.0	67.0
Net	1.9	31.5	60.6
Dry			
Gross	5.0	10.0	15.0
Net	3.2	8.2	12.0

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered. Of the gross producing exploration wells drilled in 2007, 60 were drilled in the Sacramento Basin (including two wells we consider higher impact exploration wells). See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Capital Expenditures."

Oil and Natural Gas Wells

The following table details our working interests in producing wells as of December 31, 2007. A well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion.

	Gross Producing Wells	Net Producing Wells	Average Working Interest
Oil	407	316	77.6%
Natural gas	438	311	71.0%
Total(1)	845	627	74.2%

(1) Amounts shown include 17 oil wells and seven natural gas wells with multiple completions.

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2007. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

Area	Developed		Undeveloped(1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Coastal California						
South Ellwood	1,543	1,543	6,174	6,174	7,717	7,717
Santa Clara Federal Unit	36,000	27,360	—	—	36,000	27,360
Dos Cuadras	5,875	1,460	—	—	5,875	1,460
West Montalvo	540	540	5,110	5,110	5,650	5,650
Paredon(2)	—	—	4,111	4,095	4,111	4,095
Onshore	5,542	4,627	32,285	14,035	37,827	18,662
Total Coastal California	49,500	35,530	47,680	29,414	97,180	64,944
Sacramento Basin	136,162	116,137	101,878	77,130	238,040	193,267
Texas	31,081	19,881	10,720	5,404	41,801	25,285
Other	—	—	36,770	36,450	36,770	36,450
Total	216,743	171,548	197,048	148,398	413,791	319,946

(1) The percentage of undeveloped acreage held under leases due to expire in 2008, 2009 and 2010 unless production commences is approximately 5%, 6% and 9%, respectively.

(2) Paredon is a non-producing prospect and there are no proved reserves associated with the property.

Operating Hazards and Insurance

The oil and natural gas business involves numerous operating risks, such as those described under "Risk Factors—Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy." In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and other environmental risks are generally not fully insurable. If a significant accident or similar event occurs and is not fully covered by insurance, it would adversely affect us.

Title to Properties

We believe that we have satisfactory title to all of our material assets. Title to our properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. However, we believe that none of these liens, restrictions, easements, burdens and encumbrances materially detract from the value of our properties or from our interest in those properties or materially interfere with our use of those properties, in each case in the operation of our business as currently conducted. We believe that we have obtained sufficient right-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this report. As is customary in the oil and natural gas industry, we typically make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations.

Our credit facilities and the indenture governing our senior notes, which we refer to collectively as our debt agreements, are secured by liens on substantially all of our oil and natural gas properties and other assets. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements."

Marketing and Major Customers

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is sold to competing buyers, including large oil refining companies and independent marketers. In the year ended December 31, 2007, approximately 88% of our revenues were generated from sales to four purchasers: Enserco Energy (30%), ConocoPhillips (29%), Gulfmark Energy (17%) and Tesoro Refining and Marketing Company (12%). Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. Our competitors include Plains Exploration & Production Company, Berry Petroleum Company and Breitburn Energy Partners L.P. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop our properties. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Offices

We currently lease approximately 39,100 net square feet of office space in Denver, Colorado, where our principal office is located. The lease for the Denver office expires in 2014. We lease an additional 30,000 net square feet of office space in Carpinteria, California from 6267 Carpinteria Avenue, LLC. The lease for the Carpinteria office will expire in 2019. 6267 Carpinteria Avenue, LLC was a wholly owned subsidiary of ours prior to March 2006, when we paid a dividend consisting of 100% of the membership interests in 6267 Carpinteria Avenue, LLC to our then-sole stockholder. The lease has remained in effect following the payment of the dividend. We also lease approximately 28,500 square feet of office space in Houston, Texas, where we maintain a regional office. We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

Employees

As of December 31, 2007, we had approximately 313 full-time employees, none of whom were party to collective bargaining arrangements.

Regulatory Environment

Our oil and natural gas exploration, production and transportation activities are subject to extensive regulation at the federal, state and local levels. These regulations relate to, among other things, environmental and land-use matters, conservation, safety, pipeline use, drilling and spacing of wells, well stimulation, transportation, and forced pooling and protection of correlative rights among interest owners. The following is a summary of some key regulations that affect our operations.

Environmental and Land Use Regulation

A wide variety of environmental and land use regulations apply to companies engaged in the production and sale of oil and natural gas. These regulations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect.

California Environmental Quality Act ("CEQA"). CEQA is California legislation that requires consideration of the environmental impacts of proposed actions that may have a significant effect on the environment. CEQA requires the responsible governmental agency to prepare an environmental impact report that is made available for public comment. The responsible agency also is required to consider mitigation measures. The party requesting agency action bears the expense of the report.

We currently are in the CEQA process in connection with, among other things, our requested renewal of the state lease for the marine terminal at the South Ellwood field and our proposed full-field development project at the field. A public draft of the environmental impact report relating to the request has been issued and the issuance of a final report is pending.

We may be required to undergo the CEQA process for other lease renewals and other proposed actions by state and local governmental authorities that meet specified criteria. At a minimum, the CEQA process delays and adds expense to the process of obtaining new leases, permits and lease renewals.

Discharges to Waters. The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), and comparable state statutes impose restrictions and controls on the discharge of produced waters and other oil and natural gas wastes into regulated waters and wetlands. These controls generally have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. These laws prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and other substances related to the oil and natural gas industry into onshore, coastal and offshore waters without appropriate permits. Violation of the Clean Water Act and similar state regulatory programs can result in civil, criminal and administrative penalties for unauthorized discharges of oil, hazardous substances and other pollutants. They also can impose substantial liability for the costs of removal or remediation associated with discharges of oil or hazardous substances.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction activities, and requires separate permits and implementation of a Stormwater Pollution Prevention Plan ("SWPPP") establishing best management practices, training, and periodic monitoring of covered activities. Certain operations also are required to develop and implement Spill Prevention, Control, and Countermeasure ("SPCC") plans or facility response plans to address potential oil spills. Certain exemptions from some Clean Water Act requirements have been created or broadened pursuant to the Energy Policy Act of 2005.

Oil Spill Regulation. The Oil Pollution Act of 1990, as amended ("OPA"), amends and augments the Clean Water Act as it relates to oil spills. It imposes potentially unlimited liability on responsible parties without regard to fault for the costs of cleanup and other damages resulting from an oil spill in federal waters. Responsible parties include (i) owners and operators of onshore facilities and pipelines and (ii) lessees or permittees of offshore facilities. In addition, OPA requires parties responsible for offshore facilities to provide financial assurance in the amount of $35.0 million, which can be increased to $150.0 million in some circumstances, to cover potential OPA liabilities.

Regulations imposed by the Minerals Management Service ("MMS") also require oil-spill response plans and oil-spill financial assurance from offshore oil and natural gas operations, whether operating in state or federal offshore waters. These regulations were designed to be consistent with OPA and other similar requirements. Under MMS regulations, operators must join a cooperative that makes oil-spill response equipment available to its members. The California Department of Fish and Game's Office of Oil Spill Prevention and Response ("OSPR") has adopted oil-spill prevention regulations that overlap with federal regulations. We have complied with these OPA, MMS and OSPR requirements by adopting an offshore oil spill contingency plan and becoming a member of Clean Seas, LLC, a cooperative entity operated with other offshore operators to prevent and respond to oil spills in the offshore region in which we operate.

Air Emissions. Our operations are subject to local, state and federal regulations governing emissions of air pollutants. Local air-quality districts are responsible for much of the regulation of air-pollutant sources in California. California requires new and modified stationary sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally-based permitting requirements. Because of the severity of ozone levels in portions of California, the state has the most severe restrictions on emissions of volatile organic compounds ("VOCs") and nitrogen oxides ("NOX") of any state. Producing wells, natural gas plants and electric generating facilities all generate VOCs and NOX. Some of our producing wells are in counties that are designated as non-attainment for ozone and, therefore, potentially are subject to restrictive emission limitations and permitting requirements. California also operates a stringent program to control hazardous (toxic) air pollutants, and this program could require the installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits generally are resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air-emission sources. Air emissions from oil and natural gas operations also are regulated by oil and natural gas permitting agencies, including the MMS, the State Lands Commission and other local agencies.

Waste Disposal. We currently own or lease a number of properties that have been used for production of oil and natural gas for many years. Although we believe the prior owners and/or operators of those properties generally utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we currently own or lease. State and federal laws applicable to oil and natural gas wastes have become more stringent. Under new laws, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial well-plugging operations to prevent future, or mitigate existing, contamination.

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes, although certain oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. The federal Environmental Protection Agency (the "EPA") has limited the disposal options for certain wastes that are designated as hazardous wastes under RCRA. Furthermore, it is possible that certain wastes generated by our oil and natural gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly management, disposal and clean-up requirements. State and federal oil and natural gas regulations also provide guidelines for the storage and disposal of solid wastes resulting from the production of oil and natural gas, both onshore and offshore.

Superfund. Under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, also known as CERCLA or the Superfund law, and similar state laws, responsibility for the entire cost of cleanup of a contaminated site, as well as natural resource damages, can be imposed upon current or former site owners or operators, or upon any party who released one or more designated "hazardous substances" at the site, regardless of the lawfulness of the original activities that led to the contamination. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek to recover from the potentially responsible parties the costs of such action. Although CERCLA generally exempts petroleum from the definition of hazardous substances, in the course of our operations we may have generated and may generate wastes that fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of facilities at which hazardous substances have been released by previous owners or operators. We may be responsible under CERCLA for all or part of the costs of cleaning up facilities at which such substances have been released and for natural resource damages. We have not, to our knowledge, been identified as a potentially responsible party under CERCLA, nor are we aware of any prior owners or operators of our properties that have been so identified with respect to their ownership or operation of those properties.

Abandonment, Decommissioning and Remediation Requirements. Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production and transportation facilities and the environmental restoration of operations sites. MMS regulations, coupled with applicable lease and permit requirements and each property's specific development and production plan, prescribe the requirements for decommissioning our federally leased offshore facilities. The California State Lands Commission ("CSLC"), and the California Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") are the principal state agencies responsible for regulating the drilling, operation, maintenance and abandonment of all oil and natural gas wells in the state, whether onshore or offshore. MMS regulations require federal leaseholders to post performance bonds. See "—Potentially Material Costs Associated with Environmental Regulation of Our Oil and Natural Gas Operations—Plugging and Abandonment Costs" for a discussion of our principal obligations relating to the abandonment and decommissioning of our facilities.

California Coastal Act. The California Coastal Act regulates the conservation and development of California's coastal resources. The California Coastal Commission (the "Coastal Commission") works with local governments to make permit decisions for new developments in certain coastal areas and reviews local coastal programs, such as land-use restrictions. The Coastal Commission also works with the OSPR to protect against and respond to coastal oil spills. The Coastal Commission has direct regulatory authority over offshore oil and natural gas development within the state's three mile jurisdiction and has authority, through the Federal Coastal Zone Management Act, over federally permitted projects that affect the state's coastal zone resources. We conduct activities that may be subject to the California Coastal Act and the jurisdiction of the Coastal Commission.

Other Environmental Regulation. Our leases in federal waters on the Outer Continental Shelf are administered by the MMS and require compliance with detailed MMS regulations and orders. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Our offshore leases in state waters or "tidelands" (within three miles of the coastline) are administered by the state of California and require compliance with certain regulations of the CLSC and DOGGR. The CSLC serves as the lessor of our state offshore leases and is charged with overseeing leasing, exploration, development and environmental protection of the state tidelands.

Commencing with the Cunningham Shell Act of 1955, California has enacted several pieces of legislation that withhold state tidelands from oil and natural gas leasing. The Cunningham Shell Act protected an area of tidelands offshore Santa Barbara County that stretches west from Summerland Bay to Coal Oil Point, and included waters offshore the unincorporated area of Montecito, the City of Santa Barbara and the University of California at Santa Barbara. It also protected the state tidelands around the islands of Anacapa, Santa Cruz, Santa Rosa and San Miguel. In 1994, California enacted the California Sanctuary Act which, with three exceptions, prohibits leasing of any state tidelands for oil and natural gas development. Oil and natural gas leases in effect as of January 1, 1995 are unaffected by this legislation until such leases revert back to the state, at which time they will become part of the California Coastal Sanctuary. This legislation does not restrict our existing state offshore leases or our current or planned future operations.

Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. On September 27, 2006, California's governor signed into law the "California Global Warming Solutions Act of 2006" Assembly Bill (AB) 32, which establishes a statewide cap on greenhouse gases ("GHG") that will reduce the state's GHG emissions to 1990 levels by 2020. The California Air Resources Board has been designated as the lead agency to establish and adopt regulations to implement AB 32 by January 1, 2012. We will continue to monitor the establishment of these regulations through industry trade groups and other organizations in which we are a member. Similar regulations may be adopted by other states in which we operate or by the federal government.

Other environmental protection statutes that may impact our operations included the Marine Mammal Protection Act, the Marine Life Protection Act, the Marine Protection, Research, and Sanctuaries Act of 1972, the Endangered Species Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act.

Potentially Material Costs Associated with Environmental Regulation of Our Oil and Natural Gas Operations

Significant potential costs relating to environmental and land-use regulations associated with our existing properties and operations include those relating to (i) plugging and abandonment of facilities, (ii) clean-up costs and damages due to spills or other releases and (iii) penalties imposed for spills, releases or non-compliance with applicable laws and regulations. As is customary in the oil and natural gas industry, we typically have contractually assumed, and may assume in the future, obligations relating to plugging and abandonment, clean-up and other environmental costs in connection with our acquisition of operating interests in fields, and these costs can be significant.

Plugging and Abandonment Costs. Our operations, and in particular our offshore platforms and related facilities, are subject to stringent abandonment and closure requirements imposed by the MMS and the state of California. With respect to the Santa Clara Federal Unit, Chevron retained most of the abandonment obligations relating to the platforms and facilities when it sold the fields to us in 1999. We are responsible for abandonment costs relating to the wells and to any expansions or modifications we made following our acquisition of the fields. We also agreed to assume from Chevron all abandonment obligations associated with its 25% interest in the infrastructure (but not the wells) in the Dos Cuadras field. We agreed to assume all of the abandonment costs relating to the operations, including platform Holly, in the South Ellwood field when we purchased it from Mobil Oil Corporation in 1997.

As described in note 5 to our financial statements, we have estimated the present value of our aggregate asset retirement obligations to be $52.2 million as of December 31, 2007. This figure reflects the expected future costs associated with site reclamation, facilities dismantlement and plugging and abandonment of wells. The discount rates used to calculate the present value varied depending on the estimated timing of the obligation, but typically ranged between 6% and 8%. Actual costs may exceed our estimates. Our financial statements do not reflect any reserves relating to other environmental obligations.

Under a variety of applicable laws and regulations, including CERCLA, RCRA and MMS regulations, we could in some circumstances be held responsible for abandonment and clean-up costs relating to our operations, both onshore and offshore, notwithstanding contractual arrangements that assign responsibility for those costs to other parties.

Clean-up Costs. We currently have two onshore facilities with known environmental contamination. Our onshore facility at the South Ellwood field is known to have hydrocarbon contamination. We currently are required to provide quarterly monitoring reports to the county. Because oil occurs naturally in the area, regulators have not yet determined the applicable cleanup requirements for this facility. We expect that we will be permitted to defer remedial actions at the facility until we cease operations there, and our present intention is to continue using it for the foreseeable future. We currently estimate that the cost of a clean-up of the facility will be between $2.0 and $5.0 million. This cost is included in the asset retirement obligations shown in our financial statements. For the purpose of calculating the asset retirement obligation, we estimated that the facility has a remaining useful life of 18 years. The onshore oil and natural gas plant associated with the Santa Clara Federal Unit is also known to have hydrocarbon contamination. Chevron is contractually obligated to remediate the contamination that was present at the time we purchased the property upon the closure of that facility. We will be responsible for the clean-up of any additional contamination. To our knowledge, no such additional contamination has occurred. Accordingly, we currently do not expect to incur any remediation costs in connection with this facility.

Penalties for Non-Compliance. We believe that our operations are in material compliance with all applicable oil and natural gas, safety, environmental and land-use laws and regulations. However, from time to time we receive notices of noncompliance with Clean Air Act and other requirements from relevant regulatory agencies. We received a number of minor notices of violation ("NOVs") from regulatory agencies in 2007. We do not expect to incur significant penalties with respect to any outstanding NOV. See "Legal Proceedings."

Other Regulation

The pipelines we use to gather and transport our oil and natural gas are subject to regulation by the U.S. Department of Transportation ("DOT") under the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), and the Pipeline Safety Act of 1992, which relate to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Under the Pipeline Safety Act, the Research and Special Programs Administration of DOT is authorized to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with HLPSA and the Pipeline Safety Act. Nonetheless, significant expenses could be incurred if new or additional safety requirements are implemented.

The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act and the Natural Gas Policy Act. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis.

The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines also are regulated by FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title VIII of the Energy Policy Act of 1992, comprised of an indexing system to establish ceilings on interstate oil pipeline rates. FERC has announced several important transportation related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. With respect to transportation of natural gas on the Outer Continental Shelf, FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers.

The safety of our operations primarily is regulated by the MMS, the CSLC, the Coast Guard and the Occupational Safety and Health Administration. We believe our facilities and operations are in substantial compliance with the applicable requirements of those agencies. In the event different or additional safety measures are required in the future, we could incur significant expenses to meet those requirements.

Executive Officers of the Registrant

The following table sets forth certain information with respect to our executive officers as of December 31, 2007.

Name	Age	Position
Timothy Marquez	49	Chairman and Chief Executive Officer
William Schneider	46	President
Timothy A. Ficker	40	Chief Financial Officer
Mark DePuy	52	Senior Vice President, Chief Operating Officer
Terry L. Anderson	60	General Counsel and Secretary
Douglas J. Griggs	48	Chief Accounting Officer

Timothy Marquez co-founded Venoco in September 1992 and served as our CEO from our formation until June 2002. He founded Marquez Energy in 2002 and served as its CEO until we acquired it in March 2005. Mr. Marquez returned as our Chairman, CEO and President in June 2004. Mr. Marquez has a B.S. in petroleum engineering from the Colorado School of Mines. Mr. Marquez began his career with Unocal Corporation, where he worked for 13 years managing assets offshore California and in the North Sea and performing other managerial and engineering functions.

William Schneider became our President in January 2005. Prior to joining us, Mr. Schneider was a managing director at BMO Capital Markets (formerly known as Harris Nesbitt), an investment bank, where he focused on mergers and acquisitions in the energy industry. He joined BMO Capital Markets in February 2001. From January 1998 to January 2001, he worked in the Energy Investment Banking division of Donaldson, Lufkin & Jenrette. Mr. Schneider's experience also includes service in Smith Barney's Energy Investment Banking division. Before entering investment banking, Mr. Schneider held a variety of engineering and corporate positions at Unocal for over 12 years. Mr. Schneider holds an M.B.A. in Finance from U.C.L.A. and a B.S. in petroleum engineering from the Colorado School of Mines.

Timothy A. Ficker became our CFO in April 2007. Prior to joining us, Mr. Ficker was Vice President, CFO and Secretary of Infinity Energy Resources, Inc., a NASDAQ-listed energy company, having been appointed to those positions in May 2005. From October 2003 through April 2005, Mr. Ficker served as an audit partner in KPMG LLP's Denver office, and from June 2002 through September 2003, he served as an audit director for KPMG LLP. From September 1989 through June 2002, he worked for Arthur Andersen LLP, including as an audit partner after September 2001, where he served clients primarily in the energy industry. Mr. Ficker is a certified public accountant and received a B.B.A. in accounting from Texas A&M University.

Mark DePuy became our Vice President, Northern Assets, in August 2005 and was promoted to Senior Vice President and Chief Operating Officer in January 2006. Prior to joining us, he spent 27 years with Unocal in a variety of domestic and international operating and business planning roles, most recently as a corporate planning manager for worldwide operations. With Unocal, Mr. DePuy spent 13 years working on operations onshore and offshore coastal California. He has an M.B.A. from U.C.L.A. and a B.S. in petroleum engineering from the Colorado School of Mines.

Terry L. Anderson is our General Counsel and Secretary. Mr. Anderson joined us in March 1998 and served as General Counsel until June 2002. From July 2002 to August 2004, Mr. Anderson was in private practice in Santa Barbara, California. He returned in his current capacities in August 2004. Mr. Anderson holds a B.S. in petroleum engineering and a J.D. from the University of Southern California. Mr. Anderson was Vice President and General Counsel of Monterey Resources, Inc., a NYSE-listed company, from August 1996 to January 1998. Prior to that, he was chief transactional attorney for Santa Fe Energy Resources in Houston, Texas. Mr. Anderson is licensed to practice law in Texas and California.

Douglas J. Griggs was appointed as our Chief Accounting Officer in January 2006. Mr. Griggs is a certified public accountant with twenty six years of accounting and financial management experience, including 13 years with Ernst & Young LLP. From January 2003 through December 2005, he was an independent consultant in the areas of finance, accounting and Sarbanes-Oxley compliance. From 1997 to December 2002, he served as CFO for Engineered Data Products, Inc. Mr. Griggs has an accounting degree from the University of Northern Iowa.

Available Information

We maintain a link to investor relations information on our website, *www.venocoinc.com*, where we make available, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, or Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We also make available on our website copies of the charters of the audit, compensation and corporate governance/nominating committees of our board of directors, our code of business conduct and ethics and our corporate governance guidelines. Stockholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Corporate Secretary, Venoco, Inc., 6267 Carpinteria Avenue, Carpinteria, CA 93013-1423. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at *www.sec.gov* that contains the documents we file with the SEC. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included as an inactive textual reference only.

ITEM 1A. Risk Factors

Oil and natural gas prices are volatile and change for reasons that are beyond our control. A decrease in the price we receive for our oil and natural gas production could have a material adverse effect on our business, financial condition and results of operations.

A substantial decline in the prices we receive for our oil and natural gas production would have a material adverse effect on us, as our future financial condition, income, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon those prices. For example, changes in the prices we receive for our oil and natural gas affect our ability to finance capital expenditures, make acquisitions, borrow money and satisfy our financial obligations. In addition, declines in prices could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our proved reserves.

Oil and natural gas are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Prices have historically been volatile and are likely to continue to be volatile in the future. The prices of oil and natural gas are affected by a variety of factors that are beyond our control, including changes in global supply and demand for oil and natural gas, domestic and foreign governmental regulations and taxes, the level of global oil and natural gas exploration activity and inventories, the price, availability and consumer acceptance of alternative fuel sources, the availability of refining capacity, technological advances affecting energy consumption, weather conditions, financial and commercial market uncertainty and worldwide economic conditions.

In addition to factors affecting the price of oil and natural gas generally, the prices we receive for our oil and natural gas production is affected by factors specific to us and to the local markets where the production occurs. Pricing can be influenced by, among other things, local or regional supply and demand factors (such as refinery or pipeline capacity issues, trade restrictions and governmental regulations) and the terms of our sales contracts. For example, the termination in 2006 of the sales arrangement pursuant to which we historically sold oil from the South Ellwood field required us to sell oil on a spot basis for several months at a significantly increased discount to the NYMEX price.

The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our California oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at the NYMEX price, because it requires more complex refining equipment to convert it into high value products. Accordingly, that oil sells at a discount to the NYMEX price. This discount varies over time and can be affected by factors that do not have the same impact on the price of premium grade light oil. For example, in 2005, the discount rose as a result of an increase in the supply of heavy oil from Ecuador. We cannot predict how the discount applicable to our production will change in the future, and it is possible that it will increase. The difficulty involved in predicting the differential also makes it more difficult for us to effectively hedge our production. Substantially all of our hedging arrangements are based on benchmark prices, and therefore do not protect us from adverse changes in the differential applicable to our production.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

The reserve data included in this report represent estimates only. Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes and availability of capital, estimates of required capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of our reserves, the economically recoverable quantities of oil and natural gas attributable to our properties, the classifications of reserves based on risk of recovery and estimates of our future net cash flows.

At December 31, 2007, 39% of our estimated proved reserves were proved undeveloped and 3% were proved developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells as contrasted with the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenues from estimated proved developed non-producing reserves will not be realized until some time in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV-10 estimates are based on prices and costs as of the date of the estimates. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Further, the effect of derivative instruments is not reflected in these assumed prices. Also, the use of a 10% discount factor to calculate PV-10 value may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Oil and natural gas exploration, exploitation and development activities may not be successful and could result in a complete loss of a significant investment.

Exploration, exploitation and development activities are subject to many risks. For example, new wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Similarly, previously producing wells that are returned to production after a period of being shut in may not produce at levels that justify the expenditures made to bring the wells back on line. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The cost of exploration, exploitation and development activities is subject to numerous uncertainties beyond our control, and cost factors can adversely affect the economics of a project. Further, our development activities may be curtailed, delayed or canceled as a result of numerous factors, including:

- title problems;
- problems in delivery of our oil and natural gas to market;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- shortages of, or delays in obtaining, equipment or qualified personnel;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- compliance with environmental and other governmental requirements; and
- costs of, or shortages or delays in the availability of, drilling rigs, equipment and services.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not control. For our largest field, we rely on one barge to transport production from the field. When these facilities or systems, including the barge, are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation barges and processing facilities owned by third parties. In general, we do not control these facilities and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the oil and natural gas we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our oil and natural gas is dependent upon coordination among third parties who own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. These are risks for which we generally do not maintain insurance.

We are at particular risk with respect to oil produced at our South Ellwood field, which is our largest field in terms of proved reserves. Our average net oil production from the field during the fourth quarter of 2007 was 2,587 Bbl/d, or approximately 23% of our aggregate net oil production for the quarter. The oil produced at the field is delivered via a single-hulled barge owned and operated by an unaffiliated third party. This third party is the only company that currently has a permit to deliver oil via barge in the vicinity of the field and, at this time, the barge is the only means available to us for delivery of oil produced from the field. Our loss of the use of the barge, in the absence of a satisfactory alternative delivery arrangement, would have an adverse effect on our financial condition and results of operations. Our ability to use the alternate barge described in "Business and Properties—Description of Properties—Coastal California—South Ellwood Field" is subject to receipt of certain permits and approvals, and we cannot assure you that we will obtain those consents and approvals in a timely manner or at all. In addition, our ability to use the alternate barge at any given time will be subject to its other delivery commitments. Accordingly, even after the necessary consents and approvals are obtained, we would not expect to have access to the alternate barge on short notice.

From time to time, the barge is unavailable due to maintenance and repair requirements. For example, it was out of service for part of August 2006 due to scheduled maintenance. In addition, in October 2006, it was involved in a minor collision with a tugboat and was out of service for repair and inspection for approximately two weeks. In March 2007, it was out of service for inspection for approximately one week. Because we have limited storage capacity for oil produced from the field, we were required to significantly curtail production at the field during the periods in which the barge was unavailable. In addition, the owner of the refinery to which we historically delivered oil production from the field informed us in August 2006 that it was unwilling to accept further deliveries from the barge. If the current purchaser of oil production from the field were to make a similar decision, we would have to find a new purchaser and/or enter into an alternative delivery arrangement for the production. Any new delivery or sales arrangement would require time to implement and could require us to accept lower prices for our production and/or incur higher transportation costs. In addition, if we are unable, for any sustained period, to implement an acceptable delivery or sales arrangement, we will be required to shut in or curtail production from the field. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil produced from the field, would adversely affect our financial condition and results of operations. We would be similarly affected if any of the other transportation, gathering and processing facilities we use became unavailable or unable to provide services.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

As of December 31, 2007, we had total indebtedness under the credit facilities and our 8.75% senior notes due 2011 of approximately $692 million, and this indebtedness bore interest at a weighted average rate of 9.10%. Because we must dedicate a substantial portion of our cash flow from operations to the payment of interest on our debt, that portion of our cash flow is not available for other purposes. In addition, borrowings under our credit facilities bear interest at rates that vary with changes in market rates. Accordingly, an increase in market rates could increase our debt service obligations. Our ability to make scheduled principal and interest payments on our indebtedness and pursue our capital expenditure plan will depend to a significant extent on our financial and operating performance, which is subject to prevailing economic conditions, commodity prices and a variety of other factors. Our cash flow from operations and other capital resources may not be sufficient to pay the principal and interest on our debt in the future. If our cash flow and other capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay scheduled capital projects, sell material assets or operations, obtain additional capital or restructure our debt. In the event that we are required to dispose of material assets or operations, obtain additional capital or restructure our debt to meet our debt service and other obligations, the terms of any such transaction may not be favorable to us and the transaction may not be completed in a timely fashion. In addition, our credit agreements contain provisions that would limit our ability to respond to a shortfall in our expected liquidity by selling assets or taking certain other actions. For example, we could be required to use some or all of the proceeds of an asset sale to reduce amounts outstanding under one or both of our credit facilities in some circumstances. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements."

Our level of indebtedness, and the covenants contained in our debt agreements, could have important consequences for our operations, including by:

- making it more difficult for us to satisfy our obligations under our debt agreements and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operations and certain types of transactions to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures, acquisition opportunities and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other activities;
- limiting management's discretion in operating our business;
- limiting our flexibility in planning for, or reacting to, changes in commodity prices or our business, the industry in which we operate and/or commodity prices;
- impairing our ability to withstand successfully a downturn in commodity prices or our business or the economy generally;
- placing us at a competitive disadvantage against less leveraged competitors; and
- making us vulnerable to increases in interest rates.

Our ability to comply with the covenants in our debt agreements in future periods will depend on our ongoing financial and operating performance, which in turn will be subject to general economic conditions and financial, market and competitive factors, in particular the selling prices for our oil and natural gas and our ability to successfully implement our overall business strategy.

The breach of any of the covenants in our debt agreements could result in a default under the applicable agreement, which would permit the affected lenders or noteholders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest, and to foreclose on substantially all of our assets. In the event of an actual or potential default, we could attempt to refinance the debt or repay the debt with the proceeds from an equity offering or from sales of assets. The proceeds of future borrowings, equity financings or asset sales may not be sufficient to refinance or repay the debt. The terms of our debt agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and the value of our assets and our operating performance at the time of such offering or other financing. We may not be able to complete any such offering, refinancing or sale of assets on desirable terms or at all.

We may incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future under the covenants set forth in our debt agreements. If new debt is added to our current debt levels, the related risks that we now face could intensify. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

We are subject to complex laws and regulations, including environmental laws and regulations, that can adversely affect the cost, manner and feasibility of doing business and limit our growth.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to exploration for, and the exploitation, development, production and transportation of, oil and natural gas, as well as environmental and safety matters. We cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not harm our business, results of operations and financial condition. Laws and regulations applicable to us include those relating to:

- land use restrictions, which are particularly strict along the coast of southern California where many of our operations are located;
- drilling bonds and other financial responsibility requirements;
- spacing of wells;
- emissions into the air (including emissions from ships in the Santa Barbara channel);
- unitization and pooling of properties;
- habitat and endangered species protection, reclamation and remediation;
- the containment and disposal of hazardous substances, oil field waste and other waste materials;
- the use of underground storage tanks;
- transportation and drilling permits;
- the use of underground injection wells, which affects the disposal of water from our wells;
- safety precautions;

- the prevention of oil spills;
- the closure of production facilities;
- operational reporting; and
- taxation and royalties.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- releases or discharges of hazardous materials;
- well reclamation costs;
- oil spill clean-up costs;
- other remediation and clean-up costs;
- plugging and abandonment costs, which may be particularly high in the case of offshore facilities;
- governmental sanctions, such as fines and penalties; and
- other environmental damages.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. We are a defendant in a series of lawsuits alleging, among other things, that air, soil and water contamination from the oil and natural gas facility at our Beverly Hills field caused the plaintiffs to develop cancer or other diseases or to sustain related injuries. See "Legal Proceedings—Beverly Hills Litigation." If resolved adversely to us, these suits could have a material adverse effect on our financial condition. In addition, compliance with applicable laws and regulations could require us to delay, curtail or terminate existing or planned operations.

Some environmental laws and regulations impose strict liability. Strict liability means that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of prior operators of properties we have acquired or other third parties. In addition, we may be required to make large and unanticipated capital expenditures to comply with applicable laws and regulations, for example by installing and maintaining pollution control devices. Similarly, our plugging and abandonment obligations will be substantial and may be more than our estimates. Compliance costs are relatively high for us because many of our properties are located offshore California and in other environmentally sensitive areas and because California environmental laws and regulations are generally very strict. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters, but they will be material. Environmental risks are generally not fully insurable.

In addition, our operations could be adversely affected by environmental and other laws and regulations that require us to obtain permits before commencing drilling or other activities. For example, as discussed in "Business and Properties—Coastal California," we are pursuing a full-field development project in the South Ellwood field that includes a proposed extension of the area covered by our lease. We will be required to obtain numerous consents and approvals from governmental agencies prior to commencing work on the project, including from the U.S. Coast Guard, the California State Lands Commission, the California Coastal Commission, the California Division of Oil, Gas, and Geothermal Resources, the Santa Barbara County Air Pollution Control District, Santa Barbara County and the City of Goleta. We may not be able to obtain these consents and approvals as quickly as we expect or at all. In addition, the necessary consents and approvals may be granted subject to conditions which impose delays on the project, increase its costs or reduce its benefits to us. Other projects we pursue will typically subject to similar risks.

We could also be adversely affected by existing or future tax laws and regulations. For example, proposals have been made to amend federal and California law to impose "windfall profits" taxes or other types of additional taxes on oil companies. If any of these proposals become law, our costs would increase, possibly materially.

Our operations are subject to a variety of contractual, regulatory and other constraints that can limit our production and increase our operating costs and thereby adversely affect our results of operations.

We are subject to a variety of contractual, regulatory and other operating constraints that limit the manner in which we conduct our business. These constraints affect, among other things, the permissible uses of our facilities, the availability of pipeline capacity to transport our production and the manner in which we produce oil and natural gas. These constraints can change to our detriment without our consent. For example, effective January 2003, the terms of the sales gas transportation contract relating to the South Ellwood field were revised to reduce the permitted amount of carbon dioxide in the natural gas we transport from the field and to make the method of measuring carbon dioxide levels more stringent. To comply with these new requirements, we shut in some wells with a high natural gas-to-oil ratio, and this reduced our natural gas sales from the field. Similar events may occur in the future. These events, many of which are beyond our control, could have a material adverse effect on our results of operations and financial condition and could reduce estimates of our proved reserves.

Our hedging arrangements involve credit risk and may limit future revenues from price increases, result in financial losses or reduce our income.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into hedging arrangements with respect to a substantial portion of our oil and natural gas production. See "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our hedging activity. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- a counterparty to a hedging contract fails to perform under the contract; or
- there is a change in the expected differential between the underlying price in the hedging contract and the actual prices received.

In addition, we have experienced, and may continue to experience, substantial realized and unrealized losses relating to our hedging arrangements. Realized commodity derivative gains or losses represent the difference between the strike prices set forth in hedging contracts settled during the relevant period and the ultimate settlement prices. We incur a realized commodity derivative loss when a contract is settled at a price above the strike price. Losses of this type reflect the limit our hedging arrangements impose on the benefits we would otherwise have received from an increase in the price of oil or natural gas during the period. Unrealized commodity derivative gains and losses represent the change in the fair value of our open derivative contracts from period to period. We incur an unrealized commodity derivative loss when the futures price used to estimate the fair value of a contract at the end of the period rises. Increases in oil prices have caused us to incur substantial realized and unrealized commodity derivative losses in some recent periods, and we may experience similar or greater losses of these types in future periods. We may experience more volatility in our commodity derivative gains and losses than many of our competitors because we discontinued the use of hedge accounting in 2007 and because we hedge a larger percentage of our production than some of our competitors. As discussed in "Management's Discussion and Analysis of Results of Operation and Financial Condition—Liquidity and Capital Resources—Capital Resources and Requirements," our second lien term loan agreement requires us to hedge a significant percentage of our anticipated production.

In addition, the uncertainties associated with our hedging programs are greater than those of many of our competitors because the price of the heavy oil that we produce in California is subject to risks that are in addition to the price risk associated with premium grade light oil. Also, our working capital could be impacted if we enter into derivative arrangements that require cash collateral and commodity prices subsequently change in a manner adverse to us. The obligation to post cash or other collateral could, if imposed, adversely affect our liquidity.

We may not be able to raise the capital necessary to replace our reserves.

Reserves can be replaced through acquisitions of new properties or the exploration, exploitation and development of existing properties. Either approach requires substantial capital, and capital may not always be available to us on reasonable terms or at all. If our cash flow from operations and cash available from other sources is less than we anticipate, we may not be able to finance the capital expenditures, or complete the acquisitions, necessary to replace our reserves. A reduction in our reserves could, in turn, further limit the availability of capital, as the maximum amount of available borrowing under the revolving credit facility is, and the availability of other sources of capital likely will be, based in part on the estimated quantities of our proved reserves.

Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including:

- well blowouts;
- cratering and explosions;
- pipe failures and ruptures;
- pipeline accidents and failures;
- casing collapses;
- fires;
- mechanical and operational problems that affect production;
- formations with abnormal pressures;
- uncontrollable flows of oil, natural gas, brine or well fluids; and
- releases of contaminants into the environment.

For example, in May 2005, we encountered downhole mechanical problems during a routine workover on a well in the South Ellwood field. As a result of the problems, average net production from the well dropped significantly for a period of several months. In addition, our efforts to restore production at the well required us to delay the implementation of some other projects. We may experience similar problems and delays from time to time in the future. Our offshore operations are further subject to a variety of operating risks specific to the marine environment, including a dependence on a limited number of gas and water injection wells and electrical transmission lines. Moreover, because we operate in California, we are also susceptible to risks posed by natural disasters such as earthquakes, mudslides, fires and floods. For example, our production in the first quarter of 2006 was adversely affected by heavy rain and flooding in northern California.

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because a significant portion of our operations are conducted offshore and in other environmentally sensitive areas, including areas with significant residential populations. We do not maintain insurance in amounts that cover all of the losses to which we may be subject, and the insurance we have may not continue to be available on acceptable terms. The occurrence of an uninsured or underinsured loss could result in significant costs that could have a material adverse effect on our financial condition. In addition, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

A failure to complete successful acquisitions would limit our growth.

Our strategy is to increase our reserves and production, in part through the acquisition of additional oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise. Our focus on the California market reduces the pool of suitable acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. Our substantial level of indebtedness will further limit our ability to make future acquisitions. If we are unable to complete suitable acquisitions, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we typically rely to a significant extent on information provided by the seller. We independently review only a portion of that information. In addition, our review of the business or property to be acquired will not be comprehensive enough to uncover all existing or potential problems that could affect us as a result of the acquisition. Accordingly, it is possible that we will discover problems with an acquired business or property that we did not anticipate at the time we completed the transaction. These problems may be material and could include, among other things, unexpected environmental problems, title defects or other liabilities. Often, we acquire properties on an "as-is" basis, and have limited or no remedies against the seller with respect to these types of problems.

The success of any acquisition we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales. The risks normally associated with acquisitions are heightened in the current environment, as market prices of oil and natural gas properties are generally high compared to historical norms. In addition, we may face greater risks to the extent we acquire properties in areas outside of California and the Gulf Coast of Texas, because we may be less familiar with operating, regulatory and other issues specific to those areas.

Our ability to achieve the benefits we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations with ours. Our management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business concerns. The challenges involved in the integration process may include retaining key employees and maintaining key employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding the acquired properties.

Competition in the oil and natural gas industry is intense and may adversely affect our results of operations.

We operate in a competitive environment for acquiring properties, marketing oil and natural gas, integrating new technologies and employing skilled personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be willing and able to pay more for oil and natural gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. Our competitors may also enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future with respect to acquiring prospective reserves, developing reserves, marketing our production, attracting and retaining qualified personnel, implementing new technologies and raising additional capital.

The loss of our CEO or other key personnel could adversely affect our business.

We believe our continued success depends in part on the collective abilities and efforts of Timothy Marquez, our CEO, and other key personnel, including the executive officers listed in "Business and Properties—Executive Officers of the Registrant." We do not maintain key man life insurance policies. The loss of the services of Mr. Marquez or other key management personnel could have a material adverse effect on our results of operations. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our results of operations could be materially and adversely affected.

Shortages of qualified operational personnel or field equipment and services could affect our ability to execute our plans on a timely basis, increase our costs and adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling rigs and other field equipment, as demand for rigs and equipment has increased with the number of wells being drilled. These factors can also result in significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We have experienced some difficulty in obtaining drilling rigs, experienced crews and related services in the past year and may continue to experience these difficulties in the future. In part, these difficulties arise from the fact that the California market is not as attractive for oil field workers and equipment operators as mid-continent and Gulf Coast areas where drilling activities are more widespread. In addition, the cost of drilling rigs and related services has increased significantly. If shortages persist or prices continue to increase, our profit margin, cash flow and operating results could be adversely affected and our ability to conduct our operations in accordance with current plans and budgets could be restricted.

Because we cannot control activities on properties we do not operate, we cannot control the timing of those projects. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Other companies operated approximately 5% of our production in the fourth quarter of 2007. Our ability to exercise influence over operations for these properties and their associated costs is limited. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to exploration, exploitation, development or acquisition activities. The success and timing of exploration, exploitation and development activities on properties operated by others depend upon a number of factors that may be outside our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditures associated with the project. If we are not willing and able to fund required capital expenditures relating to a project when required by the majority owner or operator, our interests in the project may be reduced or forfeited.

Our plans with respect to the proposed MLP are subject to a wide variety of risks and uncertainties.

A recently-formed subsidiary of ours, Venoco Acquisition Company, L.P., which we refer to as the master limited partnership or the MLP, has filed a preliminary registration statement on Form S-1 in connection with a proposed offering of common units representing limited partnership interests in the MLP. The completion of the proposed offering is subject to market conditions, which have generally been unfavorable in recent months, the receipt of required consents and approvals, and numerous other risks, some of which are beyond our control. It is possible that the MLP will not complete the offering, will not raise the expected amount of capital even if the offering is completed and/or will not be able to complete its proposed activities on the currently contemplated schedule. In addition, the structure, nature, purpose and proposed assets and liabilities of the MLP, and/or the terms of the MLP offering, may change materially from those currently anticipated. The MLP, and our retained investment in it, will be subject to a wide variety of risks, including those risks normally associated with operations in the oil and natural gas industry.

This report on Form 10-K shall not constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities will only be made in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom.

Changes in the financial condition of any of our large oil and natural gas purchasers could make it difficult to collect amounts due from those purchasers.

For the year ended December 31, 2007, approximately 88% of our oil and natural gas revenues were generated from sales to four purchasers: Enserco Energy, ConocoPhillips, Gulfmark Energy and Tesoro Refining and Marketing Company. A material adverse change in the financial condition of any of our largest purchasers could adversely impact our future revenues and our ability to collect current accounts receivable from such purchasers.

We may be required to write down the carrying value of our properties and a reduction in our asset values could adversely affect our stock price.

We may be required under full cost accounting rules to write down the carrying value of our properties when oil and natural gas prices decrease or when we have substantial downward adjustments of our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We use the full cost method of accounting for oil and natural gas exploitation, development and exploration activities. Under full cost accounting rules, we perform a "ceiling test." This test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of our oil and natural gas properties that is equal to the expected after-tax present value of the future net cash flows from proved reserves, including the effect of cash flow hedges, calculated using prevailing prices on the last day of the relevant period. If the net book value of our properties (reduced by any related net deferred income tax liability) exceeds the ceiling, we write down the book value of the properties. Depending on the magnitude of any future impairments, a ceiling test write down could significantly reduce our income or produce a loss. Ceiling test computations use commodity prices prevailing on the last day of the relevant period, making it impossible to predict the timing and magnitude of any future write downs. To the extent our finding and development costs increase, we will become more susceptible to ceiling test write downs in low price environments.

We are controlled by Timothy Marquez, who is able to determine the outcome of matters submitted to a vote of our stockholders. This limits the ability of other stockholders to influence our management and policies.

Timothy Marquez, our Chairman and CEO, beneficially owned approximately 57.5% of our outstanding common stock as of December 31, 2007. Through this ownership, Mr. Marquez is able to control the composition of our board of directors and direct our management and policies. Accordingly, Mr. Marquez has the direct or indirect power to:

- elect all of our directors and thereby control our policies and operations;
- amend our bylaws and some provisions of our certificate of incorporation;
- appoint our management;
- approve future issuances of our common stock or other securities;
- approve the payments of dividends, if any, on our common stock;
- approve the incurrence of debt by us; and
- agree to or prevent mergers, consolidations, sales of all or substantially all our assets or other extraordinary transactions.

Mr. Marquez's significant ownership interest could adversely affect investors' perceptions of our corporate governance. In addition, Mr. Marquez may have an interest in pursuing acquisitions, divestitures and other transactions that involve risks to us and you. For example, Mr. Marquez could cause us to make acquisitions that increase our indebtedness or to sell revenue generating assets. Mr. Marquez may from time to time acquire and hold interests in businesses that compete directly or indirectly with us. Also, we have engaged, and may continue to engage, in related party transactions involving Mr. Marquez. For example, prior to the completion of our initial public offering, we entered into agreements with the Marquez Trust, a family trust of which Mr. Marquez and his wife are the trustees, in connection with dividends of certain real property interests to the trust.

Some of our directors have relationships with other companies in the oil and natural gas industry that could result in conflicts of interest.

Some of our directors serve as directors and/or officers of other companies engaged in the oil and natural gas industry and may have other relationships with such companies. For example, Timothy Brittan is President of Infinity Oil & Gas, Inc. and Mark Snell is CFO of Sempra Energy. In addition, Mac McFarland provides consulting services to various energy-related companies from time to time, Joel Reed is the lead principal of a firm that provides investment banking services to such companies from time to time and Rick Walker provides executive search services to such companies from time to time. To the extent those companies are involved in ventures in which we may participate, or compete for acquisitions or financial resources with us, the relevant director will face a conflict of interest. In the event such a conflict arises, the relevant director will be required to disclose the nature and extent of the conflict and abstain from voting for or against any action of the board that is or could be affected by the conflict.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock in the public markets or the issuance of additional shares of common stock in future acquisitions.

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional common or preferred stock. As of December 31, 2007, Timothy Marquez beneficially owned approximately 57.5% of our common stock. As of that date, we had granted options to purchase an aggregate of approximately 4.2 million shares of our common stock to certain of our directors and employees, of which approximately 55% were vested. The Marquez Trust and certain option holders, subject to compliance with applicable securities laws, are permitted to sell shares they own or acquire upon the exercise of options in the public market. Sales of a substantial number of shares of our common stock by those holders could cause our stock price to fall.

In addition, in the future, we may issue shares of our common stock in connection with acquisitions of assets or businesses. If we use our shares for this purpose, the issuances could have a dilutive effect on the market value of shares of our common stock, depending on market conditions at the time of an acquisition, the price we pay, the value of the business or assets acquired, our success in exploiting the properties or integrating the businesses we acquire and other factors.

Our certificate of incorporation and bylaws and Delaware law contain provisions that may prevent, discourage or frustrate attempts to replace or remove our current management by our stockholders, even if such replacement or removal may be in our stockholders' best interests.

Our certificate of incorporation and bylaws and Delaware law contain provisions that could enable our management, including Mr. Marquez, to resist a takeover attempt (even if Mr. Marquez ceases to beneficially own a controlling block of our common shares). These provisions:

- restrict various types of business combinations with significant stockholders (other than the Marquez Trust, Mr. Marquez and his wife);
- provide for a classified board of directors;
- limit the right of stockholders to remove directors or change the size of the board of directors;
- limit the right of stockholders to fill vacancies on the board of directors;
- limit the right of stockholders to act by written consent or call a special meeting of stockholders;
- require a higher percentage of stockholders than would otherwise be required to amend, alter, change or repeal certain provisions of our certificate of incorporation; and
- authorize the issuance of preferred stock with any voting rights, dividend rights, conversion privileges, redemption rights and liquidation rights and other rights, preferences, privileges, powers, qualifications, limitations or restrictions as may be specified by our board of directors.

These provisions could:

- discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders;
- adversely affect the voting power of holders of common stock; and
- limit the price that investors might be willing to pay in the future for shares of our common stock.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

In the ordinary course of our business we are named from time to time as a defendant in various legal proceedings. We maintain liability insurance and believe that our coverage is reasonable in view of the legal risks to which our business ordinarily is subject.

Beverly Hills Litigation

Between June 2003 and April 2005, six lawsuits were filed against us and certain other energy companies in Los Angeles County Superior Court by persons who attended Beverly Hills High School or who were or are citizens of Beverly Hills/Century City or visitors to that area during the time period running from the 1930s to date. There are approximately 1,000 plaintiffs (including plaintiffs in two related lawsuits in which we have not been named) who claim to be suffering from various forms of cancer or other illnesses, fear they may suffer from such maladies in the future, or are related to persons who have suffered from cancer or other illnesses. Plaintiffs alleged that exposure to substances in the air, soil and water that originated from either oil-field or other operations in the area were the cause of the cancers and other maladies. We have owned an oil and natural gas facility adjacent to the school since 1995. For the majority of the plaintiffs, their alleged exposures occurred before we acquired the facility. All cases were consolidated before one judge. Twelve "representative" plaintiffs were selected to have their cases tried first, while all of the other plaintiffs' cases were stayed. In November 2006, the judge entered summary judgment in favor of all defendants in the test cases, including us. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in late 2008. We vigorously defended the actions, and will continue to do so until they are resolved. We also have defense and indemnity obligations to certain other defendants in the actions who have asserted claims for indemnity for events occurring after we acquired the property in 1995. In addition, certain defendants have made claims for indemnity for events occurring prior to 1995, which we are disputing. We cannot predict the cost of defense and indemnity obligations at the present time.

One of our insurers currently is paying for the defense of these lawsuits under a reservation of its rights. Three other insurers that provided insurance coverage to us (the "Declining Insurers") have taken the position that they are not required to provide coverage for losses arising out of, or to defend against, the lawsuits because of a pollution exclusion contained in their policies. In February 2006, we filed a declaratory relief action against the Declining Insurers in Santa Barbara County Superior Court seeking a determination that those insurers have a duty to defend us in the lawsuits. Two of the three Declining Insurers settled with us. The third Declining Insurer disputed our position and in November 2007 the Santa Barbara Court granted that insurer's motion for summary judgment, in part on the basis that the pollution exclusion provision in the policy did not require that insurer to provide a defense for us. We have appealed the Santa Barbara Court's ruling. We have no reason to believe that the insurer currently providing defense of the lawsuits will cease providing such defense. If it does, and we are unsuccessful in enforcing our rights in any subsequent litigation, we may be required to bear the costs of the defense, and those costs may be material. If it ultimately is determined that the pollution exclusion or another exclusion contained in one or more of our policies applies, we will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

In accordance with SFAS No. 5, *Accounting for Contingencies*, we have not accrued for a loss contingency relating to the Beverly Hills litigation because we believe that, although unfavorable outcomes in the proceedings may be reasonably possible, we do not consider them to be probable or reasonably estimable. If one or more of these matters are resolved in a manner adverse to us, and if insurance coverage is determined not to be applicable, their impact on our results of operations, financial position and/or liquidity could be material.

State Lands Commission Royalty Audit

We pay royalties to the state of California pursuant to certain oil and natural gas leases relating to the South Ellwood field. We have been informed by the California State Lands Commission (the "SLC") that it is in the process of auditing our royalty payment calculations on those leases. The SLC has not completed its audit, nor has it presented us with any audit conclusions. We do not currently expect that the audit adjustments, if any, will be material.

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

No matters were submitted to a vote of stockholders during the fourth quarter of the fiscal year covered by this report.

PART II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Price Range of Common Stock and Number of Holders

Our common stock is listed on the New York Stock Exchange under the symbol "VQ".

The following table sets forth the high and the low sale prices per share of our common stock for the periods indicated. The closing price of the common stock on March 13, 2008 was $13.23.

	2007		2006	
Period	High	Low	High	Low
1st Quarter	$17.90	$13.86	—	—
2nd Quarter	$21.02	$17.31	—	—
3rd Quarter	$19.64	$13.40	—	—
4th Quarter	$23.71	$16.93	$17.90(1)	$16.64(1)

(1) Our common stock began trading on the New York Stock Exchange on November 17, 2006.

As of February 12, 2008, there were 238 record holders, and approximately 2,365 beneficial owners, of our common stock.

Unregistered Sales of Equity Securities

On December 7, 2007, we acquired Gato corporation, a private company that owned approximately 4,200 net acres of producing properties in Santa Barbara County, California, for $1.5 million in cash and 171,000 shares of our common stock. The sole stockholder of Gato corporation prior to the transaction was the Tognazzini 2003 Trust, the trustees of which are Donn and Daisy Tognazzini. The issuance of our common stock was exempt from the registration requirements of the Securities Act of 1933, or Securities Act, pursuant to Section 4(2) of that act. The Tognazzini 2003 Trust represented its intention to acquire the common stock for investment only and not with a view to or for sale in connection with any unregistered distribution thereof. The transaction was effected without general solicitation or advertising. In addition, the Tognazzini 2003 Trust had access to information concerning us, including through our public filings with the SEC, generally comparable to the information that would have been provided in a registration statement had the issuance of the stock been registered.

Dividend Policy

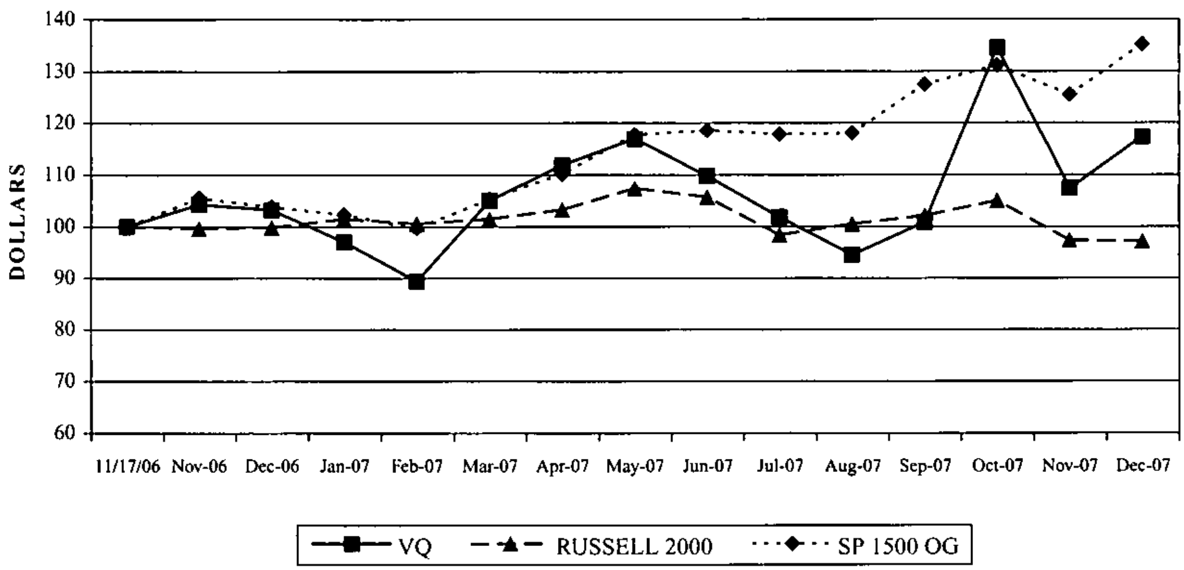
We have not declared any cash dividends on our common stock during the two most recent fiscal years and have no plans to do so in the foreseeable future. The ability of our board of directors to declare any dividend is subject to limits imposed the terms of our debt agreements, which currently prohibit us from paying dividends on our common stock. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements." Our ability to pay dividends is also subject to limits imposed by Delaware law. In determining whether to declare dividends, the board will consider the limits imposed by our debt agreements, our financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant.

Comparison of Cumulative Return

The following graph compares the cumulative return on a $100 investment in our common stock from November 17, 2006, the date the common stock trading began on the New York Stock Exchange, through December 31, 2007, to that of the cumulative return on a $100 investment in the Russell 2000

Index and the S&P 1500 Oil and Gas Consumable Fuels Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG VENOCO, INC., THE RUSSELL 2000 INDEX, AND THE S&P 1500 OIL AND GAS CONSUMABLE FUELS INDEX



ITEM 6. Selected Financial Data

The table below contains selected consolidated financial data. The statement of operations, cash flow, balance sheet and other financial data for each year has been derived from our consolidated financial statements. You should read this information together with "Management's Discussion and Analysis of Financial Condition and Results of Operation" and our consolidated financial statements and the related notes included elsewhere in this report. Amounts are in thousands, except per share data.

	Years ended December 31,				
	2003	2004(5)(6)	2005	2006	2007
Statement of Operations Data:					
Oil and natural gas revenues	$109,754	$139,961	$191,092	$ 274,813	$ 377,871
Commodity derivative losses	(10,272)	(18,685)	(57,595)	(2,365)	(147,366)
Other revenues(1)	5,253	5,457	4,456	5,470	3,355
Total revenues	104,735	126,733	137,953	277,918	233,860
Production expenses	45,617	49,567	54,038	87,505	119,321
Transportation expense	2,785	2,915	2,596	3,533	6,061
Depletion, depreciation and amortization	16,161	16,489	21,680	63,259	98,814
Accretion of abandonment liability	1,401	1,482	1,752	2,542	3,914
General and administrative expenses, net of capitalized amounts	11,632	11,272	16,007	28,317	31,770
Litigation settlement expense(2)	6,000	—	—	—	—
Interest expense, net	2,125	2,269	13,673	48,795	60,115
Amortization of deferred loan costs	370	3,050	1,755	3,776	4,197
Interest rate derivative losses, net	—	—	—	590	17,177
Loss on extinguishment of debt	—	—	—	—	12,063
Income tax provision (benefit)	7,876	16,088	10,300	15,650	(46,200)
Minority interest in Marquez Energy	—	95	42	—	—
Cumulative effect of change in accounting principle, net of tax(3)	(411)	—	—	—	—
Net income (loss)	11,179	23,506	16,110	23,951	(73,372)
Preferred stock dividends	(8,465)	(7,134)	—	—	—
Excess of carrying value over repurchase price of preferred stock(4)	—	29,904	—	—	—
Net income (loss) applicable to common equity	$ 2,714	$ 46,276	$ 16,110	$ 23,951	$ (73,372)
Basic earnings per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.07	$ 1.33	$ 0.49	$ 0.71	$ (1.58)
Cumulative effect of change in accounting principle	0.01	—	—	—	—
Total	$ 0.08	$ 1.33	$ 0.49	$ 0.71	$ (1.58)
Diluted earnings (loss) per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.07	$ 0.48	$ 0.49	$ 0.69	$ (1.58)
Cumulative effect of change in accounting principle	0.01	—	—	—	—
Total	$ 0.08	$ 0.48	$ 0.49	$ 0.69	$ (1.58)
Cash Flow Data:					
Cash provided by (used in):					
Operating activities	$ 31,557	$ 43,309	$ 39,931	$ 89,090	$ 160,863
Investing activities	(10,531)	(27,990)	(58,695)	(595,204)	(433,363)
Financing activities	(23,333)	30,979	(26,562)	505,089	273,871
Other Financial Data:					
Capital expenditures	10,785	16,442	79,470	174,613	322,283
Balance Sheet Data (end of period):					
Cash and cash equivalents	$ 8,417	$ 54,715	$ 9,389	$ 8,364	9,735
Plant, property and equipment, net	170,663	198,563	233,776	774,253	1,131,032
Total assets	212,252	298,882	302,558	893,193	1,265,485
Long-term debt, excluding current portion	22,969	163,542	178,943	529,616	691,896
Mandatorily redeemable preferred stock and accrued dividends	94,770	—	—	—	—
Stockholders' equity	2,484	48,439(6)	4,334	190,316	245,602

(1) Other revenues primarily include amounts received from purchasers of our oil production to reimburse us for transportation and barge expenses.

(2) Amount comprises settlement costs incurred by us in connection with a lawsuit brought by Mr. Marquez asserting wrongful termination and breach of contract.

(3) The amount shown for 2003 is the cumulative effect of change in accounting principle of $411,000, net of tax. On January 1, 2003, we adopted SFAS 143, *Accounting for Asset Retirement Obligations*, which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Pursuant to our adoption of SFAS 143, we recognized a credit during the first quarter of 2003 of $411,000, net of tax, for the cumulative effect of the change in accounting principle.

(4) Amount comprises the excess of the carrying value over the repurchase price of our mandatorily redeemable convertible preferred stock plus accrued and unpaid dividends net of unamortized issuance costs.

(5) We acquired Marquez Energy, a Colorado limited liability company majority owned and controlled by our CEO, Timothy Marquez, in March 2005. The purchase price for the membership interests in Marquez Energy was $16.8 million (including a $2.0 million deposit paid in 2004). Because Marquez Energy was a company under common control with us since July 12, 2004, our financial statements and production information for all of 2005 and for the third and fourth quarters of 2004 include Marquez Energy. For the same reason, the acquisition was accounted for in a manner similar to a pooling of interests whereby the historical results of Marquez Energy have been combined with our financial results since July 1, 2004.

(6) Mr. Marquez's percentage beneficial ownership in our common stock increased from approximately 94% to 100% on December 22, 2004, the date we effected a merger with a corporation the sole stockholder of which was the Marquez Trust. Accordingly, Mr. Marquez's basis in our assets has been "pushed-down" as of the date of the merger, meaning that our post-transaction financial statements reflect Mr. Marquez's basis in our assets (the successor basis) rather than our historical basis. The aggregate purchase price has been allocated to a portion of the underlying assets and liabilities based upon their respective fair values at the date of the merger, with the values of certain long-lived assets reduced on a pro rata basis for the excess of Mr. Marquez's portion of the fair value of acquired net assets over the purchase price of the shares acquired. Due to the *de minimis* impact on our results of operations for the nine-day period ended December 31, 2004, the successor basis of accounting has been applied to our financial statements as of December 31, 2004, with the consolidated statements of operations, comprehensive income (loss), and cash flows for the fiscal year ended 2004 being presented on a historical, or "predecessor" basis.

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

The following discussion and analysis should be read in conjunction with our financial statements and related notes and the other information appearing in this report.

Overview

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. Our strategy is to grow through exploration, exploitation and development projects we believe to be relatively low risk and through selective acquisitions of underdeveloped properties. Pursuit of this strategy has led to increases in our oil and natural gas production and our proved reserves in each of the past three years. Our average net production increased from 11,555 BOE/d in 2005 to 17,349 BOE/d in 2006 (calculated as described in footnote 2 to the table included in "—Results of Operations") and to 19,535 BOE/d in 2007. Our proved reserves increased from 47.6 MMBOE at December 31, 2005 to 87.9 MMBOE at December 31, 2006 and to 99.9 MMBOE at December 31, 2007.

In the execution of our strategy, our management is principally focused on increasing our reserves of oil and natural gas and on increasing annual production through exploration, exploitation and development activities and acquisitions. Our management is also focused on the risks and opportunities associated with current oil and natural gas prices, which remain high compared to longer-term historical averages, and on the goal of maximizing production rates while operating in a safe manner.

Capital Expenditures

We have developed an active capital expenditure program to take advantage of our extensive inventory of drilling prospects and other projects. Our exploration, exploitation and development capital expenditures, including amounts accrued and unpaid at December 31, 2007, were $310.1 million in 2007, up from $189.2 million in 2006, and we expect that they will be approximately $235.0 million in 2008. We expect to spend approximately 55% of the budgeted amount on projects in the Sacramento Basin, 30% in the Coastal California region and 15% in Texas. Included in the budget is $25.0 million for exploration projects. The aggregate levels of capital expenditures for 2008, and the allocation of those expenditures, are dependent on a variety of factors, including the availability of capital resources to fund the expenditures and changes in our business assessments as to where our capital can be most profitably employed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from our estimates. The following summarizes certain significant aspects of our capital spending program in 2007 and 2008:

Coastal California—Exploitation and Development

In the coastal California area, we drilled five new wells in 2007 (including one higher impact exploration well), all of which were productive. We also performed eleven workovers and recompletions. In 2008, we plan to drill three wells and perform five workovers and recompletions in the area. Our primary focus is on development activities in the West Montalvo field. Since acquiring the field in May 2007, we have drilled one well and initiated an aggressive workover, recompletion and return to production program on existing wells, a program that included eight workovers in 2007. We plan to continue the program in 2008 and to drill two to three new development wells in the field, including one offshore well (which will be drilled from an onshore location). We also plan to commission a seismic survey to assist in designing and optimizing an infill development program.

In the Sockeye field, we continue to implement our waterflood program from platform Gail and are working on the evaluation and design of a possible expansion of the program. We are also continuing to evaluate a possible expansion of our horizontal and multi-lateral well drilling activities to the Monterey formation in the field. In the Santa Clara field, we pursued a plan to return platform

Grace to production in 2007, redrilling three wells with limited success. Further drilling from the platform has been suspended pending additional geologic and engineering review.

In the South Ellwood field, the permitting process continues for our full-field development project. Key components of the project include an extension of our current field area (which would effectively double the size of the existing field) and the installation of an onshore oil transport pipeline to replace the existing barge. Development of the extended lease area can be accomplished from our existing platform, platform Holly. We anticipate receiving the draft environmental impact report for this project in the first half of 2008 with project approval and startup expected in 2009.

Sacramento Basin—Exploitation and Development

In the Sacramento Basin, we continue to pursue our infill drilling program in the greater Grimes and Willows fields. We drilled 122 wells in the basin in 2007 (80% of which were productive) and performed 113 workovers and recompletions. Of the 122 completed wells, 60 were drilled to non-proved locations and are therefore considered "exploratory wells" as defined in SEC Regulation S-X; we consider two of those wells to be higher-impact exploration wells. We currently have five drilling rigs and five workover/completion rigs working in the basin and expect to drill over 110 new wells and perform more than 125 workovers and recompletions there in 2008. As of December 31, 2007, we had identified 520 drilling locations in the basin, and we anticipate identifying additional locations as we pursue exploitation and development opportunities there.

We continue to test and evaluate potential downspacing opportunities in the basin as well as new methods of improving productivity and reducing drilling costs. In particular, we have initiated a hydraulic fracturing program targeting the Forbes and deeper formations, a program that could potentially enhance production and reserves significantly. The strategy of using hydraulic fracturing to enhance oil and natural gas production and recovery is a well established and proven process, although we have not used it in our existing completions and, to our knowledge, it has not been widely used in the basin by other operators. We initiated a fracture stimulation program by testing the process on three wells in November 2007. Although the production history on the three test wells is limited, early indications of the potential from fracturing are encouraging. We currently plan to perform between 20 and 50 fractures in 2008, but this estimate could change significantly depending on the success of the program. As of December 31, 2007, our acreage position in the basin had grown to approximately 193,000 net acres (236,000 gross).

Texas—Exploitation and Development

In Texas, we drilled nine new wells in 2007, all of which were productive, and performed 253 workovers and recompletions. In 2008, we plan to drill five wells and perform over 150 workovers and recompletions there.

Our focus in Texas has been on the redevelopment of the Hastings complex. This program has consisted principally of returning idle wells to production, increasing the lift capacity of existing wells, working over and recompleting existing wells in different producing sands, significantly upgrading surface facility fluid handling capacity and increasing water injection capabilities. In addition, we drilled five infill replacement wells in the Hastings complex in 2007, targeting unswept and undepleted sands. In 2008, we expect to continue our workover and recompletion program in an effort to further increase production and reserves. We also will focus on lowering operating expenses in 2008 as we reduce our remediation and redevelopment activities at the complex.

We also initiated a workover and recompletion program in the Manvel field, which produces from the same formation and exhibits operating characteristics that are similar to those of the Hastings complex. In 2007, we performed 23 workovers and recompletions and focused on upgrading facilities to handle greater production volumes. In 2008, we plan to accelerate our workover program and to drill up to three development wells. Our plans in Texas for 2008 also include drilling two to three additional development wells in some of our other fields to demonstrate and assess new exploitation opportunities.

Higher Impact Exploration Activities

In addition to the exploitation and development activities described above, we devoted approximately $14.4 million to higher impact exploration activities in 2007, including $5.8 million on drilling. We generally consider a well to be a higher impact exploration well when it is either a new field wildcat or a new-pool test (i.e., a well on a structural feature or other type of trap already producing oil or natural gas but outside the known limits of the producing area). We drilled three higher impact exploration wells in 2007, all of which were productive. In 2008, we expect to drill as many as fifteen higher impact exploration wells, including ten in the Sacramento Basin, three in Coastal California and two in Texas. We generally pursue higher impact exploration activities in areas where we have a strong operating base, proprietary knowledge and a well-established land position.

Acquisitions and Divestitures

West Montalvo and Manvel Acquisitions. We acquired the West Montalvo field in Ventura County, California in May 2007 for approximately $61.3 million. We acquired the Manvel field in Brazoria County, Texas, and certain other fields in Texas, in April 2007 for $44.5 million.

TexCal Transaction. We acquired TexCal Energy (LP) LLC on March 31, 2006 for $456.8 million in cash. In order to finance the purchase price for the acquisition and related transaction costs of approximately $14.4 million, we borrowed approximately $119.5 million under our revolving credit facility and $350.0 million under our second lien term loan facility.

Other. We have an active acreage acquisition program and we regularly engage in acquisitions (and, to a lesser extent, dispositions) of oil and natural gas properties, primarily in and around our existing core areas of operations, including several transactions in each of 2005, 2006 and 2007.

Trends Affecting our Results of Operations

Expected Production. We expect that the execution of our capital expenditure program in 2008 will result in increases in our average net production from each of our operating areas. Our coastal California properties, which produced 3.0 MBOE during 2007 (of which 93% was oil), will continue to be the largest contributor of production in 2008. At our newest coastal California property, the West Montalvo field, we expect the drilling and workover/recompletion programs we began there in 2007 to result in production increases in 2008. In the Sacramento Basin, we intend to continue our multi-year drilling program and plan to drill approximately 110 new wells and perform over 125 workovers and recompletions. In the Hastings complex, we expect further production increases in 2008 as a result of the enhancement of our water processing and injection capabilities and the continuation of our workover and recompletion program. At the Manvel field, which we acquired in April 2007, we are implementing a similar redevelopment program to increase production by upgrading our fluid handling and injection capacity and performing several workovers and recompletions. Our expectations with respect to future production rates are subject to a number of uncertainties, including those associated with third party services, oil and natural gas prices, events resulting in unexpected downtime, permitting issues, drilling success rates, pipeline capacity, and other factors, including those referenced in "Risk Factors."

Production Expenses. Production expenses averaged $16.74 per BOE in 2007 compared to $15.09 per BOE in 2006. The 2007 production expenses reflect our continued workover program in the Hastings complex and operating expenses from the West Montalvo and Manvel fields, where expenses increased as remedial efforts accelerated in both fields. These efforts, coupled with a production curtailment at West Montalvo for facility vessel inspections and repairs, resulted in an increase in production expenses per BOE. We expect our production expenses to decrease on a BOE basis for 2008 as a whole due to reduced remedial activities in the Hastings complex and production volume increases from the Sacramento Basin, the West Montalvo and Manvel fields and the Hastings complex. Our expectations with respect to future per-unit expenses are based in part on the projected increases in our production and are subject to numerous risks and uncertainties, including those described and referenced in the preceding paragraph.

General and Administrative Expenses. General and administrative expenses were $3.85 per BOE in 2007, excluding per BOE charges under SFAS 123R of $0.61. This represented a decrease from per BOE G&A costs of $4.41 (excluding SFAS 123R charges of $0.47) in 2006. The change resulted from an overall increase in G&A costs in the 2007 period being more than offset by production growth and the effect of an increase in the G&A costs that were capitalized as a result of being directly related to our development, exploitation, exploration and acquisition efforts. Excluding SFAS 123R charges, we expect our 2008 G&A costs to be similar to our full year 2007 costs on a per BOE basis. As with production expenses, our expectations in this regard are based in part on our projected increases in production, which are subject to numerous risks and uncertainties.

Unrealized Derivative Gains and Losses. Rising oil prices led to substantial unrealized commodity derivative losses in 2007, while fluctuating oil prices and lower natural gas prices led to unrealized commodity derivative gains in 2006. These unrealized gains and losses resulted from mark-to-market valuations of derivative positions that are not accounted for as cash flow hedges and are reflected as unrealized commodity derivative gains or losses in our income statement. Payments actually due to or from counterparties in the future on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of our production. We may incur significant gains or losses of this type in 2008 and in subsequent years. As described in the notes to the consolidated financial statements included in this report, we discontinued hedge accounting as of April 1, 2007. This may increase volatility in gains and losses of this type in subsequent periods. We may also have significant unrealized interest rate derivative gains and losses in subsequent periods due to changes in market interest rates.

Results of Operations

The following table reflects the components of our oil and natural gas production and sales prices, and our operating revenues, costs and expenses, for the periods indicated.

	Years ended December 31,		
	2005	2006(1)	2007
Production Volume			
Oil (MBbls)	2,953	3,411	3,981
Natural gas (MMcf)	7,588	14,314	18,895
MBOE	4,218	5,797	7,130
Daily Average Production Volume			
Oil (Bbls/d)	8,090	9,958	10,907
Natural gas (Mcf/d)	20,789	44,346	51,767
BOE/d	11,555	17,349	19,535
Oil Price per Bbl Produced (in dollars)			
Realized price	$ 45.66	$ 55.92	$ 64.06
Realized commodity derivative loss and amortization of commodity derivative premiums	(7.46)	(8.38)	(4.35)
Net realized price	$ 38.20	$ 47.54	$ 59.71
Natural Gas Price per Mcf Produced (in dollars)			
Realized price	$ 7.45	$ 6.04	$ 6.61
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	(0.11)	0.36	0.23
Net realized price	$ 7.34	$ 6.40	$ 6.84
Average Sale Price per BOE(2)	$ 39.55	$ 44.13	$ 50.24
Expense per BOE			
Production expenses(3)	$ 12.81	$ 15.09	$ 16.74
Transportation expenses	$ 0.62	$ 0.61	$ 0.85
Depletion, depreciation and amortization	$ 5.14	$ 10.91	$ 13.86
General and administrative expense, net(4)	$ 3.79	$ 4.88	$ 4.46
Interest expense	$ 3.24	$ 8.52	$ 8.43

(1) Includes information for TexCal from March 31, 2006, the date of acquisition. Daily average production volumes shown represent (i) second, third and fourth quarter 2006 production from TexCal properties divided by 275 days plus (ii) production from other Venoco properties for the full year 2006 divided by 365 days. Total net production for 2006 divided by 365 days results in average net production of 15,882 BOE/d.

(2) Amounts shown are based on oil and natural gas sales, net of inventory changes, realized commodity derivative gains (losses), and amortization of commodity derivative premiums, divided by sales volumes.

(3) Production expenses are comprised of oil and natural gas production expenses and property and production taxes.

(4) Net of amounts capitalized.

Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006

Oil and Natural Gas Revenues. Oil and natural gas revenues increased $103.1 million (38%) to $377.9 million in 2007 from $274.8 million in 2006. The increase was primarily due to a 23% increase in production and a 14% increase in average sales prices as described below.

Oil revenues increased by $64.7 million in 2007 (34%) to $253.0 million compared to $188.3 million in 2006. Oil production rose 17%, with production of 3,981 MBbl in 2007 compared to 3,411 MBbl in 2006. The production increase was attributable primarily to the acquisition of the TexCal properties in March 2006, the Manvel field in April 2007 and the West Montalvo field in May 2007, and to our workover program in the Hastings complex. Our average realized price for oil increased $8.14 (15%) to $64.06 per Bbl for the period.

Natural gas revenues increased $38.4 million in 2007 (44%) to $124.9 million compared to $86.5 million in 2006. Natural gas production increased 32%, with production of 18,895 MMcf compared to 14,314 MMcf in 2006. The increase was due primarily to drilling and recompletion activities in the Sacramento Basin and production attributable to the March 2006 TexCal acquisition, offset by decreases in natural gas production at the South Ellwood field and the Santa Clara Federal Unit. Our average realized price for natural gas increased $0.57 (9%) to $6.61 per Mcf for the period.

Commodity Derivatives and Other Revenues. The following table sets forth the components of commodity derivative losses, net in our consolidated statements of operations for the years indicated (in thousands):

	Years Ended December 31,	
	2006	2007
Realized commodity derivative losses	$(15,263)	$ (13,041)
Unrealized commodity derivative gains (losses)	21,079	(122,779)
Amortization of derivative premiums and other comprehensive loss	(8,181)	(11,546)
Total	$ (2,365)	$(147,366)

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative losses in 2006 and 2007 reflect the settlement of contracts at prices above the relevant strike prices. Unrealized commodity derivative gains (losses) represent the change in the fair value of our open derivative contracts from period to period. The change in unrealized commodity derivative gains (losses) reflects an increase in the notional volumes under derivative contracts outstanding in 2007 and an increase in the futures prices used to estimate the fair value of those contracts at the end of the period. Derivative premiums are amortized over the term of the underlying derivative contracts. The increase in amortization of derivative premiums and other comprehensive losses in 2007 reflects additional premiums paid in connection with the additional contracts outstanding in 2007 and amortization of other comprehensive losses beginning in the second quarter of 2007.

Other revenue decreased 39%, from $5.5 million in 2006 to $3.4 million in 2007. The change was primarily due to lower transportation income received from purchasers of oil production from the South Ellwood field.

Production Expenses. Production expenses increased $31.8 million (36%) to $119.3 million in 2007 from $87.5 million in 2006. The increase was primarily due to production expenses attributable to the TexCal, Manvel and West Montalvo acquisitions and an increase in the number of producing wells at other Venoco properties. On a per unit basis, costs increased $1.65 per BOE (11%) from $15.09 per

BOE in 2006 to $16.74 per BOE in 2007, primarily due to remedial activities in the Hastings complex and at the Manvel and West Montalvo fields.

Transportation Expenses. Transportation expenses increased 72%, from $3.5 million in 2006 to $6.1 million in 2007. This was primarily attributable to increased transportation costs for barge deliveries. On a per BOE basis, transportation expenses increased $0.24 per BOE, from $0.61 per BOE in 2006 to $0.85 per BOE in 2007.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $35.5 million (56%) to $98.8 million in 2007 from $63.3 million in 2006. DD&A expense per BOE rose $2.95, from $10.91 per BOE in 2006 to $13.86 per BOE in 2007. The increase was primarily due to a higher depletion expense resulting from the increase in the oil and natural gas property cost as a result of the TexCal, Manvel and West Montalvo acquisitions and the increase in oil and natural gas property costs during the year resulting from our capital expenditure program.

Accretion of Abandonment Liability. Accretion expense increased $1.4 million (54%) to $3.9 million in 2007 from $2.5 million in 2006. The increase was due to accretion from the properties acquired in the TexCal, Manvel and West Montalvo acquisitions and from new wells drilled and completed in the second half of 2006 and in 2007.

General and Administrative (G&A). G&A expense, net of amounts capitalized, increased $3.5 million (12%) to $31.8 million in 2007 from $28.3 million in 2006. The increase resulted primarily from increases in our professional staff and related infrastructure costs, non-recurring charges of $1.3 million for the settlement of employment contracts in 2007 and a $1.6 million increase in non-cash SFAS 123R share based compensation expense in 2007. These increases were partially offset by an increase in the G&A costs that were capitalized for payroll and related overhead for activities that are directly related to our development, exploitation, exploration and acquisition efforts. On a per BOE basis, G&A expenses decreased $0.42 (9%), from $4.88 in 2006 to $4.46 in 2007.

Financing Costs and Other. Financing costs and other increased $40.4 million (76%) to $93.4 million in 2007 from $53.2 million in 2006. Interest expense, net of interest income, increased $11.3 million (23%) from $48.8 million in 2006 to $60.1 million in 2007. The increase was primarily due to an increase in average debt outstanding in 2007. Amortization of deferred loan costs increased $0.4 million, from $3.8 million in 2006 to $4.2 million in 2007, because the 2007 total reflects a full year of amortization of loan costs related to our second lien term loan facility compared to nine months of amortization in 2006 (the debt was initially incurred on March 31, 2006). Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized losses of $0.6 million in 2006 and $17.2 million in 2007. The change between years is the result of an increase in the notional amount of debt covered by the interest rate swap and a decrease in estimated interest rates used to determine the fair value of the derivative instruments. We incurred a loss on extinguishment of debt of $12.1 million in the second quarter of 2007 when we prepaid the prior second lien term loan facility and replaced it with the new term loan facility. We paid a premium of $3.5 million and wrote off related deferred loan costs of $8.6 million in connection with the prepayment of the prior term loan facility.

Income Tax Expense. The loss before taxes in 2007 resulted in an income tax benefit of $46.2 million compared to income tax expense of $15.6 million in 2006.

Net Income (Loss). Our net loss for 2007 was $73.4 million compared to net income of $24.0 million in 2006. The change between periods is the result of the items discussed above.

Comparison of Year Ended December 31, 2006 to Year Ended December 31, 2005

Oil and Natural Gas Revenues. Oil and natural gas revenues increased $83.7 million (44%) from $191.1 million in 2005 to $274.8 million in 2006. The increase was primarily due to production attributable to the TexCal acquisition and higher realized oil prices, partially offset by a 1% decrease in production from other Venoco properties. The decline in production volumes from other Venoco properties was the result of (i) the effect of our sale, on March 31, 2005, of the Big Mineral Creek field in Grayson County, Texas (which averaged net production of 547 BOE/d in the first quarter of 2005), (i) high initial production rates in early 2005 from new offshore oil wells which had recently come on line at that time and (iii) the effect of maintenance projects in the third quarter and early fourth quarter of 2006, which limited production volumes in those periods.

Oil revenues increased by $53.7 million (40%) from $134.6 million in 2005 to $188.3 million in 2006. Oil production rose 16%, with production of 3,411 MBbl in 2006 compared to 2,953 MBbl in 2005. The production increase was attributable to the TexCal properties acquired in March 2006, partially offset by an 8% decline in production volumes from other Venoco properties. The decline in production from other Venoco properties resulted from the factors discussed above. Our average realized price for oil increased $10.26 (22%) to $55.92 per Bbl for the period.

Natural gas revenues increased $30.0 million (53%) from $56.5 million in 2005 to $86.5 million in 2006. Natural gas production increased 89%, with production of 14,314 MMcf compared to 7,588 MMcf in 2005. The majority of the increase was due to production attributable to the TexCal properties acquired in March 2006. Production increased approximately 15% as a result of increased production from other Venoco properties. The increased production from other Venoco properties relates to our ongoing field development activities. Our average realized price for natural gas decreased $1.41 (19%) to $6.04 per Mcf for the period.

Commodity Derivatives and Other Revenues. The following table sets forth the components of commodity derivative losses, net in our consolidated statements of operations for the periods indicated (in thousands):

	Years Ended December 31,	
	2005	**2006**
Realized commodity derivative losses	$(20,658)	$(15,263)
Unrealized commodity derivative gains (losses)	(33,511)	21,079
Amortization of derivative premiums and other comprehensive loss	(4,701)	(8,181)
Total	$(57,595)	$ (2,365)

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative losses in 2005 and 2006 reflect the settlement of contracts at prices above the relevant strike prices. Unrealized commodity derivative gains (losses) represent the change in the fair value of our open derivative contracts from period to period. The change in unrealized commodity derivative gains (losses) reflects an increase in the notional volumes under derivative contracts outstanding in 2006 and a net decrease in the futures prices used to estimate the fair value of those contracts at the end of the period. Derivative premiums are amortized over the term of the underlying derivative contracts. The increase in amortization of derivative premiums and other comprehensive losses in 2006 reflects additional premiums paid in connection with the additional contracts outstanding in 2006. The decrease in total commodity derivative losses in 2006 resulted primarily from the non-recurrence in 2006 of the significant increases in commodity prices that occurred in 2005.

Other revenue increased 23%, from $4.5 million in 2005 to $5.5 million in 2006. This increase was primarily due to revenues of $2.3 million from a pipeline we acquired in the fourth quarter of 2005.

Production Expenses. Production expenses increased $33.5 million (62%) from $54.0 million in 2005 to $87.5 million in 2006. The increase was primarily due to production expenses attributable to the TexCal properties acquired in March 2006 and a 9% increase in production expenses from other

Venoco properties. The increase in production expenses for other Venoco properties relates to an increase in the number of producing wells, normal variances of timing of production expenses, including expenses relating to periodic maintenance projects, and increased costs of third party services. On a per unit basis, costs increased \$2.28 per BOE, from \$12.81 per BOE in 2005 to \$15.09 per BOE in 2006. A significant part of this increase was attributable to remedial work projects performed in the Hastings complex in the second half of the year. Per unit production expenses attributable to the TexCal properties rose from \$14.02 per BOE in 2005 to \$17.34 per BOE in 2006 primarily as a result of those projects. In addition, production expenses on a per unit basis for other Venoco properties increased 11% in 2006 due primarily to increased costs of services.

Transportation Expenses. Transportation expenses increased 36%, from \$2.6 million in 2005 to \$3.5 million in 2006. This was primarily attributable to volume increases. On a per BOE basis, transportation expenses decreased \$0.01 per BOE, from \$0.62 per BOE in 2005 to \$0.61 per BOE in 2006.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased \$41.6 million (192%) from \$21.7 million in 2005 to \$63.3 million in 2006. DD&A expense rose \$5.77 per BOE, from \$5.14 per BOE in 2005 to \$10.91 per BOE in 2006. The increase was primarily due to a higher depletion expense resulting from the increase in oil and natural gas property costs as a result of the March 2006 TexCal acquisition and an increase in future development costs.

Accretion of Abandonment Liability. Accretion expense increased \$0.8 million (45%) from \$1.8 million in 2005 to \$2.5 million in 2006. The increase was due to accretion from the acquired TexCal properties and from new wells drilled and completed in 2006.

General and Administrative (G&A). G&A expense increased \$12.3 million (77%) from \$16.0 million in 2005 to \$28.3 million in 2006. G&A expense rose \$1.09 per BOE (30%), from \$3.79 per BOE in 2005 to \$4.88 per BOE in 2006. The increase resulted primarily from increases in our professional staff and related infrastructure costs, non-cash SFAS 123R share based compensation expense of \$2.8 million in 2006, \$1.0 million in direct costs related to Sarbanes-Oxley compliance activities and other indirect costs for internal systems and process conversions, and \$0.5 million in expenses related to TexCal transition and integration activities.

Financing Costs and Other. Interest expense, net of interest income, increased \$35.1 million (257%) from \$13.7 million in 2005 to \$48.8 million in 2006. Amortization of deferred loan costs increased \$2.0 million (115%) from \$1.8 million in 2005 to \$3.8 million in 2006. We incurred \$0.5 million in unrealized losses in 2006 from changes in the fair value of our interest rate swap derivative instruments as a result of a decrease in estimated interest rates used to determine the fair value of the derivative instruments. The changes were primarily due to debt incurred in March 2006 to acquire TexCal.

Income tax expense. Income tax expense in 2006 was \$15.6 million compared to \$10.3 million for 2005. The change was due to an increase in income. Our effective tax rate decreased from 40.0% for 2005 to 38.6% for 2006 due to an increase of business activity in lower taxing jurisdictions.

Net Income. Net income for 2006 was \$24.0 million as compared to net income of \$16.1 million in 2005.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operations and amounts available under our revolving credit facility.

Cash Flows

	Years ended December 31,		
	2005	2006	2007
		(in thousands)	
Cash provided by operating activities	$ 39,931	$ 89,090	$ 160,863
Cash used in investing activities	(58,695)	(595,204)	(433,363)
Cash provided by (used in) financing activities	(26,562)	505,089	273,871

Net cash provided by operating activities was $160.9 million in 2007, up from $89.0 million in 2006 and $39.9 million in 2005. Cash flows from operating activities were favorably impacted in 2006 and 2007 by increases in commodity prices and production from properties acquired in those years and our development program.

Net cash used in investing activities was $433.4 million in 2007 compared to $595.2 million in 2006 and $58.7 million in 2005. The primary investing activities in 2007 include $316.9 million in expenditures for oil and gas properties and $121.8 million paid to acquire the West Montalvo and Manvel fields and other properties. The primary investing activities in 2006 include $447.5 million paid in cash to acquire TexCal (net of TexCal cash) and $185.2 million in expenditures for oil and gas properties. The primary investing activities in 2005 were $102.9 million used to develop and acquire oil and natural gas properties, partially offset by $44.6 million in net proceeds from the sale of oil and natural gas properties.

Net cash provided by financing activities was $273.9 million in 2007 compared to $505.1 million in 2006 and net cash used in financing activities of $26.6 million in 2005. The primary financing activities in 2007 were $151.1 million in net borrowings under the second lien term loan facility to fund capital expenditures and working capital needs and $11.4 million in net borrowings under the revolving credit facility. Net proceeds from an additional offering of common stock completed in July 2007 were $116.0 million, of which $95.0 million was used to pay down amounts outstanding under our revolving credit facility; the remainder was used to fund our capital expenditure program. Proceeds from long-term debt in 2006 included $350.0 million borrowed under the prior term loan facility and $119.5 million in net borrowings under the revolving credit facility, which amounts were primarily used to fund the acquisition of TexCal and $14.4 million in loan costs. Net proceeds from our initial public offering of common stock in November 2006 were $157.5 million, of which $156.5 million and $1.1 million were used to reduce amounts outstanding under the revolving credit facility and the second lien term loan facility, respectively. Other net borrowings in 2006 under the revolving credit facility of $47.5 million were used to fund capital expenditures and working capital needs. Net cash used in financing activities in 2005 related primarily to the payment of a $35.0 million dividend to our then-sole stockholder, $5.3 million used to purchase the interests of minority stockholders and principal repayments on long-term debt of $43.7 million, partially offset by $59.0 million in new borrowings under our credit agreement.

Capital Resources and Requirements

We plan to make substantial capital expenditures in the future for the acquisition, exploration, exploitation and development of oil and natural gas properties. We expect that our exploration, exploitation and development capital expenditures, which were $310.1 million in 2007, will be approximately $235.0 million in 2008. We intend to finance these capital expenditures primarily with cash flow from operations. We expect to supplement our capital budget with additional amounts borrowed under our revolving credit facility, in particular to satisfy short-term working capital needs, but do not currently expect our total indebtedness to increase significantly by the end of 2008 relative to total indebtedness of $732.0 million at March 10, 2008. As of that date, we had $57.3 million in unused borrowing capacity under the revolving credit facility. Uncertainties relating to our capital resources and requirements in 2008 include those associated with the planned master limited partnership offering discussed below and the possibility that we will pursue one or more significant acquisitions that would require additional debt or equity financing. In addition, as discussed in "Business and Properties—Description of Properties—Texas," we have entered into an agreement pursuant to which Denbury Resources has an option to acquire our interest in part of the Hastings complex for cash or by entering into a volumetric production payment or similar arrangement with us. If the option is exercised, the consideration we would receive would be a significant additional source of liquidity, subject to potential mandatory repayment requirements under our credit facilities. However, we would not expect to receive any such consideration until the first quarter of 2009 at the earliest.

Master Limited Partnership. A recently-formed subsidiary of ours, Venoco Acquisition Company, L.P., which we refer to as the master limited partnership or the MLP, has filed a preliminary registration statement on Form S-1 in connection with a proposed offering of common units representing limited partnership interests in the MLP. We expect to capitalize the MLP through the contribution of our interests in certain onshore fields in California and a portion of our interests in the South Ellwood field and in the Hastings complex. We anticipate receiving an initial cash distribution in connection with the offering of MLP interests, but the amount of the distribution, if any, has not been determined. We currently expect to use any such distribution, net of any required tax payments, to reduce indebtedness under one or both of our credit facilities or to repurchase or redeem some or all of our senior notes. The nature, amount and timing of such a reduction in indebtedness will depend on a variety of factors, including the amount of the distribution and the amount then outstanding under our revolving credit facility. In some circumstances, we would be required to use some or all of the distribution to reduce the amount outstanding under the revolving credit facility. Our plans with respect to the MLP, the MLP offering and any related distribution to us may change, and we cannot assure you that any MLP offering will be completed. We expect the MLP offering to be completed only if capital market conditions are favorable.

Amended Revolving Credit Facility. We entered into a second amended and restated agreement governing our revolving credit facility in March 2006, and have entered into several subsequent amendments to the agreement. The borrowing base under the facility is currently $140.0 million. The agreement contains customary representations, warranties, events of default, indemnities and covenants, including operational covenants that restrict our ability to incur indebtedness and financial covenants that require us to maintain specified ratios of EBITDA (as defined in the agreement) to interest expense, current assets to current liabilities, debt to EBITDA and PV-10 to total debt. The agreement will require us to reduce amounts outstanding under the facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. The completion of the MLP offering could result in a reduction of the borrowing base under the facility, and thus require us to prepay some of the borrowings then outstanding under the facility. Principal on the revolving credit facility is payable on March 30, 2009. The revolving credit facility is secured by a first priority lien on substantially all of our assets.

Loans under the revolving credit facility designated as "Base Rate Loans" bear interest at a floating rate equal to (i) the greater of Bank of Montreal's announced base rate and the overnight federal funds rate plus 0.50% plus (ii) an applicable margin ranging from zero to 0.75%, based upon utilization. Loans designated as "LIBO Rate Loans" under the revolving credit facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.50% to 2.25%, based upon utilization. A commitment fee ranging from 0.375% to 0.5% per annum is payable with respect to unused borrowing availability under the facility.

Second Lien Term Loan. We entered into a new second lien term loan agreement in May 2007 to refinance and replace our prior second lien term loan facility. We borrowed $500.0 million pursuant to the new term loan agreement, of which $350.5 million was used to repay all amounts outstanding under the prior second lien term loan facility plus accrued interest, $3.5 million was used to pay a prepayment premium on those amounts and $4.6 million was used to pay transaction costs associated with the new facility. The remaining borrowings were used to reduce amounts then outstanding under our revolving credit facility.

The term loan agreement contains customary representations, warranties, events of default and indemnities and certain customary covenants, including covenants that restrict our ability to incur additional indebtedness. The covenants and other terms of the agreement contain exceptions that are intended to permit us to form an MLP and certain related entities, to contribute assets to the MLP, to sell securities of the MLP and to cause the MLP to incur indebtedness and issue securities, subject in each case to the satisfaction of certain requirements. The agreement requires us to maintain derivative contracts covering at least 70% of our projected oil and natural gas production attributable to proved developed producing reserves through May 8, 2010, and at least 50% of such production on an annual basis thereafter. We cannot, however, enter into derivative contracts (other than certain put contracts) covering more than 80% of such oil and gas production in any month. The agreement also prohibits us from paying dividends on our common stock. The agreement will require us to make offers to prepay amounts outstanding under the second lien term loan facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. Amounts prepaid under the facility may not be reborrowed. The new term loan facility is secured by a second priority lien on substantially all of our assets.

Loans under the term loan facility designated as "Base Rate Loans" bear interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and the administrative agent's announced base rate, plus (ii) 3.00%. Loans designated as "LIBO Rate Loans" bear interest at LIBOR plus 4.00%. We have entered into interest rate swaps pursuant to which amounts borrowed under the new term loan agreement will effectively bear interest at a fixed rate of approximately 9.3% until June 2010. See "—Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Derivative Transactions."

Senior Notes. We issued $150.0 million of our senior notes in December 2004. The notes bear interest at 8.75% per year and will mature on December 15, 2011. We may redeem the notes after December 15, 2008, initially at a redemption price equal to 104.375% of the principal amount. In addition, before December 15, 2008, we may redeem all or part of the notes at a specified "make-whole" price. Upon the occurrence of a change of control of our company, each holder of notes may require us to repurchase all or a portion of its notes for cash at a price equal to 101% of the aggregate principal amount of those notes, plus any accrued and unpaid interest. The indenture governing the notes also contains operational covenants that, among other things, limit our ability to make investments, incur additional indebtedness or create liens on our assets. The notes are guaranteed by all of our subsidiaries other than Ellwood Pipeline, Inc. and are secured with the second lien term loan on an equal and ratable basis.

Because we must dedicate a substantial portion of our cash flow from operations to the payment of interest on our debt, that portion of our cash flow is not available for other purposes. Our ability to make scheduled interest payments on our indebtedness and pursue our capital expenditure plan will depend to a significant extent on our financial and operating performance, which is subject to prevailing economic conditions, commodity prices and a variety of other factors. If our cash flow and other capital resources are insufficient to fund our debt service obligations and our capital expenditure budget, we may be forced to reduce or delay scheduled capital projects, sell material assets or operations and/or seek additional capital. Needed capital may not be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness and certain other means is limited by covenants in our debt agreements. In addition, pursuant to mandatory prepayment provisions in our credit facilities, our ability to respond to a shortfall in our expected liquidity by selling assets or incurring additional indebtedness would be limited by provisions in the facilities that require us to use some or all of the proceeds of such transactions to reduce amounts outstanding under one or both of the facilities in some circumstances. If we are unable to obtain funds when needed and on acceptable terms, we may not be able to complete acquisitions that may be favorable to us, meet our debt obligations or finance the capital expenditures necessary to replace our reserves.

Commitments and Contingencies

As of December 31, 2007, the aggregate amounts of contractually obligated payment commitments for the next five years were as follows (in thousands):

	Less than One Year	1 to 3 Years	3 to 5 Years	After 5 years	Total(1)
Long-term debt	$ 3,449	$42,443	$649,453	$ —	$695,345
Interest on senior notes	13,125	26,250	12,514	—	51,889
Rental of office space	2,235	4,899	4,607	10,307	22,048
Total	$18,809	$73,592	$666,574	$10,307	$769,282

(1) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts, obligations to taxing authorities or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations, due to the uncertainty surrounding the ultimate settlement amounts and timing of these obligations. Our total asset retirement obligations were $52.2 million at December 31, 2007.

(2) Amounts related to interest expense on our revolving credit facility and second lien term loan facility are not included in the table above because the interest rates on those debt instruments are variable. During the years ended December 31, 2005, 2006 and 2007, we incurred interest expense on those debt instruments of $0.6 million, $35.4 million and $50.0 million, respectively.

Off-Balance Sheet Arrangements

At December 31, 2007, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon financial statements that have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain accounting policies as being of particular importance to the presentation of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and natural gas revenues, oil and natural gas properties, fair value of derivative instruments, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies and estimates affect our more significant judgments and estimates used in the preparation of our financial statements.

Reserve Estimates

Our estimates of oil and natural gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulation by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on the likelihood of recovery and estimates of the future net cash flows expected from them may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value and the rate of depletion of the oil and natural gas properties. For example, oil and natural gas price changes affect the estimated economic lives of oil and natural gas properties and therefore cause reserve revisions. Our December 31, 2007 estimate of net proved oil and natural gas reserves totaled 99.9 MBOE. Had oil and natural gas prices been 10% lower as of the date of the estimate, our total oil and natural gas reserves would have been approximately 0.6% lower. In addition, our proved reserves are concentrated in a relatively small number of wells. At December 31, 2007, 17% of our proved reserves were concentrated in our twenty-one largest wells. As a result, any changes in proved reserves attributable to such individual wells could have a significant effect on our total reserves. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Oil and Natural Gas Properties, Depletion and Full Cost Ceiling Test

We follow the full cost method of accounting for oil and natural gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition of, exploration for and exploitation and development of oil and natural gas reserves are capitalized. Such capitalized costs include costs associated with lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and natural gas wells, and salaries, benefits and other internal salary related costs directly attributable to these activities. Proceeds from the disposition of oil and natural gas properties are generally accounted for as a reduction in capitalized costs, with no gain or loss recognized. Depletion of the capitalized costs of oil and natural gas properties, including estimated future development and capitalized asset retirement costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the capitalized investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. For example, a 10% reduction in our estimated reserves as of December 31, 2007 would have resulted in an increase of approximately $1.39 per BOE in our depletion expense rate during 2007. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Unproved property costs not subject to amortization consist primarily of leasehold and seismic costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves established or impairment determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized, but are assessed for impairment either individually or on an aggregated basis using a comparison of the carrying values of the unproved properties to net future cash flows.

Capitalized costs of oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the last day of the relevant quarter, including the effects of cash flow hedges, and requires a write down for accounting purposes if the ceiling is exceeded. At December 31, 2007, our net capitalized costs did not exceed the ceiling. We last incurred a write down due to the ceiling test at the end of 1998, at which time our net capitalized cost exceeded the ceiling by $6.5 million, net of income tax effects, and we recorded a write down of our oil and natural gas properties in that amount.

Asset Retirement Obligations

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). SFAS 143 provides that, if the fair value for asset retirement obligations can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and natural gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with the offsetting charge to property cost. Periodic accretion of discount of the estimated liability is recorded in the income statement. Prior to adoption of SFAS No. 143, we accrued for future abandonment costs of wells and related facilities through our depletion calculation in accordance with Regulation S-X Rule 4-10 and industry practice. This method resulted in recognition of the obligation over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our properties at the end of their productive lives, in accordance with applicable laws. We have determined our asset retirement obligation by calculating the present value of estimated cash flows related to each liability. The discount rates used to calculate the present value varied depending on the estimated timing of the relevant obligation, but typically ranged between 6% and 8%. We periodically review the estimate of costs to plug, abandon and remediate our properties at the end of their productive lives. This includes a review of both the estimated costs and the expected timing to incur such costs. We believe most of these costs can be estimated with reasonable certainty based upon existing laws and regulatory requirements and based upon wells and facilities currently in place. Any changes in regulatory requirements, which changes cannot be predicted with reasonable certainty, could result in material changes in such costs. Changes in reserve estimates and the economic life of oil and natural gas properties could affect the timing of such costs and accordingly the present value of such costs.

Income Tax Expense

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. We have not recognized a valuation allowance against our net deferred taxes because we believe that it is more likely than not that the net deferred tax assets will be realized based on estimates of our future operating income.

Derivative Instruments

Under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, we reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity swap agreements, and in substantially similar changes in the fair value of our commodity collars to the extent the changes are outside the floor or cap of our collars.

Recent Accounting Pronouncements

In December 2007, the FASB issued Statement SFAS No. 141, *Business Combinations* ("SFAS 141R"), and SFAS No. 160, *Accounting and Reporting of Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51* ("SFAS 160"). SFAS 141R and SFAS 160 will significantly change the accounting for and reporting of business combination transactions and noncontrolling (minority) interests in consolidated financial statements. SFAS 141R retains the fundamental requirements in Statement 141, *Business Combinations*, while providing additional definitions, such as the definition of the acquirer in a purchase and improvements in the application of how the acquisition method is applied. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests, and classified as a component of equity. These Statements become simultaneously effective January 1, 2009. Early adoption is not permitted. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on the Company's operating results, financial position or cash flows.

In May 2007, the FASB issued FSP No. FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48*, ("FIN 48-1") which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is "effectively," rather than, as previously required, "ultimately," settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. We have adopted FIN 48-1 and no retroactive adjustments were necessary.

In April 2007, the FASB issued Staff Position (FSP) No. FIN 39-1, *Amendment of FASB Interpretation No. 39*, ("FIN 39-1") to amend FIN 39, *Offsetting of Amounts Related to Certain Contracts* ("FIN 39"). The terms "conditional contracts" and "exchange contracts" used in FIN 39 have been replaced with the more general term "derivative contracts." In addition, FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a company's accounting policy with respect to offsetting fair value amounts. The guidance in FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. We are currently assessing the impact, if any, that the adoption of this pronouncement will have on our operating results, financial position and cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* ("SFAS 159"), which permits entities to choose to measure many financial instruments and certain other items at fair value (the Fair Value Option). Election of the Fair Value Option is made on an instrument-by-instrument basis and is irrevocable. At the adoption date, unrealized gains and losses on financial assets and liabilities for which the Fair Value Option has been elected would be reported as a cumulative adjustment to beginning retained earnings. If we elect the Fair Value Option for certain financial assets and liabilities, we will report unrealized gains and losses due to changes in fair value in earnings at each subsequent reporting date. The provisions of SFAS 159 are effective January 1, 2008. We are currently assessing the impact, if any, that the adoption of this pronouncement will have on our operating results, financial position and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurement. The provisions of SFAS 157 are effective for us on January 1, 2008. We are currently assessing the impact, if any, that the adoption of this pronouncement will have on our operating results, financial position and cash flows.

PV-10 Value and Reserve Replacement Costs

PV-10 Value

The pre-tax present value of future net cash flows, or PV-10 value, is a non-GAAP measure because it excludes income tax effects. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a company's unique tax position and strategies, can make after-tax amounts less comparable. We derive PV-10 value based on the present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs and future plugging and abandonment costs, using prices and costs as of the date of estimate without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%. The following table reconciles the standardized measure of future net cash flows to PV-10 value as of the dates shown (in thousands):

	December 31,		
	2005(1)	2006(2)	2007(3)
Standardized measure of discounted future net cash flows	$565,385	$ 819,302	$1,655,641
Add: Present value of future income tax discounted at 10%	328,445	301,774	703,674
PV-10 value	$893,830	$1,121,076	$2,359,315

(1) Based on unescalated prices of (i) $57.75 per Bbl for oil and natural gas liquids, adjusted for quality, transportation fees and regional price differentials and (ii) $10.08 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $5.64 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

(3) Based on unescalated prices of $95.97 per Bbl for oil and natural gas liquids and $7.48 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

Reserve Replacement Costs

We discuss our historical reserve replacement costs in "Business and Properties—Our Strengths—Attractive Reserve Replacement Costs." We define the term "reserve replacement cost" to mean an amount per BOE equal to the sum of all costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers as of the end of the relevant period, and includes, where applicable, production from the date acquisitions were completed through the date of the reserve report. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, our historical reserve replacement costs are not necessarily indicative of the reserve replacement costs we will incur in the future. Historical sources of reserve additions, such as acquisitions, may be more expensive or unavailable in the future. Increases in commodity prices in recent years, and corresponding increases in the market value of oil and natural gas properties, have resulted in increases in our reserve replacement costs. In addition, some companies define reserve replacement cost differently than we do, a fact that limits the usefulness of reserve replacement cost as a comparative measure in some circumstances.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

This section provides information about derivative financial instruments we use to manage commodity price volatility. Due to the historical volatility of crude oil and natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of the prices we receive for our production and providing a minimum revenue stream. Currently, we purchase puts and enter into other derivative transactions such as collars and fixed price swaps in order to hedge our exposure to changes in commodity prices. All contracts are settled with cash and do not require the delivery of a physical quantity to satisfy settlement. While this hedging strategy may result in us having lower revenues than we would have if we were unhedged in times of higher oil and natural gas prices, management believes that the stabilization of prices and protection afforded us by providing a revenue floor on a portion of our production is beneficial.

This section also provides information about derivative financial instruments we use to manage interest rate risk. See "—Interest Rate Derivative Transactions."

Commodity Derivative Transactions

Oil. As of December 31, 2007, we had entered into option (including collar) agreements to receive average minimum and maximum NYMEX West Texas Intermediate prices as summarized below. Location and quality differentials attributable to our properties are not reflected in those prices. The agreements provide for monthly settlement based on the differential between the agreement price and the actual NYMEX crude oil price.

	Minimum		Maximum	
	Bbls/d	**Weighted Avg. Prices**	**Bbls/d**	**Weighted Avg. Prices**
Crude oil derivatives at December 31, 2007 for production:				
January 1 - December 31, 2008	10,100	$63.02	8,100	$73.46
January 1 - December 31, 2009	6,983	58.09	6,983	74.38
January 1 - December 31, 2010	6,150	61.10	6,150	72.88

Natural Gas. As of December 31, 2007, we had entered into option, swap and collar agreements to receive average minimum and maximum NYMEX or PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/d	Weighted Avg. Prices	MMBtu/d	Weighted Avg. Prices
Natural gas derivatives at December 31, 2007 for production:				
January 1 - December 31, 2008	20,650	$7.59	19,097	$11.27
January 1 - December 31, 2009	14,625	7.65	14,625	11.57
January 1 - December 31, 2010	11,900	7.22	11,900	10.57

Portfolio of Derivative Transactions

Our portfolio of commodity derivative transactions as of December 31, 2007 is summarized below:

Oil

Type of Contract	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	NYMEX	3,450	$52.00/$75.00	Jan 1 - Jun 30, 08
Collar	NYMEX	2,450	$52.00/$75.00	Jul 1 - Dec 31, 08
Collar	NYMEX	1,000	$58.00/$78.00	Jul 1 - Dec 31, 08
Collar	NYMEX	1,500	$58.00/$75.25	Jan 1 - Dec 31, 08
Swap	NYMEX	2,500	$67.25	Jan 1 - Dec 31, 08
Collar	NYMEX	800	$60.00/$82.75	Jan 1 - Dec 31, 08
Collar	NYMEX	(150)	$60.00/$82.75	Jan 1 - Dec 31, 08
Put	NYMEX	2,000	$80.00	Jan 1 - Dec 31, 08
Collar	NYMEX	2,170	$50.00/$75.00	Jan 1 - Jun 30, 09
Collar	NYMEX	1,000	$56.00/$79.25	Jul 1 - Dec 31, 09
Collar	NYMEX	3,000	$55.00/$77.00	Jan 1 - Dec 31, 09
Swap	NYMEX	2,000	$67.22	Jan 1 - Dec 31, 09
Collar	NYMEX	750	$60.00/$82.75	Jan 1 - Dec 31, 09
Collar	NYMEX	(700)	$60.00/$82.75	Jan 1 - Jun 30, 09
Collar	NYMEX	1,000	$60.00/$72.80	Jan 1 - Dec 31, 10
Collar	NYMEX	3,500	$60.00/$73.00	Jan 1 - Dec 31, 10
Swap	NYMEX	1,000	$66.75	Jan 1 - Dec 31, 10
Collar	NYMEX	650	$60.00/$81.75	Jan 1 - Dec 31, 10

Natural Gas

Type of Contract	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Put	NYMEX	6,000	$8.00 Floor	Jan 1 - Dec 31, 08
Call	NYMEX	4,513	$12.15 Cap	Jan 1 - Jun 30, 08
Call	NYMEX	4,382	$10.60 Cap	Jul 1 - Dec 31, 08
Collar	NYMEX	7,500	$8.00/$12.75	Jan 1 - Dec 31, 08
Collar	NYMEX	5,700	$7.75/$10.05	Jan 1 - Dec 31, 08
Basis Swap	PG&E Citygate	10,000	$(0.32)	Jan 1 - Dec 31, 08
Basis Swap	PG&E Citygate	10,000	$(0.38)	Jan 1 - Dec 31, 08
Collar	NYMEX	1,450	$8.00/$12.95	Jan 1 - Dec 31, 08
Swap	NYMEX	1,250	$8.72 Fixed	Jan 1 - Jun 30, 09
Collar	NYMEX	1,250	$7.75/$13.05	Jan 1 - Jun 30, 09
Swap	NYMEX	1,250	$8.00 Fixed	Jul 1 - Dec 31, 09
Collar	NYMEX	1,250	$7.25/$11.30	Jul 1 - Dec 31, 09
Collar	NYMEX	7,000	$7.50/$12.75	Jan 1 - Dec 31, 09
Basis Swap	PG&E Citygate	6,000	$0.10	Jan 1 - Dec 31, 09
Basis Swap	PG&E Citygate	7,500	$0.11	Jan 1 - Dec 31, 09
Collar	NYMEX	4,000	$7.30/$9.85	Jan 1 - Dec 31, 09
Collar	NYMEX	1,125	$8.00/$12.00	Jan 1 - Dec 31, 09
Collar	NYMEX	10,000	$7.00/$10.35	Jan 1 - Dec 31, 10
Basis Swap	PG&E Citygate	10,000	$0.22	Jan 1 - Dec 31, 10
Collar	NYMEX	1,000	$7.00/$9.10	Jan 1 - Dec 31, 10
Collar	NYMEX	900	$7.50/$12.20	Jan 1 - Dec 31, 10

In February 2008, we entered into additional derivative contracts for oil and natural gas production from March 2008 through December 2011 as summarized below.

Oil

Type of Contract	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	NYMEX	1,000	$70.00/$130.75	Mar 1 - Dec 31, 08
Collar	NYMEX	1,000	$70.00/$140.00	Jan 1 - Dec 31, 09
Collar	NYMEX	1,000	$70.00/$150.00	Jan 1 - Dec 31, 10
Collar	NYMEX	2,000	$70.00/$144.75	Jan 1 - Dec 31, 11
Collar	NYMEX	2,000	$70.00/$141.00	Jan 1 - Dec 31, 11
Collar	NYMEX	3,000	$70.00/$140.00	Jan 1 - Dec 31, 11

Natural Gas

Type of Contract	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Collar	NYMEX	12,000	$7.50/$11.75	Mar 1 - Dec 31, 08
Collar	NYMEX	8,500	$7.50/$11.15	Jan 1 - Dec 31, 09
Collar	NYMEX	6,000	$7.50/11.95	Jan 1 - Dec 31, 10
Collar	NYMEX	12,000	$7.50/$13.50	Jan 1 - Dec 31, 11

We enter into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. The objective of our hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. Our hedging activities mitigate our exposure to price declines and allow us more flexibility to continue to execute our capital plan even if prices decline. Our collar and swap contracts, however, prevent us from receiving the full advantage of increases in oil or natural gas prices above the maximum fixed amount specified in the hedge agreement. Also, if production is less than the amount we have hedged and the price of oil or natural gas exceeds a fixed price in a hedge contract, we will be required to make payments against which there are no offsetting sales of production. This could impact our ability to fund future capital expenditures. In addition, we have incurred, and may incur in the future, substantial unrealized commodity derivative losses in connection with our hedging activities, although we do not expect such losses to have a material effect on our ability to fund expected capital expenditures. Finally, the use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts.

Because a large portion of our commodity derivatives do not qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting effective April 1, 2007. Consequently, from that date forward, we have recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

All derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of derivatives are recorded in commodity derivative gains (losses) on the consolidated statement of operations.

Interest Rate Derivative Transactions

We are subject to interest rate risk with respect to amounts borrowed under our credit facilities because those amounts bear interest at variable rates. As of March 10, 2008, there was approximately $582.0 million outstanding under those facilities. We have entered into two interest rate swap transactions to limit our exposure to changes in interest rates with respect to our second lien term loan facility. In May 2006, we entered into a swap to lock in our interest cost on $200.0 million of borrowings through May 2008. In June 2007, we entered into a second swap to lock in our interest cost on $300.0 million of borrowings through May 2008 and on $500.0 million of borrowings from May 2008 through June 2010. As a result of these transactions, amounts borrowed under the second lien term loan facility will effectively bear interest at a fixed rate of approximately 9.3% until June 2010. Accordingly, we expect to be subject to interest rate risk until that time only with respect to amounts borrowed under the revolving credit facility. A 1.0% increase in interest rates on unhedged variable rate borrowings of $42.0 million at December 31, 2007 would result in additional annualized interest expense of $0.4 million. As of December 31, 2007, the fair value of our interest rate derivatives was a liability of $17.8 million.

See notes to our consolidated financial statements for a discussion of our long-term debt as of December 31, 2007.

Item 8. Financial Statements and Supplementary Data

See "Index to Financial Statements" on page F-1 of this report.

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

None.

Item 9A. Controls and Procedures

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications. Included in this report is the report of Deloitte & Touche LLP, our independent registered public accounting firm, regarding its audit of our internal control over financial reporting. This section should be read in conjunction with the certifications and the Deloitte & Touche LLP report for a more complete understanding of the topics presented.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2007. This evaluation was conducted under the supervision and with the participation of management, including our CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that, subject to the limitations noted in this section, as of December 31, 2007, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed our internal control over financial reporting as of December 31, 2007, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, our independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Effectiveness of Controls. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2008 annual stockholders' meeting and is incorporated by reference in this report. Certain information concerning our executive officers is set forth in "Business and Properties—Executive Officers of the Registrant."

Item 11. Executive Compensation

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2008 annual stockholders' meeting and is incorporated by reference in this report.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2008 annual stockholders' meeting and is incorporated by reference in this report.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2008 annual stockholders' meeting and is incorporated by reference in this report.

Item 14. Principal Accounting Fees and Services

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2008 annual stockholders' meeting and is incorporated by reference in this report.

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1.

Exhibits

Exhibit Number	Exhibit
3.1	Restated Certificate of Incorporation of Venoco, Inc. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
3.2	Bylaws of Venoco, Inc. (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
4.2	Indenture, dated as of December 20, 2004, by and among Venoco, Inc., the Guarantors party thereto and U.S. Bank National Association, as Trustee, and supplemental indenture dated as of December 14, 2007.
10.1	Second Amended and Restated Credit Agreement, dated as of March 30, 2006, by and among Venoco, Inc. and Bank of Montreal, as Administrative Agent and Lead Syndication Agent, Harris Nesbitt Corp., as Lead Arranger, Credit Suisse Securities (USA) LLC and Lehman Brothers Inc., as Co-Arrangers, and Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents and Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.1.1	First Amendment to the Second Amended and Restated Credit Agreement, dated as of May 2, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1.1 to Pre-Effective Amendment No. 2 to the Registration Statement on Form S-1 of Venoco, Inc. filed on June 12, 2006).
10.1.2	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of October 25, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1.2 to Pre-Effective Amendment No. 5 to the Registration Statement on Form S-1 of Venoco, Inc. filed on October 30, 2006).
10.1.3	Third Amendment to the Second Amended and Restated Credit Agreement, dated as of November 29, 2006, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 1, 2006).

Exhibit Number	Exhibit
10.1.4	Fourth Amendment to the Second Amended and Restated Credit Agreement, dated as of March 1, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on March 7, 2007).
10.1.5	Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 7, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, Credit Suisse, Cayman Islands Branch and Lehman Commercial Paper Inc., as Co-Syndication Agents, and Fortis Capital Corp., as Documentation Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on May 11, 2007).
10.2	Term Loan Agreement, dated as of May 7, 2007, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Credit Suisse, Cayman Islands Branch, as Administrative Agent, UBS Securities LLC, as Syndication Agent, Credit Suisse Securities (USA) LLC and UBS Securities LLC, as Joint Lead Arrangers, Lehman Commercial Paper Inc. and Bank of Montreal, as Co-Documentation Agents, and Lehman Brothers Inc. and BMO Capital Markets Corp., as Co-Arrangers, and First Amendment to Term Loan Agreement, dated as of November 7, 2007.
10.3	Collateral Trust Agreement, dated as of March 30, 2006, by and between Venoco, Inc. and Credit Suisse, Cayman Islands Branch, as Administrative Agent and Collateral Trustee (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.4	Option Agreement, dated as of November 1, 2006, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on November 9, 2006).
10.5	Contract of Affreightment, dated as of March 13, 1998, by and between Public Service Marine Inc. and Venoco, LLC (incorporated by reference to Exhibit 10.4 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).
10.5.1	First Amendment to Contract of Affreightment, by and between Public Service Marine Inc. and Venoco, Inc. (incorporated by reference to Exhibit 10.5 to Pre-Effective Amendment No. 1 to the Registration Statement on Form S-4 of Venoco, Inc. filed on April 20, 2005).
10.6	Platform Agreement, dated as of March 1, 2006, by and between Venoco, Inc. and Clearwater Port, LLC (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.7	Venoco, Inc. 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).
10.7.1	Form of Non-Qualified Stock Option Agreement for Non-Employee Directors Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.7.2	Form of Non-Qualified Stock Option Agreement for Non-Executive Officer Employees Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).

Exhibit Number	Exhibit
10.7.3	Form of Amendment to Nonqualified Stock Option Agreement Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.7.4	Form of Bonus Payment Agreement Relating to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.8	Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 12, 2006).
10.8.1	Amendment No. 1 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.8.2	Form of Non-Qualified Stock Option Agreement Pursuant to the 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 the Current Report on Form 8-K of Venoco, Inc. filed on May 12, 2006).
10.8.3	Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.8.4	Venoco, Inc. 2007 Long-Term Incentive Program (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.9	Venoco, Inc. 2007 Senior Executive Bonus Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.10	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Timothy Marquez (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.11.1	Employment Agreement, dated as of January 25, 2005, by and between Venoco, Inc. and William Schneider (incorporated by reference to Exhibit 10.11 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).
10.11.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and William Schneider (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.12	Employment Agreement, dated as of March 19, 2007, by and between Venoco, Inc. and Timothy A. Ficker (incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 2, 2007).
10.13.1	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Terry Anderson (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.13.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and Terry Anderson (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.14.1	Employment Agreement, dated as of August 15, 2005, by and between Venoco, Inc. and Mark DePuy (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).

Exhibit Number	Exhibit
10.14.2	Non-Qualified Stock Option Agreement, dated as of August 15, 2005, by and between Venoco, Inc. and Mark DePuy (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.15.1	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and David Christofferson (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.15.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and David Christofferson (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.15.3	Separation Agreement, dated as of January 29, 2007, by and between Venoco, Inc. and David Christofferson (incorporated by reference to Exhibit 10.10.3 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 2, 2007).
10.16	Form of Amendment to Employment Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on July 12, 2006).
10.17	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 31, 2005).
10.18	Registration Rights Agreement, dated as of August 25, 2006, by and between Venoco, Inc. and the Marquez Trust (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.18.1	Amendment to Registration Rights Agreement and Joinder, dated as of May 23, 2007, by and among Venoco, Inc., the Marquez Trust and the Marquez Foundation (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 25, 2007).
10.19	Indemnity and Guaranty Agreement, dated as of March 22, 2006, by the Marquez Trust in favor of Venoco, Inc. (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.20	Assignment and Subordination of Master Lease and Consent of Master Tenant, dated as of December 9, 2004, by and among 6267 Carpinteria Avenue, LLC, Venoco, Inc. and German American Capital Corporation (incorporated by reference to Exhibit 10.30 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.20.1	Ground Lease, dated as of August 29, 2006, by and between Venoco, Inc. and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.20.2	Development Agreement, dated as of August 29, 2006, by and between Venoco, Inc. and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
10.20.3	Dividend Distribution Agreement, dated as of August 29, 2006, by and among Venoco, Inc., the Marquez Trust and Carpinteria Bluffs, LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K of Venoco, Inc. filed on August 31, 2006).
21.1	Subsidiaries of the Registrant
23.1	Consent of Deloitte & Touche LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.

Exhibit Number	Exhibit
23.3	Consent of DeGolyer & MacNaughton.
31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VENOCO, INC.

By:	/s/ TIMOTHY M. MARQUEZ
Name:	Timothy M. Marquez
Title:	*Chairman and Chief Executive Officer*
Date:	March 14, 2008

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

Signature	Title	Date
/s/ TIMOTHY M. MARQUEZ Timothy M. Marquez	Chairman and Chief Executive Officer (Principal Executive Officer)	March 14, 2008
/s/ TIMOTHY A. FICKER Timothy A. Ficker	Chief Financial Officer (Principal Financial Officer)	March 14, 2008
/s/ DOUGLAS J. GRIGGS Douglas J. Griggs	Chief Accounting Officer (Principal Accounting Officer)	March 14, 2008
J. Timothy Brittan	Director	
/s/ J.C. MCFARLAND J.C. McFarland	Director	March 14, 2008
/s/ JOEL L. REED Joel L. Reed	Director	March 14, 2008
/s/ M. W. SCOGGINS M. W. Scoggins	Director	March 14, 2008
/s/ MARK A. SNELL Mark A. Snell	Director	March 14, 2008
/s/ RICHARD S. WALKER Richard S. Walker	Director	March 14, 2008

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Venoco, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Venoco Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 14, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Venoco, Inc.
Denver, Colorado

We have audited internal control over financial reporting of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007 of the Company and our report dated March 14, 2008 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 14, 2008

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except shares amounts)

	December 31, 2006	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8,364	$ 9,735
Accounts receivable, net of allowance for doubtful accounts of $1,250 and $850 at December 31, 2006 and 2007, respectively	48,042	55,597
Inventories	3,211	10,377
Prepaid expenses and other current assets	7,226	4,391
Income tax receivable	8,098	6,725
Deferred income taxes	879	21,967
Commodity derivatives	10,348	7,780
Total current assets	86,168	116,572
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Oil and natural gas properties (full cost method, of which $4,850 and $12,034 for unproved properties were excluded from amortization at December 31, 2006 and 2007, respectively)	881,570	1,331,531
Drilling equipment	13,731	14,460
Other property and equipment	12,380	17,208
Total property, plant and equipment	907,681	1,363,199
Accumulated depletion, depreciation and amortization	(133,428)	(232,167)
Net property, plant and equipment	774,253	1,131,032
OTHER ASSETS:		
Commodity derivatives	8,591	3,768
Deferred loan costs	17,318	9,699
Other	6,863	4,414
Total other assets	32,772	17,881
TOTAL ASSETS	$ 893,193	$1,265,485
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 53,406	$ 82,094
Undistributed revenue payable	15,596	11,298
Interest payable	5,295	6,839
Current maturities of long-term debt	3,557	3,449
Commodity and interest derivatives	8,907	68,756
Total current liabilities	86,761	172,436
LONG-TERM DEBT	529,616	691,896
DEFERRED INCOME TAXES	40,424	16,607
COMMODITY AND INTEREST DERIVATIVES	7,092	87,224
ASSET RETIREMENT OBLIGATIONS	38,984	51,720
Total liabilities	702,877	1,019,883
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value (200,000,000 shares authorized; 42,783,300 and 50,593,403 shares issued and outstanding at December 31, 2006 and 2007, respectively)	428	506
Additional paid-in capital	181,444	309,887
Retained earnings (accumulated deficit)	10,910	(62,462)
Accumulated other comprehensive loss	(2,466)	(2,329)
Total stockholders' equity	190,316	245,602
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 893,193	$1,265,485

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31, 2005	2006	2007
REVENUES:			
Oil and natural gas sales	$191,092	$274,813	$ 377,871
Commodity derivative gains (losses), net	(57,595)	(2,365)	(147,366)
Other	4,456	5,470	3,355
Total revenues	137,953	277,918	233,860
EXPENSES:			
Oil and natural gas production	54,038	87,505	119,321
Transportation expense	2,596	3,533	6,061
Depletion, depreciation and amortization	21,680	63,259	98,814
Accretion of asset retirement obligations	1,752	2,542	3,914
General and administrative, net of amounts capitalized	16,007	28,317	31,770
Total expenses	96,073	185,156	259,880
Income (loss) from operations	41,880	92,762	(26,020)
FINANCING COSTS AND OTHER:			
Interest expense, net	13,673	48,795	60,115
Amortization of deferred loan costs	1,755	3,776	4,197
Interest rate derivative losses, net	—	590	17,177
Loss on extinguishment of debt	—	—	12,063
Total financing costs and other	15,428	53,161	93,552
Income (loss) before income taxes and minority interest	26,452	39,601	(119,572)
INCOME TAXES:			
Current	13,000	610	1,100
Deferred	(2,700)	15,040	(47,300)
Income tax provision (benefit)	10,300	15,650	(46,200)
Net income (loss) before minority interest	16,152	23,951	(73,372)
Minority interest in Marquez Energy	42	—	—
Net income (loss)	$ 16,110	$ 23,951	$ (73,372)
Earnings per common share:			
Basic	$ 0.49	$ 0.71	$ (1.58)
Diluted	$ 0.49	$ 0.69	$ (1.58)
Weighted average common shares outstanding:			
Basic	32,693	33,795	46,372
Diluted	32,979	34,860	46,372

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2005	2006	2007
Net income (loss)	$ 16,110	$23,951	$(73,372)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Hedging activities:			
Reclassification adjustments for settled contracts(1)	(410)	3,602	2,877
Changes in fair value of outstanding hedging positions(2)	(14,697)	7,116	(2,740)
Other comprehensive income (loss)	(15,107)	10,718	137
Comprehensive income (loss)	$ 1,003	$34,669	$(73,235)

(1) Net of income tax expense (benefit) of $(270), $2,389 and $1,840 for the years ended December 31, 2005, 2006 and 2007, respectively.

(2) Net of income tax expense (benefit) of $(9,686), $4,720 and $(1,722) for the years ended December 31, 2005, 2006 and 2007, respectively.

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
BALANCE AT DECEMBER 31, 2004	32,693	$327	$ 31,085	$ 15,104	$ 1,923	$ 48,439
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	(410)	(410)
Change in value of derivatives, net of tax	—	—	—	—	(14,697)	(14,697)
Distribution payments to Marquez Energy member, net of minority interest	—	—	(645)	—	—	(645)
Payment of dividends to shareholder	—	—	—	(35,000)	—	(35,000)
Marquez Energy acquisition adjustment	—	—	(9,464)	1	—	(9,463)
Net income	—	—	—	16,110	—	16,110
BALANCE AT DECEMBER 31, 2005	32,693	327	20,976	(3,785)	(13,184)	4,334
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	3,602	3,602
Change in value of derivatives, net of tax	—	—	—	—	7,116	7,116
Issuance of stock, net of underwriters' discounts	10,090	101	160,292	—	—	160,393
Stock issuance costs	—	—	(2,874)	—	—	(2,874)
Distributions to shareholder	—	—	—	(9,256)	—	(9,256)
Share-based payments	—	—	3,050	—	—	3,050
Net income	—	—	—	23,951	—	23,951
BALANCE AT DECEMBER 31, 2006	42,783	428	181,444	10,910	(2,466)	190,316
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	2,877	2,877
Change in value of derivatives, net of tax	—	—	—	—	(2,740)	(2,740)
Issuance of stock, net of underwriters' discounts	6,565	65	116,530	—	—	116,595
Stock issuance costs	—	—	(561)	—	—	(561)
Issuance of stock for acquisition of oil and gas properties	171	2	3,028	—	—	3,030
Issuance of stock for cash upon exercise of options	703	7	4,770	—	—	4,777
Issuance of restricted shares	371	4	(4)	—	—	—
Share-based payments	—	—	4,680	—	—	4,680
Net loss	—	—	—	(73,372)	—	(73,372)
BALANCE AT DECEMBER 31, 2007	50,593	$506	$309,887	$(62,462)	$ (2,329)	$245,602

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2005	2006	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 16,110	$ 23,951	$ (73,372)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	21,680	63,259	98,814
Accretion of asset retirement obligations	1,752	2,542	3,914
Deferred income taxes (benefit)	(2,700)	15,040	(47,300)
Share-based compensation	—	3,050	4,680
Amortization of deferred loan costs	1,755	3,776	4,197
Loss on extinguishment of debt	—	—	12,063
Amortization of bond discounts and other non-cash interest	137	1,124	700
Minority interest in undistributed earnings	42	—	—
Unrealized interest rate swap derivative losses	—	494	17,312
Unrealized commodity derivative (gains) losses and amortization of premiums and other comprehensive loss	36,937	(12,898)	134,325
Other	—	(177)	—
Changes in operating assets and liabilities, net of working capital acquired:			
Accounts receivable	(12,739)	3,534	(10,055)
Inventories	(674)	(1,458)	(7,166)
Prepaid expenses and other current assets	(873)	(955)	2,606
Income tax receivable	(201)	(2,092)	1,373
Other assets	(559)	272	(2,551)
Accounts payable and accrued liabilities	410	(4,795)	29,632
Undistributed revenue payable	(2,619)	1,865	(4,298)
Other liabilities	(92)	—	—
Net premiums paid on derivative contracts	(18,435)	(7,442)	(4,011)
Net cash provided by operating activities	39,931	89,090	160,863
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for oil and natural gas properties	(77,657)	(165,748)	(316,894)
Acquisitions of oil and natural gas properties	(10,636)	(19,461)	(121,822)
Expenditures for drilling equipment	(353)	(5,666)	(847)
Expenditures for other property and equipment	(1,460)	(3,199)	(4,542)
Proceeds from sale of oil and natural gas properties	44,619	46,389	10,742
Acquisition of TexCal Energy, net of cash acquired	—	(447,519)	—
Acquisition of Marquez Energy, LLC	(14,628)	—	—
Notes receivable—officers	1,420	—	—
Net cash used in investing activities	(58,695)	(595,204)	(433,363)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	59,000	569,529	777,421
Principal payments on long-term debt	(43,737)	(210,101)	(619,729)
Payments for deferred loan costs	(817)	(15,335)	(4,923)
Premium to retire debt	—	—	(3,489)
Proceeds from derivative premium financing	—	3,903	3,780
Proceeds from issuance of common stock	—	160,393	116,595
Stock issuance costs	—	(2,874)	(561)
Proceeds from exercise of stock options	—	—	4,777
Dividend paid to shareholder	(35,000)	(426)	—
Distribution payments to Marquez Energy members	(707)	—	—
Repurchase of common shares	(5,301)	—	—
Net cash (used in) provided by financing activities	(26,562)	505,089	273,871
Net (decrease) increase in cash and cash equivalents	(45,326)	(1,025)	1,371
Cash and cash equivalents, beginning of period	54,715	9,389	8,364
Cash and cash equivalents, end of period	$ 9,389	$ 8,364	$ 9,735
Supplemental Disclosure of Cash Flow Information—			
Cash paid for interest	$ 14,223	$ 44,540	$ 58,650
Cash paid (received) for income taxes	$ 13,400	$ 2,701	$ (273)
Supplemental Disclosure of Noncash Activities—			
Decrease (increase) in accrued capital expenditures	$ 11,899	$ (19,420)	$ (3,165)
Distributions of land and building	$ —	$ 18,399	$ —
Distribution of building note payable	$ —	$ 9,857	$ —
Common stock issued for the acquisition of oil and natural gas properties	$ —	$ —	$ 3,030

See notes to consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Venoco, Inc. (the "Company"), a Delaware corporation, is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties with a focus on properties offshore and onshore California and the Gulf Coast of Texas.

Principles of Consolidation—The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates—The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity and interest derivative instruments; (8) accrued liabilities; (9) valuation of share-based payments and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Business Segment Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Concentration of Credit Risk—The Company's accounts receivable result from oil and natural gas sales to major oil and intrastate gas pipeline companies and to joint venture partners that own interests in properties operated by the Company. The Company's trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, most of the Company's significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. For the year ended December 31, 2005, the Company's oil and natural gas sales to three major customers represented 48%, 20% and 15% of its total revenues. For the year ended December 31, 2006, the Company's oil and natural gas sales to four major customers represented 31%, 20%, 13% and 12% of its total revenues. For the year ended December 31, 2007, the Company's oil and natural gas sales to four major customers represented 30%, 29%, 17% and 12% of its total revenues. The Company recorded an allowance for doubtful accounts as of December 31, 2006 and 2007 of $1.3 million and $0.9 million, respectively, for customer accounts. As of December 31, 2007, 23%, 17%, 16% and 11% of the total accounts receivable balance was receivable from the Company's four major customers.

Revenue Recognition and Gas Imbalances—Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectibility is reasonably assured and evidenced by a contract. This generally occurs when a barge

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

completes delivery, oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession. Oil revenues are generally recognized based on actual volumes of completed deliveries where title has transfered. Title to oil sold is typically transferred at the wellhead, except in the case of the South Ellwood field, where title is transferred when the barge that transports production from the field completes delivery.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under-deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over- and under-deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at December 31, 2006 and 2007.

Other revenues primarily include amounts received from purchasers of oil production to reimburse the Company for transportation and barge expenses. Transportation expense, net of pipeline tariff, is excluded from production expenses and is reflected separately in the consolidated statement of operations.

Cash and Cash Equivalents—Cash and cash equivalents consist of cash and liquid investments with an original maturity of three months or less.

Inventories—Included in inventories are oil field materials and supplies, stated at the lower of cost or market, cost being determined by the first-in, first-out method.

Crude Oil Inventories—Crude oil inventories are carried at the lower of current market value or cost (generally determined under the first-in, first-out method). Inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition and location.

Oil and Natural Gas Properties—The Company's oil and natural gas producing activities are accounted for using the full cost method of accounting. Accordingly, the Company capitalizes all costs incurred in connection with the acquisition of oil and natural gas properties and with the exploration for and development of oil and natural gas reserves. Proceeds from the disposition of oil and natural gas properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Depletion of the capitalized costs of oil and natural gas properties, including estimated future development and abandonment costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves. Depletion expense for the years ended December 31, 2005, 2006, and 2007 was $20.5 million, $61.0 million, and $94.7 million, respectively ($4.85, $10.52, and $13.29, respectively, per equivalent barrel of oil).

Unproved property costs not subject to amortization consist primarily of leasehold costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves established or impairment determined. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Company will continue to evaluate these properties and costs which will be transferred into the amortization base as the undeveloped areas are tested. No impairment losses were incurred in 2005, 2006 or 2007. No interest costs were capitalized in 2005, 2006 or 2007 because the Company did not have any unusually significant investments in unproved properties that qualify for interest capitalization.

In accordance with the full cost method of accounting, the net capitalized costs of oil and natural gas properties are subject to a ceiling based upon the related estimated future net revenues, discounted at 10 percent, net of tax considerations, plus the lower of cost or estimated fair value of unproved properties. The ceiling test is calculated using oil and natural gas prices in effect as of the balance sheet date. At December 31, 2006 and 2007, the Company's net capitalized costs did not exceed the ceiling.

General and Administrative Expenses—Under the full cost method of accounting, the Company capitalizes a portion of general and administrative expenses that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other specifically identifiable costs and do not include costs related to production operations, general corporate overhead or similar activities. The Company capitalized general and administrative costs of $2.5 million, $4.4 million, and $11.8 million directly related to its acquisition, exploration and development activities during 2005, 2006 and 2007, respectively.

Drilling Equipment and Other Property and Equipment—Drilling equipment and other property and equipment, which includes buildings, leasehold improvements, office and other equipment, are stated at cost. Depreciation and amortization are calculated using the straight-line method over the estimated useful lives of the related assets, ranging from 3 to 25 years. Depreciation and amortization expense for the years ended December 31, 2005, 2006 and 2007 was $1.2 million, $2.3 million and $4.1 million, respectively.

Derivative Financial Instruments—The Company enters into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, all derivative instruments are recorded on the balance sheet at fair value.

If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings as a component of revenues. If the derivative qualifies for cash flow hedge accounting, the gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income (Loss) ("OCI"), a component of Stockholders' Equity, to the extent the hedge is effective. Gains and losses are reclassified from OCI to the income statement as a component of revenues in the period the hedged production occurs.

Because a large portion of the Company's commodity derivatives do not qualify for hedge accounting, the Company elected to discontinue hedge accounting prospectively for its commodity derivatives beginning April 1, 2007. Consequently, from that date forward, the Company has recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in OCI for those commodity derivatives that qualify as cash flow hedges.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Company has also entered into interest rate swap contracts to mitigate the risk of interest rate fluctuations on $500 million of borrowings under its second lien term loan facility. The Company does not designate the interest rate swap contacts as hedges.

Fair Value of Financial Instruments—The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, derivatives and long-term debt. The carrying values of cash equivalents and accounts receivable and payable are representative of their fair values due to their short-term maturities. The estimated fair value of the Company's revolving credit facility and second lien term loan approximate carrying value because the facilities' interest rates are tied to current market rates. The carrying amount of the Company's 8.75% senior notes was $149.3 million and $149.5 million on December 31, 2006 and 2007, respectively. The estimated fair value of the Company's 8.75% senior notes was $148 million on December 31, 2006 and 2007. The Company's derivative financial instruments are reported on the balance sheet at fair value.

Deferred Loan Costs—Deferred loan costs, included in Other Assets, are amortized over the estimated lives of the related obligations or, in certain circumstances, accelerated if the obligation is refinanced, using the straight line method, which approximates the effective interest method.

Income Taxes—Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainties in Income Taxes*, an interpretation of FASB Statement No. 109, *Accounting for Income Taxes.* This interpretation addresses how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes and accounting in interim periods and requires increased disclosures.

The Company adopted the provisions of FIN 48 on January 1, 2007, and has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. As a result of the implementation of FIN 48 on January 1, 2007, the Company recognized a $3.8 million reduction in prepaid income taxes for unrecognized tax benefits which was offset by a corresponding reduction to deferred income tax liabilities. There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in income tax expense. The Company did not recognize any interest or penalties upon the adoption of FIN 48 on January 1, 2007, or during the twelve months ended December 31, 2007.

Environmental—The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company believes that it is in material compliance with existing laws and regulations.

Earnings Per Share—Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of "basic" and "diluted" earnings per share. Basic earnings per common share of stock is calculated by dividing net income (loss) by the weighted average number of common shares outstanding during each period. The weighted average number of common shares outstanding used to calculate basic net income (loss) per share excludes the effect of non-vested restricted shares subject to future vesting. As those restricted shares vest, they will be included in the shares outstanding used to calculate basic earnings per common share (although all restricted shares are issued and outstanding upon grant). Diluted earnings per common share of stock is calculated by dividing net income by the weighted average number of common shares outstanding and other dilutive securities. The Company's dilutive securities include non-qualified stock option awards and non-vested restricted shares with only service conditions. Non-vested restricted shares with service and market conditions are excluded from basic earnings per common share calculations until they vest.

The treasury stock method is used to measure the dilutive impact of stock options. The following table details the weighted average dilutive and anti-dilutive securities related to stock options for the periods presented:

	Years ended December 31,		
	2005	2006	2007
Dilutive	2,272,239	3,952,569	—
Anti-dilutive	816,553	318,169	4,501,894

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

	Years ended December 31,		
	2005	2006	2007
Net income (loss)	$16,110	$23,951	$(73,372)
Adjustments to net income for dilution	—	—	—
Net income (loss) adjusted for the effect of dilution	$16,110	$23,951	$(73,372)
Basic weighted average common shares outstanding	32,693	33,795	46,372
Add: dilutive effect of stock options and non-vested restricted shares	286	1,065	—
Diluted weighted average common shares outstanding	32,979	34,860	46,372
Basic earnings per common share	$ 0.49	$ 0.71	$ (1.58)
Diluted earnings per common share	$ 0.49	$ 0.69	$ (1.58)

Stock-Based Compensation—Prior to January 1, 2006, the Company accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees if the grant price equaled or exceeded the market price on the date of the option grant. Effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123 (Revised), *Share-Based Payment* ("SFAS 123R") using the modified prospective method. Under this method, compensation cost is recorded for all unvested stock options beginning in the period of adoption and prior period financial statements are not restated. Under the fair value recognition provisions of SFAS 123R, stock-based compensation is measured at the grant date based on the value of the awards and the value is recognized on a straight-line basis over the requisite service period (usually the vesting period). SFAS 123R requires the recognition of the equity component of deferred compensation as additional paid-in capital. SFAS 123R also requires the Company to estimate forfeitures in calculating the cost related to stock-based compensation as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur. The cumulative adjustment from adopting SFAS 123R as of January 1, 2006 to include estimated forfeitures in the calculation was not material and had no impact on earnings per share.

No compensation cost was recorded prior to January 1, 2006 as all stock options had an exercise price equal to or greater than the market value of the underlying common stock on the date of grant. The following table illustrates the pro forma effect on net income and earnings per common share if the Company had recognized compensation expense for all options granted based upon the estimated

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

fair value on the grant date under the fair value methodology prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation* (in thousands, except per share amounts):

	Year ended December 31, 2005
Net income as reported	$16,110
Less: Total stock based compensation expense determined under the fair value method for all awards, net of related tax effects	(2,300)
Pro forma net income	$13,810
Basic earnings per share:	
As reported	$ 0.49
Pro forma	$ 0.42
Diluted earnings per share:	
As reported	$ 0.49
Pro forma	$ 0.42

For purposes of the pro forma disclosures, the estimated fair values of the options are amortized to expense over the options' vesting periods.

Reclassifications—The Company made certain reclassifications to prior period consolidated balance sheets, statements of operations and statements of cash flows to be consistent with the current presentation. The consolidated balance sheet was modified to reclassify interest rate derivative liabilities from accounts payable and accrued liabilities to commodity and interest derivative liabilities, and the consolidated statements of operations were modified to separately disclose interest rate derivative losses. These reclassifications were not material to the Company's financial position or cash flows from operating, investing or financing activities and had no impact on total revenues or income (loss) before taxes.

New Accounting Standards

In December 2007, the FASB issued SFAS No. 141, *Business Combinations* ("SFAS 141R"), and SFAS No. 160, *Accounting and Reporting of Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51* ("SFAS 160"). SFAS 141R and SFAS 160 will significantly change the accounting for and reporting of business combination transactions and noncontrolling (minority) interests in consolidated financial statements. SFAS 141R retains the fundamental requirements in Statement 141, *Business Combinations*, while providing additional definitions, such as the definition of the acquirer in a purchase and improvements in the application of how the acquisition method is applied. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests, and classified as a component of equity. These statements become simultaneously effective on January 1, 2009. Early adoption is not permitted. The Company is currently assessing the impact, if any, that the adoption of these pronouncements will have on its operating results, financial position and cash flows.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

In May 2007, the FASB issued Staff Position (FSP) No. FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48*, ("FIN 48-1") which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is "effectively," rather than, as previously required, "ultimately," settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. The Company has adopted FIN 48-1 and no retroactive adjustments were necessary.

In April 2007, the FASB issued FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39*, ("FIN 39-1") to amend FIN 39, *Offsetting of Amounts Related to Certain Contracts* ("FIN 39"). The terms "conditional contracts" and "exchange contracts" used in FIN 39 have been replaced with the more general term "derivative contracts." In addition, FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a company's accounting policy with respect to offsetting fair value amounts. The guidance in FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on its operating results, financial position and cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* ("SFAS 159"), which permits entities to choose to measure many financial instruments and certain other items at fair value (the Fair Value Option). Election of the Fair Value Option is made on an instrument-by-instrument basis and is irrevocable. At the adoption date, unrealized gains and losses on financial assets and liabilities for which the Fair Value Option has been elected would be reported as a cumulative adjustment to beginning retained earnings. If the Company elects the Fair Value Option for certain financial assets and liabilities, the Company will report unrealized gains and losses due to changes in fair value in earnings at each subsequent reporting date. The provisions of SFAS 159 are effective January 1, 2008. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on its operating results, financial position and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurement. The provisions of SFAS 157 are effective for the Company on January 1, 2008. The Company is currently assessing the impact, if any, that the adoption of this pronouncement will have on its operating results, financial position and cash flows.

2. ACQUISITIONS AND SALES OF PROPERTIES

West Montalvo and Manvel acquisitions. The Company acquired the West Montalvo field in Ventura County, California in May 2007 for approximately $61.3 million. The Company acquired the Manvel field in Brazoria County, Texas, and certain other fields in Texas, in April 2007 for $44.5 million.

TexCal Energy Acquisition. On March 31, 2006, the Company acquired 100% of the members' interest in TexCal Energy (LP) LLC (the "TexCal Acquisition"), an independent exploration and production company with properties in Texas and California, for approximately $456.8 million in cash and related financing costs of $14.4 million. TexCal's operations are located entirely onshore and are concentrated in the Gulf Coast region of Texas and in the Sacramento Basin in California. The Company financed the acquisition through loans advanced under a second amendment and restatement of its existing revolving credit facility and a senior secured second lien term loan facility. The purchase price was allocated to assets and liabilities, adjusted for tax effects, based on their estimated fair values at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the Company's consolidated financial statements as of the date of the acquisition.

The cash consideration paid for the TexCal Acquisition was allocated as follows (in thousands):

	Purchase Price Allocation
Current assets	$ 25,834
Oil and natural gas properties	461,907
Other non-current assets	1,018
Current liabilities	(22,411)
Long-term asset retirement obligations	(9,538)
Cash consideration	$456,810

The following unaudited pro forma condensed consolidated operating results for the years ended December 31, 2006 and 2007 give effect to the TexCal Acquisition (for the three months ended March 31, 2006 only) and the West Montalvo and Manvel acquisitions as if they had been completed as of January 1, 2006. The pro forma amounts shown below are not necessarily indicative of the operating results that would have occurred if the transactions had occurred on such date. The pro forma adjustments made are based on certain assumptions that the Company believes are reasonable based on currently available information (in thousands, except per share amounts) (unaudited).

	Years Ended December 31,	
	2006	2007
	Pro Forma	Pro Forma
Total revenues	$338,925	$243,205
Net income (loss)	$ 37,467	$(71,315)
Basic earnings per common share	$ 1.11	$ (1.54)
Diluted earnings per common share	$ 1.07	$ (1.54)

2. ACQUISITIONS AND SALES OF PROPERTIES (Continued)

Project with Denbury. In November 2006, the Company entered into an option agreement with Denbury Resources relating to a potential CO_2 enhanced recovery project in the Hastings complex. Pursuant to the agreement, Denbury will pay the Company a total of $50.0 million for an option to acquire the Company's interest in parts of the complex and certain related property for use in an enhanced recovery project in which the Company will have a continuing interest. Of the total option payment, $37.5 million was paid in December 2006, $7.5 million was paid in November 2007 and the remaining $5.0 million will be paid in November 2008. No part of the option payment is refundable. Denbury may not exercise the option prior to September 2008 and the initial exercise period will end in October 2009, subject to Denbury's right to extend it for successive one-year periods until 2016 for an annual extension fee of $30.0 million. Following the exercise of the option, Denbury will either purchase the properties subject to the option or enter into a volumetric production payment arrangement with the Company with respect to the properties. The purchase price or volumetric production payment will be based on the value of the properties as determined with respect to the net proved reserves associated with the properties based on then-existing operations and NYMEX forward strip pricing, subject to certain adjustments. The $50.0 million option payment will not be deducted from the purchase price or payment. In accordance with its accounting policies, the Company did not recognize a gain on sale for financial reporting purposes, but applied the $50.0 million in option payments to reduce the capitalized cost of its oil and natural gas properties and has recorded a current receivable of $5.0 million for the option payment to be received in November 2008. The Company will continue to operate the properties in the normal course of business.

Marquez Energy Acquisition. On March 21, 2005, the Company acquired Marquez Energy, a Colorado limited liability company that was majority-owned and controlled by Tim Marquez. Because of the common ownership of Marquez Energy and the Company, this acquisition has been recorded in a manner similar to a pooling-of-interests. Common control occurred in 2004 when Tim Marquez acquired an additional 53% of the Company's common stock, bringing his common stock holdings to 94%. The Company's financial statements were previously adjusted to give effect to the acquisition of Marquez Energy as if it had occurred in 2004. In addition, because of the common control, Tim Marquez's historical basis in Marquez Energy has been carried over and the excess purchase price of $9.4 million, net of deferred taxes, has been charged directly to equity. Oil and natural gas properties were written up to their pro rata fair values for amounts paid to minority interests. Due to the *de minimis* impact on Marquez Energy's results of operations for the ten-day period following the closing, the acquisition was recorded as if it had occurred on March 31, 2005.

2. ACQUISITIONS AND SALES OF PROPERTIES (Continued)

The following table summarizes the recording of the Marquez Energy acquisition (in thousands).

Write up of oil and natural gas properties to fair value—amount paid to minority interests	$ 3,652
Deferred income tax asset	3,658
Charge to equity for excess of purchase price over Mr. Marquez's historical basis, net of deferred taxes	9,831
Credit to equity for elimination of minority interest	(367)
Total purchase price	$16,774

Big Mineral Creek. In March 2005, the Company sold its interest in the Big Mineral Creek field ("BMC"), located in Grayson County, Texas, for $44.6 million. In order to facilitate a like-kind exchange of the Company's BMC property under Section 1031 of the Internal Revenue Code, the proceeds from the sale of $44.6 million were deposited with a qualified intermediary. The Company acquired qualified replacement properties of approximately $15.6 million, deferred a portion of the gain under the provisions of Section 1031 and recognized a gain for tax purposes on the sale of the BMC property of approximately $27.9 million, since the qualified replacement property acquired was less than the proceeds from the sale of the BMC property. In accordance with its accounting policies, the Company did not recognize a gain on sale for financial reporting purposes, but applied the proceeds to reduce the capitalized cost of its oil and natural gas properties.

3. LONG-TERM DEBT

As of the dates indicated, the Company's long-term debt consisted of the following (in thousands):

	December 31,	
	2006	2007
Revolving credit agreement due March 2009	$ 30,579	$ 42,000
Second lien term loan due March 2011	348,882	—
New second lien term loan due September 2011	—	500,000
8.75% senior notes due December 2011	149,317	149,453
Financed derivative premiums due through 2010	4,395	3,892
Total long-term debt	533,173	695,345
Less: current portion of long-term debt	3,557	3,449
Long-term debt, net of current portion	$529,616	$691,896

Revolving credit facility. The Company has a $300.0 million revolving credit facility with a syndicate of banks ("revolving credit facility") with a maturity date of March 30, 2009. At December 31, 2007, the revolving credit facility had a borrowing base of $140.0 million, was secured by a first priority lien on substantially all of the Company's oil and natural gas properties and other assets, including the equity interests in all of the Company's subsidiaries, and was unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. The collateral also secured the Company's obligations to hedging counterparties that were also lenders, or affiliates of lenders, under the revolving credit agreement. Base Rate Loans under the revolving credit facility bear interest at a

3. LONG-TERM DEBT (Continued)

floating rate equal to (i) the greater of a market base rate and the overnight federal funds rate plus 0.50% plus (ii) an applicable margin ranging from zero to 0.75%, based upon utilization. LIBO Rate Loans under the revolving credit facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.50% to 2.25%, based upon utilization. A commitment fee ranging from 0.375% to 0.5% per annum is payable with respect to unused borrowing availability under the facility. The agreement governing the facility contains customary representations, warranties, events of default, indemnities and covenants, including operational covenants that restrict the Company's ability to incur indebtedness and financial covenants that require the Company to maintain specified ratios of EBITDA (as defined in the agreement) to interest expense, current assets to current liabilities, debt to EBITDA and PV-10 (as defined in the agreement) to total debt. As of December 31, 2007, the Company had available borrowing capacity of $97.3 million (net of $0.7 million in outstanding letters of credit) under the revolving credit facility.

Second lien term loan facility. The Company entered into a $350.0 million senior secured second lien term loan facility in connection with the TexCal Acquisition. Principal on amounts borrowed under the facility was payable on March 30, 2011. Optional prepayments were subject to a prepayment premium. In May 2007, the Company prepaid and replaced this facility with a new $500.0 million second lien term loan facility. In connection with the settlement of the prior facility, the Company paid a prepayment premium of $3.5 million and wrote off related deferred loan costs of $8.6 million. Those amounts are reflected as loss on extinguishment of debt in the consolidated statement of operations.

Of the total amount borrowed under the new facility, $350.5 million was used to repay all amounts outstanding under the prior facility plus accrued interest, $3.5 million was used to pay a prepayment premium on those amounts and $4.6 million was used to pay transaction costs associated with the new facility. The remaining borrowings were used to reduce amounts outstanding under the revolving credit facility.

Loans made under the new facility are designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Base Rate Loans bear interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and a market base rate, plus (ii) 3.00%. LIBO Rate Loans bear interest at LIBOR plus 4.00%.

The new term loan agreement contains customary representations, warranties, events of default and indemnities and certain customary covenants, including covenants that restrict the Company's ability to incur additional indebtedness. The new facility is secured by second priority liens on substantially all of the Company's oil and natural gas properties and other assets, including the equity interests in all of its subsidiaries, and is unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. Principal on the new facility is payable on May 8, 2014. However, if the senior notes (see below) are not refinanced in full prior to September 20, 2011, principal on the new facility will be payable on that date.

The Company may from time to time make optional prepayments of amounts borrowed under the new facility if no amounts are outstanding under the revolving credit facility. Optional prepayments made prior to May 8, 2008 are subject to a prepayment premium of 2%. The premium will be reduced to 1% for prepayments made between May 9, 2008 and May 8, 2009, after which no premium will be

3. LONG-TERM DEBT (Continued)

payable with respect to any optional prepayment. Amounts prepaid under the new facility may not be reborrowed.

Senior notes. In December 2004, the Company issued $150.0 million in 8.75% senior notes (the "senior notes") due December 2011. Interest on the senior notes is due each June 15 and December 15. The senior notes are senior obligations and contain covenants that, among other things, limit the Company's ability to make investments, incur additional debt, issue preferred stock, pay dividends, repurchase its stock, create liens or sell assets. The senior notes were issued as unsecured obligations, but became secured equally and ratably with the Company's second lien term loan facility on March 30, 2006. Upon the replacement of the Company's second lien term loan facility with a new second lien term loan facility in May 2007 (see "—Second lien term loan facility"), the senior notes became secured equally and ratably with the new facility.

The Company was in compliance with all debt covenants at December 31, 2007.

Financed Derivative Premiums. The Company entered into derivative contracts in 2006 and 2007 that contain provisions for the deferral of the payment or receipt of premiums until the period of production for which the derivative contract relates. Both the derivative and the net liability for the payment of premiums were recorded at their fair values at the inception of the derivative contracts.

Scheduled annual maturities of long-term debt were as follows at December 31, 2007:

Year Ending December 31 (in thousands):	
2008	$ 3,449
2009	42,353
2010	90
2011	649,453
2012	—
2013 and after	—
	$695,345

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes swap and collar agreements and option contracts to hedge the effect of price changes on a portion of its future oil and natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts.

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

The components of commodity derivative losses in the consolidated statements of operations are as follows (in thousands):

	Years ended December 31,		
	2005	2006	2007
Realized commodity derivative losses	$(20,658)	$(15,263)	$ (13,041)
Amortization of commodity derivative premiums and other comprehensive loss	(4,701)	(8,181)	(11,546)
Unrealized commodity derivative gains (losses):			
Change in fair value of derivatives that do not qualify for hedge accounting	(33,511)	25,040	(122,892)
Ineffective portion of derivatives qualifying for hedge accounting	1,275	(3,961)	113
Total unrealized commodity derivative gains (losses)	(32,236)	21,079	(122,779)
Commodity derivative gains (losses), net	$(57,595)	$ (2,365)	$(147,366)

Because a large portion of the Company's commodity derivatives do not qualify for hedge accounting and to increase clarity in its financial statements, the Company elected to discontinue hedge accounting prospectively for its commodity derivatives beginning April 1, 2007. Consequently, from that date forward, the Company has recognized mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (loss) for those commodity derivatives that qualify as cash flow hedges. The net mark-to-market loss on outstanding derivatives on the date the Company discontinued hedge accounting included in accumulated other comprehensive loss of $8.3 million ($5.1 million after tax) is being amortized into future earnings as the original hedged transactions affect earnings. This change in reporting has no impact on the Company's reported cash flows, although future results of operations are affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

As of December 31, 2007, an unrealized derivative fair value loss of $3.8 million ($2.3 million after tax), related to derivative contracts previously designated as cash flow hedges, was recorded in accumulated other comprehensive loss. The Company will amortize net unrealized derivative losses of $1.4 million ($0.9 million after tax) out of accumulated other comprehensive loss into earnings during the next twelve months.

Crude Oil Agreements. As of December 31, 2007, the Company had entered into option, swap and collar agreements to receive average minimum and maximum New York Mercantile Exchange (NYMEX) West Texas Intermediate (WTI) prices as summarized below. Location and quality differentials attributable to the Company's properties are not included in the following prices. The

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

agreements provide for monthly settlement based on the differential between the agreement price and the actual NYMEX crude oil price.

	Minimum		Maximum	
	Barrels/day	Avg. Prices	Barrels/day	Avg. Prices
Crude oil derivatives at December 31, 2007 for production:				
January 1 - December 31, 2008	10,100	$63.02	8,100	$73.46
January 1 - December 31, 2009	6,983	$58.09	6,983	$74.38
January 1 - December 31, 2010	6,150	$61.10	6,150	$72.88

Natural Gas Agreements. As of December 31, 2007, the Company had entered into option, swap and collar agreements to receive average minimum and maximum PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/Day	Avg. Prices	MMBtu/Day	Avg. Prices
Natural gas derivatives at December 31, 2007 for production:				
January 1 - December 31, 2008	20,650	$7.59	19,097	$11.27
January 1 - December 31, 2009	14,625	$7.65	14,625	$11.57
January 1 - December 31, 2010	11,900	$7.22	11,900	$10.57

In February 2008, the Company entered into additional derivative contracts for crude oil and natural gas production from March 1, 2008 through December 31, 2011. The average production and maximum and minimum prices from the contracts are summarized below:

Crude Oil Agreements

	Minimum		Maximum	
	Barrels/day	Avg. Prices	Barrels/day	Avg. Prices
Crude oil derivatives for production:				
March 1 - December 31, 2008	1,000	$70.00	1,000	$130.75
January 1 - December 31, 2009	1,000	$70.00	1,000	$140.00
January 1 - December 31, 2010	1,000	$70.00	1,000	$150.00
January 1 - December 31, 2011	7,000	$70.00	7,000	$141.64

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

Natural Gas Agreements

	Minimum		Maximum	
	MMBtu/Day	Avg. Prices	MMBtu/Day	Avg. Prices
Natural gas derivatives for production:				
March 1 - December 31, 2008	12,000	$7.50	12,000	$11.75
January 1 - December 31, 2009	8,500	$7.50	8,500	$11.15
January 1 - December 31, 2010	6,000	$7.50	6,000	$11.95
January 1 - December 31, 2011	12,000	$7.50	12,000	$13.50

Interest Rate Swap. The Company entered into an interest rate swap transaction during 2006 to lock in its interest cost on $200.0 million of borrowings under its second lien term loan facility through May 2008. The Company pays a fixed interest rate of 5.4225% and receives a floating interest rate based on the three-month LIBO rate. Settlements are made quarterly. In June 2007, the Company entered into an additional interest rate swap relating to borrowings under the second lien term loan. The swap fixes the interest rate on $300.0 million of borrowings through May 2008 and on $500.0 million of borrowings from May 2008 through June 2010. The Company pays a fixed interest rate of 5.32% and receives a floating interest rate based on the three-month LIBO rate, with settlements made quarterly. As a result of these transactions, amounts borrowed under the second lien term loan facility will effectively bear interest at a fixed rate of approximately 9.3% until June 2010 (including the 4.0% margin payable on borrowed amounts). The Company has not designated either interest rate swap as a hedge. The fair value liability of the interest rate swaps of $0.5 million at December 31, 2006 and $17.8 million at December 31, 2007 has been recorded in commodity and interest derivatives.

The components of interest rate derivative losses in the consolidated statements of operations are as follows (in thousands):

	Years ended December 31,	
	2006	2007
Realized interest rate derivative gains (losses)	$ (96)	$ 135
Unrealized interest rate derivative losses	(494)	(17,312)
Interest rate derivative losses, net	$(590)	$(17,177)

The estimated fair values of derivatives included in the consolidated balance sheets at December 31, 2006 and December 31, 2007 are summarized below. The net fair value of the Company's derivatives decreased by $147.3 million from a net asset of $2.9 million at December 31, 2006 to a net liability of $144.4 million at December 31, 2007 due to higher futures prices for crude oil and natural gas, which are used in the calculation of the fair value of commodity derivatives, and lower estimated futures interest rates, which are used in the calculation of the fair value of interest

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

derivatives. As of the dates indicated, the Company's derivative assets and liabilities consisted of the following (in thousands):

	December 31, 2006	December 31, 2007
Derivative assets:		
Oil derivative contracts	$ 1,658	$ 3,341
Gas derivative contracts	17,281	8,207
Derivative liabilities:		
Oil derivative contracts	(8,905)	(134,505)
Gas derivative contracts	(6,600)	(3,668)
Interest rate derivative contracts	(494)	(17,807)
Net derivative asset (liability)	$ 2,940	$(144,432)

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in properties (including removal of certain onshore and offshore facilities) at the end of their productive lives in accordance with applicable state and federal laws. The Company determines asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended December 31, 2006 and 2007 (in thousands):

	2006	2007
Asset retirement obligations at beginning of period	$22,757	$42,049
Revisions of estimated liabilities	4,214	(502)
Liabilities incurred	13,372	6,880
Liabilities settled	(836)	(121)
Accretion expense	2,542	3,914
Asset retirement obligations at end of period	42,049	52,220
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	(3,065)	(500)
Long-term asset retirement obligations	$38,984	$51,720

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 6% and 8%. The 2006 and 2007 revisions primarily relate to updated estimates for expected cash outflows and changes in the timing of obligations based on reserve

5. ASSET RETIREMENT OBLIGATIONS (Continued)

evaluations. Liabilities incurred in 2006 include $11.1 million of asset retirement obligations attributable to the acquisition of TexCal. In 2007, we incurred $3.8 million in new liabilities related to acquisitions.

6. INCOME TAXES

The Company accounts for income taxes under SFAS No. 109, *Accounting for Income Taxes*. SFAS 109 is an asset and liability approach that requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's consolidated financial statements or tax returns.

The Company's income tax provision (benefit) is composed of the following (in thousands):

	Years ended December 31,		
	2005	2006	2007
Current:			
Federal	$ 9,700	$ 580	$ 1,200
State	3,300	30	(100)
	13,000	610	1,100
Deferred:			
Federal	(2,360)	13,640	(43,465)
State	(340)	1,400	(3,835)
	(2,700)	15,040	(47,300)
Total income tax provision (benefit)	$10,300	$15,650	$(46,200)

A reconciliation of the income tax provision (benefit) computed by applying the federal statutory rate of 35% to the Company's income tax provision (benefit) is as follows (in thousands):

	2005	2006	2007
Income tax expense (benefit) at federal statutory rate	$ 9,200	$13,860	$(41,850)
State income taxes	1,300	1,424	(3,693)
Other	(200)	366	(657)
	$10,300	$15,650	$(46,200)

6. INCOME TAXES (Continued)

The components of deferred tax assets and (liabilities) are as follows (in thousands):

	December 31, 2006	December 31, 2007
Deferred income tax assets:		
Bad debts	$ 306	$ 149
Accrued liabilities	570	1,543
Unrealized commodity derivative losses	4,913	53,395
Unrealized interest rate swap losses	191	6,782
Share-based compensation	1,177	938
Net operating losses	—	48,967
State tax benefit	11	—
Alternative minimum tax credits	55	—
Charitable contributions	215	730
	7,438	112,504
Deferred income tax liabilities:		
Oil and natural gas properties	(45,469)	(105,733)
Prepaid expenses	(1,514)	(1,398)
Other	—	(13)
	(46,983)	(107,144)
Net deferred income tax assets (liabilities)	(39,545)	5,360
Net current deferred tax asset	879	21,967
Noncurrent deferred tax liability	$(40,424)	$ (16,607)

The Company has net operating loss carryovers as of December 31, 2007 of $138.0 million for federal income tax purposes and $129.3 million for financial reporting purposes. The difference of $8.7 million relates to $6.7 million of tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable and $2.0 million related to FIN 48 adjustments. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset taxable income through 2027.

The Company's federal income tax returns for the 2003 and 2004 tax years are currently under examination by the U.S. Internal Revenue Service ("IRS"). A 30-Day Letter was issued by the IRS in May 2007 for the 2003 tax year. The Company filed a formal protest letter with the IRS in July 2007 and requested a conference with the Appeals Office in Denver, Colorado. The IRS granted the request. With respect to the 2004 tax year, the Company received a Notice of Proposed Adjustments ("NOPA") in July 2007. The Company provided a formal response to the 2004 NOPA in September 2007 and the IRS responded in November 2007 to our response.

In both the 2003 and 2004 examinations, the IRS is proposing adjustments that relate to the amount of cost depletion deducted and the capitalization of certain lease operating expenses as depreciable property rather than as deductible expenses in the year incurred. In the 2004 examination,

6. INCOME TAXES (Continued)

the IRS is proposing additional adjustments that relate to the capitalization of intangible drilling costs as depreciable property rather than as deductible expenses in the year incurred. Further, the IRS is proposing adjustments to the amount of certain legal fees deducted. The Company disagrees with a majority of the IRS proposed adjustments and anticipates a favorable settlement in the conference with the Appeals Office. The California Department of Revenue has also notified the Company that it intends to examine the Company's 2003 and 2004 California tax returns. The Company does not expect the state examinations to begin until the current federal examinations are finalized.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainties in Income Taxes*, an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*. This interpretation addresses how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes and accounting in interim periods and requires increased disclosures.

The Company adopted the provisions of FIN 48 on January 1, 2007, and has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. As a result of the implementation of FIN 48, the Company recognized a \$3.8 million reduction in prepaid income taxes for unrecognized tax benefits which was offset by a corresponding reduction to deferred income tax liabilities. There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007. Subsequent to the implementation of FIN 48, the Company recorded a \$1.4 million reduction to the above balance of unrecognized tax benefits due to additions for tax positions related to the current year and reductions for tax positions related to prior years. The reduction was based on the NOPA received in July 2007 for the 2004 tax year. The Company's uncertain tax positions relate primarily to timing differences and management does not believe any such uncertain tax positions will materially impact the Company's effective tax rate in future periods.

A rollforward of changes in the Company's unrecognized tax benefits is shown below (in thousands).

Balance at January 1, 2007	\$ 3,800
Additions based on tax positions related to the current year	500
Additions for tax positions of prior years	—
Reductions for tax positions of prior years	(1,900)
Settlements	—
Balance at December 31, 2007	\$ 2,400

The Company is subject to taxation in federal and various state jurisdictions. The Company's tax years for 2003 and forward are subject to examination by state tax authorities. The Company has

6. INCOME TAXES (Continued)

received notices from the IRS relating to 2003 and 2004 in which the IRS has indicated that it is proposing adjustments in an aggregate amount that would exceed the amounts accrued as of December 31, 2007. The Company does not believe that, when ultimately determined, the adjustments, if any, will materially exceed the accrued amount. The Company anticipates that none of the uncertain tax positions will be recognized within the next twelve month period.

The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in income tax expense. The Company did not recognize any interest or penalties upon the adoption of FIN 48 on January 1, 2007, or during the twelve months ended December 31, 2007.

7. CAPITAL STOCK AND TRANSACTIONS WITH SHAREHOLDER

All of the Company's outstanding common stock was controlled by the Company's CEO from December 2004 until August 2006, when the Company's then sole stockholder, a trust affiliated with the CEO, donated shares of stock to two charitable institutions. The Company issued and sold 10,090,800 shares of its common stock in the fourth quarter of 2006 in an initial public offering and received net proceeds of $160.4 million. In July 2007, the Company completed an additional public offering of common stock in which it issued and sold 6,565,000 shares of stock and received net proceeds of $116.0 million. The majority of the net proceeds from the offering were used to repay the outstanding balance under the Company's revolving credit facility.

The Company has 57.3 million shares of common stock issued or reserved for issuance at December 31, 2007, including 7.5 million shares issued or reserved for issuance under the Company's stock incentive plans. At December 31, 2007, the Company has 50,593,403 common shares issued and outstanding, of which 370,785 shares are restricted stock granted under the Company's 2005 stock incentive plan. At December 31, 2007, the Company had approximately 2.3 million shares available to be issued pursuant to awards under its stock incentive plans.

On January 3, 2005, a dividend of $35 million was paid to the Company's then sole stockholder, a trust controlled by the Company's CEO, from the proceeds of the issuance of the senior notes.

On March 22, 2006, the Company paid a dividend consisting of 100% of its membership interest in 6267 Carpinteria to its then sole stockholder, a trust controlled by the Company's CEO. 6267 Carpinteria owns the office building and related land used by the Company in Carpinteria, California. At the date of the dividend, 6267 Carpinteria had net assets of $4.7 million, including $0.4 million in cash and land and building with a net book value of $13.4 million, and a note payable of $9.9 million. The Company makes lease payments to 6267 Carpinteria under a lease for the office building entered into prior to the dividend. The lease provides for minimum lease payments of approximately $1.1 million per year through 2019.

Venoco operates a property located in Carpinteria, California as a transit point for several of the Company's offshore oil and gas producing properties in the Santa Barbara Channel (the "Bluffs Property"). During the third quarter of 2006, the Company declared and paid a dividend on its common stock of 51 acres of real property at the Bluffs Property and entered into certain agreements with its then-sole stockholder and an affiliate of the stockholder, including a ground lease and a development agreement relating to the property. Under the ground lease, which has a 20-year term, the Company will lease the property for use in its oil and gas operations for rent of $1 per year. The

7. CAPITAL STOCK AND TRANSACTIONS WITH SHAREHOLDER (Continued)

stockholder's affiliate has the right to require the Company to consolidate its operations at a future date from an approximate 14 acre footprint to 2 acres (the "consolidation"). If consolidation is requested, the Company estimates that it will incur approximately $10 million in capital cost to acquire and install new equipment to effect the consolidation. After the consolidation is completed, the Company has the ability to enter into a new ground lease for $1 per year for up to 99 years (effectively the remaining productive life of the related offshore oil and gas producing properties). Independent third party appraisals were obtained which valued the unencumbered value of the land in excess of the Company's historical cost of $10.3 million. In addition, the fair value of the property was appraised at $5.0 million after taking into account the encumbrance for the ground lease and the time value of money for the consolidation. Therefore, the Company recorded a dividend of $5.0 million for the appraised value of the interest conveyed and a retained leasehold interest of $5.3 million which will be amortized over the expected life of the ground lease of 20 years.

The Company made donations to a number of educational, medical and other charitable organizations of approximately of $0.9 million and $1.4 million in the years ended December 31, 2006 and 2007, respectively. Of the amounts contributed, $220,000 in 2006 and $189,000 in 2007 relates to the Denver Scholarship Foundation, a non-profit corporation dedicated to providing college scholarships and related assistance to graduates of Denver public schools. Timothy Marquez is the President and Chairman of the Denver Scholarship Foundation.

8. SHARE-BASED PAYMENTS

The Company has granted options to directors, certain employees and officers of the Company other than its CEO. As of December 31, 2007, there are a total of 4,159,463 options outstanding with a weighted average exercise price of $9.19 ($6.00 to $20.00). The options vest over a four year period, with 20% vesting on the grant date and 20% vesting on each subsequent anniversary of the grant date. The options will generally vest upon a change in control of the Company. The agreements with employee option holders generally provide that all of the holder's options will vest if the Company terminates the holder's employment, unless the termination is for specified types of misconduct. The agreements with director option holders provide that any unvested options will terminate when the director's service to the Company ceases.

For the year ended December 31, 2007, the Company granted 371,785 shares of restricted stock under the Company's 2005 stock incentive plan, including 205,882 shares to its CEO. The restricted shares generally vest over a four year service period. The vesting of 225,882 of the shares is also subject to market conditions based on the Company's total shareholder return in comparison to peer group companies for each calendar year. The weighted-average fair value of the restricted shares subject to market conditions was estimated to be $13.53 per share using a Monte Carlo technique. As of December 31, 2007 (the first year of measurement), none of the shares subject to market conditions vested.

In accordance with the provisions of SFAS 123R, the Company recognized total stock-based compensation expense in the amount of $3.1 million for the year ended December 31, 2006, including $2.8 million in general and administrative expense and $0.3 million as oil and natural gas production expense, and $4.7 million for the year ended December 31, 2007, including $4.4 million as general and administrative expense and $0.3 million as oil and natural gas production expense. There was no excess

8. SHARE-BASED PAYMENTS (Continued)

income tax benefit recognized in 2006 or 2007 related to the Company's share based payment arrangements.

As of December 31, 2007, there was $4.9 million of total unrecognized compensation cost related to stock options which is expected to be amortized over a weighted-average period of 2.4 years and $4.2 million of total unrecognized compensation cost related to restricted stock which is expected to be amortized over a weighted-average period of 3.3 years.

The following summarizes the Company's stock option activity for the years ended December 31, 2005, 2006 and 2007:

	Years Ended December 31,						
	2005		2006		2007		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value of Options
							(in thousands)
Outstanding, start of period	—	—	4,013,663	$ 7.04	4,740,663	$ 8.55	
Granted	4,013,663	$7.04	727,000	$16.85	265,000	$16.93	
Exercised	—	—	—	—	(702,690)	$ 6.80	
Cancelled	—	—	—	—	(143,510)	$13.85	
Outstanding, end of period	4,013,663	$7.04	4,740,663	$ 8.55	4,159,463	$ 9.19	$14,307
Exercisable, end of period	802,732	$7.04	1,750,865	$ 7.86	2,296,318	$ 8.62	$ 9,434
Weighted average grant-date fair value of options granted during the period		$2.79		$ 6.45		$ 7.54	

Additional information related to options outstanding at December 31, 2007 is as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted-Average Exercise Prices	Number Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Prices
$6.00 - $7.33	2,395,200	7.2 years	$ 6.12	1,389,120	7.2 years	$ 6.12
$8.00 - $8.68	478,963	6.8 years	$ 8.35	290,578	6.5 years	$ 8.38
$10.67 - $14.97	548,500	7.6 years	$12.27	311,500	7.1 years	$11.75
$15.00 - $20.00	736,800	8.2 years	$17.45	305,120	7.2 years	$17.04
	4,159,463	7.4 years	$ 9.19	2,296,318	7.1 years	$ 8.62

The aggregate intrinsic value of options exercised in 2007 was $1.7 million. There were no options exercised prior to 2007.

8. SHARE-BASED PAYMENTS (Continued)

Non-vested stock options	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2007	2,989,798	$3.51
Granted	265,000	$7.54
Vested	(1,260,963)	$3.32
Forfeited	(130,690)	$7.02
Non-vested at December 1, 2007	1,863,145	$3.97

The fair value of each option is estimated on the grant date using the Black-Scholes option valuation model. Option valuation models require the input of highly subjective assumptions, including the expected volatility of the price of the underlying stock. The Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

The following assumptions were used during 2005, 2006 and 2007 to compute the weighted average fair market value of options granted during the periods presented:

	Years Ended December 31		
	2005	2006	2007
Expected option life	5 years	6 years	6 years
Risk free interest rates	3.7% - 4.2%	4.3% - 4.8%	4.3% - 5.1%
Estimated volatility	76%	40%	37%
Dividend yield	0.0%	0.0%	0.0%

The expected life of the options is based, in part, on historical exercise patterns of the holders of options with similar terms with consideration given to how historical patterns may differ from future exercise patterns based on current or expected market conditions and employee turnover. For all periods presented above, the Company calculated the expected life of all options granted using the "simplified" method set forth in Staff Accounting Bulletin 107 (average of vesting period and the term of the option) due to the limited exercise history of options that have been granted. The risk free interest rate was based on the U.S. Treasury yield curve in effect at the time of grant. The expected volatility was based on the historical volatility of other public companies with characteristics similar to the Company for the past six years.

8. SHARE-BASED PAYMENTS (Continued)

Additional information related to restricted stock at December 31, 2007 is as follows:

Non-vested restricted stock	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2007	—	—
Granted	371,785	$14.24
Vested	(1,000)	$15.34
Forfeited	—	—
Non-vested at December 1, 2007	370,785	$14.24

9. COMMITMENTS

Leases—The Company has entered into lease agreements for office space and an office building. As of December 31, 2007, future minimum lease payments under operating leases that have initial or remaining non-cancelable terms in excess of one year are $2.2 million in 2008, $2.5 million in 2009, $2.4 million in 2010, $2.3 million in 2011, $2.3 million in 2012 and $10.3 million thereafter. Net rent expense incurred for office space and the office building was $0.9 million, $1.8 million and $2.7 million in 2005, 2006 and 2007, respectively.

10. LITIGATION

Beverly Hills Litigation

Between June 2003 and April 2005, six lawsuits were filed against the Company and certain other energy companies in Los Angeles County Superior Court by persons who attended Beverly Hills High School or who were or are citizens of Beverly Hills/Century City or visitors to that area during the time period running from the 1930s to date. There are approximately 1,000 plaintiffs (including plaintiffs in two related lawsuits in which the Company has not been named) who claimed to be suffering from various forms of cancer or other illnesses, fear they may suffer from such maladies in the future, or are related to persons who have suffered from cancer or other illnesses. Plaintiffs alleged that exposure to substances in the air, soil and water that originated from either oil-field or other operations in the area were the cause of the cancers and other maladies. The Company has owned an oil and natural gas facility adjacent to the school since 1995. For the majority of the plaintiffs, their alleged exposures occurred before the Company acquired the facility. All cases were consolidated before one judge. Twelve "representative" plaintiffs were selected to have their cases tried first, while all of the other plaintiffs' cases were stayed. In November 2006, the judge entered summary judgment in favor of all defendants in the test cases, including the Company. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in late 2008. The Company vigorously defended the actions, and will continue to do so until they are resolved. The Company also has defense and indemnity obligations to certain other defendants in the actions who have asserted claims for indemnity for events occurring after the Company acquired the property in 1995. In addition, certain defendants have made claims for indemnity for events

10. LITIGATION (Continued)

occurring prior to 1995, which the Company is disputing. The Company cannot predict the cost of defense and indemnity obligations at the present time.

One of the Company's insurers currently is paying for the defense of these lawsuits under a reservation of its rights. Three other insurers that provided insurance coverage to the Company (the "Declining Insurers") took the position that they were not required to provide coverage for losses arising out of, or to defend against, the lawsuits because of a pollution exclusion contained in their policies. In February 2006, the Company filed a declaratory relief action against the Declining Insurers in Santa Barbara County Superior Court seeking a determination that those insurers have a duty to defend the Company in the lawsuits. Two of the three Declining Insurers settled with the Company. The third Declining Insurer disputed the Company's position and in November 2007 the Santa Barbara Court granted that insurer's motion for summary judgement, in part on the basis that the pollution exclusion provision in the policy did not require that insurer to provide a defense for the Company. The Company has appealed the Santa Barbara Court's ruling. The Company has no reason to believe that the insurer currently providing defense of these actions will cease providing such defense. If it does, and the Company is unsuccessful in enforcing its rights in any subsequent litigation, the Company may be required to bear the costs of the defense, and those costs may be material. If it ultimately is determined that the pollution exclusion or another exclusion contained in one or more of the Company's policies applies, it will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

In accordance with SFAS No. 5, *Accounting for Contingencies*, the Company has not accrued for a loss contingency relating to the Beverly Hills litigation because the Company believes that, although unfavorable outcomes in the proceedings may be reasonably possible, the Company does not consider them to be probable or reasonably estimable. If one or more of these matters are resolved in a manner adverse to the Company, and if insurance coverage is determined not to be applicable, their impact on the Company's results of operations, financial position and/or liquidity could be material.

State Lands Commission Royalty Audit

The Company pays royalties to the state of California pursuant to certain oil and natural gas leases relating to the South Ellwood field. The Company has been informed by the California State Lands Commission (the "SLC") that the SLC is in the process of auditing the Company's royalty payment calculations on those leases. The SLC has not completed its audit, nor has it presented the Company with any audit conclusions. The Company does not currently expect that the audit adjustments, if any, will be material.

Other

In addition, the Company is subject from time to time to other claims and legal actions that arise in the ordinary course of business. The Company believes that the ultimate liability, if any, with respect to these other claims and legal actions will not have a material adverse effect on its consolidated financial position, results of operations or liquidity.

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2006 and 2007 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
Year Ended December 31, 2006:				
Revenues	$37,415	$65,573	$98,639	$76,291
Income from operations	$12,718	$16,413	$44,509	$19,122
Net income	$ 5,107	$ 324	$16,239	$ 2,281
Basic earnings per common share	$ 0.16	$ 0.01	$ 0.50	$ 0.06
Diluted earnings per common share	$ 0.15	$ 0.01	$ 0.47	$ 0.06

	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Year Ended December 31, 2007:				
Revenues	$ 55,738	$82,828	$86,999	$ 8,295
Income (loss) from operations	$ (2,393)	$23,837	$23,573	$(71,037)
Net income (loss)	$(10,365)	$(3,123)	$ 481	$(60,365)
Basic earnings per common share	$ (0.24)	$ (0.07)	$ 0.01	$ (1.21)
Diluted earnings per common share	$ (0.24)	$ (0.07)	$ 0.01	$ (1.21)

Operating results for the quarter ended December 31, 2007 were comparable to the prior quarters, excluding the effects of realized losses on commodity derivative contracts of $13.6 million, unrealized losses on commodity derivative contracts of $91.4 million and unrealized losses on interest rate derivative contracts of $8.8 million during the quarter.

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

The following information concerning the Company's natural gas and oil operations has been provided pursuant to SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. At December 31, 2007, the Company's oil and natural gas producing activities were conducted onshore within the continental United States and offshore in federal and state waters off the coast of California. The evaluations of the oil and natural gas reserves at December 31, 2005 were estimated by independent petroleum reserve engineers, Netherland, Sewell & Associates, Inc. The evaluations of oil and natural gas reserves for certain properties at December 31, 2006 were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, independent petroleum reserve engineers. The evaluations of the oil and natural gas reserves at December 31, 2007 were estimated by DeGolyer and MacNaughton, independent petroleum reserve engineers.

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

Capitalized Costs of Oil and Natural Gas Properties

	As of December 31,		
	2005	2006	2007
		(in thousands)	
Unevaluated properties(1)	$ 2,275	$ 4,850	$ 12,034
Properties subject to amortization	267,647	876,720	1,319,496
Total capitalized costs	269,922	881,570	1,331,530
Accumulated depreciation, depletion and amortization	(66,218)	(127,207)	(221,953)
Net capitalized costs	$203,704	$ 754,363	$1,109,577

(1) Unevaluated costs represent amounts the Company excludes from the amortization base until proved reserves are established or impairment is determined. The Company estimates that the remaining costs will be evaluated within one year.

Capitalized Costs Incurred

Costs incurred for oil and natural gas exploration, development and acquisition are summarized below. Costs incurred during the years ended December 31, 2005, 2006 and 2007 include capitalized general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $2.5 million, $4.4 million and $11.8 million, respectively. Costs incurred also include asset retirement costs incurred of $1.3 million, $13.4 million and $6.9 million during the years ended December 31, 2005, 2006 and 2007, respectively.

	Years ended December 31,		
	2005	2006	2007
		(in thousands)	
Property acquisition and leasehold costs:			
Unevaluated property	$ 1,891	$ 2,238	$ 4,985
Proved property	10,636	479,112	134,890
Exploration costs	20,592	26,180	99,822
Development costs	62,082	163,005	210,264
Total costs incurred	$95,201	$670,535	$449,961

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

Estimated Net Quantities of Natural Gas and Oil Reserves

The following table sets forth the Company's net proved reserves, including changes, and proved developed reserves (all within the United States) at the end of each of the three years in the periods ended December 31, 2005, 2006 and 2007.

	Crude Oil, Liquids and Condensate (MBbls)			Natural Gas (MMcf)		
	2005(1)	2006(2)	2007(3)	2005(1)	2006(2)	2007(3)
Beginning of the year reserves	39,935	35,300	49,607	69,876	74,053	229,952
Revisions of previous estimates	(318)	2,580	9,759	(6,083)	10,766	(28,201)
Extensions, discoveries and improved recovery(4)	1,580	935	4	7,240	54,061	13,359
Purchases of reserves in place	2	14,484	8,787	13,390	105,570	18,390
Production	(2,953)	(3,411)	(3,981)	(7,588)	(14,314)	(18,895)
Sales of reserves in place	(2,946)	(281)	—	(2,782)	(184)	—
End of year reserves	35,300	49,607	64,176	74,053	229,952	214,605
Proved developed reserves:						
Beginning of year	28,035	24,154	37,497	49,418	53,390	79,796
End of year	24,154	37,497	44,730	53,390	79,796	96,522

(1) Based on unescalated prices of (i) $57.75 per Bbl for oil and natural gas liquids, adjusted for quality, transportation fees and regional price differentials and (ii) $10.08 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $5.64 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

(3) Based on unescalated prices of $95.97 per Bbl for oil and natural gas liquids and $7.48 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

(4) Extensions for the years ended December 31, 2006 and 2007 include 2,668 MMcf and 1,939 MMcf, respectively, resulting from the Company's infill program in the Sacramento Basin.

The Company's estimated proved reserves increased 40.3 MMBOE from December 31, 2005 to December 31, 2006. The increase was primarily due to the acquisition of TexCal and increases due to extensions and discoveries, partially offset by sales of properties and depletion that occurred as a result of production. The Company's estimated proved reserves increased 12.0 MMBOE from December 31, 2006 to December 31, 2007. The increase was primarily due to the acquisition of the West Montalvo and Manvel fields, increases due to extensions, discoveries and revisions of previous estimates, partially offset by depletion that occurred as a result of production.

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

The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year. The

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

information disclosed, as prescribed by Statement of Financial Accounting Standards 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 the Company's interest in oil and natural gas properties as of December 31 of the years presented. These estimates were prepared by independent petroleum reserve engineers. Proved reserves are estimated quantities of crude oil and natural gas 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 periods during which they are expected to be produced based on year-end economic conditions.

(2) The estimated future cash flows are compiled by applying year-end prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves.

(3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions.

(4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves.

(5) 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 the Company's oil and natural gas 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 oil and natural gas reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates.

	As of December 31,		
	2005	2006	2007
		(in thousands)	
Future cash inflows	$2,456,617	$ 3,783,163	$ 7,027,334
Future production costs	(876,858)	(1,485,192)	(2,155,902)
Future development costs	(163,476)	(441,846)	(562,852)
Future income taxes	(516,416)	(465,412)	(1,275,076)
Future net cash flows	899,867	1,390,713	3,033,504
10% annual discount for estimated timing of cash flows	(334,482)	(571,411)	(1,377,863)
Standardized measure of discounted future net cash flows	$ 565,385	$ 819,302	$ 1,655,641

12. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED) (Continued)

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

	Years ended December 31,		
	2005	2006	2007
		(in thousands)	
Beginning of the year	$ 404,052	$ 565,385	$ 819,302
Changes in prices and production costs	332,940	(325,398)	1,145,648
Revisions of previous quantity estimates	(28,544)	59,631	179,148
Changes in future development costs	(54,784)	(201,200)	(132,166)
Development costs incurred during the period	61,404	113,791	58,393
Extensions, discoveries and improved recovery, net of related costs	59,733	135,578	49,055
Sales of oil and natural gas, net of production costs	(137,054)	(187,458)	(252,796)
Accretion of discount	65,308	89,383	112,108
Net change in income taxes	(79,418)	26,672	(401,902)
Sale of reserves in place	(73,081)	(5,071)	—
Purchases of reserves in place	47,046	551,774	168,210
Production timing and other	(32,217)	(3,785)	(89,359)
End of year	$ 565,385	$ 819,302	$1,655,641

13. GUARANTOR FINANCIAL INFORMATION

Company subsidiaries TexCal Energy (LP) LLC and its two subsidiaries, Catco Energy LLC and Whittier Pipeline Corp. ("Guarantors") have fully and unconditionally guaranteed, on a joint and several basis, the Company's obligations under the senior notes. In addition to two subsidiaries formed in connection with the Company's proposed master limited partnership, each of which has nominal assets, the Company has one subsidiary, Ellwood Pipeline, Inc., that is not a Guarantor (the "Non-Guarantor Subsidiary"). The condensed consolidating financial information for prior periods has been revised to reflect the guarantor and non-guarantor status of the Company's subsidiaries as of December 31, 2007. All Guarantors are 100% owned by the Company. Presented below are the Company's condensed consolidating balance sheets, statements of operations and statements of cash flows as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934.

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2005
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$189,126	$ 1,966	$ —	$ —	$191,092
Commodity derivative losses	(57,595)	—	—	—	(57,595)
Other	24,940	13	7,110	(27,607)	4,456
Total revenues	156,471	1,979	7,110	(27,607)	137,953
EXPENSES:					
Oil and natural gas production	52,251	47	1,740	—	54,038
Transportation expense	6,817	—	—	(4,221)	2,596
Depletion, depreciation and amortization	21,303	80	297	—	21,680
Accretion of asset retirement obligations	1,672	58	22	—	1,752
General and administrative, net of amounts capitalized	17,074	1	654	(1,722)	16,007
Total expenses	99,117	186	2,713	(5,943)	96,073
Income from operations	57,354	1,793	4,397	(21,664)	41,880
FINANCING COSTS AND OTHER:					
Interest expense, net	14,956	—	(1,283)	—	13,673
Amortization of deferred loan costs	1,755	—	—	—	1,755
Interest rate derivative losses, net	—	—	—	—	—
Loss on extinguishment of debt	—	—	—	—	—
Total financing costs and other	16,711	—	(1,283)	—	15,428
Equity in subsidiary income	(8,944)	—	—	8,944	—
Income before income taxes	31,699	1,793	5,680	(12,720)	26,452
Income tax provision	15,547	700	2,211	(8,158)	10,300
Income before minority interest	16,152	1,093	3,469	(4,562)	16,152
Minority interest in Marquez Energy	42	—	—	—	42
Net income	$ 16,110	$ 1,093	$ 3,469	$ (4,562)	$ 16,110

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$221,291	$53,522	$ —	$ —	$274,813
Commodity derivative losses	(2,365)	—	—	—	(2,365)
Other	4,717	52	5,227	(4,526)	5,470
Total revenues	223,643	53,574	5,227	(4,526)	277,918
EXPENSES:					
Oil and natural gas production	58,545	26,910	2,050	—	87,505
Transportation expense	7,204	250	—	(3,921)	3,533
Depletion, depreciation and amortization	53,633	9,483	143	—	63,259
Accretion of asset retirement obligations	2,090	429	23	—	2,542
General and administrative, net of amounts capitalized	27,219	1,389	314	(605)	28,317
Total expenses	148,691	38,461	2,530	(4,526)	185,156
Income from operations	74,952	15,113	2,697	—	92,762
FINANCING COSTS AND OTHER:					
Interest expense, net	51,160	(336)	(2,029)	—	48,795
Amortization of deferred loan costs	3,776	—	—	—	3,776
Interest rate derivative losses, net	590	—	—	—	590
Loss on extinguishment of debt	—	—	—	—	—
Total financing costs and other	55,526	(336)	(2,029)	—	53,161
Equity in subsidiary income	12,199	—	—	(12,199)	—
Income before income taxes	31,625	15,449	4,726	(12,199)	39,601
Income tax provision	7,674	6,108	1,868	—	15,650
Net income	$ 23,951	$ 9,341	$ 2,858	$(12,199)	$ 23,951

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2007
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 282,396	$95,475	$ —	$ —	$ 377,871
Commodity derivative losses	(147,366)	—	—	—	(147,366)
Other	2,823	54	5,193	(4,715)	3,355
Total revenues	137,853	95,529	5,193	(4,715)	233,860
EXPENSES:					
Oil and natural gas production	73,737	43,840	1,744	—	119,321
Transportation expense	10,491	5	—	(4,435)	6,061
Depletion, depreciation and amortization	78,112	20,622	80	—	98,814
Accretion of asset retirement obligations	3,334	547	33	—	3,914
General and administrative, net of amounts capitalized	29,425	2,344	281	(280)	31,770
Total expenses	195,099	67,358	2,138	(4,715)	259,880
Income from operations	(57,246)	28,171	3,055	—	(26,020)
FINANCING COSTS AND OTHER:					
Interest expense, net	62,876	(56)	(2,705)	—	60,115
Amortization of deferred loan costs	4,197	—	—	—	4,197
Interest rate derivative losses, net	17,177	—	—	—	17,177
Loss on extinguishment of debt	12,063	—	—	—	12,063
Total financing costs and other	96,313	(56)	(2,705)	—	93,552
Equity in subsidiary income	20,854	—	—	(20,854)	—
Income (loss) before income taxes	(132,705)	28,227	5,760	(20,854)	(119,572)
Income tax provision (benefit)	(59,333)	10,907	2,226	—	(46,200)
Net income (loss)	$ (73,372)	$17,320	$ 3,534	$(20,854)	$ (73,372)

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2006
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (12)	$ 8,358	$ 18	$ —	$ 8,364
Accounts receivable	26,182	21,738	122	—	48,042
Inventories	3,210	1	—	—	3,211
Prepaid expenses and other current assets	5,777	1,449	—	—	7,226
Income taxes receivable	8,098	—	—	—	8,098
Deferred income taxes	879	—	—	—	879
Commodity derivatives	10,348	—	—	—	10,348
TOTAL CURRENT ASSETS	54,482	31,546	140	—	86,168
PROPERTY, PLANT & EQUIPMENT, NET	556,640	238,505	772	(21,664)	774,253
COMMODITY DERIVATIVES	8,591	—	—	—	8,591
INVESTMENTS IN AFFILIATES	375,332	—	—	(375,332)	—
OTHER	18,413	5,768	—	—	24,181
TOTAL ASSETS	$1,013,458	$ 275,819	$ 912	$(396,996)	$893,193
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 49,526	$ 3,880	$ —	$ —	$ 53,406
Undistributed revenue payable	7,831	7,765	—	—	15,596
Interest payable	5,300	(5)	—	—	5,295
Current maturities of long-term debt	3,557	—	—	—	3,557
Commodity and interest derivatives	8,907	—	—	—	8,907
TOTAL CURRENT LIABILITIES:	75,121	11,640	—	—	86,761
LONG-TERM DEBT	529,616	—	—	—	529,616
DEFERRED INCOME TAXES	40,424	—	—	—	40,424
COMMODITY AND INTEREST DERIVATIVES	7,092	—	—	—	7,092
ASSET RETIREMENT OBLIGATIONS	32,261	6,443	280	—	38,984
INTERCOMPANY PAYABLES (RECEIVABLES)	138,628	(107,464)	(31,164)	—	—
OTHER LONG-TERM LIABILITIES	—	—	—	—	—
TOTAL LIABILITIES	823,142	(89,381)	(30,884)	—	702,877
TOTAL STOCKHOLDERS' EQUITY	190,316	365,200	31,796	(396,996)	190,316
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,013,458	$ 275,819	$ 912	$(396,996)	$893,193

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS AT DECEMBER 31, 2007 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 8,762	$ 973	$ —	$ —	$ 9,735
Accounts receivable	38,020	17,512	65	—	55,597
Inventories	5,217	5,160	—	—	10,377
Prepaid expenses and other current assets	4,391	—	—	—	4,391
Income taxes receivable	6,725	—	—	—	6,725
Deferred income taxes	21,967	—	—	—	21,967
Commodity derivatives	7,780	—	—	—	7,780
TOTAL CURRENT ASSETS	92,862	23,645	65	—	116,572
PROPERTY, PLANT & EQUIPMENT, NET	755,487	374,246	1,299	—	1,131,032
COMMODITY DERIVATIVES	3,768	—	—	—	3,768
INVESTMENTS IN AFFILIATES	431,083	—	—	(431,083)	—
OTHER	13,296	817	—	—	14,113
TOTAL ASSETS	$1,296,496	$398,708	$ 1,364	$(431,083)	$1,265,485
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 75,524	$ 6,570	$ —	$ —	$ 82,094
Undistributed revenue payable	11,298	—	—	—	11,298
Interest payable	6,839	—	—	—	6,839
Current maturities of long-term debt	3,449	—	—	—	3,449
Commodity and interest derivatives	68,756	—	—	—	68,756
TOTAL CURRENT LIABILITIES:	165,866	6,570	—	—	172,436
LONG-TERM DEBT	691,896	—	—	—	691,896
DEFERRED INCOME TAXES	16,607	—	—	—	16,607
COMMODITY AND INTEREST DERIVATIVES	87,224	—	—	—	87,224
ASSET RETIREMENT OBLIGATIONS	40,587	10,317	816	—	51,720
INTERCOMPANY PAYABLES (RECEIVABLES)	48,714	(11,705)	(37,009)	—	—
OTHER LONG-TERM LIABILITIES	—	—	—	—	—
TOTAL LIABILITIES	1,050,894	5,182	(36,193)	—	1,019,883
TOTAL STOCKHOLDERS' EQUITY	245,602	393,526	37,557	(431,083)	245,602
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,296,496	$398,708	$ 1,364	$(431,083)	$1,265,485

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2005 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by operating activities	$ 42,819	$ (8,772)	$ 5,884	$—	$ 39,931
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natrual gas properties	(77,241)	(408)	(8)	—	(77,657)
Acqusitions of oil and natural gas properties	(10,636)	—	—	—	(10,636)
Expenditures for property and equipment and other	(1,813)	—	—	—	(1,813)
Proceeds from sale of oil and natural gas properties	44,619	—	—	—	44,619
Acquisition of Marquez Energy, LLC	(14,628)	—	—	—	(14,628)
Notes receivable—officers and employees	—	1,420	—	—	1,420
Net cash provided by (used in) investing activities	(59,699)	1,012	(8)	—	(58,695)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	(6,036)	11,561	(5,525)	—	—
Proceeds from long-term debt	59,000	—	—	—	59,000
Principal payments on long-term debt	(39,000)	(4,684)	(53)	—	(43,737)
Payments for deferred loan costs	(817)	—	—	—	(817)
Premium to retire debt	—	—	—	—	—
Proceeds from derivative premium financing	—	—	—	—	—
Proceeds from issuance of common stock	—	—	—	—	—
Stock issuance costs	—	—	—	—	—
Repurchase common stock	(5,301)	—	—	—	(5,301)
Proceeds from exercise of stock options	—	—	—	—	—
Excess income tax benefits from share-based compensation	—	—	—	—	—
Distribution payments to Marquez Energy member	—	(707)	—	—	(707)
Dividend paid to shareholder	(35,000)	—	—	—	(35,000)
Net cash provided by (used in) financing activities	(27,154)	6,170	(5,578)	—	(26,562)
Net increase (decrease) in cash and cash equivalents	(44,034)	(1,590)	298	—	(45,326)
Cash and cash equivalents, beginning of period	53,075	1,590	50	—	54,715
Cash and cash equivalents, end of period	$ 9,041	$ —	$ 348	$—	$ 9,389

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2006 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 106,804	$(16,164)	$(1,550)	$—	$ 89,090
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(151,974)	(13,774)	—	—	(165,748)
Acqusitions of oil and natural gas properties	(19,461)	—	—	—	(19,461)
Expenditures for property and equipment and other	(8,734)	(131)	—	—	(8,865)
Proceeds from sale of oil and natural gas properties	8,564	37,825	—	—	46,389
Acquisition of Texcal Energy, net of cash acquired	(456,810)	9,291	—	—	(447,519)
Net cash provided by (used in) investing activities	(628,415)	33,211	—	—	(595,204)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	7,436	(8,689)	1,253	—	—
Proceeds from long-term debt	569,529	—	—	—	569,529
Principal payments on long-term debt	(210,068)	—	(33)	—	(210,101)
Payments for deferred loan costs	(15,335)	—	—	—	(15,335)
Premium to retire debt	—	—	—	—	—
Proceeds from derivative premium financing	3,903	—	—	—	3,903
Proceeds from issuance of common stock	160,393	—	—	—	160,393
Stock issuance costs	(2,874)	—	—	—	(2,874)
Proceeds from exercise of stock options	—	—	—	—	—
Excess income tax benefits from share-based compensation	—	—	—	—	—
Dividend paid to shareholder	(426)	—	—	—	(426)
Net cash provided by (used in) financing activities	512,558	(8,689)	1,220	—	505,089
Net increase (decrease) in cash and cash equivalents	(9,053)	8,358	(330)	—	(1,025)
Cash and cash equivalents, beginning of period	9,041	—	348	—	9,389
Cash and cash equivalents, end of period	$ (12)	$ 8,358	$ 18	$—	$ 8,364

13. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2007 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 121,086	$ 36,126	$ 3,651	$—	$ 160,863
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natrual gas properties	(212,717)	(104,073)	(104)	—	(316,894)
Acqusitions of oil and natural gas properties	(72,512)	(49,310)	—	—	(121,822)
Expenditures for property and equipment and other	(5,182)	(207)	—	—	(5,389)
Proceeds from sale of oil and natural gas properties	829	9,913	—	—	10,742
Acquisition of Texcal Energy, net of cash acquired	—	—	—	—	—
Net cash used in investing activities	(289,582)	(143,677)	(104)	—	(433,363)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	(96,601)	100,166	(3,565)	—	—
Proceeds from long-term debt	777,421	—	—	—	777,421
Principal payments on long-term debt	(619,729)	—	—	—	(619,729)
Payments for deferred loan costs	(4,923)	—	—	—	(4,923)
Premium to retire debt	(3,489)	—	—	—	(3,489)
Proceeds from derivative premium financing	3,780	—	—	—	3,780
Proceeds from issuance of common stock	116,595	—	—	—	116,595
Stock issuance costs	(561)	—	—	—	(561)
Proceeds from exercise of stock options	4,777	—	—	—	4,777
Excess income tax benefits from share-based compensation	—	—	—	—	—
Dividend paid to shareholder	—	—	—	—	—
Net cash provided by financing activities	177,270	100,166	(3,565)	—	273,871
Net increase (decrease) in cash and cash equivalents	8,774	(7,385)	(18)	—	1,371
Cash and cash equivalents, beginning of period	(12)	8,358	18	—	8,364
Cash and cash equivalents, end of period	$ 8,762	$ 973	$ —	$—	$ 9,735

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DIRECTORS AND OFFICERS

Timothy Marquez
Chairman and Chief Executive Officer

William Schneider
President

Timothy A. Ficker
Chief Financial Officer

Mark DePuy
Executive Vice President and Chief Operating Officer

Terry L. Anderson
General Counsel and Secretary

Douglas Griggs
Chief Accounting Officer

Carla J. Wolin
Chief Human Resources Officer

Ed O'Donnell
Senior Vice President, Coastal California Operations

Brady McConaty
Vice President, Texas Operations

Terry Sherban
Vice President, Acquisitions

Gregory B. Schrage
Vice President, Asset Development

Kevin Morrato
Vice President, Sacramento Basin Operations

Michael G. Edwards
Vice President, Investor Relations

Joel L. Reed
Lead Director

J. Timothy Brittan
Director

J.C. "Mac" McFarland
Director

M.W. "Bill" Scoggins, PhD
Director

Mark Snell
Director

Richard S. Walker
Director

CORPORATE OFFICES

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INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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Denver, Colorado

LEGAL COUNSEL

Davis Graham & Stubbs LLP
Denver, Colorado

INDEPENDENT RESERVOIR ENGINEERS

DeGolyer and MacNaughton
Dallas, Texas

TRANSFER AGENT

Contact for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

Computershare Trust Company, Inc.
Post Office Box 1596
Denver, Colorado 80201
(303) 262-0600

FORM 10-K

We will provide, without charge, a copy of our Annual Report on Form 10-K for 2007 (including financial statements and schedules but excluding exhibits) to any stockholder who requests one. Requests should be directed to Venoco, Inc., Attention Secretary, 6267 Carpinteria Avenue, Suite 100, Carpinteria, California 93013. Copies of the 10-K and all exhibits thereto can also be obtained from our website.

CODE OF BUSINESS CONDUCT AND ETHICS

The Code of Business Conduct and Ethics of Venoco, Inc. is available on our website at www.venocoinc.com or a copy may be obtained by writing to the company.

ANNUAL MEETING

The annual meeting of stockholders of Venoco, Inc. will be held at the Brown Palace Hotel, 321 17th Street, Denver, Colorado on May 15, 2008, at 7:30 a.m.

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