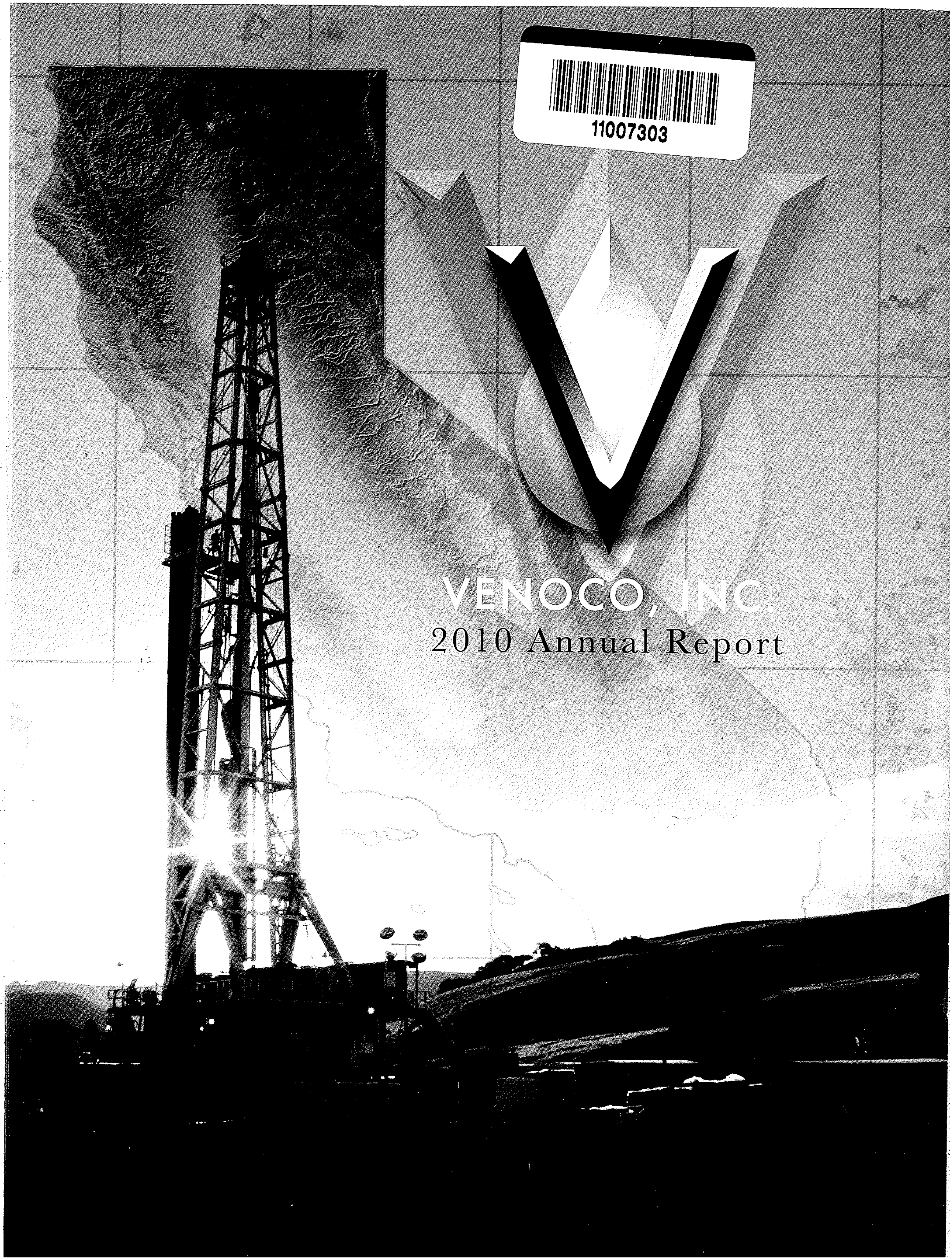


VENOCO, INC.
2010 Annual Report

Selected Financial and Operating Data

Years Ended December 31, ($ in thousands, except per share amounts)	2008	2009	2010
Production Volumes (MBOE)	7,933	7,527	6,658
Average Daily Production Volume (BOE/Day)	21,674	20,622	18,241
Proved Reserves (MMBOE)	97.5	98.3	85.1
Standardized Measure of Discounted Future Net Cash Flows	$ 610,096	$ 692,805	$ 902,901
Oil and Natural Gas Sales	$ 554,270	$ 267,163	$ 290,608
Total Revenues	$ 557,873	$ 270,494	$ 295,292
Income (Loss) from Operations	$ (418,729)	$ 33,060	$ 72,935
Net Income (Loss)	$ (391,132)	$ (47,298)	$ 67,520
Earnings Per Share - Basic	$ (7.75)	$ (0.93)	$ 1.23
Earnings Per Share - Diluted	$ (7.75)	$ (0.93)	$ 1.21
Current Assets	$ 115,965	$ 90,814	$ 72,778
Net Property, Plant and Equipment	$ 702,734	$ 619,430	$ 648,044
Other Long-Term Assets	$ 45,555	$ 29,299	$ 30,101
Total Assets	$ 864,254	$ 739,543	$ 750,923
Current Liabilities	$ 112,884	$ 111,449	$ 84,417
Long-Term Debt	$ 797,670	$ 695,029	$ 633,592
Other Liabilities	$ 88,867	$ 107,561	$ 117,151
Stockholders' Equity	$ (135,167)	$ (174,496)	$ (84,237)
Total Liabilities and Stockholders' Equity	$ 864,254	$ 739,543	$ 750,923

Adjusted EBITDA Reconciliations

Years Ended December 31, Unaudited ($ in thousands)	2008	2009	2010
Net Income (Loss)	$ (391,132)	$ (47,298)	$ 67,520
Interest Expense, Net	$ 54,049	$ 40,984	$ 40,584
Realized Interest Rate Derivative (Gains) Losses	$ 10,231	$ 18,479	$ 18,094
Income Taxes	$ 11,200	$ (14,400)	$ (1,300)
DD&A	$ 134,483	$ 86,226	$ 78,504
Accretion of Asset Retirement Obligation	$ 4,203	$ 5,765	$ 6,241
Ceiling Test Impairment	$ 641,000	$ –	$ –
Amortization of Deferred Loan Costs	$ 3,344	$ 2,862	$ 2,362
Loss on Extinguishment of Debt	$ –	$ 8,493	$ –
Share-Based Payments	$ 3,064	$ 2,824	$ 5,653
Texas Severance Costs	$ –	$ –	$ 1,254
Amortization of Derivative Premiums and Other Comprehensive Loss	$ 7,694	$ 24,985	$ 24,808
Unrealized Commodity Derivative (Gains) Losses	$ (184,459)	$ 71,511	$ (39,356)
Unrealized Interest Rate Derivative (Gains) Losses	$ 10,336	$ (1,803)	$ 13,724
Adjusted EBITDA	$ 304,013	$ 198,628	$ 218,088

Adjusted Earnings Reconciliations

Years Ended December 31, Unaudited ($ in thousands)	2008	2009	2010
Net Income (Loss)	$ (391,132)	$ (47,298)	$ 67,520
Unrealized Commodity Derivative (Gains) Losses	$ (184,459)	$ 71,511	$ (39,356)
Unrealized Interest Rate Derivative (Gains) Losses	$ 10,336	$ (1,803)	$ 13,724
Texas Severance Costs	$ –	$ –	$ 1,254
Write-Off of MLP Offering Costs	$ 2,690	$ –	$ –
Loss on Extinguishment of Debt	$ –	$ 8,493	$ –
Ceiling Test Impairment	$ 641,000	$ –	$ –
Tax Effects	$ (690)	$ (276)	$ –
Adjusted Earnings	$ 77,745	$ 30,627	$ 43,142

Letter To Stockholders

The past year was a transitional one for Venoco; we completed the divestiture of our producing oil and gas assets in Texas, which allowed us to pay down debt for a second straight year and better position the company to focus on our oil and natural gas opportunities in California – specifically the onshore development of the Monterey shale formation.

As the country's third largest oil producing state, California's resource potential is well demonstrated. However, despite a well-known reputation as a prolific source rock and a long history as reservoir rock, the potential of the state's onshore Monterey shale formation has never been fully developed. The Monterey shale is estimated to have sourced some 38 billion barrels of oil equivalent (BOE) in conventional fields and represents another 2.5 billion BOE as the reservoir rock in currently producing fields. Two of our legacy Southern California oil assets—the offshore South Ellwood and Sockeye fields—currently produce from the Monterey shale formation and, along with our West Montalvo field, remain a steady, low-decline production base for the company as we continue our pursuit of the onshore Monterey shale formation.

As a California exploration and production company we enjoy several advantages. First, we have decades of experience operating in California, and that expertise allows us to operate in a state where we and our stockholders are exposed to high-impact opportunities. Second, because of the perception that California is a difficult place to operate, there is less competition. Third, we believe one of the largest opportunities in the entire industry lies within California's borders in the development of the Monterey shale. Lastly, in addition to our excitement about the Monterey shale and our other oil properties in Southern California, we operate the state's first and third largest natural gas producing fields, in the Sacramento Basin where we are also the most active operator.

We operate over 95% of our producing properties which provides us the flexibility to manage our capital budget, direct our investment to the highest return projects, and drive operating efficiencies. Our geoscientists, engineers, and operations personnel continue to find new, cost-efficient ways of generating greater returns while operating in an environmentally sensitive manner. We held our lease operating expense to $12.65 per BOE in 2010, the same as 2009, and generated operating cash flow of $160.7 million, an increase of 35% from 2009.

We continued to add to our Monterey shale acreage in 2010; as of our 10-K filing, we had built a position of approximately 183,000 net acres across 38 prospects in three basins: Santa Maria, Salinas Valley and San Joaquin. We spud 12 wells in 2010 targeting the onshore Monterey – eight were vertical 'science' wells where we collected cores, gathered a full suite of logs and performed production tests on prospective intervals. This is the oil business, and, as we've seen in other unconventional plays, we know it will take many wells to optimize drilling and completions. We have been encouraged by the scientific information we gathered in 2010 from cores, logs and production tests; as a result, we expect to spud 30 gross wells in the Monterey in 2011. We enter 2011 confident that the resource is there and that we have the tools and the expertise to successfully pursue it.

On the natural gas side, production in 2010 from the Sacramento Basin remained level with 2009 at around 60 million cubic feet per day. We continue to identify exciting opportunities in the Basin, though the speed with which we expect to pursue them is impacted by low domestic gas prices. We have more than 600 identified drilling locations in the Sacramento Basin and plan to drill 40 of them in 2011. Our plan for this year is to hold average daily production level with 2010, which will generate solid cash flow since we are well hedged for the year. Our 2011 budget, however, contemplates exiting the year at reduced activity levels in anticipation of continued depressed natural gas prices.

Our 2010 accomplishments include:

- Adjusted EBITDA of $218 million, up 10% from $199 million in 2009
- Completed sale of Texas assets for approximately $100 million (retained our 22.3% reversionary working interest in the Hastings Field)
- Achieved lease operating expenses of $12.65 per BOE
- Reduced long-term debt by $61 million
- Added leasehold of approximately 36,000 net acres prospective for the onshore Monterey shale
- Spud 12 wells in the onshore Monterey shale to evaluate specific prospect areas and to assess drilling and completion techniques

"With a weighted-average hedged floor of $5.43 per MCF in 2011, drilling in the Sacramento Basin continues to be very economic."

In 2010, we spent $104 million or 47% of our capital budget in the Sacramento Basin. We completed 75 new wells and performed 213 recompletions. We believe the Sacramento Basin is one of the best places in the country to produce natural gas, given its proximity to West Coast markets. California consumes approximately 12 billion cubic feet (BCF) of natural gas per day while in-state production is only about 1 BCF per day; as a result, gas prices in the Basin received a premium to Henry Hub in 2010. Given a positive basis differential and our low cost structure, we estimate that a typical successful well will generate a 25% internal rate of return at $4.00 per thousand cubic feet (MCF) gas. With a weighted-average hedged floor of $5.43 per MCF in 2011, drilling in the Basin continues to be very economic.

The Monterey shale is one of the oldest and largest producing oil plays in the continental United States with first production in the late 1880s and more than 26 fields that are expected to collectively produce 2.5 billion BOE. It has been well delineated; more than 17,000 wells have penetrated the Monterey in our three target basins: the Salinas Valley, San Joaquin and Santa Maria. While most of the production from the Monterey shale has been from conventional traps and natural-fracture-dominated fields, we believe that advances in horizontal drilling techniques, well completion technology and 3-D seismic will transform the play. We believe certain facies of the Monterey shale will have the advantage of natural fracturing and can be much thicker than other U.S. shale plays. We have more than 13 years of experience operating in the Monterey, and we began drilling horizontal wells into a Monterey interval at our Sockeye field five years ago. In 2010 we spud the eight vertical and four horizontal wells to evaluate our onshore acreage and to test various drilling and completion techniques. We are currently completing a joint 3-D seismic shoot covering 320,000 acres in the San Joaquin Basin and continue to aggressively acquire leases. We are allocating 50% of our 2011 capital budget or $100 million to Monterey shale activity.

Our net proved reserves as of December 31, 2010 were 85.1 million BOE (MMBOE), relatively flat with 2009 when adjusted for production and asset sales. Due to higher commodity prices, our pre-tax PV-10 value at December 31, 2010 was $1.1 billion compared to $801.1 million in 2009. Net commodity prices used in the reserve valuation were $69.18 per barrel of oil and $4.37 per million British Thermal Units (MMBTU) of natural gas.

We reduced our debt in 2010 with the ~$100 million of proceeds from the sale of our Texas assets in the second quarter. We ended the year with $634 million of long-term debt; then in the first quarter of 2011 we refinanced a portion of that debt by issuing $500 million of 8.875% senior unsecured notes due in February 2019 that extended the maturity of our long-term debt and provided us with additional liquidity. In connection with the refinancing, we also issued 4.6 million shares of common stock at $18.75 per share netting approximately $82 million. We utilized the proceeds from these two transactions to retire secured debt maturing in 2014, and repay the outstanding balance on our revolving credit facility. This left us in a much stronger financial position with no pending debt maturities and an undrawn revolving credit facility with a current borrowing base of $200 million, while providing $33 million in cash. We expect to be able to fund our 2011 capital program from cash flow, supplemented by cash on hand and our revolving credit facility.

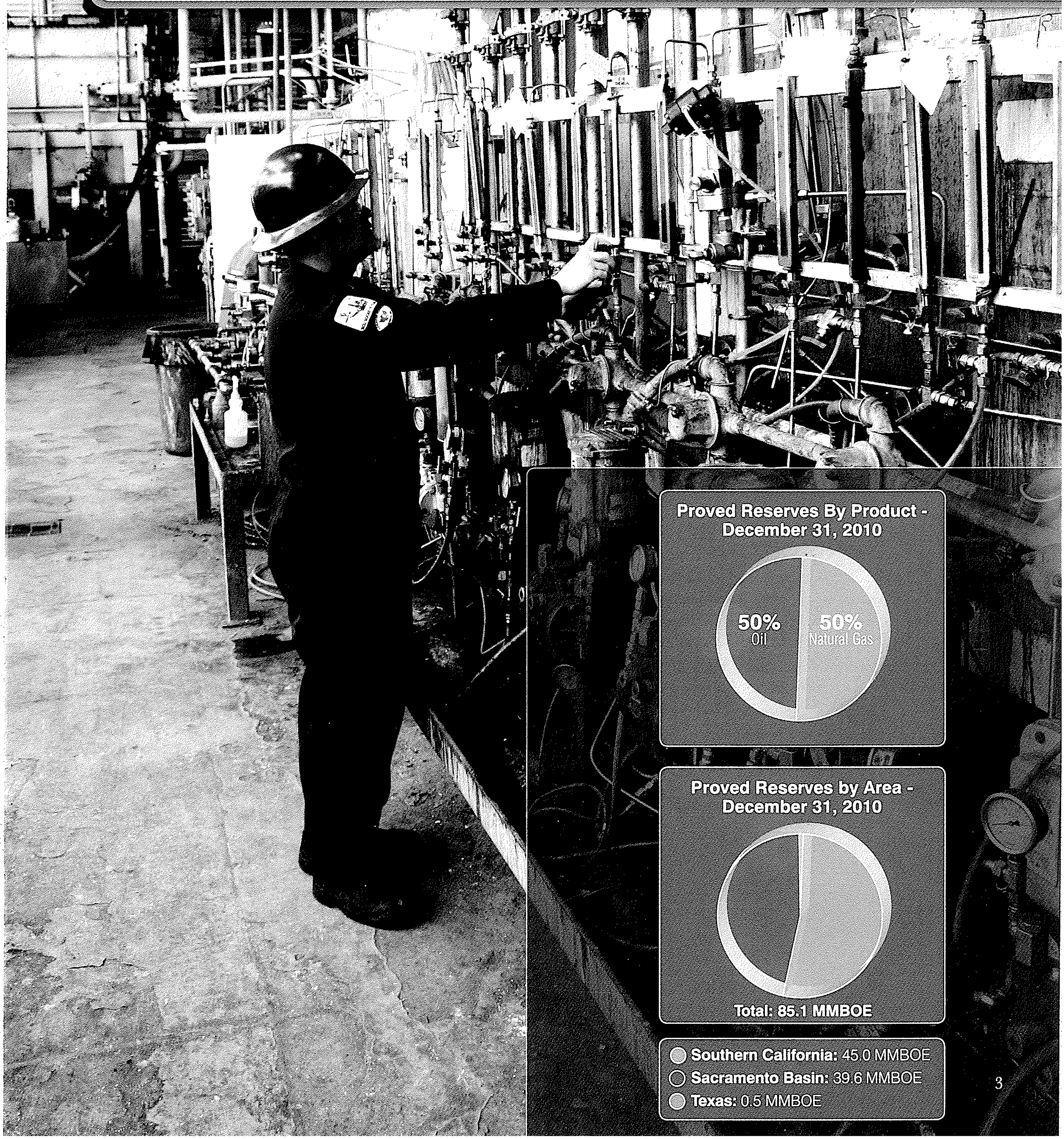
While we've sold all of our producing properties in Texas, we still own a very valuable asset in the state - our reversionary interest in the Hastings field. Denbury Resources implemented a CO_2 flood of the field in mid-December 2010 and we believe the field will respond sometime later this year. Depending on the timing of the response, we expect to be able to move some of our 15 MMBOE of probable reserves into the proved category this year. Given the opportunities we have in California, we have tentative plans to market this property sometime after the field has responded to the CO_2 flood.

Looking towards 2011 we remain focused on what we do best, applying technology to efficiently develop and operate our legacy assets in the Sacramento Basin and Southern California and pursuing our Monterey shale opportunities. Our competitive strengths include maintaining an efficient cost structure, making opportunistic acquisitions of underdeveloped properties, and using our experience and expertise to grow within the California market.

I would like to thank all of our employees for their hard work and our board of directors for providing their leadership and expertise. And on behalf of all of us at Venoco, I would like to thank you, our stockholders, for your continued support.

Timothy Marquez,
Chairman and Chief Executive Officer

"As the country's third largest oil producing state, California's resource potential is well demonstrated."



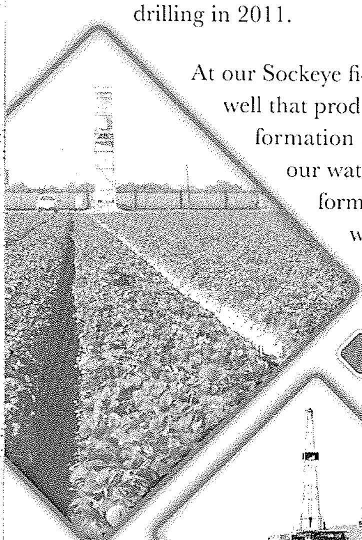
Operations

Southern California

Venoco was founded on oil operations in Southern California. Our legacy Southern California assets include our three principal oil fields: South Ellwood, Sockeye and West Montalvo. These three fields generated 85% of our Southern California production in 2010 and received nearly all of the $39 million from our 2010 capital budget allocated to Southern California.

During the year, we completed two wells and recompleted three wells in the West Montalvo field, which is located in coastal Ventura County. At year-end we had 30 producing wells and two injection wells in this field which we've owned since 2007. We continue to perform various facility upgrades and are permitting several wells targeting the offshore portion of the field, which we plan to begin drilling in 2011.

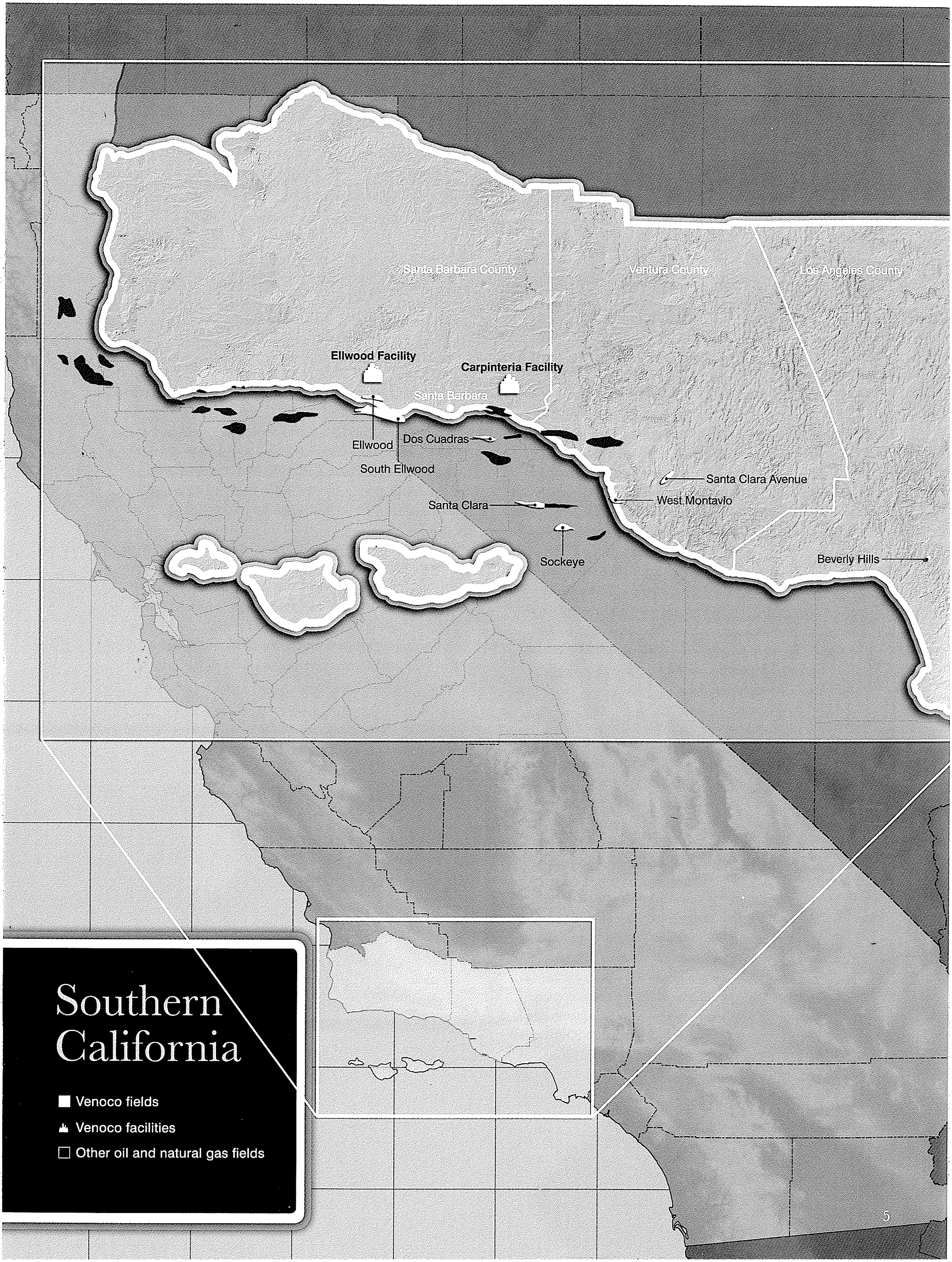
At our Sockeye field we drilled a dual completion well that produces from the Monterey shale formation and improves the sweep of our waterflood in the Lower Topanga formation. At the South Ellwood field we performed six recompletions during 2010 and are permitting three proved undeveloped locations in the field. We have completed structural work on Platform Holly necessary for drilling those locations. Ellwood Pipeline, Inc., a wholly owned subsidiary, is pursuing permits to construct a new, onshore common carrier pipeline which would allow us to discontinue use of the barge to transport oil to refineries. We expect the pipeline will enhance our realizations from the field by reducing transportation costs and providing access to more purchasers.



Just under half of our oil production is sold based on NYMEX pricing, while the balance is sold based on California postings. Those California postings, like other coastal US grades, tend to trade with Brent and not the landlocked WTI index. As a result, we have not only benefited from the recent increases in oil prices in general, but have also further benefited from the strengthening of the Brent index relative to NYMEX.

We have budgeted $40 million, or 20% of our 2011 capital budget, for drilling, recompletion and facilities work in our legacy Southern California fields.

"Our legacy Southern California oil assets provide us with steady, low-decline production and solid cash flow."



Southern California

- Venoco fields
- Venoco facilities
- Other oil and natural gas fields

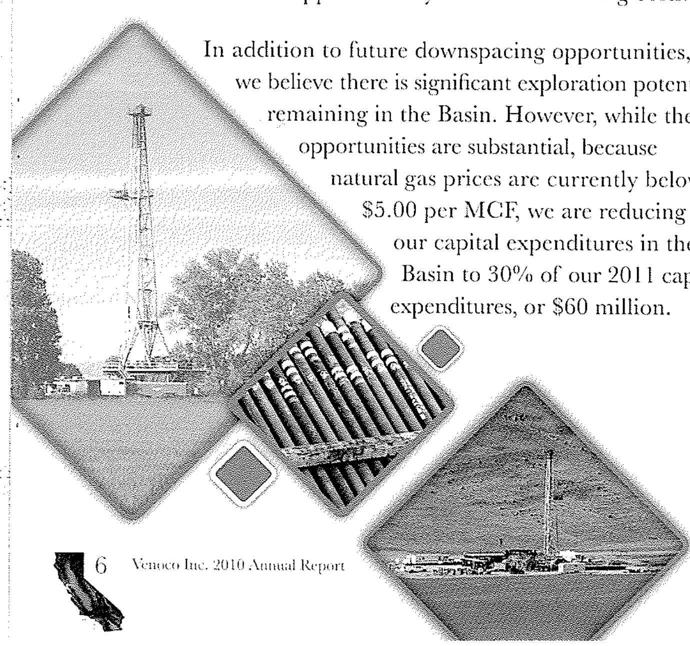
Operations

Sacramen

Venoco is the largest gas producer and most active operator in the Sacramento Basin. We have drilled more than 450 wells since 2005 and have accumulated approximately 223,000 net acres in this area. We have both 2-D and 3-D seismic data covering more than 1,100 square miles in the Basin which we use to identify exploration, exploitation, development and acquisition opportunities. We recently announced an extension of the Grimes field after we drilled an anomaly discovered on 3-D seismic data we acquired with leasehold in 2009. The successful exploratory well had an initial production rate of more than 3 million cubic feet per day. Our exploratory efforts will continue as we plan to test additional anomalies identified from the seismic data.

During 2010, we completed 75 wells, performed 213 recompletions and fracture stimulated 12 wells. We have identified over 600 drilling locations on 20-acre spacing in the Basin and continue exploratory efforts to further expand our development program. We have been able to maintain the drilling efficiencies we achieved between 2008 and 2009 when we significantly reduced drilling times, which has translated into approximately 30% lower drilling costs.

In addition to future downspacing opportunities, we believe there is significant exploration potential remaining in the Basin. However, while these opportunities are substantial, because natural gas prices are currently below $5.00 per MCF, we are reducing our capital expenditures in the Basin to 30% of our 2011 capital expenditures, or $60 million.



This budget anticipates drilling 40 new wells and performing 220 recompletions and 20 fracture stimulations. We are expecting our reduced activity levels to result in average daily production in the Basin for 2011 that is roughly flat compared to 2010 average daily production.

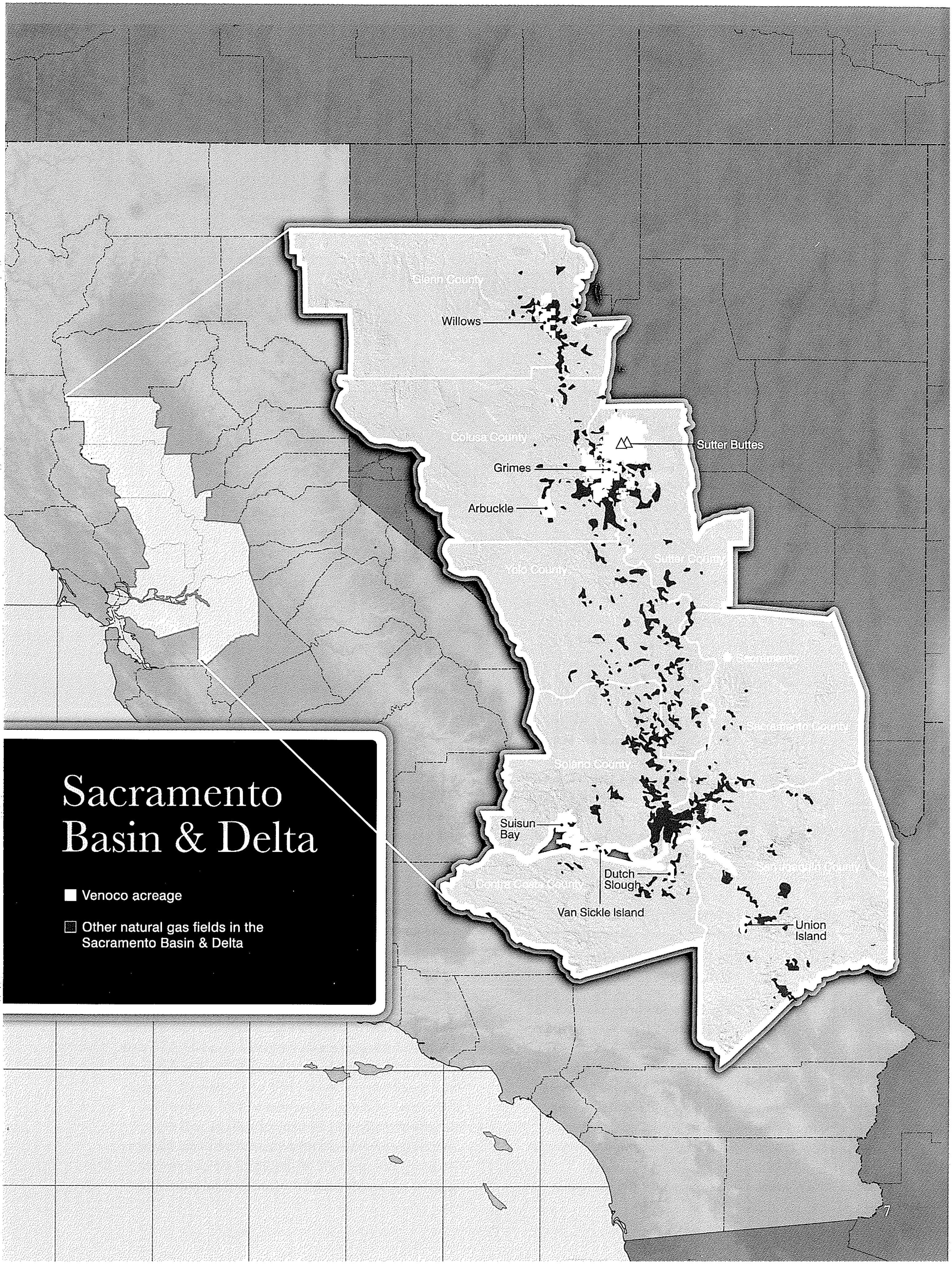
Our extensive activity in the Basin has allowed us to reduce costs by increasing drilling efficiencies to the point where a natural gas price of just $4.00 per MCF is expected to generate a 25% rate of return on a typical successful well. The Sacramento Basin continues to be a valuable asset and, with our hedge positions for 2011, will generate positive cash flow even at current natural gas prices.

"We have identified over 600 drilling locations on 20-acre spacing in the Basin."

Sacramento Basin & Delta

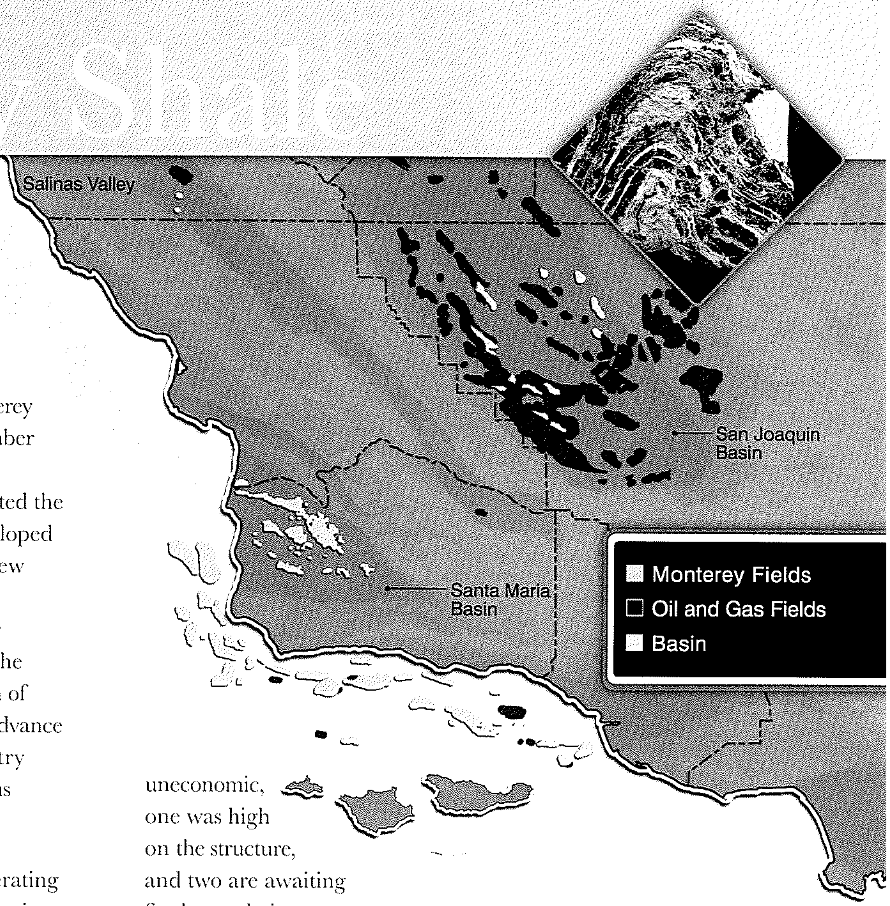
Venoco acreage

Other natural gas fields in the Sacramento Basin & Delta



Operations

Monterey Shale



Through more than 13 years operating the offshore South Ellwood and Sockeye fields, we have developed an extensive knowledge of the Monterey shale formation which we believe has parallels to exploration and development opportunities onshore. We believe the development of the unconventional onshore Monterey shale formation has been largely overlooked for a number of reasons, including California's unique competitive landscape. In addition, industry majors have dominated the state's significant oil production and prospective undeveloped acreage for decades with little incentive to explore new reservoirs due to highly favorable economics in their existing, shallow fields. The relative scarcity of other independent operators in the area has not only slowed the development of the play but also delayed the application of current drilling and completion technologies utilized to advance other unconventional resource plays across the country in recent years. We believe this has created a tremendous opportunity for Venoco.

Utilizing our experience and expertise gained from operating offshore fields producing from the Monterey shale formation, we have identified significant opportunities onshore. In 2006, we began actively studying onshore regions in Southern California with Monterey potential. We screened the extensive well data for several criteria, including light oil, moderate reservoir depths, favorable operating areas near existing infrastructure, and a geologic structural component.

As of our 10-K filing, our onshore Monterey shale acreage position totaled approximately 183,000 net acres including 46,000 acres held by production with existing Monterey production or potential. We spud eight vertical 'science' wells and four horizontal wells in 2010. We have cut hundreds of feet of core from the Monterey and tested different completion techniques such as acidizing and fracture stimulations. Production test rates on the vertical wells have ranged from 20 BOE per day to 150 BOE per day. Of the four horizontal wells we spud in 2010, one was uneconomic, one was high on the structure, and two are awaiting final completion.

The information from our vertical science wells will aid in the development and refinement of drilling and completion techniques that are expected to increase efficiency for our onshore Monterey shale drilling programs. We expect horizontal drilling to have greater production capabilities based on preliminary information we have gathered from our science wells. We currently have three drilling rigs operating in the onshore Monterey shale to accommodate our 2011 drilling program. We plan to spud 30 gross wells in 2011, 22 horizontals and 8 verticals. We also expect to have data from the second half of California's largest 3-D seismic shoot by this summer. This data will be valuable for orienting horizontal wells as well as in identifying conventional targets above or below the Monterey. We have allocated half of our 2011 capital budget, or $100 million, to onshore Monterey shale activities.

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, 2010

☐ **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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 ☐ (Do not check if a smaller reporting company)	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, 2010 was $361.9 million, 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 56,241,672 shares of common stock outstanding as of December 31, 2010.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its 2011 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. 2010 ANNUAL REPORT ON FORM 10-K
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FORWARD-LOOKING STATEMENTS

This report on Form 10-K 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, debt levels and anticipated liquidity;
- amounts and nature of future capital expenditures;
- acquisitions and other business opportunities, including those relating to the proposed pipeline project in the South Ellwood field and our onshore Monterey shale development project;
- our ability to raise capital through debt or equity offerings, borrowings under our revolving credit facility or other transactions, including lenders' willingness and ability to fund amounts under the revolving credit facility and our ability to comply with covenants set forth in the revolving credit agreement;
- 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;
- the amount and timing of expenses relating to asset retirement obligations;
- the ability and willingness of counterparties to our commodity derivative contracts to perform their obligations;
- expiration of oil and natural gas leases that are not held by production;
- declines in the values of our natural gas and oil properties that may result in write-downs;
- estimates of proved oil and natural gas reserves, PV-10 and related cash flows;
- reserve potential;
- development and infill drilling potential;
- business strategy;
- future production of oil and natural gas;
- the receipt of governmental permits and other approvals relating to our operations, including permits and approvals relating to the proposed pipeline project in the South Ellwood field, to the availability of the barge we plan to use to deliver oil production from the South Ellwood field and our ability to maintain delivery and sales arrangements relating to that production;
- transportation of the oil and natural gas we produce;
- 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:

- changes in oil and natural gas prices, including reductions in prices that would adversely affect our revenues, income, cash flow from operations, liquidity and reserves;
- adverse conditions in global credit markets and in economic conditions generally;
- risks related to our level of indebtedness;
- our ability to replace oil and natural gas reserves;
- 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 in the onshore Monterey shale, where our results will depend on, among other things, our ability to identify productive intervals and drilling and completion techniques necessary to achieve commercial production from those intervals;
- our ability to manage expenses, including expenses associated with asset retirement obligations;
- a lack of available capital and financing, including as a result of a reduction in the borrowing base under our revolving credit facility;
- 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;
- factors affecting the nature and timing of our capital expenditures;
- the impact and costs related to compliance with or changes in laws or regulations governing or affecting our operations, including changes resulting from the Deepwater Horizon well blowout in the Gulf of Mexico, from the Dodd-Frank Wall Street Reform and Consumer Protection Act or its implementing regulations and from regulations relating to greenhouse gas emissions;
- delays, denials or other problems relating to our receipt of operational consents and approvals from governmental entities and other parties;
- environmental liabilities;
- loss of senior management or technical personnel;
- natural disasters, including severe weather;
- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us;
- 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 or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.
Condensate	A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
/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.
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 of SEC Regulation S-X and refers to a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

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.
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.
MMcfe	One million 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.
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.
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 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 fourth quarter of the relevant year 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 gas reserves	This term means "proved oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X and refers to the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.
Proved reserves to production ratio	The ratio of total proved reserves to total net production for the fourth quarter of the relevant year or other specified period.
Proved undeveloped reserves or PUDs	Undeveloped reserves that qualify as proved reserves.
PV-10	The PV-10 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 the twelve-month arithmetic average of the first of the month prices (except that for periods prior to December 31, 2009, the period end price was used), without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, without 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 formation or producing horizon, either deeper or shallower, from that in which the well was previously completed.

Reserves	This term is defined in Rule 4-10 of SEC Regulation S-X and refers to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
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.
Spacing	The number of wells which can be drilled on a given area of land under applicable regulations.
Undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved oil and natural gas reserves.
Undeveloped reserves	This term is defined in Rule 4-10 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.
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 producing properties are located both onshore and offshore Southern California and onshore in California's Sacramento Basin, and are characterized by long reserve lives, predictable production profiles and substantial opportunities for further exploitation and development. We are also pursuing a major exploration and development project targeting the onshore Monterey shale formation in Southern California.

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 85.1 MMBOE as of December 31, 2010, based on adjusted prices of $69.18 per Bbl for oil and $4.37 per MMBtu for natural gas. As of that date, 50% of our proved reserves were oil and 50% were proved developed, and the PV-10 of those reserves was approximately $1.1 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." Our average net production in 2010 was 18,241 BOE/d.

The following table summarizes certain information concerning our production in 2010 and our reserves and inventory of drilling locations as of December 31, 2010.

	2010 Net Production			Proved Reserves(1)			
	Oil (MBbl)	Gas (MMCF)	(MBOE)	Total (MMBOE)	% Oil	PV-10 ($MM)	Drilling Locations(2)
Southern California	2,677	897	2,827	45.0	93.4%	$ 895.9	42
Sacramento Basin	3	21,958	3,662	39.6	0.0%	$ 227.3	610
Texas(3)	112	341	169	0.5	100.0%	$ 5.5	—
Total	2,792	23,196	6,658	85.1	50.0%	$1,128.7	652

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted for regional price differentials and other factors to arrive at prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the calculation of proved reserves at December 31, 2010.

(2) Represents total gross drilling locations identified by management as of December 31, 2010, excluding potential onshore Monterey shale drilling locations. Of the total shown, 309 locations are classified as proved.

(3) We sold our producing properties in Texas in a series of transactions that closed in the second quarter of 2010.

Our Strengths

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

High quality asset base with a long reserve life and growth potential. 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 Southern California fields generally have well-established production histories and exhibit relatively moderate production declines. As of

December 31, 2010, our proved reserves to production ratio was 13 years based on production during the fourth quarter of 2010. In addition, because our producing properties typically have substantial volumes of remaining hydrocarbons, they provide significant potential upside in proved reserves. We believe that we can develop additional reserves from these properties on a cost effective basis with relatively limited risk. As of December 31, 2010, we had identified 652 drilling locations on our legacy Southern California and Sacramento Basin properties, and we anticipate identifying additional locations on those properties as we pursue our exploitation and development activities.

Extensive knowledge of the Monterey shale formation and substantial onshore Monterey acreage. A substantial portion of our production is from offshore wells targeting the fractured Monterey shale formation. 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 shale formation onshore as well, and that our offshore expertise will help us take advantage of those opportunities. To date, our onshore Monterey shale acreage position is approximately 207,000 gross and 137,000 net acres. An additional 60,000 gross and 46,000 net acres with Monterey shale production or potential are held by production. We began drilling wells targeting the onshore Monterey shale in 2010, and plan a significant expansion of our activities there in 2011.

Substantial operational flexibility. We have substantial flexibility in adapting our activities to respond to changes in commodity prices and business conditions generally. We have relatively few medium and long-term drilling commitments and are therefore capable of deferring a large portion of our capital expenditures and/or shifting those expenditures between natural gas and oil-oriented projects as commodity prices dictate. In addition, we have operating control of substantially all of our properties, which allows us 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 and the onshore facility that services our South Ellwood field. Additionally, the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement presented us with the Safety Award for Excellence for our offshore operations in the Santa Clara Federal Unit, recognizing us as the top operator in the Pacific Outer Continental Shelf in 2008. 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.

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. We have drilled over 450 wells in the basin in the last five years and we are currently one of the largest operators there in terms of production and acreage. 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 favorable historical differential to NYMEX prices received for natural gas produced there contribute to the value of our position.

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 oil and natural gas industry across a broad range of disciplines, including geology, drilling and operations, and regulatory and environmental matters. Our team includes 63 engineers and geoscientists as of December 31, 2010. We believe that our experience and knowledge of the California oil and natural gas industry are important competitive advantages for us.

Our Strategy

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

Explore and develop the onshore Monterey shale formation. We plan to use the expertise we have developed with the fractured Monterey shale formation from our work in the offshore South Ellwood and Sockeye fields to facilitate our acquisition, exploration, exploitation and development of onshore properties with similar characteristics. We plan to devote approximately 50% of our $200 million capital expenditure budget for 2011, or $100 million, on activities targeting the onshore Monterey shale formation, including the drilling of approximately 30 gross wells and the acquisition of additional acreage and 3D seismic data. We expect only modest production from our onshore Monterey shale project in 2011, with our principal current objective being the development and refinement of successful prospect identification, drilling and completion processes. We expect a further expansion of our activities in the area in subsequent years.

Continue development of the Sacramento Basin. We intend to continue to pursue an active drilling and acreage acquisition program in the Sacramento Basin. We believe the basin presents significant exploration, exploitation and development opportunities from both conventional and unconventional reservoirs. As one of the largest operators in the basin, we believe that we are well positioned to identify and exploit these opportunities.

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. We intend to continue to take advantage of development opportunities in the Sockeye, South Ellwood, West Montalvo and other California fields that have these characteristics. 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.

Maintain an efficient cost structure. We have maintained low lease operating expenses, due in part to the sale of relatively high-cost fields in Texas in 2009 and 2010 and increased efficiencies in a variety of operating areas. In 2010, we began increasing our focus on oil projects and because those projects tend to have higher operating costs than natural gas projects, we expect a slight increase in per BOE production expenses going forward. However, we will continue to focus on our operating cost structure in order to create additional production and processing efficiencies and reduce operational downtime.

Make opportunistic acquisitions of underdeveloped properties. We pursue acquisitions that we believe will add 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. We intend to continue to pursue acquisition opportunities to selectively expand our portfolio of properties.

Description of Properties

Southern California—Legacy Fields

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 shale formation is the primary oil reservoir in the field, producing sour oil with a gravity of approximately 22 degrees. As of December 31, 2010, there were 18 producing wells and five injection wells in the field.

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 a barge that is owned and operated by a third party. Title to the oil is transferred when the barge completes delivery. We currently sell oil production from the field to a major oil company pursuant to a contract that is terminable by either party with 60 days notice. Natural gas produced at the field is processed at the onshore facility and transported by common carrier pipeline.

Our subsidiary Ellwood Pipeline, Inc. is pursuing the permits necessary to build a common carrier pipeline that would allow us to transport our oil to refiners without the use of a barge or the marine terminal. We anticipate that approval hearings for the project will be held during mid-2011. While we believe the pipeline should be approved, the outcome of these hearings cannot be predicted. Pending regulatory approvals and completion of the pipeline, we expect to use a double-hulled barge to transport oil production from the field.

It will be important for us that Ellwood Pipeline, Inc. complete the proposed common carrier pipeline as our ability to continue the barging operation after 2013 will depend on our receipt of the consent of a third party. Even with that consent, by 2016, our lease for the site where our oil storage tanks are located, which is held by the University of California, Santa Barbara, will expire and the current barging operation will likely not be feasible if that lease is not extended or renewed.

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 shale, at about 4,000 feet, to the Middle Sespe at approximately 7,000 feet. Other formations include the Upper Topanga, Lower Topanga and Sespe. As of December 31, 2010, there were 22 producing wells and 13 injection wells in the field. The oil produced from the Monterey shale 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. Chevron shut in production at platform Grace in the Santa Clara field in 1997, and we currently use the platform 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.

West Montalvo Field. 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 and produces sour oil with gravity of approximately 16 degrees. As of December 31, 2010, there were 30 producing wells and two injection wells in the field. 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.

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, 2010, there were 82 producing wells and 17 injection wells in the field.

Beverly Hills West 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. As of December 31, 2010, there were 15 producing wells and 3 injection wells in the field, which produce oil with gravity of approximately 23 degrees.

Santa Clara Avenue Field. 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%. As of December 31, 2010, there were a total of 18 producing wells in the field, which produce oil with gravity of approximately 22 degrees.

Southern California—Onshore Monterey Shale

We have developed an extensive knowledge of the Monterey shale formation through our work at the offshore South Ellwood and Sockeye (Santa Clara Unit) fields and believe the formation holds significant exploration opportunities onshore. Despite production history that dates back to the late 1880s, including in recent years some unconventional production, we believe the development of the unconventional onshore Monterey shale formation has been largely overlooked due to a number of circumstances, including California's unique competitive landscape. Industry majors have dominated the state's significant oil production and prospective undeveloped acreage for several decades with little incentive to explore new reservoirs due to highly favorable economics in their existing fields. We believe the relative scarcity of other independent operators in the area has not only slowed the development of the play, but also delayed the application of current drilling and completion technologies that have helped to advance other unconventional resources plays across the country in recent years.

In 2006 we began actively leasing onshore acreage in Southern California targeting the Monterey shale formation. Our leasing strategy has focused on areas where we believe the Monterey shale will produce light, sweet oil, where the quality and depth of the Monterey shale is expected to be advantageous, and is near existing infrastructure. As of December 31, 2010, our onshore Monterey shale acreage position totaled approximately 120,000 net acres. As of February 18, 2011, our onshore Monterey shale acreage position is approximately 137,000 net acres, and we intend to aggressively add to this position in the coming years. An additional 46,000 net acres with Monterey shale production or potential are held by production, primarily offshore.

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 over 1,100 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 183,000 net acres as of December 31, 2010. We operate substantially all of the fields and have a volume-weighted average working interest of approximately 92% (based on production during the fourth quarter of 2010). 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 553 producing wells in the fields as of December 31, 2010.

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 approximately 84% (based on production during the fourth quarter of 2010). As of December 31, 2010, there were a total of 38 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.

Exploration. We drill a significant number of wells on non-proved locations in the Sacramento Basin. These wells are considered "exploratory wells" as defined in SEC Regulation S-X. See "—Drilling Activity." The majority of the wells in the basin that are "exploratory wells" under SEC Regulation S-X are wells drilled on the border of existing fields in an attempt to test and expand the limits of a producing area. We generally do not distinguish between those wells and development wells from an operating perspective. We also believe there are significant exploration opportunities on our existing leasehold.

Texas

We sold our producing assets in Texas in a series of transactions that were completed in the second quarter of 2010 to multiple purchasers for aggregate net proceeds of $98.1 million (after closing adjustments and related expenses). We used the proceeds to repay $66.9 million of principal on the revolving credit facility and $30.7 million of principal on the second lien term loan. We retained our 22.3% reversionary working interest in the Hastings Complex described below. The Texas properties sold comprised 7.2% of our proved reserves at December 31, 2009 or 7.1 MMBOE and contributed approximately 460 BOE/d to our production during 2010.

In February 2009, we sold our interest in properties producing from the Frio formation in the Hastings Complex to Denbury Resources, Inc., or Denbury, for approximately $197.7 million, after certain post-closing adjustments, pursuant to an option agreement we entered into with Denbury in November 2006. The purchase price was in addition to the $50.0 million option payment Denbury previously made to us under the agreement. We retained certain interests in the complex not related to the Frio formation. Substantially all of the current production from the complex is from the Frio formation.

Pursuant to the agreement, Denbury has committed to a plan to pursue a CO_2 enhanced recovery project at properties it acquired. The plan calls for Denbury to make capital expenditures of at least

$178.7 million by the end of 2014. As part of the plan, Denbury is responsible for providing the necessary CO_2. We 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. If CO_2 recovery operations do not meet certain development milestones by January 2013, Denbury will be required to either resell the properties to us at a discount or make additional payments to us. The agreement also establishes an area of mutual interest with respect to us and Denbury in specified areas adjacent to the properties. The success of the planned CO_2 enhanced recovery project 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. Denbury commenced injecting CO_2 at the complex in December 2010.

Other Exploration

From time to time, we pursue exploration opportunities outside of our core areas that we believe align with our corporate strengths and strategy. Amounts allocated to these types of projects in 2010 were nominal and are expected to be nominal in 2011 as well.

Oil and Natural Gas Reserves

The following table sets forth our net proved reserves as of the dates indicated. Our reserves as of December 31, 2009 and 2010 are set forth in a reserve report prepared by DeGolyer & MacNaughton. DeGolyer & MacNaughton reviews production histories and other geological, economic, ownership and engineering data related to our properties in arriving at their reserve estimates. Proved reserves as of each date indicated reflect all acquisitions and dispositions completed as of that date. A report of DeGolyer & MacNaughton regarding its estimates of our proved reserves as of December 31, 2010 has been filed as Exhibit 99.1 to this report.

	Years Ended December 31,	
	2009(1)	**2010(2)**
Net proved reserves (end of period)		
Oil (MBbl)		
Developed	29,309	22,270
Undeveloped	22,657	20,301
Total	51,966	42,571
Natural gas (MMcf)		
Developed	126,671	122,928
Undeveloped	151,411	132,235
Total	278,082	255,163
Total proved reserves (MBOE)	98,313	85,098
% Oil	53%	50%
% Proved Developed	51%	50%
Proved Reserves to Production Ratio	13 years	13 years

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $61.04 per Bbl for oil and natural gas liquids and $3.87 per MMBtu for natural gas were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at prices of $51.15 per Bbl for oil, $37.98 per Bbl for natural gas liquids and $3.80 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2009.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

Reserves Sensitivity Analysis

The following table sets forth our net proved reserves at December 31, 2010 based on alternative price scenarios as identified below in the footnotes to the table. The following price scenarios illustrate the sensitivity of our estimated reserve quantities under various price assumptions.

	Price Case			
	A (SEC)	B (Strip)	C (SEC −10%)	D (SEC +10%)
Net proved reserves (end of period)				
Oil (MBbl)				
Developed	22,270	22,378	22,186	22,332
Undeveloped	20,301	20,302	20,300	20,302
Total	42,571	42,680	42,486	42,634
Natural gas (MMcf)				
Developed	122,928	126,273	121,032	124,442
Undeveloped	132,235	134,284	131,128	133,122
Total	255,163	260,557	252,160	257,564
Total proved reserves (MBOE)	85,098	86,106	84,513	85,561

A. Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas. Production costs were held constant for the life of the wells.

B. Prices based on the five year NYMEX forward strip at December 31, 2010, were adjusted as described in note (A) above, resulting in prices which averaged $82.89 per Bbl for oil, $70.64 per Bbl for natural gas liquids and $5.36 per MMBtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case. (The five year NYMEX forward strip represents the futures prices for oil and natural gas as reported on the New York Mercantile Exchange as of a specific date.)

C. Prices based on a 10% reduction of the prices used in the year-end SEC case (Price Case A), resulting in prices, adjusted as described in note (A) above, of $61.63 per Bbl for oil, $53.87 per Bbl for natural gas liquids and $3.93 per MMbtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case.

D. Prices based on a 10% increase of the prices used in the year-end SEC case (Price Case A), resulting in prices, adjusted as described in note (A) above, of $76.72 per Bbl for oil, $65.84 per Bbl for natural gas liquids and $4.81 per MMbtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case.

Changes in Proved Reserves

Our net proved reserves of 85,098 MBOE as of December 31, 2010 decreased 13% from 98,313 MBOE as of December 31, 2009. Our estimated oil and natural gas reserves were principally affected by the following during 2010:

- Sales of reserves in place decreased reserves by 7,436 MBOE related to sales of our Texas assets and the Cat Canyon field;
- Current year production decreased reserves by 6,658 MBOE;
- Extensions and discoveries increased reserves by 4,625 MBOE primarily as a result of drilling in the Sacramento Basin, which provided supporting evidence to record additional PUD locations in the same area;
- Revisions of previous estimates decreased reserves by 3,799 MBOE due to (i) removal of PUDs not drilled within five years and changes to the timing of PUD development forecasts, (ii) loss of reserves from PUDs converted to developed reserves at lower reserve amounts in the Sacramento Basin and West Montalvo and, to a lesser extent, unsuccessful frac results at Sockeye, partially offset by (i) improved performance in the Sacramento Basin and at South Ellwood, and (ii) price changes that resulted in a positive impact of approximately 1.0 MBOE; and
- Purchases of reserves in place increased reserves by 53 MBOE.

Our PUD reserves of 42,340 MBOE as of December 31, 2010 decreased 12% from 47,892 MBOE as of December 31, 2009. Our estimated PUDs were principally affected by the following during 2010:

- Revisions of previous estimates decreased PUDs by 4,724 MBOE due to (i) removal of PUDs not drilled within five years and changes to the timing of PUD development forecasts, and (ii) loss of reserves from PUDs converted to developed reserves at lower reserve amounts in the Sacramento Basin and West Montalvo and, to a lesser extent, unsuccessful frac results at Sockeye;
- Extensions, discoveries and improved recovery increased PUDs by 3,167 MBOE primarily as a result of drilling in the Sacramento Basin, which provided supporting evidence to record additional PUD locations in the same area;
- Sales of PUDs in place decreased those reserves by 2,414 related to sales of our Texas assets; and
- 1,581 MBOE of proved undeveloped reserves were developed primarily as a result of drilling in the Sacramento Basin—capital expenditures related to PUD drilling during 2010 were approximately $37 million.

At December 31, 2010, we have no PUDs that are scheduled for development five years or more beyond the date the reserves were initially recorded. All PUD locations are within one spacing offset of proved locations.

Uncertainties with respect to future acquisition and development of reserves include (i) the success of our development programs, including with respect to the development of the onshore Monterey shale formation and potential changes to our drilling schedule based on ongoing operational results, (ii) our ability to obtain permits from relevant regulatory bodies to pursue development projects, (iii) changes in commodity prices, including potential changes to our drilling schedule if natural gas prices decline further, (iv) the availability of sufficient cash flow from operations or external financing to fund our capital expenditure program, (v) the effect of legislative or regulatory changes on our ability to pursue our hedging strategy, and (vi) the availability and cost of viable acquisition candidates.

As discussed in "Business and Properties—Description of Properties—Texas," Denbury commenced CO_2 injection at the Hastings complex in December 2010. Once the field responds to the flood, we expect to record a portion of the proved reserves related to our reversionary interest in the project. Any proved reserves recorded attributable to our reversionary interest will be subject to a significant degree of variability until Denbury has recovered all of its costs as defined in the agreement and we are able to back in to our 22.3% working interest. The amount of reserves and resulting production necessary for Denbury to recover its costs will be determined in large part by such factors as the existing commodity prices and operating cost environment.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our year-end reserve report is prepared by DeGolyer & MacNaughton in accordance with guidelines established by the SEC. Reserve definitions comply with the definitions provided by Regulation S-X of the SEC. DeGolyer & MacNaughton prepares the reserve report based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information we provide to them. This information is reviewed by knowledgeable members of our company to ensure accuracy and completeness of the data prior to submission to DeGolyer & MacNaughton. Upon analysis and evaluation of data provided, DeGolyer & MacNaughton issues a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our Reserves Manager, relevant Reservoir Engineers and our Vice President of Acquisitions for completeness of the data presented, reasonableness of the results obtained and compliance with the reserves definitions in Regulation S-X of the SEC. Once all questions have been addressed, DeGolyer & MacNaughton issues the final appraisal report, reflecting their conclusions.

A letter which identifies the professional qualifications of the individual at DeGolyer & MacNaughton who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2010 has been filed as an addendum to Exhibit 99.1 to this report.

Internally, Terry Sherban, Vice President of Acquisitions, is responsible for overseeing our reserves process. Mr. Sherban started with us in 1998 and has over 30 years of experience in the oil and natural gas industry. He holds a Bachelor's degree in Mechanical Engineering from the University of Saskatchewan and is a registered Petroleum Engineer. Mr. Sherban is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

Production, Prices, Costs and Balance Sheet Information

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. No pro forma adjustments have been made for acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below. The information set forth below is not necessarily indicative of future results.

	Years Ended December 31,		
	2008	2009	2010
Production Volume(1):			
Oil (MBbls)(2)	4,091	3,402	2,792
Natural gas (MMcf)	23,050	24,748	23,196
MBOE	7,933	7,527	6,658
Daily Average Production Volume:			
Oil (Bbls/d)	11,178	9,321	7,649
Natural gas (Mcf/d)	62,978	67,803	63,551
BOE/d	21,674	20,622	18,241
Oil Price per Bbl Produced (in dollars):			
Realized price	$ 89.28	$50.60	$68.86
Realized commodity derivative gain (loss)	(20.71)	(0.95)	(1.77)
Net realized price	$ 68.57	$49.65	$67.09
Natural Gas Price per Mcf Produced (in dollars):			
Realized price	$ 8.21	$ 3.84	$ 4.34
Realized commodity derivative gain (loss)	0.08	2.58	1.70
Net realized price	$ 8.29	$ 6.42	$ 6.04
Expense per BOE:			
Lease operating expenses	$ 16.86	$12.65	$12.65
Production and property taxes	$ 1.98	$ 1.35	$ 1.01
Transportation expenses	$ 0.54	$ 0.42	$ 1.37
Depletion, depreciation and amortization	$ 16.95	$11.46	$11.79
General and administrative expense, net(3)	$ 5.43	$ 4.91	$ 5.64
Interest expense	$ 6.81	$ 5.44	$ 6.10

(1) The South Ellwood field comprised more than 15% of our total proved reserves as of December 31, 2010. Production from the field was 825 MBbls and 447 MMcf in 2008, 806 MBbls and 252 MMcf in 2009, and 746 MBbls and 93 MMcf in 2010.

(2) Amounts shown are oil production volumes for offshore properties and sales volumes for onshore properties (differences between onshore production and sales volumes are minimal). Revenue accruals for offshore properties are adjusted for actual sales volumes since offshore oil inventories can vary significantly from month to month based on the timing of barge deliveries, oil in tank and pipeline inventories, and oil pipeline sales nominations.

(3) Net of amounts capitalized.

Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2008 through December 31, 2010. 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 or net wells.

	Development Wells Drilled		
	2008	2009	2010
Productive(1)			
Gross	24.0	24.0	30.0
Net	22.0	22.8	28.3
Dry(2)			
Gross	4.0	2.0	5.0
Net	3.8	1.8	5.0

	Exploration(3) Wells Drilled		
	2008	2009	2010
Productive(1)			
Gross	69.0	43.0	55.0
Net	59.1	39.7	50.6
Dry(2)			
Gross	19.0	10.0	11.0
Net	17.2	9.3	10.5

(1) A productive well is not a dry well, as described below, but a well for which we have set casing. Wells classified as productive above, do not always result in wells that provide economic levels of production.

(2) A dry well is a well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(3) We drill a significant number of wells on non-proved locations in the Sacramento Basin. These wells are considered "exploratory wells" as defined in SEC Regulation S-X and are included in the Exploration Wells Drilled category above. The majority of the wells in the basin that are "exploratory wells" under SEC Regulation S-X are wells drilled on the border of existing fields in an attempt to test and expand the limits of a producing area. We generally do not distinguish between those wells and development wells from an operating perspective. Of the gross productive exploration wells drilled in 2010, 48 were drilled in the Sacramento Basin.

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.

Present Activities

See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Capital Expenditures" for a discussion of our present development activities.

Oil and Natural Gas Wells

The following table details our working interests in producing wells as of December 31, 2010. 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	183.0	118.7	64.9%
Natural gas	594.0	495.4	83.4%
Total(1)	777.0	614.1	79.0%

(1) Amounts shown include 17 oil wells and 9 natural gas wells with multiple completions.

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2010. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped(1)		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Southern California						
South Ellwood	7,682	7,682	—	—	7,682	7,682
Santa Clara Federal Unit	36,000	27,360	—	—	36,000	27,360
Dos Cuadras	5,400	1,350	—	—	5,400	1,350
West Montalvo	3,453	3,453	5,492	5,304	8,945	8,757
Onshore Monterey Shale	7,815	6,115	175,257	113,777	183,072	119,892
Other Southern California	1,528	516	4,205	4,183	5,733	4,699
Total Southern California	61,878	46,476	184,954	123,264	246,832	169,740
Sacramento Basin	126,163	109,744	139,139	113,144	265,302	222,888
Texas	11,481	8,595	3	—	11,484	8,595
Other	—	—	49,740	42,625	49,740	42,625
Total	199,522	164,815	373,836	279,033	573,358	443,848

(1) The percentage of undeveloped acreage held under leases due to expire in 2011, 2012 and 2013, unless extended by exploration or production activities or extension of lease terms, is approximately 9%, 7% and 20%, respectively.

Risk and Insurance Program

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 the risk of well blowouts, oil spills and other adverse events. We could be held responsible for injuries suffered by third parties, contamination, property damage or other losses resulting from these types of events. In addition, we have generally agreed to indemnify our drilling rig contractors against certain of these types of losses. Because of these risks, we maintain insurance against some, but not all, of the potential risks affecting our operations and in coverage amounts and deductible levels that we believe to be economic. Our insurance program is designed to provide us with what we believe to be an economically appropriate level of financial protection from significant unfavorable losses resulting from damages to, or the loss of, physical assets or loss of human life or liability claims of third parties, attributed to certain assets and including such occurrences as well blowouts and resulting oil spills. We regularly review our risks of loss and the cost and availability of insurance and consider the need to revise our insurance program accordingly. Our insurance coverage includes deductibles which must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In general, our current insurance policies covering a blowout or other insurable incident resulting in damage to one of our offshore oil and gas wells provide up to $50 million of well control, pollution cleanup and consequential damages coverage and $250 million of third party liability coverage for additional pollution cleanup and consequential damages, which also covers personal injury and death. We expect the future availability and cost of insurance to be impacted by the Gulf of Mexico Deepwater Horizon incident. In particular, we expect that less insurance coverage will be available and at a higher cost.

If a well blowout, spill or similar event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our financial condition, results of operations and cash flows. See "Risk Factors—Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy. We do not have insurance to cover all of the risks that we may face".

Remediation Plans and Procedures

As required by regulations imposed by the Bureau of Ocean Energy Management, Regulation and Enforcement, or BOEMRE, we have updated our existing company oil-spill response plan, we continue to maintain oil spill response equipment on the platforms, including oil spill containment boom and a boat for boom deployment, and have maintained oil-spill financial assurance in connection with our offshore operations. Our oil-spill response plan details procedures for rapid response to spill events that may occur as a result of our operations. The plan calls for training personnel in spill response. Periodically, drills are conducted to measure and maintain the effectiveness of the plan. We review the plan annually and update where necessary.

Also pursuant to BOEMRE regulations, and similar regulations adopted by the California Department of Fish and Game's Office of Oil Spill Prevention and Response, we continue to be a member of Clean Seas, LLC, or Clean Seas, a cooperative entity operated with other offshore operators to effectively respond to oil spills in the offshore region in which we operate. The purpose of Clean Seas is to act as a resource to its member companies by providing an inventory of state-of-the-art oil spill response equipment, trained personnel, and expertise in the planning and execution of response techniques. Clean Seas' equipment consists primarily of oil spill response vessels, including two equipped with approximately 4,500 feet of oil spill containment boom, advanced oil recovery systems, high capacity stationary skimmers, storage tanks for recovered oil, infrared radar and advanced electronic equipment for directing and monitoring oil spill response activities. Clean Seas also recruits and trains local fishermen to assist in oil recovery and the recovery of impacted wildlife. Clean Seas' designated area of response, which encompasses all of our offshore operations, comprises the open oceans and coastline of the South Central Coast of California including Ventura, Santa Barbara, and San Luis Obispo Counties, and the Santa Barbara Channel Islands.

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 current 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.

Indebtedness under our revolving credit facility is 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, Major Customers and Delivery Commitments

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, 2010, approximately 93% of our revenues were generated from sales to four purchasers: ConocoPhillips (57%), Enserco Energy (26%), Calpine Producer Services LP (6%), and Tesoro Refining and Marketing Company (4%). 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. We had no material delivery commitments as of February 18, 2011.

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, but are not limited to, Occidental Petroleum Corporation, 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 47,200 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 51,000 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 entered into a new lease in April 2010 for 7,700 net square feet of office space in Bakersfield, California. The lease for Bakersfield office space will expire in 2013. We also have leases for certain field offices which are insignificant on a quantitative basis. 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, 2010, we had approximately 379 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 a California statute 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 Ellwood Pipeline, Inc.'s proposed common carrier pipeline project and several exploration wells that are part of our Monterey shale project in several counties in California. 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, hazardous substances, or other pollutants.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction sites, 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 were 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 BOEMRE 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 BOEMRE 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, BOEMRE 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. See "—Remediation Plans and Procedures".

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 BOEMRE, the California State Lands Commission ("CSLC"), 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, as amended ("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 ("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 may therefore become 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 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. BOEMRE 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. 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. BOEMRE 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.

Marine Protected Areas ("MPAs"). In 2000, President Clinton issued Executive Order 13158, which directs federal agencies to strengthen management, protection and conservation of existing MPAs and to establish new MPAs. The executive order requires federal agencies to avoid causing harm to MPAs through federally conducted, approved, or funded activities. The order also directs EPA to propose new regulations under its Clean Water Act authority to ensure protection of the marine environment. This order and related Clean Water Act regulations have the potential to adversely affect our operations by restricting areas in which we may engage in future exploration, development, and production operations and by causing us to incur increased expenses.

Naturally Occurring Radioactive Materials ("NORM"). Our operations my generate wastes containing NORM. Certain oil and natural gas exploration and production activities can enhance the radioactivity of NORM. NORM primarily is regulated by state radiation control regulations. The Occupational Safety and Health Administration also has promulgated regulations addressing the handling and management of NORM. These regulations impose certain requirements regarding worker protection, the treatment, storage, and disposal of NORM waste, the management of NORM containers, tanks, and waste piles, and certain restrictions on the uses of land with NORM contamination.

Other Environmental Regulation. Our leases in federal waters on the Outer Continental Shelf are administered by the BOEMRE and require compliance with detailed BOEMRE regulations and orders. Under certain circumstances, BOEMRE 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 CSLC and DOGGR regulations. 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 protects an area of tidelands offshore Santa Barbara County that stretches west from Summerland Bay to Coal Oil Point, and includes waters offshore the unincorporated area of Montecito, the City of Santa Barbara and the University of California at Santa Barbara. It also protects 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 ("GHG") emissions that have been or 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. EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which establishes a statewide cap on GHGs that will reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board adopted regulations in December 2010 to implement AB 32 by January 1, 2012. These regulations are not expected to directly impact our operations as the first phase, beginning in 2012, includes all major industrial sources and utilities, while the second phase, which starts in 2015, will address distributors of transportation fuels, natural gas, and other fuels. We will continue to monitor the implementation of these regulations through industry trade groups and other organizations in which we are a member.

Other environmental protection statutes that may impact our operations include 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 BOEMRE 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 6 to our financial statements, we have estimated the present value of our aggregate asset retirement obligations to be $94.2 million as of December 31, 2010. 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 4% and 9%. Actual costs may differ from our estimates. Our financial statements do not reflect any liabilities relating to other environmental obligations.

Under a variety of applicable laws and regulations, including CERCLA, RCRA and BOEMRE 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 which occurred prior to our acquisition of the facility. We currently are required to provide semi-annual 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 clean-up and abandonment of the facility will be approximately $8.0 million (undiscounted). 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 will be abandoned in 23 years (as of 2010). The onshore oil and natural gas plant associated with the Santa Clara Federal Unit also is known to have hydrocarbon contamination. Chevron is contractually obligated to remediate the contamination 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 2010. 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 BOEMRE, 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, 2010.

Name	Age	Position
Timothy Marquez	52	Chairman and Chief Executive Officer
Timothy A. Ficker	43	Chief Financial Officer
Terry L. Anderson	63	General Counsel and Secretary
Edward O'Donnell	57	Senior Vice President

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.

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.

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.

Edward O'Donnell is our Senior Vice President and has responsibility for our Southern California assets. Mr. O'Donnell initially joined us in 1997 as Vice President of Development and was later Vice President of the Offshore Business Unit. From April 2001 to June 2002 he served as the President of our Domestic Division. From June 2002 through 2005 he provided independent business consulting to non-profit organizations and small retail businesses. In 2006 he became the CEO of Gong Zhu Enterprises, a provider of financial, accounting, and management consulting services to small retail businesses. Mr. O'Donnell also served two terms on Venoco's board of directors. He re-joined Venoco in March 2007 as Senior Vice President. He has 20 years of experience with Unocal Corporation in various engineering and management positions. He holds a B.S. degree in petroleum engineering from Montana Tech, an M.S. in petroleum engineering from the University of Southern California and an M.B.A. from Pepperdine University.

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. Decreases in the price we receive for our oil and natural gas production adversely affect our business, financial condition, results of operations and liquidity.

Declines in the prices we receive for our oil and natural gas production adversely affect many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. For example, due in significant part to lower commodities prices, our revenues from oil and natural gas sales and cash flow from operations declined 52% and 44%, respectively, in 2009 compared to 2008. Declines in the prices we receive for our oil and natural gas also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices reduce the amount of oil and natural gas that we can produce economically and, as a result, adversely affect our quantities of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our revolving credit facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities of those 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, speculative activity, 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 enter into a new contract with a new purchaser which priced our oil at a significantly greater 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. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it sells at a discount to the NYMEX price. This discount, or differential, varies over time and can be affected by factors that do not have the same impact on the price of premium grade light oil. We cannot predict how the differential 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. Many of our hedging arrangements are based on benchmark prices and therefore do not fully protect us from adverse changes in the differential applicable to our production. In the first quarter of 2010, we changed the terms of sale of our South Ellwood field oil production from pricing based on a fixed differential to NYMEX to pricing with a variable differential, a change that increases the risk to us of unfavorable changes in differentials. In addition, the oil we produced from our Texas properties typically sold at a smaller discount to NYMEX than our California oil. Because we sold all of our producing properties in Texas during the second quarter of 2010, the risks associated with the differential are currently greater, relative to our overall production, than they have been in some prior years.

Our planned operations will require additional capital that may not be available.

Our business is capital intensive, and requires substantial expenditures to maintain currently producing wells, to make the acquisitions and/or conduct the exploration, exploitation and development activities necessary to replace our reserves, to pay expenses and to satisfy our other obligations. In recent years, we have chosen to pursue projects that required capital expenditures in excess of cash flow from operations. That fact has made us dependent on external financing to a greater degree than many of our competitors. Our substantial existing indebtedness increases the risk that external financing will not be available to us when needed. If we reduce our capital spending in an effort to conserve cash, this would likely result in production being lower than anticipated, and could result in reduced revenues, cash flow from operations and income.

It may be difficult or impossible for us to finance our operations through the incurrence of additional indebtedness.

We have relied on borrowings under our revolving credit facility to finance our operations in some recent periods. Lenders may not fund borrowings under the facility when we request them to do so. In 2009, a former lender under the facility, Lehman Commercial Paper, Inc., ceased funding amounts under the facility as a result of the bankruptcy of its parent company, Lehman Brothers Holdings Inc. Existing lenders under the revolving credit facility may face similar issues. Our ability to borrow under the facility may also be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the facility. It may be difficult to maintain compliance with the maximum debt to EBITDA (as defined in the agreement) ratio in the future if we borrow a significant portion of the available capacity under the facility and/or our EBITDA is adversely affected by operational problems, counterparties' failure to perform under hedge agreements or other factors. In addition, the borrowing base under the facility is subject to redetermination periodically and from time to time in the lenders' discretion. Borrowing base reductions may occur with respect to the revolving credit facility as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. Due in significant part to lower commodity prices, the borrowing base under the revolving credit facility was reduced in early 2009 from $200 million to $125 million. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time.

Sources of external debt financing other than revolving credit facility borrowings may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Our ability to incur additional indebtedness will be limited under the terms of the revolving credit facility, the indenture governing our recently-issued 8.875% senior notes (see—"Liquidity and Capital Resources—Capital Resources and Requirements") and the indenture governing our 11.50% senior notes, which we refer to collectively as our debt agreements. In addition, if we finance our operations through borrowings under our revolving credit facility or other additional indebtedness, the risks that we now face relating to our current debt level would intensify, and it may be more difficult to satisfy our existing financial obligations.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness. At February 18, 2011, we had total outstanding debt of $643.3 million, comprised of $500.0 million under our 8.875% senior notes and $143.3 million (net of discount) under our 11.50% senior notes. Interest obligations on our indebtedness are significant. Our debt bears interest at a weighted average interest rate of approximately 9.5% as of February 18, 2011. In 2010, we had interest expense of $40.6 million.

Our level of indebtedness could have important effects on our business. For example, it could:

- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations;
- require us to dedicate a substantial portion of our cash flow from operations and certain types of transactions to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisition and other investment opportunities and other general business activities;
- limit our flexibility in planning for, or reacting to, changes in commodity prices, our business or the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds on favorable terms or at all;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in our debt agreements which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

If our cash flow and other capital resources are insufficient to fund our obligations under our debt agreements on a current basis and at maturity, we could attempt to refinance or restructure the debt or to 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, and we may be unable to complete such transactions in a timely manner, on favorable terms, or at all. In addition, our debt agreements contain provisions that would limit our flexibility in responding 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 our debt agreements in some circumstances. Any refinancing that requires the use of cash could require us to reduce or delay planned capital expenditures. There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

We also face a refinancing risk. Significant amounts of our indebtedness do not require current payments of principal, but are payable in full on maturity. Cash flow from operations may not be sufficient to repay the outstanding balance on our debt when it matures. Global capital markets have experienced a severe contraction in the availability of debt financing in the recent past. Financial effects of this crisis were exacerbated in the oil and natural gas industry by the effect of volatile commodity prices. The ability to pay principal and interest on our debt, and to refinance our debt upon maturity, will depend not only upon our financial and operating performance, but on the state of the global economy, credit markets and commodity prices during the period through the time of refinancing, many of which are factors over which we have no control. There can be no assurances that we will be able to make principal and interest payments on our indebtedness and to refinance our indebtedness at maturity as needed.

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, 2010, 50% of our estimated proved reserves were proved undeveloped and 8% 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 assumed future prices and costs. Actual future prices and costs may be materially higher or lower than the assumed prices and costs. 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 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 holes 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. In addition, the cost of exploration, exploitation and development activities is subject to numerous uncertainties, and cost factors can adversely affect the economics of a project. Further, our exploration, exploitation and 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;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- compliance with environmental and other governmental requirements, including with respect to permitting issues; and
- costs of, or shortages or delays in the availability of, drilling rigs, equipment, qualified personnel 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.

Drilling results in emerging plays, such as the onshore Monterey shale, are subject to heightened risks.

Part of our strategy is to pursue acquisition, exploration and development activities in emerging plays such as our onshore Monterey shale project. Our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Because emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. In addition, part of our drilling strategy to maximize recoveries from the onshore Monterey shale formation may involve the drilling of horizontal wells and/or using completion techniques that have proven to be successful in other shale formations. We have drilled a limited number of these types of onshore wells to the Monterey shale formation and have not yet achieved significant commercial levels of production from our onshore Monterey shale wells. These drilling and completion strategies and techniques require greater amounts of capital investment than more established plays. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established. If drilling success rates or production are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations or other operational problems, the value of our position in the affected area will decline, our results of operations, financial condition and liquidity will be adversely impacted and we could incur material write-downs of unevaluated properties.

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 to a significant degree 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 2010 was 1,950 Bbl/d, or approximately 29% of our aggregate net oil production for the quarter. The oil produced at the field is delivered via a double-hulled barge owned and operated by an unaffiliated third party. 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. We are currently operating the barge with a temporary permit that will expire at the end of February 2011, but can be extended by the relevant agency. We expect to either receive the permit to operate or an extension of the temporary permit, but we have encountered some operational issues with the barge and it is possible that we could be denied the extension of the temporary permit and could be forced to curtail operations until the permit to operate is received.

From time to time, the barge will be unavailable due to maintenance and repair requirements. Because we have limited storage capacity for oil produced from the field, we may be required to significantly curtail production at the field during the periods in which the barge is unavailable. Moreover, our ability to continue the barging operation after 2013 will depend on our receipt of the consent of a third party, and, even with that consent, we believe it may not be feasible to continue the barging operation after 2016. If Ellwood Pipeline, Inc. is unable to complete the proposed common carrier pipeline to transport oil production from the field by the time we are no longer able to continue the barging operation, we will likely be required to shut in the field. 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 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.

A significant percentage of our cash flow in some prior periods resulted from payments made to us by our hedge counterparties. If hedge counterparties are unable to make payments to us under our hedging arrangements, our results of operation, financial condition and liquidity would be adversely affected. 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.

Moreover, 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 do not designate our derivatives as cash flow hedges for accounting purposes and because we hedge a larger percentage of our production than some of our competitors.

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, safety and other matters. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, may 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, including suspension or termination of operations. 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." These suits and/or related indemnity claims could have a material adverse effect on our financial condition. Moreover, 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, including, in some circumstances, operators of properties in which we have an interest and parties that provide transportation services for us. Similarly, some environmental laws and regulations impose joint and several liability, meaning that we could be held responsible for more than our share of a particular reclamation or other obligation, and potentially the entire obligation, where other parties were involved in the activity giving rise to the liability. 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.

Similarly, 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, our subsidiary Ellwood Pipeline, Inc. is pursuing a pipeline project that will, if and when completed, replace the current barging operation for oil production from the South Ellwood field. Ellwood Pipeline, Inc. will be required to obtain permits from numerous governmental agencies prior to commencing work on the project. We may not be able to obtain these permits as quickly as we expect or at all. The process of obtaining these permits is subject to the California Environmental Quality Act, or CEQA. At a minimum, CEQA delays and adds expense to the permitting process. In addition, the necessary permits 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 be subject to similar risks. For example, we are also currently in the CEQA process with respect to some of our planned onshore Monterey shale wells. In addition, we recently terminated the process of seeking permits for a proposed lease extension in the South Ellwood field. These risks are high for us relative to many of our competitors because oil and natural gas projects are frequently the source of considerable political controversy in California, and political opposition may make it more difficult for us to obtain consents and approvals for our projects.

Changes in applicable laws and regulations could increase our costs, reduce demand for our production, impede our ability to conduct operations or have other adverse effects on our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, the EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to human health and the environment, which allows the EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress is considering "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which establishes a statewide cap on GHGs that will reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. 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. Similar regulations may be adopted by the federal government. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

Additionally, the recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Reform Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through implementing regulations to be adopted by the SEC, the Commodities Futures Trading Commission and other regulators. We are currently assessing the likely impact of the Reform Act on our operations, and this assessment will continue as the regulatory process contemplated by the Reform Act progresses. If, as a result of the Reform Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy or to meet the hedging requirements contained in our revolving credit facility. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy. We are more vulnerable to the adverse consequences of changes in laws and regulations relating to derivatives than many of our competitors because we hedge a relatively large proportion of our expected production and because our hedging strategy is integral to our overall business strategy.

The Secretary of the U.S. Department of Interior imposed a drilling moratorium in May 2010, which delayed a planned redrill of an inactive well from Platform Gail. That moratorium was subsequently lifted for fixed-leg platforms like Platform Gail. However, additional moratoria, or similar rules promulgated by other governmental authorities, could have significant impacts on our operations in the future. In addition, the U.S. Department of Interior has experienced significant delays in processing permit applications for new drilling projects. Delays in the government's permitting process could have significant impacts on the industry as a whole and our future results of operations.

In addition, some of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation. Legislative and regulatory efforts at the federal level and in some states have been made to render permitting and compliance requirements more stringent for hydraulic fracturing. These proposals, if adopted, would likely increase our costs and make it more difficult, or impossible, to pursue some of our development projects.

We could also be adversely affected by future changes to applicable tax laws and regulations. For example, proposals have been made to amend federal and/or California law to impose "windfall profits," severance or other taxes on oil and natural gas companies. If any of these proposals become law, our costs would increase, possibly materially. Significant financial difficulties currently facing the State of California may increase the likelihood that one or more of these proposals will become law.

President Obama's 2011 Fiscal Year Budget includes proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy. We do not have insurance to cover all of the risks that we may face.

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.

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 as well as risks associated with barge transport such as collisions or capsizing. Moreover, because we operate in California, we are also susceptible to risks posed by natural disasters such as earthquakes, mudslides, fires and floods.

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. Moreover, some risks we face are not insurable. Also, we could in some circumstances have liability for actions taken by third parties over which we have no or limited control, including operators of properties in which we have an interest. The occurrence of an uninsured or underinsured loss could result in significant costs that could have a material adverse effect on our financial condition and liquidity. 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.

Because our oil and natural gas properties are depleting assets, our future oil and natural gas reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Acquiring additional oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise is an important component of our strategy. 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 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. When we acquire properties on an "as-is" basis, we 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. In addition, we may face greater risks to the extent we acquire properties in areas outside of California, 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.

Enhanced recovery techniques may not be successful, which could adversely affect our financial condition or results of operations.

Certain of our properties may provide opportunities for a CO_2 enhanced recovery project. Risks associated with enhanced recovery techniques include, but are not limited to, the following:

- geologic unsuitability of the properties subject to the enhanced recovery project;
- unavailability of an economic and reliable supply of CO_2, or other shortages of equipment;
- lower than expected production;
- longer response times;
- higher operating and capital costs; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect the results of the affected project, our financial condition and our results of operations. We may pursue other enhanced recovery activities from time to time as well, and those activities may be subject to the same or similar risks.

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. 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.

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 our other executive officers. 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. For example, we have recently experienced an increase in drilling, completion and other costs associated with certain Monterey shale wells. 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. From time to time, we have experienced some difficulty in obtaining drilling rigs, experienced crews and related services 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 over the past several years. 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 4% of our production in the fourth quarter of 2010. 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. Also, we could be responsible for plugging and abandonment and other liabilities in excess of our proportionate interest in the property.

Changes in the financial condition of any of our large oil and natural gas purchasers or other significant counterparties could adversely affect our results of operations and liquidity.

For the year ended December 31, 2010, approximately 93% of our oil and natural gas revenues were generated from sales to four purchasers: ConocoPhillips, Enserco Energy, Calpine Producer Services LP and Tesoro Refining and Marketing Company. ConocoPhillips is also the purchaser of oil production from the South Ellwood field under a contract that became effective in March 2010, and following the effectiveness of that contract, a majority of our total revenues have derived from sales to ConocoPhillips. 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 face similar counterparty risks in connection with other contracts under which we may be entitled to receive cash payments, including insurance policies and commodity derivative agreements. Major counterparties may also seek price or other concessions from us if they perceive us to be dependent on them or to lack viable alternatives.

We were required to write down the carrying value of our properties as of December 31, 2008 and may be required to do so again in the future.

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, calculated using the twelve month arithmetic average of the first of the month prices (for periods prior to December 31, 2009, the prevailing price on the last day of the relevant period was used). 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. At December 31, 2008, our net capitalized costs exceeded the ceiling by $641 million, net of income tax effects, and we recorded an impairment of our oil and gas properties in that amount. We could recognize further impairments in the future. To the extent our acquisition and development costs increase, we will become more susceptible to ceiling test write downs in low price environments.

All of our producing properties are located in one state and adverse developments in that state would negatively affect our financial condition and results of operations.

All of our principal properties are located in California. Our Southern California and Sacramento Basin properties represented approximately 53% and 47%, respectively, of our proved reserves as of December 31, 2010 and accounted for a combined 97% of our 2010 production. Any circumstance or event that negatively impacts the production or marketing of oil and natural gas in California generally, or in Southern California or the Sacramento Basin in particular, would adversely affect our results of operations and cash flows. Many of our competitors have operations that are more geographically dispersed than ours, and therefore may be less subject than we are to risks affecting a particular geographic area.

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 51% of our outstanding common stock as of February 16, 2011. 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. 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, we purchased certain real property interests from an affiliate of Mr. Marquez for $5.3 million in December 2008.

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 February 16, 2011, Timothy Marquez beneficially owned approximately 51% of our common stock, primarily through the Marquez Trust. As of December 31, 2010, we had granted options to purchase an aggregate of approximately 1.1 million shares of our common stock and 2.6 million shares of restricted stock to certain of our directors and employees. The Marquez Trust and these other 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. Similarly, our debt agreements have provisions relating to a change of control of our company that could have a similar effect.

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 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. 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 grounds 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 2011. We vigorously defended the actions, and will continue to do so until they are resolved. Certain defendants have made claims for indemnity for events occurring prior to 1995, which we are disputing. We cannot predict the cost of these indemnity claims 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") 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, 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. That decision was upheld on appeal. We have no reason to believe that the insurer currently providing defense of these actions 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.

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

In 2004 the California State Lands Commission (the "SLC") initiated an audit of our royalty payments for the period from August 1, 1997 through December 31, 2003 on oil and gas produced from the South Ellwood Field, State Leases 3120 and 3240 (the "Leases"). The audit period was subsequently extended through September 2009. In December 2009, we were notified that the SLC's audit for the period January 2004 through September 2009 (the "Audit Period") indicated that we underpaid royalties due on oil and gas production from the Leases during the Audit Period by approximately $5.8 million. Based on our review of the SLC's audit contentions and additional historical records, we believe that we may have overpaid royalties due on oil and gas production during the Audit Period and for prior periods and may be owed a refund of such overpayments. We believe the position of the SLC is without merit and we intend to vigorously contest the audit findings and to enforce our rights for refunds of royalties we may have overpaid during the Audit Period and prior periods. We have not accrued any amounts related to the SLC audit contentions or potential refunds.

ITEM 4. Reserved

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 February 18, 2011 was $18.14.

	2009		2010	
Period	**High**	**Low**	**High**	**Low**
1st Quarter	$ 4.38	$ 2.15	$14.40	$11.29
2nd Quarter	$ 9.54	$ 3.39	$18.50	$12.20
3rd Quarter	$11.80	$ 6.74	$21.07	$15.63
4th Quarter	$15.87	$10.49	$20.55	$14.97

As of February 16, 2011, there were 367 record holders of our common stock.

Unregistered Sales of Equity Securities

Not applicable.

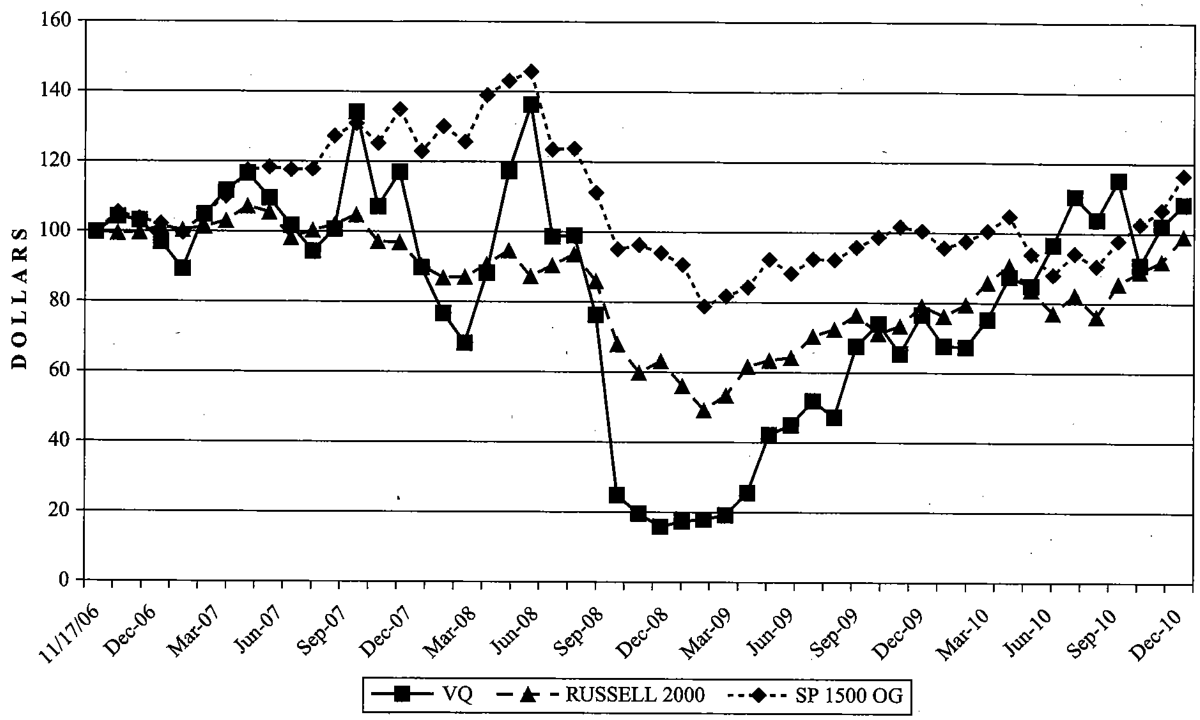
Dividend Policy

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 by the terms of our debt agreements, which currently prohibit us from paying dividends on our common stock. 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, 2010, 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 of 1933 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. No pro forma adjustments have been made for the acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below. Amounts are in thousands, except per share data.

	Years ended December 31,				
	2006	2007	2008	2009	2010
	(in thousands, except per share data)				
Statement of Operations Data:					
Oil and natural gas sales	$ 268,822	$ 371,450	$ 554,270	$ 267,163	$ 290,608
Other	5,470	3,355	3,603	3,331	4,684
Total revenues	274,292	374,805	557,873	270,494	295,292
Lease operating expense	82,213	107,295	133,773	95,213	84,255
Production and property taxes	5,292	12,026	15,731	10,128	6,701
Transportation expense	3,533	4,356	4,311	3,163	9,102
Depletion, depreciation and amortization	63,259	98,814	134,483	86,226	78,504
Impairment of oil and natural gas properties	—	—	641,000	—	—
Accretion of asset retirement obligations	2,542	3,914	4,203	5,765	6,241
General and administrative, net of amounts capitalized	28,317	31,770	43,101	36,939	37,554
Total expenses	185,156	258,175	976,602	237,434	222,357
Income (loss) from operations	89,136	116,630	(418,729)	33,060	72,935
Interest expense, net	48,795	60,115	54,049	40,984	40,584
Amortization of deferred loan costs	3,776	4,197	3,344	2,862	2,362
Interest rate derivative losses (gains), net	590	17,177	20,567	16,676	31,818
Loss on extinguishment of debt	—	12,063	—	8,493	—
Commodity derivative losses (gains), net	(3,626)	142,650	(116,757)	25,743	(68,049)
Total financing costs and other	49,535	236,202	(38,797)	94,758	6,715
Income (loss) before income taxes	39,601	(119,572)	(379,932)	(61,698)	66,220
Income tax provision (benefit)	15,650	(46,200)	11,200	(14,400)	(1,300)
Net income (loss)	$ 23,951	$ (73,372)	$(391,132)	$ (47,298)	$ 67,520
Earnings per common share:					
Basic	$ 0.71	$ (1.58)	$ (7.75)	$ (0.93)	$ 1.23
Diluted	$ 0.69	$ (1.58)	$ (7.75)	$ (0.93)	$ 1.21
Cash Flow Data:					
Cash provided (used) by:					
Operating activities	$ 89,090	$ 160,863	$ 212,379	$ 118,691	$ 160,673
Investing activities	(595,204)	(433,363)	(332,861)	(1,953)	(108,296)
Financing activities	505,089	273,871	110,938	(116,510)	(47,772)
Other Financial Data:					
Capital expenditures	$ 174,613	$ 322,283	$ 318,582	$ 176,812	$ 211,621
Balance Sheet Data (end of period):					
Cash and cash equivalents	$ 8,364	$ 9,735	$ 191	$ 419	$ 5,024
Property, plant and equipment, net	774,253	1,131,032	702,734	619,430	648,044
Total assets	893,193	1,265,485	864,254	739,543	750,923
Long-term debt, excluding current portion	529,616	691,896	797,670	695,029	633,592
Total stockholders' equity (deficit)	190,316	245,602	(135,167)	(174,496)	(84,237)

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. As used in this report, unless the context otherwise indicates, references to "we," "our," "ours," and "us" refer to Venoco, Inc. and its subsidiaries collectively.

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 have the potential to add significant reserves on a cost-effective basis and through selective acquisitions of underdeveloped properties. In recent years, the exploration, exploitation and development of the onshore Monterey shale formation has taken a fundamental role in our corporate strategy, and efforts to expand our knowledge of the onshore formation have increased significantly. A substantial portion of our production is from offshore wells targeting the fractured Monterey shale formation, and we believe that there are significant opportunities relating to the Monterey shale formation onshore as well. We are in the early stages of our onshore Monterey shale project and, as expected, have not yet recorded any material proved reserves as of December 31, 2010. As a result of asset sales, our increased focus on an unproved asset and the development of oil projects over natural gas projects, our proved reserves and production have decreased in recent years. We believe the opportunity is significant for future reserve and production growth from the oil projects we have pursued in 2010 and contemplate in our 2011 capital expenditure budget.

Our average net production was 18,241 BOE/d in 2010, compared to 20,622 BOE/d in 2009 and 21,674 BOE/d in 2008. Excluding production from producing properties in Texas, which we sold in a series of transactions in the first quarter of 2009 and the second quarter of 2010 (see "—Acquisitions and Divestitures"), our average net production was 17,779 BOE/d in 2010, compared to 18,756 BOE/d in 2009 and 17,690 BOE/d in 2008. Our proved reserves were 85.1 MMBOE at December 31, 2010, compared to 98.3 MMBOE at December 31, 2009 and 97.5 MMBOE at December 31, 2008. Excluding reserves attributable to our producing Texas properties, our reserves were 85.1 MMBOE at December 31, 2010 compared to 91.2 MMBOE at December 31, 2009 and 82.3 MMBOE at December 31, 2008.

In the execution of our strategy, our management is principally focused on economically developing additional reserves of oil and natural gas and on maximizing production levels through exploration, exploitation and development activities on a cost-effective basis and in a manner consistent with preserving adequate liquidity and financial flexibility.

Capital Expenditures

We have developed an active capital expenditure program to take advantage of our extensive inventory of drilling prospects and other projects. Our development, exploitation and exploration capital expenditures were $218.0 million in 2010, up from $161.3 million in 2009. Approximately $158 million of the 2010 capital expenditures went to drilling and rework activities, $12 million for facilities, and the remaining $48 million went to land, seismic and capitalized G&A costs. We incurred approximately $113 million or 52% of our 2010 capital expenditures in Southern California, $104 million or 47% in the Sacramento Basin, and the remaining 1% in areas outside of our core operating areas. Of the approximately $113 million spent in Southern California, approximately $74 million went to projects targeting the onshore Monterey shale formation.

Our 2011 development, exploitation and exploration capital expenditure budget is $200 million, of which approximately $140 million or 70% is expected to be deployed in Southern California and

$60 million or 30% to the Sacramento Basin. Of the $140 million allocated to Southern California, approximately $100 million is expected to be deployed to onshore Monterey shale activities with the remainder going to activities at legacy Southern California fields. The aggregate levels of capital expenditures for 2011, 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 2010 capital spending program and the outlook for 2011.

Southern California—Legacy Fields

In the West Montalvo field, we have pursued an aggressive workover, recompletion and return to production program since acquiring the field in May 2007 that has resulted in significant production gains. The field has not been fully delineated offshore or fully developed onshore and we continue to evaluate our drilling results and refine our development program for the coming years. During 2010, our principal activities in the field were the completion of two wells that were spud toward the end of 2009, workover activities on three wells, and various facility upgrades to optimize future development. We plan to drill at least two wells in the field during 2011.

In the Sockeye field, we completed a hydraulic fracture of the E-8 well and drilled a dual completion well that produces from the Monterey shale formation and injects into the Lower Topanga formation, increasing the sweep of the waterflood in that zone. A planned redrill of an inactive well that targets the Monterey shale formation was delayed as a result of a drilling moratorium imposed by the Secretary of the U.S. Department of the Interior. Wells drilled from Platform Gail are no longer subject to a moratorium and we plan to proceed with the redrill in 2011. Our 2011 capital expenditure budget contemplates minimal activity levels at Sockeye other than the redrill.

At the South Ellwood field, we performed six recompletions during 2010. We continue to work on advancing the permitting process for three of the five proved undeveloped locations on our existing leases and continue to perform the facilities work in order to begin drilling those locations in 2011. Our 2011 capital expenditure budget includes plans to drill one of our proved undeveloped locations and perform six recompletions at South Ellwood.

In addition, our subsidiary Ellwood Pipeline, Inc. is pursuing the permits necessary to build a common carrier pipeline that would allow us to transport our oil from the South Ellwood field to refiners without the use of a barge or the marine terminal we currently use. We anticipate that approval hearings for the project will be held during mid-2011. While we believe the pipeline should be approved, the outcome of these hearings cannot be predicted. Pending completion of the pipeline, we expect to use a double-hulled barge to transport oil production from the field.

Southern California—Onshore Monterey Shale

In 2006, we began actively leasing onshore acreage in Southern California targeting the Monterey shale, a Miocene age strata. Our leasing has focused on areas where we believe the Monterey shale will produce light, sweet oil, and where the quality and depth of the Monterey shale is expected to be advantageous. As of December 31, 2010, our onshore Monterey shale acreage position totaled approximately 183,000 gross and 120,000 net acres. An additional 60,000 gross and 46,000 net acres with Monterey shale production or potential are held by production. As of February 18, 2011, our onshore Monterey shale acreage position is approximately 137,000 net acres (183,000 net acres including acreage held by production).

We spud seven vertical wells designed as science wells in the onshore Monterey shale in 2010, which involved logging and coring to be used to correlate our petrophysical model, and one additional vertical well that was used as a pilot hole for our first horizontal well. We have used various completion techniques on these wells, including acidizing and fracture stimulations. Production test rates on the vertical wells have ranged from 20 BOE/d to more than 150 BOE/d, and all but one of the wells have tested light oil (23 to 39 degree API). We also spud four horizontal wells in 2010 targeting the onshore Monterey shale. The first of these, drilled in the San Joaquin Basin, was uneconomic. The second and third wells were drilled in the Santa Maria Basin and final completion and testing is expected late in the first quarter of 2011. We have completed drilling the fourth horizontal well and expect final completion and testing in the second quarter of 2011.

As described in "—Trends Affecting Our Results of Operations—Expected Production," we currently expect only modest production from our onshore Monterey shale wells in 2011. We have designed the initial vertical wells to provide scientific information that we will use to evaluate the specific prospect area, as well as individual zones in the wellbore that are prospective for drilling horizontal wells. Information developed from cutting cores in these vertical wells and analysis of those cores will be used to correlate our petrophysical model with data from historical well logs in the area. We expect our horizontal wells to have greater potential for production. Our primary focus with respect to our initial horizontal wells, however, is on using our experience with, and the data generated from, those wells to develop and refine drilling and completion techniques that will be successful in the formation and effective processes for the identification of productive intervals on a replicable basis.

We currently have two drilling rigs operating in the onshore Monterey shale, both of which are capable of drilling horizontal wells, and we have secured a third rig, which is scheduled to arrive by March. We are also working to secure a fourth rig in order to execute our 2011 capital expenditure program. Our 2011 capital expenditure budget includes plans to drill approximately 30 gross wells. We also plan to complete the second and final phase of what we believe to be California's largest 3D seismic shoot during the first half of 2011 and to continue leasing throughout the year.

Sacramento Basin

In the Sacramento Basin, we continue to pursue our infill drilling program in the greater Grimes and Willows fields. During 2010, we spud 93 wells (83% were productive), completed 75 (including wells spud in 2009), and performed 213 recompletions in the basin. We continue to test and evaluate potential downspacing opportunities in the basin as well as new methods of improving productivity and reducing drilling costs. We also continue to pursue our hydraulic fracturing program in the basin and fractured 12 wells in 2010. As of December 31, 2010, we had identified 610 drilling locations in the basin, and we anticipate identifying additional locations as we pursue further exploration, exploitation and development opportunities. We believe the Sacramento Basin presents significant exploration opportunities and in order to further our understanding of these opportunities we drill a small number of what we consider to be exploratory wells in the basin each year. Operationally, we distinguish these exploratory wells from the numerous non-proved locations that we drill each year as part of our development drilling program but are considered "exploratory wells" as defined in SEC Regulation S-X.

We plan to reduce activity levels in the basin in 2011 as a result of depressed natural gas prices and our increased focus on our oil-based Monterey shale activities. Our 2011 capital expenditure budget for the basin includes plans for approximately 40 wells, 220 recompletions, and 20 fracs. We anticipate the activity levels contemplated in our 2011 budget will result in average daily production in 2011 that is roughly consistent with 2010 average daily production. Production from the basin in the beginning of 2011 is expected to be relatively flat with the fourth quarter of 2010, then decline throughout the year as a result of the lower activity in 2011. We would expect to return to a focus on growth in the basin when natural gas prices improve. As of December 31, 2010, our acreage position in the basin was approximately 223,000 net acres (265,000 gross).

Texas

In anticipation of the sale of our Texas producing assets (see "—Acquisitions and Divestitures"), we did not invest any significant capital in Texas in 2010.

Acquisitions and Divestitures

Sale of Cat Canyon Field. In December 2010, we sold our interests in the Cat Canyon field for \$8.5 million (before closing adjustments). The field comprised less than 1% of our proved reserves at December 31, 2009, or 0.6 MBOE, and contributed approximately 70 BOE/d to our production during 2010. We used the proceeds to repay \$8.5 million of principal on the second lien term loan.

Sale of Other Texas Assets. Following the sale of the Hastings Complex, we sold our remaining producing assets in Texas in a series of transactions that were completed in the second quarter of 2010 to multiple purchasers for aggregate net proceeds of \$98.1 million (after closing adjustments and related expenses). We used the proceeds to repay \$66.9 million of principal on the revolving credit facility and \$30.7 million of principal on the second lien term loan. We retained the right to back into a working interest of approximately 22.3% in the CO_2 project Denbury is pursuing at the field after it recoups certain costs. In December 2010, Denbury commenced injecting CO_2 at the Hastings Complex. The Texas properties sold comprised 7.2% of our proved reserves at December 31, 2009 or 7.1 MMBOE and contributed approximately 460 BOE/d to our production during 2010.

Sacramento Basin Asset Acquisition. In June 2009, we acquired certain natural gas producing properties in the Sacramento Basin for approximately \$21.4 million.

Hastings Complex Sale. In February 2009, we completed the sale of our principal interests in the Hastings Complex to Denbury for approximately \$197.7 million.

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 transactions in each of 2008, 2009 and 2010.

Trends Affecting our Results of Operations

Oil and Natural Gas Prices. Historically, prices received for our oil and natural gas production have been volatile and unpredictable, and that volatility is expected to continue. Changes in the market prices for oil and natural gas directly impact many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth, the carrying value of our oil and natural gas properties and borrowing capacity under our revolving credit facility, all of which depend in part upon those prices. We employ a hedging strategy in order to reduce the variability of the prices we receive for our production and provide a minimum revenue stream. As of February 18, 2011 we had hedge contract floors covering approximately 87% of our 2011 annual production guidance. We have also begun to secure hedge contracts for our 2012 and 2013 production. All of our derivatives counterparties are members, or affiliates of members, of our revolving credit facility syndicate. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Derivative Transactions" for further details concerning our hedging activities.

Expected Production. During 2010, we began to emphasize our oil projects in Southern California relative to our natural gas projects in the Sacramento Basin. We plan to continue this strategy in 2011, with approximately 50% of our planned capital expenditures allocated to our onshore Monterey shale program in Southern California and an additional 20% allocated to our legacy Southern California fields. We expect that the execution of our capital expenditure plan will result in a modest increase in average daily production volumes in 2011 relative to 2010. We expect our onshore Monterey shale project to contribute a relatively small percentage of our overall production in 2011. However, we expect production from that project to provide the modest production growth we anticipate for the year. If successful, we believe that the project could result in significant production growth in subsequent years. Our expectations with respect to future production rates are subject to a number of uncertainties, including those associated with third party services, the availability of drilling rigs, oil and natural gas prices, events resulting in unexpected downtime, permitting issues, drilling success rates, including our ability to identify productive intervals and the drilling and completion techniques necessary to achieve commercial production in the onshore Monterey shale, and other factors, including those referenced in "Risk Factors".

Lease Operating Expenses. Lease operating expenses ("LOE") of $12.65 per BOE remained consistent compared to our full year 2009 results of $12.65 per BOE. We expect our 2011 LOE per BOE to increase slightly relative to 2010 due to our expected focus on oil projects, which tend to have higher operating costs than natural gas projects. Our expectations with respect to future expenses are subject to numerous risks and uncertainties, including those described and referenced in the preceding paragraph.

Production and Property Taxes. Production and property taxes per BOE decreased to $1.01 per BOE for 2010 compared to $1.35 per BOE for 2009. We expect 2011 production/property taxes to increase slightly on a per BOE basis compared to our 2010 results. As with lease operating expenses, our expectations with respect to future expenses are subject to numerous risks and uncertainties.

General and Administrative Expenses. General and administrative expenses increased slightly from $4.63 per BOE for 2009 (excluding share-based compensation charges of $0.28 per BOE), to $4.78 per BOE (excluding share-based compensation charges of $0.68 per BOE and one-time charges of $0.19 per BOE for severance payments resulting from the sale of our Texas producing properties) in 2010. Excluding share-based compensation charges, on a per BOE basis, we expect our G&A costs to be relatively flat in 2011 compared to 2010. As with our lease operating expenses and production and property taxes, our expectations with respect to G&A costs are subject to numerous risks and uncertainties.

Depreciation, Depletion and Amortization (DD&A). DD&A for 2010 of $11.79 per BOE increased slightly from our full year 2009 DD&A of $11.46 per BOE. We expect our 2011 DD&A to increase modestly on a per BOE basis compared to our full year 2010 results. As with lease operating expenses, production and property taxes and G&A expenses, our expectations with respect to DD&A expenses are subject to numerous risks and uncertainties.

Unrealized Derivative Gains and Losses. Unrealized gains and losses result 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 have incurred significant unrealized gains and losses in recent periods and may continue to incur these types of gains and losses in the future. In February 2011, we settled our outstanding interest rate swap contracts.

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. No pro forma adjustments have been made for the acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below.

	Years Ended December 31,		
	2008	2009	2010
Production Volume(1):			
Oil (MBbls)	4,091	3,402	2,792
Natural gas (MMcf)	23,050	24,748	23,196
MBOE	7,933	7,527	6,658
Daily Average Production Volume:			
Oil (Bbls/d)	11,178	9,321	7,649
Natural gas (Mcf/d)	62,978	67,803	63,551
BOE/d	21,674	20,622	18,241
Oil Price per Bbl Produced (in dollars):			
Realized price	$ 89.28	$50.60	$68.86
Realized commodity derivative gain (loss)	(20.71)	(0.95)	(1.77)
Net realized price	$ 68.57	$49.65	$67.09
Natural Gas Price per Mcf Produced (in dollars):			
Realized price	$ 8.21	$ 3.84	$ 4.34
Realized commodity derivative gain (loss)	0.08	2.58	1.70
Net realized price	$ 8.29	$ 6.42	$ 6.04
Expense per BOE:			
Lease operating expenses	$ 16.86	$12.65	$12.65
Production and property taxes	$ 1.98	$ 1.35	$ 1.01
Transportation expenses	$ 0.54	$ 0.42	$ 1.37
Depletion, depreciation and amortization	$ 16.95	$11.46	$11.79
General and administrative expense, net(2)	$ 5.43	$ 4.91	$ 5.64
Interest expense	$ 6.81	$ 5.44	$ 6.10

(1) Amounts shown are oil production volumes for offshore properties and sales volumes for onshore properties (differences between onshore production and sales volumes are minimal). Revenue accruals are adjusted for actual sales volumes since offshore oil inventories can vary significantly from month to month based on the timing of barge deliveries, oil in tanks and pipeline inventories, and oil pipeline sales nominations.

(2) Net of amounts capitalized.

Comparison of Year Ended December 31, 2010 to Year Ended December 31, 2009

Oil and Natural Gas Sales. Oil and natural gas sales increased $23.4 million (9%) to $290.6 million in 2010 from $267.2 million in 2009. The increase was due to increases in realized oil and natural gas prices, partially offset by a decrease in production as described below.

Oil sales increased by $17.9 million (10%) in 2010 to $190.0 million compared to $172.1 million in 2009. Oil production decreased by 18%, with production of 2,792 MBbl in 2010 compared to 3,402 MBbl in 2009. The production decrease was due in large part to the sale of the Hastings Complex in early February 2009 and the sales of our remaining producing properties in Texas in the second quarter of 2010. Excluding production from the Texas properties, production decreased by 285 MBbls (10%) from 2,965 MBbls in 2009 to 2,680 MBbls in 2010. This decrease is primarily due to (i) the natural decline of production at the Sockeye and South Ellwood fields and (ii) reduced production at the Dos Cuadras field as a result of certain wells being taken offline due to temporary operational difficulties.

Our average realized price for oil increased $18.26 (36%) from $50.60 per Bbl in 2009 to $68.86 per Bbl in 2010.

Natural gas sales increased $5.5 million (6%) in 2010 to $100.6 million compared to $95.1 million in 2009. Natural gas production decreased 6%, with production of 23,196 MMcf in 2010 compared to 24,748 MMcf in 2009. The decrease was due in large part to the sales of our producing properties in Texas during the second quarter of 2010. Excluding production from the Texas properties, natural gas production decreased by 428 MMcf (2%) from 23,283 MMcf in 2009 to 22,855 MMcf in 2010. The slight decrease in production is primarily due to the natural decline of production from wells in the Sacramento Basin, the majority of which has been offset by production from newly drilled and recompleted wells. Our average realized price for natural gas increased $0.50 (13%) from $3.84 per Mcf in 2009 to $4.34 per Mcf for 2010.

Other Revenues. Other revenues increased by $1.4 million (41%) to $4.7 million in 2010 from $3.3 million in 2009. The increase is primarily due to a contract that became effective in April 2010, related to the double-hulled barge that transports oil produced at our South Ellwood field (see "*—Transportation Expenses*"). The contract allows us to sub-charter the barge and retain the revenues from those activities. The increase in other revenues is the result of sub-charter activities in 2010.

Lease Operating Expenses. Lease operating expenses ("LOE") decreased $10.9 million (12%) to $84.3 million in 2010 from $95.2 million in 2009. The decrease was primarily due to the sale of the Hastings Complex in early February 2009 and the sale of our remaining Texas properties in the second quarter of 2010. Excluding the Texas properties, production expenses decreased $1.8 million (2%) from $83.4 million in 2009 to $81.6 million in 2010. The decrease was primarily due to lower non-recurring maintenance costs incurred at our South Ellwood field in 2010 compared to 2009. On a per unit basis, LOE was $12.65 per BOE in both 2009 and 2010. Excluding the Texas assets, LOE per BOE increased from $12.18 per BOE in 2009 to $12.57 per BOE in 2010. The increase on a per BOE basis is the result of lower production levels in 2010 compared to 2009.

Production and Property Taxes. Production and property taxes decreased $3.4 million (34%) to $6.7 million in 2010 from $10.1 million in 2009. The decrease was partially due to the sale of the Hastings Complex in early February 2009 and the sale of our remaining Texas properties in the second quarter of 2010. Excluding the Texas properties, production and property taxes decreased $1.9 million (23%) from $8.1 million in 2009 to $6.2 million in 2010. The decrease was primarily due to lower supplemental property taxes incurred in 2010 as compared to 2009 resulting from lower gas prices and lower assessed mineral rights valuations for drilling and recompletion activities.

Transportation Expenses. Transportation expenses increased $5.9 million (188%) to $9.1 million in 2010 from $3.2 million in 2009. On a per BOE basis, transportation expenses increased $0.95 per BOE, from $0.42 per BOE in 2009 to $1.37 per BOE in 2010. The increase is primarily due to the contract described in "*—Other Revenues*", related to the time-charter of a double-hulled barge to transport oil produced from our South Ellwood field. Under that contract we pay a flat day rate, regardless of our usage of the barge, but have the ability to sub-charter the vessel when it is not in use transporting production from the South Ellwood field (see "*—Other Revenues*"). We also incurred additional transportation costs from the use of a single-hulled barge during the transition period to the double-hulled barge, which was completed late in the fourth quarter of 2010.

Depletion, Depreciation and Amortization (DD&A). DD&A expense decreased $7.7 million (9%) to $78.5 million in 2010 from $86.2 million in 2009. The decrease is related to (i) a lower amortizable base in 2010 resulting from the application of the net proceeds from the sales of our Texas producing properties and the Cat Canyon field and (ii) lower production in 2010 compared to 2009. DD&A expense on a per unit basis increased by $0.33 (3%) from $11.46 per BOE for 2009 to $11.79 per BOE for 2010.

Accretion of Abandonment Liability. Accretion expense increased $0.4 million (8%) to $6.2 million in 2010 from $5.8 million in 2009. The increase is primarily due to accretion from new wells drilled and completed in 2009 and 2010.

General and Administrative (G&A). The following table summarizes the components of general and administrative expense incurred during the periods indicated (in thousands):

	Years Ended December 31,	
	2009	**2010**
Share-based compensation costs	$ 3,890	$ 6,930
One-time severance costs	—	1,254
Other general and administrative costs	58,135	52,052
General and administrative costs capitalized	(25,086)	(22,682)
General and administrative expense	$ 36,939	$ 37,554

G&A expense increased $0.7 million (2%) to $37.6 million in 2010 from $36.9 million in 2009. The overall increase in G&A costs was primarily due to increases resulting from: (i) lower capitalized G&A costs in 2010 compared to the amount capitalized in 2009 due to lower levels of drilling activity in the first quarter of 2010, (ii) one-time severance payments of $1.3 million in 2010 related to the sale of our Texas properties and the related closure of our Texas operations and (iii) non-cash share-based compensation expense of $4.5 million (net of amount capitalized) charged to G&A in 2010 compared to $2.1 million (net of amount capitalized) in 2009. We issued annual restricted stock awards in the first quarter of both 2010 and 2009. The fair value of the awards issued in the 2010 period was significantly greater than the grants in the 2009 period due to the increase in our stock price between the periods, which contributed to the increase in non-cash share-based compensation expense. These increases were partially offset by lower other general and administrative costs resulting from the closing of our Texas office and other G&A decreases. Excluding the effect of the non-cash share-based compensation expense and one-time severance charges, G&A expense increased to $4.78 per BOE in 2010 from $4.63 per BOE in 2009. The increase on a per unit basis is primarily the result of lower production levels in 2010 compared with 2009.

Interest Expense, Net. Interest expense, net of interest income, remained relatively constant at $40.6 million in 2010 compared to $41.0 million in 2009.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs was $2.4 million in 2010 compared to $2.9 million in 2009. The costs incurred relate to our loan agreements, which are amortized over the estimated lives of the agreements.

Interest Rate Derivative (Gains) Losses, Net. Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized losses of $13.7 million in 2010 and unrealized gains of $1.8 million in 2009. Unrealized interest rate (gains) losses represent the change in the fair value of our interest rate derivative contracts from period to period based on estimated future interest rates at the end of the reporting period. Realized interest rate swap losses were $18.1 million in 2010 and $18.4 million in 2009.

Loss on Extinguishment of Debt. We recognized losses on extinguishment of debt in 2009 of $8.5 million related to repayment of the financed derivative premiums balance in May 2009 and the refinancing of our $150 million senior notes in October 2009.

Commodity Derivative (Gains) Losses, Net. The following table sets forth the components of commodity derivative (gains) losses, net in our consolidated statements of operations for the periods indicated (in thousands):

	Years Ended December 31,	
	2009	2010
Realized commodity derivative (gains) losses	$(68,429)	$(53,501)
Amortization of commodity derivative premiums	22,661	24,808
Unrealized commodity derivative (gains) losses for changes in fair value	71,511	(39,356)
Commodity derivative (gains) losses	$ 25,743	$(68,049)

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 gains in both 2010 and 2009 reflect the settlement of contracts at prices below the relevant strike prices. In the first quarter of 2009, we unwound certain 2009 oil collars and certain 2009 gas puts which resulted in non-recurring gains of $7.7 million which are reflected in the 2009 realized commodity derivative gains. In the fourth quarter of 2010, we settled certain 2011 gas puts and collars which resulted in non-recurring gains of $19.1 million which are reflected in the 2010 realized commodity derivative gains. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. Derivative premiums are amortized over the term of the underlying derivative contracts.

Income Tax Expense (Benefit). We incurred losses before income taxes in 2008 and 2009. These losses were a key consideration that led us to provide a valuation allowance against our net deferred tax assets at December 31, 2009 and December 31, 2010 since we could not conclude that it is more likely than not that the net deferred tax assets will be fully realized. As long as we continue to conclude that we have a need for a full valuation allowance against our net deferred tax assets, we likely will not have any income tax expense or benefit other than for federal alternative minimum tax expense, a release of a portion of the valuation allowance for net operating loss carryback claims, or for state income taxes. The current tax benefit for 2009 of $14.4 million reflects a reduction of prior year current tax expense (a $6.0 million benefit) and, due to the temporary five-year carryback period that became available in 2009, a carryback of net operating losses (a $8.4 million benefit). The income tax benefit we recorded for 2010 primarily relates to an increase in the estimated net operating loss carryback claims for the 2003 through 2005 tax years and a reduction in the amount owed for prior year state income taxes. Additionally, we amended prior year returns in 2010 for certain share based compensation matters, which will result in additional income tax refunds.

Net Income (Loss). Net income for 2010 was $67.5 million compared to net loss of $47.3 million for 2009. The change between years is the result of the items discussed above.

Comparison of Year Ended December 31, 2009 to Year Ended December 31, 2008

Oil and Natural Gas Sales. Oil and natural gas sales decreased $287.1 million (52%) to $267.2 million in 2009 from $554.3 million in 2008. The decrease was due to a decline in average sales prices in addition to lower production in 2009 as compared to 2008, which resulted from the Hastings sale as described below.

Oil sales decreased by $192.8 million (53%) to $172.1 million in 2009 compared to $364.9 million in 2008. Oil production decreased by 17%, with production of 3,402 MBbl in 2009 compared to 4,091 MBbl in 2008. The production decrease was due to the sale of the Hastings Complex in early February 2009. Excluding Hastings, production increased 167 MBbl (5%) from 3,154 MBbl in 2008 to 3,321 MBbl in 2009. The increase is primarily due to increased production at the West Montalvo field as a result of drilling and recompletion activities in the latter half of 2008 and 2009. Our average realized price for oil decreased $38.68 (43%) to $50.60 per Bbl for 2009.

Natural gas sales decreased $94.2 million (50%) in 2009 to $95.1 million compared to $189.3 million in 2008. Natural gas production increased 7%, with production of 24,748 MMcf in 2009 compared to 23,050 MMcf in 2008. The increase was due primarily to drilling and recompletion activities in the Sacramento Basin as well as production from wells acquired in the Sacramento Basin asset acquisition in June 2009. Our average realized price for natural gas decreased $4.37 (53%) to $3.84 per Mcf for 2009.

Other Revenues. Other revenues were relatively consistent at $3.6 million in 2008 and $3.3 million in 2009.

Lease Operating Expenses. Lease operating expenses ("LOE") decreased $38.6 million (29%) to $95.2 million in 2009 from $133.8 million in 2008. The decrease was primarily due to the sale of Hastings, which was historically a relatively high cost field. On a per unit basis, LOE decreased to $12.65 per BOE in 2009 from $16.86 per BOE in 2008. Excluding Hastings, LOE per BOE decreased $1.75 from $14.32 per BOE in 2008 to $12.57 per BOE in 2009. In 2008, we incurred relatively high non-recurring maintenance costs related to certain wells in the Sockeye field, which were not incurred in 2009. Additionally, we incurred scheduled maintenance costs in 2008 related to Platform Gail in the Sockeye field that we did not incur in 2009. We were also able to achieve certain price/cost reductions from external contractors and suppliers during 2009 which reduced our overall LOE costs.

Production and Property Taxes. Production and property taxes decreased $5.6 million (36%) to $10.1 million in 2009 from $15.7 million in 2008. The decrease was primarily due to a reduction in production taxes in 2009 as a result of the sale of the Hastings Complex in early February 2009.

Transportation Expenses. Transportation expenses decreased $1.1 million (27%) to $3.2 million in 2009 from $4.3 million in 2008. On a per BOE basis, transportation expenses decreased $0.12 per BOE, from $0.54 per BOE in 2008 to $0.42 per BOE in 2009. The decrease is primarily due to maintenance costs incurred in 2008 related to the barge that transports South Ellwood oil production, which were not incurred in 2009.

Depletion, Depreciation and Amortization (DD&A). DD&A expense decreased $48.3 million (36%) to $86.2 million in 2009 from $134.5 million in 2008. DD&A expense decreased $5.49 per BOE, from $16.95 per BOE in 2008 to $11.46 per BOE in 2009. The decrease is principally due to a reduced depletable base as a result of the full cost ceiling write down recorded at December 31, 2008 and the application of proceeds from the Hastings sale in February 2009 to reduce the full cost pool.

Impairment of Oil and Natural Gas Properties. During the fourth quarter of 2008, we recorded an impairment charge to the net book value of oil and gas properties of $641 million as the result of the required full cost ceiling test. The impairment was caused principally by lower year-end oil and natural gas prices.

Accretion of Abandonment Liability. Accretion expense increased $1.6 million (37%) to $5.8 million in 2009 from $4.2 million in 2008. The increase was due to revisions to estimated liabilities recorded in the fourth quarter of 2008 and accretion from new wells drilled and completed in 2008 and 2009.

General and Administrative (G&A). The following table summarizes the components of general and administrative expense incurred during the periods indicated (in thousands):

	Years Ended December 31,	
	2008	2009
Share-based compensation costs	$ 5,030	$ 3,890
One-time write off of MLP costs	2,690	—
Other general and administrative costs	54,147	58,135
General and administrative costs capitalized	(18,766)	(25,086)
General and administrative expense	$ 43,101	$ 36,939

G&A expense decreased $6.2 million (14%) to $36.9 million in 2009 from $43.1 million in 2008. The decrease is primarily related to $2.7 million of costs that were expensed in the second quarter of 2008 related to the cancellation of a planned MLP offering. The decrease also resulted from an increase in the G&A costs that were capitalized in 2009 for payroll and related overhead for activities that are directly involved in our development, exploitation, exploration and acquisition efforts. Additionally, we incurred lower legal/professional fees and travel costs in 2009 compared to 2008. Non-cash share-based compensation expense charged to G&A (net of amount capitalized) decreased $0.3 million (11%) from $2.4 million in 2008 to $2.1 million in 2009, primarily as a result of certain awards that became fully vested in the first quarter of 2009. Excluding the effect of the non-cash share-based compensation expense charges and MLP write-off charges, G&A expense decreased $0.16 from $4.79 per BOE in 2008 to $4.63 per BOE in 2009.

Interest Expense, Net. Interest expense, net of interest income, decreased $13.0 million (24%) from $54.0 million in 2008 to $41.0 million in 2009. The decrease was primarily the result of a reduction in our average debt outstanding and lower interest rates realized during 2009.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs decreased $0.4 million from $3.3 million in 2008 to $2.9 million in 2009. The costs incurred relate to our loan agreements, which are amortized over the estimated lives of the agreements.

Interest Rate Derivative (Gains) Losses, Net. Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized gains of $1.8 million in 2009 and unrealized losses of $10.3 million in 2008. Unrealized interest rate (gains) losses represent the change in the fair value of our interest rate derivative contracts from period to period based on estimated future interest rates at the end of the reporting period. Realized interest rate swap losses were $18.5 million in 2009 compared to realized losses of $10.2 million in 2008.

Loss on Extinguishment of Debt. We recognized losses on extinguishment of debt in 2009 of $8.5 million related to repayment of the financed derivative premiums balance in May 2009 and the refinancing of our $150 million senior notes in October 2009.

Commodity Derivative (Gains) Losses, Net. The following table sets forth the components of commodity derivative (gains) losses, net in our consolidated statements of operations for the periods indicated (in thousands):

	Years Ended December 31,	
	2008	2009
Realized commodity derivative (gains) losses	$ 61,446	$(68,429)
Amortization of commodity derivative premiums	6,256	22,661
Unrealized commodity derivative (gains) losses for changes in fair value	(184,459)	71,511
Commodity derivative (gains) losses	$(116,757)	$ 25,743

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 gains in 2009 reflect the settlement of contracts at prices below the relevant strike prices, while the realized derivative losses in the 2008 period reflect the settlement of contracts at prices above the relevant strike prices. In addition, during the first quarter of 2009, we unwound certain 2009 oil collars and certain 2009 gas puts which resulted in non-recurring gains of $7.7 million which are reflected in the 2009 realized commodity derivative gains. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. Derivative premiums are amortized over the term of the underlying derivative contracts.

Income Tax Expense (Benefit). We incurred losses before income taxes in 2008 and 2009. These losses were a key consideration that led us to provide a valuation allowance against our net deferred tax assets at December 31, 2008 and 2009 since we could not conclude that it is more likely than not that the net deferred tax assets will be recognized. The current tax benefit for 2009 of $14.4 million reflects a reduction of prior year current tax expense (a $6.0 million benefit) and, due to the temporary five-year carryback period that became available in 2009, a carryback of net operating losses (a $8.4 million benefit). The valuation allowance resulted in income tax expense of $11.2 million in 2008.

Net Income (Loss). Net loss for 2009 was $47.3 million compared to net loss of $391.1 million for 2008. The change between years is the result of the items discussed above.

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,		
	2008	2009	2010
		(in thousands)	
Cash provided by (used in) operating activities	$ 212,379	$ 118,691	$ 160,673
Cash provided by (used in) investing activities	(332,861)	(1,953)	(108,296)
Cash provided by (used in) financing activities	110,938	(116,510)	(47,772)

Net cash provided by operating activities was $160.7 million in 2010 compared with $118.7 million in 2009 and $212.4 million in 2008. Cash flows from operating activities in 2010 as compared to 2009 were favorably impacted by increases in commodity prices, partially offset by decreased production. Cash flows from operating activities in 2009 were unfavorably impacted by significant decreases in commodity prices compared with 2008.

Net cash used in investing activities was $108.3 million in 2010 compared with net cash used of $2.0 million in 2009 and net cash used of $332.9 million in 2008. The primary investing activities in 2010 were $208.4 million in capital expenditures on oil and natural gas properties related to our capital expenditure program, partially offset by the receipt of $107.4 million in net cash proceeds from the sales of our Texas producing properties in the second quarter of 2010 and the sale of our Cat Canyon field in the fourth quarter of 2010. The primary investing activities in 2009 were $174.8 million in capital expenditures for our oil and gas exploration and development programs together with $21.3 million paid to acquire certain Sacramento Basin assets. These total expenditures of $196.1 million were offset by the receipt of $197.7 million in cash proceeds from the sale of our Hastings Complex in Texas. The primary investing activities in 2008 include $311.2 million in expenditures for oil and gas properties and $14.3 million for acquisitions.

Net cash used in financing activities was $47.8 million in 2010 compared to net cash used of $116.5 million in 2009 and net cash provided of $110.9 million in 2008. The primary financing activities in 2010 were $22.9 million in net payments made on our revolving credit facility and $39.2 million of principal repayments on the second lien term loan, both of which were primarily funded by proceeds from the sales of our producing properties in Texas and our Cat Canyon field. The primary financing activities in 2009 were as follows: (i) we made net repayments of $77.2 million on our revolving credit facility and $5.5 million of principal payments on the second lien term loan, both of which were primarily funded with proceeds from the Hastings sale, (ii) we paid approximately $15.3 million in May 2009 to settle financed derivative premiums, (iii) in October 2009, we refinanced our 8.50% senior notes with the issuance of our 11.50% senior notes, which resulted in a principal repayment of $150 million and a premium payment of $3.3 million. From the issuance of the 11.50% notes, we received cash of $142.5 million, net of the $7.5 million original issue discount. We incurred $2.9 million in debt issuance costs related to the senior notes refinancing. Additionally, we incurred $1.9 million of debt issuance costs related to the third amendment and restatement of the agreement governing the revolving credit facility, which we entered into in December 2009. The primary financing activities in 2008 were $93.1 million in net borrowings under the revolving credit facility to fund capital expenditures and working capital needs.

Capital Resources and Requirements

In February 2011, we completed two capital raising transactions which provided us with additional liquidity. First, we issued 4.0 million shares of common stock at a price to the public of $18.75 per share. The underwriters have the option to purchase up to an aggregate of 0.6 million additional shares of common stock to cover any over-allotments. We received net proceeds of approximately $71.4 million in the equity transaction after deducting estimated offering-related expenses. Second, we issued $500 million of 8.875% senior unsecured notes which are due in February 2019. We received net proceeds of approximately $489.7 million from the offering, after deducting estimated offering-related expenses. The proceeds from the two transactions were used to repay the outstanding principal and accrued interest related to our second lien term loan, settle the related interest rate swap contracts and repay the outstanding balance on our revolving credit facility. Estimated remaining cash on hand from the transactions after those uses and estimated offering related expenses was $21.1 million.

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 $218.0 million in 2010, will be approximately $200 million in 2011. We expect to fund our 2011 capital expenditure budget primarily with cash flow from operations, supplemented with borrowings under our revolving credit facility and proceeds from the equity transaction described above. Additionally, we continue to pursue joint venture transactions related to our Monterey shale development project. We have significant flexibility to reduce 2011 capital expenditures if warranted by business conditions or limits on our capital resources. Uncertainties relating to our capital resources and requirements in 2011 include the possibility that one or more of the counterparties to our hedging arrangements may fail to perform under the contracts, the effects of changes in commodity prices and differentials, results from our onshore Monterey shale program, which could lead us to accelerate or decelerate activities depending on the extent of our success in developing the program, and the possibility that we will pursue one or more significant acquisitions that would require additional debt or equity financing.

Amended Revolving Credit Facility. In December 2009, we entered into the third amended and restated credit agreement governing our revolving credit facility, which now has a maturity date of January 15, 2013. The agreement contains customary representations, warranties, events of default, indemnities and covenants, including covenants that restrict our ability to incur indebtedness, require us to maintain derivative contracts covering a portion of our anticipated production and require us to maintain specified ratios of current assets to current liabilities and debt to EBITDA. The minimum ratio of current assets to current liabilities (as those terms are defined in the agreement) is one to one; the maximum ratio of debt to EBITDA (as defined in the agreement) is four to one. While we do not expect to be in violation of any of our debt covenants during 2011, we believe that it will be important to monitor the debt to EBITDA ratio requirement, especially if our EBITDA is less than we expect due to operational problems or other factors, or if our borrowing needs are greater than we expect. The agreement requires us to reduce amounts outstanding under the facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. 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 (x) Bank of Montreal's announced base rate, (y) the overnight federal funds rate plus 0.50% and (z) the one-month LIBOR plus 1.5%, plus (ii) an applicable margin ranging from 0.75% to 1.50%, 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 2.25% to 3.00%, based upon utilization. A commitment fee of 0.5% per annum is payable with respect to unused borrowing availability under the facility.

The revolving credit facility has a total capacity of $300.0 million, but is limited by a borrowing base which is currently established at $125.0 million. The borrowing base is subject to redetermination twice each year, and may be redetermined at other times at our request or at the request of the lenders. Lending commitments under the facility have been allocated at various percentages to a syndicate of ten banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with events in the credit markets. A failure of any members of the syndicate to fund under the facility, or a reduction in the borrowing base, would adversely affect our liquidity. In February 2011, we repaid the outstanding principal balance on our revolving credit facility using proceeds from the issuance of 4.0 million shares of our common stock. As of February 18, 2011, there was no balance drawn on our revolving credit facility. During 2010, we paid $66.9 million toward the principal balance of our revolving credit facility during the second quarter of 2010 with the proceeds from the sales of our Texas producing properties, which we completed in the second quarter of 2010.

Second Lien Term Loan and 8.875% Senior Notes. We entered into a $500.0 million senior secured second lien term loan agreement in May 2007. Prior to repayment as described below, the term loan facility was secured by a second priority lien on substantially all of our assets and was due to mature on May 8, 2014. Loans under the second lien term loan facility designated as "Base Rate Loans" bore 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" bore interest at LIBOR plus 4.00%.

We repaid $39.2 million of principal under the facility in 2010 after the sales of our Texas producing properties and the Cat Canyon field and $5.5 million of principal in 2009 after the Hastings Complex sale.

In February 2011, we issued $500 million in 8.875% senior unsecured notes due in February 2019 at par. Concurrently with the sale of the 8.875% senior notes, we repaid the full outstanding principal balance of $455.3 million on the second lien term loan, plus accrued interest of $1.6 million.

The 8.875% senior notes pay interest semi-annually in arrears on February 15 and August 15 of each year. We may redeem the notes prior to February 15, 2015 at a "make whole premium" defined in the indenture. Beginning February 15, 2015, we may redeem the notes at a redemption price of 104.438% of the principal amount and declining to 100% by February 15, 2017. The 8.875% senior notes are senior unsecured obligations and contain operational covenants that, among other things, limit our ability to make investments, incur additional indebtedness or create liens on our assets.

11.50% Senior Notes. In October 2009, we issued $150.0 million of 11.50% senior unsecured notes due in October 2017 at a price of 95.03% of par. The senior notes pay interest semi-annually in arrears on April 1 and October 1 of each year. We may redeem the senior notes prior to October 1, 2013 at a "make-whole price" defined in the indenture. Beginning October 1, 2013, we may redeem the notes at a redemption price equal to 105.75% of the principal amount and declining to 100% by October 1, 2016. The indenture governing the notes contains operational covenants that, among other things, limit our ability to make investments, incur additional indebtedness or create liens on our assets.

Because we must dedicate a substantial portion of our cash flow from operations to the payment of amounts due under our debt agreements, 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 revolving credit facility, 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 facility that require us to use some or all of the proceeds of such transactions to reduce amounts outstanding under the facility 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, 2010, 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(2)(3)	$ —	$35,000	$455,311	$143,281	$633,592
Interest on senior notes	17,250	34,500	34,500	30,152	116,402
Office, property and equipment leases	2,736	5,657	3,967	8,314	20,674
Seismic(4)	3,912	—	—	—	3,912
Total	$23,898	$75,157	$493,778	$181,747	$774,580

(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 $94.2 million at December 31, 2010.

(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, 2008, 2009 and 2010, we incurred interest expense on those debt instruments of $40.3 million, $25.3 million and $22.1 million, respectively.

(3) The principal balance of the second lien term loan of $455.3 million, which was due in 2014, was repaid with proceeds from the issuance of $500 million in 8.875% senior notes in February 2011. The 8.875% senior notes are due in February 2019.

(4) We are contractually obligated to pay certain costs related to a 3D seismic shoot in the San Joaquin basin that is targets the Monterey shale formation.

Off-Balance Sheet Arrangements

At December 31, 2010, 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, 2010 estimate of net proved oil and natural gas reserves totaled 85.1 MMBOE. 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 1% lower. In addition, our proved reserves are concentrated in a relatively small number of wells. At December 31, 2010, 16% of our proved reserves were concentrated in our 20 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 sum of the capitalized investment and estimated future development costs associated with the 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, 2010 would have resulted in an increase of approximately $1.22 per BOE in our average 2010 depletion expense rate. Costs associated with production and general corporate activities are expensed in the period incurred. 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 are established or impairment is 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, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under full cost accounting rules, capitalized costs of oil and natural gas properties, excluding costs associated with unproved 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 twelve month arithmetic average of the prices in effect on the first day of each month of the relevant period and requires a write down for accounting purposes if the ceiling is exceeded.

We did not have ceiling test write downs during 2009 or 2010. At December 31, 2008, our net capitalized costs exceeded the ceiling by $641 million, net of income tax effects, and we recorded a write down of our oil and natural gas properties in that amount. Per the guidance in effect at the time, the year-end prices were used to determine reserves at December 31, 2008. We could be required to recognize additional impairments of oil and gas properties in future periods if market prices of oil and natural gas decline.

Asset Retirement Obligations

The accounting standards set forth by the FASB with respect to accounting for asset retirement obligations provide 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 this method, 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. 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 4% and 9%. 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 recognized a valuation allowance against our net deferred taxes because we cannot conclude that it is more likely than not that the net deferred tax assets will be realized as a result of estimates of our future operating income based on current oil and natural gas commodity pricing. In assessing the realization of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. We will continue to evaluate whether the valuation allowance is needed in future reporting periods.

Derivative Instruments

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, risk-free interest rates, credit adjusted discount rates and estimated volatility factors. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity derivative 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. We do not apply hedge accounting to any of our derivative contracts, therefore we recognize mark-to-market gains and losses in earnings currently.

Recent Accounting Pronouncements

In December 2008, the SEC published revised rules regarding oil and gas reserves reporting requirements. The objective of the rules is to provide readers of financial statements with more meaningful and comprehensive understanding of oil and gas reserves. Key elements of the revised rules include a change in the pricing used to estimate reserves at period end, certain revised definitions, optional disclosure of probable and possible reserves, allowance of the use of new technologies in the determination of reserves and additional disclosure requirements. The rules also revised the prices used for reserves in determining depletion and the full cost ceiling test from a period end price to a twelve month arithmetic average price. The revised rules are effective for annual reporting periods for fiscal years ending on or after December 31, 2009. Application of the revised rules resulted in changes to the prices used to determine proved reserves at December 31, 2009 and 2010, as well as additional disclosures.

In January 2010, the FASB issued an Accounting Standards Update ("ASU") which amended existing oil and gas reserve accounting and disclosure guidance to align its requirements with the SEC's revised rules discussed above. The significant revisions involve revised definitions of oil and gas producing activities, changing the pricing used to estimate reserves at period end to a twelve month arithmetic average and additional disclosure requirements. In contrast to the SEC rule, the FASB does not permit the disclosure of probable and possible reserves in the supplemental oil and gas information in the notes to the financial statements. The amendments are effective for annual reporting periods ending on or after December 31, 2009. Application of the revised rules is prospective and companies are not required to change prior period presentation to conform to the amendments. Application of the amended guidance resulted in changes to the prices used to determine proved reserves at December 31, 2009 and 2010, which did not result in significant changes to our oil and natural gas reserves.

PV-10

The pre-tax present value of future net cash flows, or PV-10, 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 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 the twelve-month arithmetic average of the first of the month prices (except that for periods prior to December 31, 2009, the period end price was used), without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, 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 as of the dates shown (in thousands):

	December 31,		
	2008(1)	2009(2)	2010(3)
Standardized measure of discounted future net cash flows	$610,096	$692,805	$ 902,901
Add: Present value of future income tax discounted at 10%	6,585	108,248	225,795
PV-10	$616,681	$801,053	$1,128,696

(1) Unescalated year-end posted prices of (i) $44.60 per Bbl for oil and natural gas liquids and $5.62 per MMBtu for natural gas were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at realized prices of $36.54 per Bbl for oil, $35.96 per Bbl for natural gas liquids and $5.35 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2008.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of $61.04 per Bbl for oil and natural gas liquids and $3.87 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at realized prices of $51.15 per Bbl for oil, $37.98 per Bbl for natural gas liquids and $3.80 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2009.

(3) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted in note (1) above to arrive at realized prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

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. We may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of our existing positions. We may use the proceeds from such transactions to secure additional contracts for periods in which we believe there is additional unmitigated commodity price risk.

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

Commodity Derivative Transactions

Commodity Derivative Agreements. As of December 31, 2010, we had entered into swap, collar and option agreements related to our oil and natural gas production. The aggregate economic effects of those agreements are summarized below. Location and quality differentials attributable to our properties are not included in the following prices. The agreements provide for monthly settlement based on the differential between the agreement price and the actual NYMEX WTI (oil) or NYMEX Henry Hub (natural gas) price.

	Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Barrels/day	Weighted Avg. Prices per Bbl	MMBtu/day	Weighted Avg. Prices per MMBtu
January 1 - December 31, 2011:				
Swaps	—	$—	24,000	$4.44
Collars(1)	5,000	$50.00/$100.00	—	$—
Puts(1)	2,000	$50.00	36,000	$5.92
January 1 - December 31, 2012:				
Collars(1)	3,000	$60.00/$121.10	—	$—
Puts(1)	—	$—	37,300	$5.81
January 1 - December 31, 2013:				
Collars(1)	—	$—	20,000	$5.00/$7.02

(1) Reflects the impact of call spreads and purchased calls, which are transactions we entered into for the purpose of modifying or eliminating the ceiling (or call) portion of certain collar arrangements.

We also use natural gas basis swaps to fix the differential between the NYMEX Henry Hub price and the PG&E Citygate price, the index on which the majority of our natural gas is sold. Our natural gas basis swaps as of December 31, 2010 are presented below:

	Floating Index	MMBtu/Day	Weighted Avg. Basis Differential to NYMEX HH (per MMBtu)
Basis Swaps:			
January 1 - December 31, 2011	PG&E Citygate	57,224	$0.11
January 1 - December 31, 2012	PG&E Citygate	47,400	$0.28

Portfolio of Derivative Transactions

Our portfolio of commodity derivative transactions as of December 31, 2010 is summarized below:

Oil

Type of Contract	Counterparty	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	Key Bank	NYMEX	2,000	$50.00/$141.00	Jan 1 - Dec 31, 11
Call Spread	Key Bank	NYMEX	2,000	$141.00/$100.00	Jan 1 - Dec 31, 11
Collar	Credit Suisse	NYMEX	3,000	$50.00/$140.00	Jan 1 - Dec 31, 11
Call Spread	Credit Suisse	NYMEX	3,000	$140.00/$100.00	Jan 1 - Dec 31, 11
Put	Key Bank	NYMEX	2,000	$50.00	Jan 1 - Dec 31, 11
Collar	RBS	NYMEX	3,000	$60.00/$121.10	Jan 1 - Dec 31, 12

Natural Gas

Type of Contract	Counterparty	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Call (sold)	Credit Suisse	NYMEX	12,000	$13.50	Jan 1 - Dec 31, 11
Call (purchased)	RBS	NYMEX	12,000	$13.50	Jan 1 - Dec 31, 11
Collar	Bank of Montreal	NYMEX	24,000	$5.75/$7.12	Jan 1 - Dec 31, 11
Call (purchased)	Bank of Montreal	NYMEX	12,000	$7.12	Jan 1 - Dec 31, 11
Collar (sold put; purchased call)	Bank of Montreal	NYMEX	12,000	$5.75/$7.12	Jan 1 - Dec 31, 11
Put	Credit Suisse	NYMEX	10,000	$6.00	Jan 1 - Dec 31, 11
Put	Key Bank	NYMEX	14,000	$6.00	Jan 1 - Dec 31, 11
Swap	Scotia Capital	NYMEX	12,000	$4.44	Jan 1 - Dec 31, 11
Swap	Key Bank	NYMEX	12,000	$4.4475	Jan 1 - Dec 31, 11
Basis Swap	Credit Suisse	PG&E Citygate	12,000	$0.03	Jan 1 - Dec 31, 11
Basis Swap	Credit Suisse	PG&E Citygate	16,000	$0.14	Jan 1 - Dec 31, 11
Basis Swap	RBS	PG&E Citygate	11,000	$0.04	Jan 1 - Dec 31, 11
Basis Swap	Scotia Capital	PG&E Citygate	6,624	$0.03	Jan 1 - Dec 31, 11
Basis Swap	Scotia Capital	PG&E Citygate	11,600	$0.27	Jan 1 - Dec 31, 11
Collar	Credit Suisse	NYMEX	15,500	$6.00/$9.10	Jan 1 - Dec 31, 12
Call (purchased)	Credit Suisse	NYMEX	15,500	$9.10	Jan 1 - Dec 31, 12
Collar	Credit Suisse	NYMEX	14,000	$5.50/$8.00	Jan 1 - Dec 31, 12
Call (purchased)	Credit Suisse	NYMEX	14,000	$8.00	Jan 1 - Dec 31, 12
Put	RBS	NYMEX	7,800	$6.00	Jan 1 - Dec 31, 12
Basis Swap	Credit Suisse	PG&E Citygate	36,000	$0.275	Jan 1 - Dec 31, 12
Basis Swap	Key Bank	PG&E Citygate	11,400	$0.275	Jan 1 - Dec 31, 12
Collar	Credit Suisse	NYMEX	20,000	$5.00/$7.02	Jan 1 - Dec 31, 13

Subsequent to December 31, 2010, we entered into the following commodity derivative transactions:

Oil

Type of Contract	Counterparty	Basis	Quantity Bbl/d	Strike Price $/Bbl	Term
Collar	Bank of Montreal	NYMEX	1,500	$80.00/$110.85	Jan 1 - Dec 31, 12
Collar	Bank of Montreal	NYMEX	1,000	$85.00/$120.30	Jan 1 - Dec 31, 12
Collar	Scotia Capital	NYMEX	1,000	$85.00/$120.10	Jan 1 - Dec 31, 12
Collar	BNP Paribas	NYMEX	2,000	$85.00/$120.10	Jan 1 - Dec 31, 12
Collar	Credit Suisse	NYMEX	1,000	$80.00/$110.00	Jan 1 - Dec 31, 13
Collar	Credit Suisse	NYMEX	500	$80.00/$110.00	Jan 1 - Dec 31, 13
Collar	Credit Suisse	NYMEX	1,400	$85.00/$120.00	Jan 1 - Dec 31, 13
Collar	BNP Paribas	NYMEX	1,000	$80.00/$110.00	Jan 1 - Dec 31, 13

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 seek to mitigate our exposure to price declines and allow us more flexibility to continue to execute our capital expenditure 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. We do not enter into hedge positions for amounts greater than our expected production levels; however, if actual 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 liquidity and our ability to fund future capital expenditures. If we were unable to satisfy such a payment obligation, that default could result in a cross-default under our revolving credit agreement. 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 liquidity or our ability to fund expected capital expenditures.

In addition, the use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We generally have netting arrangements with our counterparties that provide for the offset of payables against receivables from separate derivative arrangements with that counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. All of the counterparties to our derivative contracts are also lenders, or affiliates of lenders, under our revolving credit facility. Collateral under the revolving credit facility supports our collateral obligations under our derivative contracts. Therefore, we are not required to post additional collateral when we are in a derivative liability position. Our revolving credit facility and our derivative contracts contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

We have elected not to apply hedge accounting to any of our derivative transactions and consequently, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would 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. As of December 31, 2010, the fair value of our commodity derivatives was a net asset of $31.0 million.

Interest Rate Derivative Transactions

During 2010, we were subject to interest rate risk with respect to amounts borrowed under our credit facilities because those amounts bore interest at variable rates. We entered into interest rate swap transactions to limit our exposure to changes in interest rates with respect to $500.0 million of variable rate borrowings through May 2014 whereby we paid a fixed interest rate of 3.840% and received a floating interest rate based on the one-month LIBO rate. As a result, $500 million of our variable rate debt effectively bore interest at a fixed rate of approximately 7.8% until May 2014. In February 2011, we repaid the full principal balance outstanding on the second lien term loan from proceeds received from the issuance of our 8.875% senior notes (see —"Capital Resources and Requirements"), which reduced our debt subject to variable rate interest to any amounts which may be outstanding under our revolving credit facility. As a result, we settled our interest rate swaps for $38.1 million in February 2011. The fair value of our interest rate derivatives was a liability of $40.1 million at December 31, 2010.

See notes to our consolidated financial statements for a discussion of our long-term debt as of December 31, 2010.

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 Ernst & Young 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 Ernst & Young 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, 2010. 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, as of December 31, 2010, 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, 2010, 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, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Ernst & Young 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 2010 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 2011 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 2011 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 2011 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 2011 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 2011 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	Amended and Restated Bylaws of Venoco, Inc. (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K of Venoco, Inc. filed on September 5, 2008).
4.1	Indenture, dated as of October 7, 2009, by and among Venoco, Inc., the Guarantors named therein and U.S. Bank Trust National Association, as Trustee, relating to the 11.50% Senior Notes due 2017 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 7, 2009).
4.2	Indenture, dated as of February 15, 2011, by and among Venoco, Inc., the Guarantors named therein and U.S. Bank Trust National Association, as Trustee, relating to the 8.875% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Venoco, Inc. filed on February 16, 2011).

Exhibit Number	Exhibit
10.1	Third Amended and Restated Credit Agreement, dated as of December 21, 2009, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, BMO Capital Markets, as Lead Arranger, The Bank of Nova Scotia and The Royal Bank of Scotland PLC, as Co-Syndication Agents and Key Bank National Association and Union Bank, N.A., as Co-Documentation Agents. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 23, 2009).
10.1.1	First Amendment and Waiver Related to the Third Amended and Restated Credit Agreement, dated as of February 4, 2011, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, The Bank of Nova Scotia and The Royal Bank of Scotland PLC as co-syndication agents, and KeyBank National Association and Union Bank, N.A., as co-documentation agents (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on February 8, 2011).
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 (incorporated by reference to Exhibit 10.2 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 17, 2008). (This agreement was terminated in February 2011).
10.3	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).
10.3.1	First Amendment to Option Agreement, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC, dated as of August 29, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on September 2, 2008).
10.4	Venoco, Inc. 2008 Employee Stock Purchase Plan, dated as of November 18, 2008, as amended as of December 31, 2008 (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 5, 2009).
10.5	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).
10.5.1	Amendment No. 1 to the Venoco, Inc. 2000 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.5.2	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).
10.5.3	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
10.5.4	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).
10.5.5	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).
10.6	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).
10.6.1	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).
10.6.2	Amendment No. 2 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.6.3	Amendment No. 3 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.7.3 to the Annual Report on Form 10-K of Venoco, Inc. filed on February 25, 2010).
10.6.4	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).
10.6.5	Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan and Stock Award Agreement, as amended (incorporated by reference to Exhibit 10.8.4 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 5, 2009).
10.6.6	2010 Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.7.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on February 25, 2010).
10.6.7	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).
10.7	Venoco, Inc. 2007 Senior Executive Bonus Plan, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 12, 2008).
10.8	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).
10.9.1	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).
10.9.2	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).
10.10	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).

Exhibit Number	Exhibit
10.11.1	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).
10.11.2	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).
10.12	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).
10.13	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).
10.14	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).
10.14.1	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).
10.15	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 10.29 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.16	Purchase and Sale Agreement, dated as of December 23, 2008, by and between Carpinteria Bluffs, LLC and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 29, 2008).
10.17	Exchange and Registration Rights Agreement, dated as of February 15, 2011, by and among Venoco, Inc., the Guarantors named in the indenture governing the 8.875% Senior Notes due 2019 and certain representatives of the initial purchasers of such notes identified therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on February 16, 2011).
10.18	Sales Agency Agreement, dated October 12, 2010 by and between Venoco, Inc. and BMO Capital Markets Corp. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 12, 2010).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Ernst & Young LLP.
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.
99.1	Report of DeGolyer & MacNaughton Regarding the Registrant's Reserves as of December 31, 2010 and Addendum thereto.

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: February 22, 2011

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)	February 22, 2011
/s/ TIMOTHY A. FICKER Timothy A. Ficker	Chief Financial Officer (Principal Financial Officer)	February 22, 2011
/s/ DOUGLAS J. GRIGGS Douglas J. Griggs	Chief Accounting Officer (Principal Accounting Officer)	February 22, 2011
Donna L. Lucas	Director	
/s/ J. C. MCFARLAND J. C. McFarland	Director	February 22, 2011
/s/ JOEL L. REED Joel L. Reed	Director	February 22, 2011
/s/ M. W. SCOGGINS M. W. Scoggins	Director	February 22, 2011
Mark A. Snell	Director	
/s/ RICHARD S. WALKER Richard S. Walker	Director	February 22, 2011

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. 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 audits 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, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Venoco, Inc. and subsidiaries at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2010, 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 February 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 22, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Venoco, Inc.'s (the "Company") internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). 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 included in the accompanying Management's Report on 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 and 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 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 a material effect on the financial statements.

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010 and our report dated February 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 22, 2011

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

	December 31, 2009	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 419	$ 5,024
Accounts receivable	33,853	29,602
Inventories	6,139	6,229
Other current assets	4,276	4,585
Income tax receivable	3,116	931
Deferred income taxes	8,400	—
Commodity derivatives	34,611	26,407
Total current assets	90,814	72,778
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Oil and gas properties, full cost method of accounting		
Proved	1,640,967	1,734,190
Unproved	31,934	42,686
Accumulated depletion	(1,073,664)	(1,147,688)
Net oil and gas properties	599,237	629,188
Other property and equipment, net of accumulated depreciation and amortization of $14,875 and $16,588 at December 31, 2009 and December 2010, respectively	20,193	18,856
Net property, plant and equipment	619,430	648,044
OTHER ASSETS:		
Commodity derivatives	18,720	21,462
Deferred loan costs	7,908	6,096
Other	2,671	2,543
Total other assets	29,299	30,101
TOTAL ASSETS	$ 739,543	$ 750,923
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 56,855	$ 45,396
Interest payable	4,885	5,538
Commodity and interest derivatives	49,709	33,483
Total current liabilities	111,449	84,417
LONG-TERM DEBT	695,029	633,592
COMMODITY AND INTEREST DERIVATIVES	15,076	23,430
ASSET RETIREMENT OBLIGATIONS	92,485	93,721
Total liabilities	914,039	835,160
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value (200,000,000 shares authorized; 52,513,397 and 56,241,672 shares issued and outstanding at December 31, 2009 and 2010, respectively)	525	562
Additional paid-in capital	325,871	348,573
Retained earnings (accumulated deficit)	(500,892)	(433,372)
Total stockholders' equity	(174,496)	(84,237)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 739,543	$ 750,923

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Years Ended December 31,		
	2008	2009	2010
REVENUES:			
Oil and natural gas sales	$ 554,270	$267,163	$290,608
Other	3,603	3,331	4,684
Total revenues	557,873	270,494	295,292
EXPENSES:			
Lease operating expense	133,773	95,213	84,255
Production and property taxes	15,731	10,128	6,701
Transportation expense	4,311	3,163	9,102
Depletion, depreciation and amortization	134,483	86,226	78,504
Impairment of oil and natural gas properties	641,000	—	—
Accretion of asset retirement obligations	4,203	5,765	6,241
General and administrative, net of amounts capitalized	43,101	36,939	37,554
Total expenses	976,602	237,434	222,357
Income (loss) from operations	(418,729)	33,060	72,935
FINANCING COSTS AND OTHER:			
Interest expense, net	54,049	40,984	40,584
Amortization of deferred loan costs	3,344	2,862	2,362
Interest rate derivative losses (gains), net	20,567	16,676	31,818
Loss on extinguishment of debt	—	8,493	—
Commodity derivative losses (gains), net	(116,757)	25,743	(68,049)
Total financing costs and other	(38,797)	94,758	6,715
Income (loss) before income taxes	(379,932)	(61,698)	66,220
INCOME TAXES:			
Current	6,300	(6,000)	(9,700)
Deferred	4,900	(8,400)	8,400
Income tax provision (benefit)	11,200	(14,400)	(1,300)
Net income (loss)	$(391,132)	$(47,298)	$ 67,520
Earnings per common share:			
Basic	$ (7.75)	$ (0.93)	$ 1.23
Diluted	$ (7.75)	$ (0.93)	$ 1.21
Weighted average common shares outstanding:			
Basic	50,486	50,805	52,249
Diluted	50,486	50,805	53,018

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2008	**2009**	**2010**
Net income (loss)	$(391,132)	$(47,298)	$67,520
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Hedging activities—Reclassification adjustments for settled contracts(1)	905	1,424	—
Other comprehensive income (loss)	905	1,424	—
Comprehensive income (loss)	$(390,227)	$(45,874)	$67,520

(1) Net of income tax expense (benefit) of $532, $899 and $0 for the years ended December 31, 2008, 2009 and 2010, 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, 2007	50,593	506	309,887	(62,462)	(2,329)	245,602
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	905	905
Issuance of stock for cash upon exercise of options	451	5	2,951	—	—	2,956
Issuance of restricted shares, net of cancellations	516	5	(5)	—	—	—
Restricted stock used for tax withholding	(11)	(1)	(156)	—	—	(157)
Share-based compensation	—	—	5,710	—	—	5,710
Disgorgement of stock sale profits	—	—	949	—	—	949
Net income (loss)	—	—	—	(391,132)	—	(391,132)
BALANCE AT DECEMBER 31, 2008	51,549	515	319,336	(453,594)	(1,424)	(135,167)
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	899	—	1,424	2,323
Issuance of stock for cash upon exercise of options	66	1	680	—	—	681
Issuance of restricted shares, net of cancellations	835	8	(8)	—	—	—
Share-based compensation	—	—	4,590	—	—	4,590
Issuance of common stock pursuant to Employee Stock Purchase Plan	63	1	359	—	—	360
Disgorgement of stock sale profits	—	—	15	—	—	15
Net income (loss)	—	—	—	(47,298)	—	(47,298)
BALANCE AT DECEMBER 31, 2009	52,513	525	325,871	(500,892)	—	(174,496)
Issuance of stock for cash upon exercise of options	2,103	21	14,262	—	—	14,283
Issuance of restricted shares, net of cancellations	1,598	16	(16)	—	—	—
Share-based compensation	—	—	8,080	—	—	8,080
Issuance of common stock pursuant to Employee Stock Purchase Plan	28	—	376	—	—	376
Net income (loss)	—	—	—	67,520	—	67,520
BALANCE AT DECEMBER 31, 2010	56,242	$562	$348,573	$(433,372)	$ —	$(84,237)

See notes to consolidated financial statements.

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

	Years Ended December 31,		
	2008	2009	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(391,132)	$ (47,298)	$ 67,520
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	134,483	86,226	78,504
Impairment of oil and natural gas properties	641,000	—	—
Accretion of asset retirement obligations	4,203	5,765	6,241
Deferred income tax provision (benefit)	4,900	(8,400)	8,400
Share-based compensation	3,064	2,824	5,653
Amortization of deferred loan costs	3,344	2,862	2,362
Loss on extinguishment of debt	—	8,493	—
Amortization of bond discounts and other	519	479	734
Unrealized interest rate swap derivative (gains) losses	10,336	(1,803)	13,724
Unrealized commodity derivative (gains) losses and amortization of premiums and other comprehensive loss	(176,768)	96,496	(14,548)
Changes in operating assets and liabilities:			
Accounts receivable	14,291	7,491	4,251
Inventories	(1,984)	(2,205)	(419)
Other current assets	(63)	81	(463)
Income tax receivable	6,179	(2,570)	2,185
Other assets	1,558	112	128
Accounts payable and accrued liabilities	674	(10,860)	(12,013)
Net premiums paid on derivative contracts	(42,225)	(19,002)	(1,586)
Net cash provided by (used in) operating activities	212,379	118,691	160,673
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for oil and natural gas properties	(311,173)	(174,824)	(208,383)
Acquisitions of oil and natural gas properties	(14,279)	(22,794)	(4,112)
Expenditures for other property and equipment	(7,409)	(1,988)	(3,238)
Proceeds from sale of oil and natural gas properties	—	197,653	107,437
Net cash provided by (used in) investing activities	(332,861)	(1,953)	(108,296)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	260,052	276,562	135,000
Principal payments on long-term debt	(169,892)	(382,280)	(197,035)
Payments for deferred loan costs	(963)	(5,221)	(396)
Payments to retire debt	—	(6,627)	—
Proceeds from derivative premium financing	17,993	—	—
Proceeds from stock incentive plans and other	3,748	1,056	14,659
Net cash provided by (used in) financing activities	110,938	(116,510)	(47,772)
Net (decrease) increase in cash and cash equivalents	(9,544)	228	4,605
Cash and cash equivalents, beginning of period	9,735	191	419
Cash and cash equivalents, end of period	$ 191	$ 419	$ 5,024
Supplemental Disclosure of Cash Flow Information—			
Cash paid for interest	$ 55,350	$ 40,990	$ 39,402
Cash paid (received) for income taxes	$ 124	$ (3,430)	$ (11,753)
Supplemental Disclosure of Noncash Activities—			
(Decrease) increase in accrued capital expenditures	$ (12,477)	$ (14,968)	$ 5,138
Write off of deferred financing costs related to 8.75% senior notes	$ —	$ 1,866	$ —

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2008, 2009 AND 2010

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Venoco, Inc. ("Venoco" or 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 in California.

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. The Company has evaluated subsequent events and transactions for matters that may require recognition or disclosure in these financial statements.

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.

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, collectability is reasonably assured and evidenced by a contract. This generally occurs when a barge 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 transferred. 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, 2009 and 2010.

Other revenues primarily include pipeline revenues, barge sub-charter revenues and other miscellaneous revenues.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Accounts Receivable The components of accounts receivable include the following (in thousands):

	December 31,	
	2009	2010
Oil and natural gas sales related	$28,536	$22,652
Joint interest billings related	4,036	3,319
Other	2,181	4,431
Allowance for doubtful accounts	(900)	(800)
Total accounts receivable, net	$33,853	$29,602

The Company's accounts receivable result from (i) oil and natural gas sales to oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are dispersed among various customers and purchasers and most of the Company's significant purchasers are large companies with solid credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support the extension of credit. For most joint working interest partners, the Company may have the right of offset against related oil and natural gas revenues. As of December 31, 2010, 55%, 20% and 6% of the total accounts receivable balance was receivable from the Company's three major customers.

The following table provides the percentage of revenue derived from oil and natural gas sales to the Company's top four customers (the customers in each year are not necessarily the same from year to year):

	Years Ended December 31,		
	2008	2009	2010
Customer A	32%	41%	57%
Customer B	27%	27%	26%
Customer C	16%	10%	6%
Customer D	12%	5%	4%

Crude Oil Inventories Crude oil inventories are carried at the lower of current market value or cost. Inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition and location.

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.

Recent Accounting Pronouncements Regarding Oil and Natural Gas Resources

In December 2008, the SEC published revised rules regarding oil and gas reserves reporting requirements. The objective of the revised rules is to provide readers of financial statements with more meaningful and comprehensive understanding of oil and gas reserves. Key elements of the revised rules

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

include a change in the pricing used to estimate reserves at period end, certain revised definitions, optional disclosure of probable and possible reserves, allowance of the use of new technologies in the determination of reserves and additional disclosure requirements. The rules also revised the prices used for reserves in determining depletion and the full cost ceiling test from a period end price to a twelve month average of the first day of the month prices. The revised rules are effective for annual reporting periods ending on or after December 31, 2009. Application of the revised rules resulted in changes to the prices used to determine proved reserves at December 31, 2009 and 2010, as well as additional disclosures.

In January 2010, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") which amended existing oil and gas reserve accounting and disclosure guidance to align its requirements with the SEC's revised rules discussed above. The significant revisions involve revised definitions of oil and gas producing activities, changing the pricing used to estimate reserves at period end to a twelve month average of the first day of the month prices and additional disclosure requirements. In contrast to the SEC rule, the FASB does not permit the disclosure of probable and possible reserves in the supplemental oil and gas information in the notes to the financial statements. The amendments are effective for annual reporting periods ending on or after December 31, 2009 and 2010. Application of the revised rules is prospective and companies are not required to change prior period presentation to conform to the amendments. Application of the amended guidance resulted in changes to the prices used to determine proved reserves at December 31, 2009 and 2010, which did not result in significant changes to our oil and natural gas reserves.

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, 2008, 2009 and 2010 was $129.4 million, $81.3 million, and $74.1 million, respectively ($16.31, $10.80 and $11.13, 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 are established or impairment is determined. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The Company will continue to evaluate these properties and costs which will be transferred into the amortization base as the undeveloped areas are tested. The Company transferred $2.4 million, $9.7 million, and $13.7 million of unproved costs into the amortization base in 2008, 2009 and 2010, respectively, due to impairment. No interest costs were capitalized in 2008, 2009 or 2010 because the

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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. Effective December 31, 2009, the ceiling test is calculated using proved reserves based on a twelve month arithmetic average of the oil and natural gas prices in effect on the first of each month. For all periods prior to December 31, 2009, the ceiling test was calculated using proved reserves valued at the applicable period-end oil and natural gas prices. Due to lower oil and natural gas prices at December 31, 2008, the Company's net capitalized costs exceeded the ceiling by $641.0 million, net of income tax effects, and the Company recorded an impairment of oil and natural gas properties in the same amount. The Company did not record an impairment of oil and natural gas properties in 2009 or 2010, however, the Company could be required to recognize additional impairments of oil and natural gas properties in future periods if market prices of oil and natural gas decline.

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 $18.8 million, $25.1 million and $22.7 million directly related to its acquisition, exploration and development activities during 2008, 2009 and 2010, respectively.

Other Property and Equipment Other property and equipment, which includes buildings, drilling equipment, 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, 2008, 2009 and 2010 was $5.1 million, $4.9 million and $4.4 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. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are commercial banks that are parties to its revolving credit facility. The Company has elected not to apply hedge accounting to any of its derivative transactions and consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

The Company has also, as of December 31, 2010, entered into interest rate swap contracts to mitigate the risk of interest rate fluctuations on $500 million of borrowings under its variable rate credit facilities. The Company does not designate the interest rate swap contacts as hedges.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Asset Retirement Obligations The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the well is spud or acquired.

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.

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 if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

The Company recognizes 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 are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

Earnings Per Share Basic earnings (loss) per share is calculated by dividing net earnings (loss) attributable to common stock by the weighted average number of shares outstanding for the period (unvested restricted stock is excluded from the weighted average shares outstanding used in the basic earnings per share calculation). Under the treasury stock method, diluted earnings per share is calculated by dividing net earnings (loss) by the weighted average number of shares outstanding including all potentially dilutive common shares (unvested restricted stock and unexercised stock options). In the event of a net loss, no potential common shares are included in the calculation of shares outstanding, as their inclusion would be anti-dilutive.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company's unvested restricted stock awards contain nonforfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, the two class method will not have an effect on the Company's basic earnings per share.

The following table details the weighted average dilutive and anti-dilutive securities, which consist of options and unvested restricted stock, for the periods presented (in thousands):

	Years Ended December 31,		
	2008	2009	2010
Dilutive	—	—	4,539
Anti-dilutive	4,608	4,914	474

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

	Years Ended December 31,		
	2008	2009	2010
Net income (loss)	$(391,132)	$(47,298)	$67,520
Allocation of net income to unvested restricted stock	—	—	(3,177)
Net earnings (loss) attributable to common stock	$(391,132)	$(47,298)	$64,343
Basic weighted average common shares outstanding	50,486	50,805	52,249
Add: dilutive effect of stock options	—	—	769
Diluted weighted average common shares outstanding	50,486	50,805	53,018
Basic earnings per common share	$ (7.75)	$ (0.93)	$ 1.23
Diluted earnings per common share	$ (7.75)	$ (0.93)	$ 1.21

In February 2011, the Company issued 4.0 million shares of common stock in a public offering, which will increase the amount of weighted average common shares outstanding.

Stock-Based Compensation Stock-based compensation is measured at the estimated grant date fair value of the awards and is recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company estimates 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. Compensation expense is then adjusted based on the actual number of awards for which

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

the requisite service period is rendered. A market condition is not considered to be a vesting condition with respect to compensation expense. Therefore, an award is not deemed to be forfeited solely because a market condition is not satisfied.

Reclassifications The Company made certain reclassifications to its prior consolidated statements of operations to be consistent with the current presentation. The consolidated statements of operations were modified to reclassify oil gravity adjustments paid to other oil pipeline participants from transportation expense to oil and natural gas sales to more appropriately present the impact of oil gravity on the price received rather than as a component of transportation. These reclassifications had no impact on the Company's financial position, income (loss) before taxes or cash flows from operating, investing or financing activities.

2. ACQUISITIONS AND SALES OF PROPERTIES

Sale of Cat Canyon Field. In December 2010, the Company sold its interests in the Cat Canyon field in Southern California for $8.5 million (before closing adjustments). The Company applied the proceeds from the sale to repay $8.5 million of the principal balance on the second lien term loan. No gain or loss was recognized on the sale as the Company recorded the net proceeds as a reduction to the capitalized costs of its oil and natural gas properties.

Sales of Texas Assets. In April 2010, the Company signed certain Purchase and Sale Agreements ("PSAs") to divest its producing properties in Texas ("Texas Sales") for $98.1 million (after closing adjustments and related expenses), each with an effective date of January 1, 2010. The PSAs covered the Company's interests in the Manvel field, the Company's overriding royalty interest in the Hastings Complex and its other oil and natural gas producing properties in the Texas Gulf Coast. The sales closed in a series of transactions in the second quarter of 2010 and involved multiple purchasers, including Denbury Resources, Inc. ("Denbury"), which purchased the overriding royalty interest in the Hastings Complex. The aggregate net proceeds from the transactions were $98.1 million (after closing adjustments and related expenses). The Company used the proceeds from the sales to repay $66.9 million of the principal balance on the revolving credit facility and $30.7 million of the principal balance on the second lien term loan. The Company did not recognize a gain or loss for financial reporting purposes on the sale in accordance with the full cost method of accounting, but recorded the proceeds from the Texas Sales as a reduction to the capitalized cost of its oil and natural gas properties. As a result of the Texas Sales, the Company no longer has any interests in producing oil and natural gas properties in Texas. The Company did, however, retain its 22.3% reversionary working interest in the Hastings Complex as described below.

Sacramento Basin Asset Acquisition. In February 2009, the Company entered into a purchase and sale agreement to acquire certain natural gas producing properties in the Sacramento Basin. The transaction closed in June 2009 with a total purchase price of $21.4 million. The acquisition qualified as a business combination and was therefore recorded at the estimated fair value of the assets acquired and liabilities assumed.

Hastings Complex Sale. In February 2009, the Company completed the sale of its principal interests in the Hastings Complex to Denbury for approximately $197.7 million. As a result of the sale, the Company repaid all amounts then outstanding under the revolving credit facility and $5.5 million of

2. ACQUISITIONS AND SALES OF PROPERTIES (Continued)

the outstanding principal balance on the second lien term loan facility. The proceeds from the Hastings Complex sale were applied as a reduction of capitalized costs of oil and natural gas properties.

As a result of the sale, Denbury committed to a development plan related to a CO_2 enhanced recovery project that will require it to make minimum capital expenditures in the amount of $178.7 million by the end of 2014. As part of the plan, Denbury is responsible for providing the necessary CO_2. The Company retained an overriding royalty interest of 2.0% in the production from the properties, which, as described above, was subsequently sold to Denbury in the second quarter of 2010. In addition, the Company has the right to back-in to a working interest of approximately 22.3% in the CO_2 project after Denbury recoups certain costs.

3. LONG-TERM DEBT

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

	December 31,	
	2009	2010
Revolving credit agreement due January 2013	$ 57,860	$ 35,000
Second lien term loan due May 2014	494,485	455,311
11.50% senior notes due October 2017 (face value $150,000)	142,684	143,281
Total long-term debt	695,029	633,592
Less: current portion of long-term debt	—	—
Long-term debt, net of current portion	$695,029	$633,592

Revolving credit facility. In December 2009, the Company entered into the Third Amended and Restated Credit Agreement related to its $300 million revolving credit facility with a syndicate of banks ("revolving credit facility"). The facility has a maturity date of January 15, 2013 and the borrowing base (currently established at $125 million) is subject to redetermination twice each year, and may be redetermined at other times at the Company's request or at the request of the lenders. The facility is 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 is unconditionally guaranteed by each of the Company's operating subsidiaries other than Ellwood Pipeline, Inc. The collateral also secures the Company's obligations to hedging counterparties that are also lenders, or affiliates of lenders, under the facility. Loans designated as Base Rate Loans under the facility bear interest at a floating rate equal to (i) the greater of (x) the Bank of Montreal's announced base rate, (y) the overnight federal funds rate plus 0.50% and (z) the one-month LIBOR plus 1.5%, plus (ii) an applicable margin ranging from 0.75% to 1.50%, based upon utilization. Loans designated as LIBO Rate Loans under the facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 2.25% to 3.00%, based upon utilization. A commitment fee of 0.50% 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 current assets to current liabilities and debt to EBITDA.

3. LONG-TERM DEBT (Continued)

The borrowing base under the revolving credit facility has been allocated at various percentages to a syndicate of ten banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with events in the credit markets.

In February 2011, the Company repaid the outstanding balance of the revolving credit facility with proceeds from the issuance of 4.0 million shares of common stock (see note 8). As of February 18, 2011, the Company had available borrowing capacity of $121.1 million under the facility, net of $3.9 million in outstanding letters of credit.

Second lien term loan facility and 8.875% Senior notes. In May 2007, the Company entered into its $500.0 million senior secured second lien term loan facility (the "second lien term loan facility"), which was due to mature on May 8, 2014. Prior to repayment of the second lien term loan facility in February 2011 (see below), loans made under the second lien term loan facility were designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Loans 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 a market base rate, plus (ii) 3.00%. Loans designated as LIBO Rate Loans bear interest at LIBOR plus 4.00%.

The facility was 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 was unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. As a result of the Hastings Sale in February 2009, the Company was required to repay $5.5 million of the outstanding principal balance on the second lien term loan facility. Additionally, the Company repaid $39.2 million of principal under the facility in 2010 after the sales of its Texas producing properties and the Cat Canyon field.

In February 2011, the Company issued $500 million in 8.875% senior notes due in February 2019 at par. Concurrently with the sale of the 8.875% senior notes, the Company repaid the full outstanding principal balance of $455.3 million on the second lien term loan, plus accrued interest of $1.6 million. The 8.875% senior notes pay interest semi-annually in arrears on February 15 and August 15 of each year. The Company may redeem the notes prior to February 15, 2015 at a "make whole premium" defined in the indenture. Beginning February 15, 2015, the Company may redeem the notes at a redemption price of 104.438% of the principal amount and declining to 100% by February 15, 2017. The 8.875% senior notes are senior unsecured obligations and contain operational covenants that, among other things, limit the Company's ability to make investments, incur additional indebtedness or create liens on Company assets.

11.50% Senior notes. In October 2009, the Company issued $150.0 million of 11.50% senior notes due October 2017 at a price of 95.03% of par. The notes are senior unsecured 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 pay interest semi-annually in arrears on April 1 and October 1 of each year. The Company may redeem the senior notes prior to October 1, 2013 at a "make-whole price" defined in the indenture. Beginning October 1, 2013, the Company may redeem the notes at a redemption price equal to 105.75% of the principal amount and declining to 100% by October 1, 2016.

3. LONG-TERM DEBT (Continued)

The Company was in compliance with all debt covenants at December 31, 2010.

Scheduled annual maturities of long-term debt outstanding as of December 31, 2010 were as follows (in thousands):

Year Ending December 31 (in thousands):	
2011	$ —
2012	—
2013	35,000
2014	455,311
2015	—
Thereafter	143,281
	$633,592

The principal balance of the second lien term loan of $455.3 million, due in 2014, was repaid with proceeds from the issuance of $500 million in 8.875% senior notes in February 2011. The 8.875% notes are due in February 2019.

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Agreements. 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 may limit future revenues from favorable price movements. The Company may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of the Company's existing positions. The Company may use the proceeds from such transactions to secure additional contracts for periods in which the Company believes it has additional unmitigated commodity price risk.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are with multiple counterparties to minimize exposure to any individual counterparty. The Company generally has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with that counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. All of the counterparties to the Company's derivative contracts are also lenders, or affiliates of lenders, under its revolving credit facility. Collateral under the revolving credit facility supports the Company's collateral obligations under the Company's derivative contracts. Therefore, the Company is not required to post additional collateral when the Company is in a derivative liability position. The Company's revolving credit facility and derivative contracts contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

The Company has elected not to apply hedge accounting to any of its derivative transactions and, consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges.

Because a large portion of the Company's commodity derivatives did 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. As of December 31, 2009, the Company recognized all of the unrealized derivative fair value loss for derivative contracts previously designated as cash flow hedges which were recorded in accumulated other comprehensive loss.

The Company has paid premiums related to certain of its outstanding derivative contracts. These premiums are amortized into commodity derivative (gains) losses over the period for which the contracts are effective. At December 31, 2010, the balance of unamortized net derivative premiums paid was $15.3 million, of which $8.0 million, $6.6 million and $0.7 million will be amortized in 2011, 2012 and 2013, respectively.

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

	Years Ended December 31,		
	2008	2009	2010
Realized commodity derivative losses (gains)	$ 61,446	$(68,429)	$(53,501)
Amortization of commodity derivative premiums	6,256	22,661	24,808
Unrealized commodity derivative losses (gains) for changes in fair value	(184,459)	71,511	(39,356)
Commodity derivative losses (gains), net	$(116,757)	$ 25,743	$(68,049)

As of December 31, 2010, the Company had entered into swap, collar and option agreements related to its oil and natural gas production. The aggregate economic effects of those agreements are summarized below. Location and quality differentials attributable to the Company's properties are not included in the following prices. The agreements provide for monthly settlement based on the

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

differential between the agreement price and the actual NYMEX WTI (oil) or NYMEX Henry Hub (natural gas) price.

	Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Barrels/day	Weighted Avg. Prices per Bbl	MMBtu/day	Weighted Avg. Prices per MMBtu
January 1 – December 31, 2011:				
Swaps	—	$—	24,000	$4.44
Collars(1)	5,000	$50.00/$100.00	—	$—
Puts(1)	2,000	$50.00	36,000	$5.92
January 1 – December 31, 2012:				
Collars(1)	3,000	$60.00/$121.10	—	$—
Puts(1)	—	$—	37,300	$5.81
January 1 – December 31, 2013:				
Collars(1)	—	$—	20,000	$5.00/$7.02

(1) Reflects the impact of call spreads and purchased calls, which are transactions entered into for the purpose of modifying or eliminating the ceiling (or call) portion of certain collar arrangements.

The Company also uses natural gas basis swaps to fix the differential between the NYMEX Henry Hub price and the PG&E Citygate price, the index on which the majority of the Company's natural gas is sold. The Company's natural gas basis swaps as of December 31, 2010 are presented below:

	Floating Index	MMBtu/Day	Weighted Avg. Basis Differential to NYMEX HH (per MMBtu)
Basis Swaps:			
2011	PG&E Citygate	57,224	$0.11
2012	PG&E Citygate	47,400	$0.28

Subsequent to December 31, 2010, the Company entered certain oil collars, the weighted average terms of which are $83.64/$117.61 on 5,500 Bbls per day for the period from January 1, 2012 through December 31, 2012 and $81.79/$113.59 on 3,900 Bbls per day for the period from January 1, 2013 through December 31, 2013.

Interest Rate Swap. The Company had entered into interest rate swap transactions to lock in its interest cost on $500.0 million of variable rate borrowings through May 2014. Under the swap arrangements, the Company paid a fixed interest rate of 3.840% and received a floating interest rate based on the one-month LIBO rate, with settlements made monthly. As a result of the interest rate swap agreement, $500 million of the Company's variable rate debt effectively bore interest at a fixed rate of approximately 7.8%. The Company did not designate the interest rate swap as a hedge.

In February 2011, the Company repaid the principal balance outstanding on the second lien term loan from proceeds received from the issuance of 8.875% senior notes (see note 3), which reduced the

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

Company's debt subject to variable rate interest to any amounts which may be outstanding under the Company's revolving credit facility. As a result, the Company settled the interest rate swaps for $38.1 million in February 2011.

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

	Years Ended December 31,		
	2008	2009	2010
Realized interest rate derivative losses (gains)	$10,231	$18,479	$18,094
Unrealized interest rate derivative losses (gains)	10,336	(1,803)	13,724
Interest rate derivative losses (gains), net	$20,567	$16,676	$31,818

Fair Value of Derivative Instruments. The estimated fair values of derivatives included in the consolidated balance sheets at December 31, 2009 and 2010 are summarized below. The net fair value of the Company's derivatives changed by $2.5 million from a net liability of $11.5 million at December 31, 2009 to a net liability of $9.0 million at December 31, 2010, primarily due to (i) changes in the futures prices for oil and natural gas, which are used in the calculation of the fair value of commodity derivatives, (ii) changes to the Company's commodity derivative portfolio during 2010, and (iii) changes in the future interest rates used in the calculation of the fair value of interest rate derivatives. The Company does not offset asset and liability positions with the same counterparties within the financial statements, rather, all contracts are presented at their gross estimated fair value. As of the dates indicated, the Company's derivative assets and liabilities are presented below (in thousands). These balances represent the estimated fair value of the contracts. The Company has not

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

designated any of its derivative contracts as hedging instruments. The main headings represent the balance sheet captions for the contracts presented.

	December 31, 2009	December 31, 2010
Current Assets—Commodity derivatives:		
Oil derivative contracts	$ 12,461	$ 95
Gas derivative contracts	22,150	26,312
	34,611	26,407
Other Assets—Commodity derivatives:		
Oil derivative contracts	296	—
Gas derivative contracts	18,424	21,462
	18,720	21,462
Current Liabilities—Commodity and interest derivatives:		
Oil derivative contracts	(25,690)	(8,039)
Gas derivative contracts	(7,787)	(6,890)
Interest rate derivative contracts	(16,232)	(18,554)
	(49,709)	(33,483)
Commodity and interest derivatives:		
Oil derivative contracts	—	(1,921)
Gas derivative contracts	(4,968)	—
Interest rate derivative contracts	(10,108)	(21,509)
	(15,076)	(23,430)
Net derivative asset (liability)	$(11,454)	$ (9,044)

5. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received in the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. The FASB has established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

5. FAIR VALUE MEASUREMENTS (Continued)

Level 2—Pricing inputs are other than quoted prices in active markets included in level 1, but are either directly or indirectly observable as of the reported date and for substantially the full term of the instrument. Inputs may include quoted prices for similar assets and liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2010 (in thousands).

	Level 1	Level 2	Level 3	Fair Value as of December 31, 2010
Assets (Liabilities):				
Commodity derivative contracts	$—	$ 47,869	$—	$ 47,869
Commodity derivative contracts	—	(16,850)	—	(16,850)
Interest rate derivative contracts	—	(40,063)	—	(40,063)

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Contracts. The Company's commodity derivative instruments consist primarily of swaps, collars and option contracts for oil and natural gas. The Company values the derivative contracts using industry standard models, based on an income approach, which considers various assumptions including quoted forward prices and contractual prices for the underlying commodities, time value and volatility factors, as well as other relevant economic measures. Substantially all of the assumptions can be observed throughout the full term of the contracts, can be derived from observable data or are supportable by observable levels at which transactions are executed in the marketplace and are therefore designated as level 2 within the fair value hierarchy. The discount rates used in the assumptions include a component of non-performance risk. The Company utilizes the relevant counterparty valuations to assess the reasonableness of the calculated fair values.

Interest Rate Derivative Contracts. The Company's interest rate swap is valued using an industry standard model, based on an income approach that utilizes quoted forward prices for interest rates, time value and contractual interest rates per the swap contract. The discount rates used in the assumption include a component of non-performance risk. The interest rate swap is designated as level 2 within the fair value hierarchy. The Company utilizes the relevant counterparties' valuations to assess the reasonableness of the calculated fair values.

5. FAIR VALUE MEASUREMENTS (Continued)

Fair Value of Financial Instruments. The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, derivatives (discussed above) 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 carrying amount of the Company's revolving credit facility approximated fair value because the interest rate of the facility is variable. The fair value of the second lien term loan facility and the senior notes listed in the tables below were derived from available market data. This disclosure does not impact the Company's financial position, results of operations or cash flows (in thousands).

	December 31, 2009		December 31, 2010	
	Carrying Value	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Revolving credit agreement	$ 57,860	$ 57,860	$ 35,000	$ 35,000
Second lien term loan	494,485	445,037	455,311	434,253
11.50% senior notes	142,684	142,545	143,281	162,000

6. 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 the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. 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, 2009 and 2010 (in thousands):

	2009	2010
Asset retirement obligations at beginning of period	$80,579	$92,985
Revisions of estimated liabilities	3,221	(3,016)
Liabilities incurred or acquired	7,736	5,552
Liabilities settled	(1,323)	(1,078)
Disposition of properties	(2,993)	(6,463)
Accretion expense	5,765	6,241
Asset retirement obligations at end of period	92,985	94,221
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	(500)	(500)
Long-term asset retirement obligations	$92,485	$93,721

6. ASSET RETIREMENT OBLIGATIONS (Continued)

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 4% and 9%. The 2009 and 2010 revisions primarily relate to updated estimates for expected cash outflows and changes in the timing of obligations.

7. INCOME TAXES

The Company accounts for income taxes under the asset and liability approach prescribed by GAAP, which 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,		
	2008	2009	2010
Current:			
Federal	$ 2,700	$ (3,550)	$(9,400)
State	3,600	(2,450)	(300)
	6,300	(6,000)	(9,700)
Deferred:			
Federal	4,500	(8,400)	8,400
State	400	—	—
	4,900	(8,400)	8,400
Total income tax provision (benefit)	$11,200	$(14,400)	$(1,300)

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):

	Years Ended December 31,		
	2008	2009	2010
Income tax expense (benefit) at federal statutory rate	$(132,976)	$(21,594)	$ 23,177
State income taxes	(12,837)	(1,864)	2,328
Other	68	2,103	(286)
Valuation allowance	156,945	6,955	(26,519)
	$ 11,200	$(14,400)	$ (1,300)

7. INCOME TAXES (Continued)

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

	December 31,	
	2009	2010
Deferred income tax assets:		
Oil and gas properties	$ 100,091	$ 50,978
Net operating losses	47,606	66,459
Unrealized commodity derivative losses	8,926	—
Unrealized interest rate swap losses	10,015	15,431
Bad debts	168	132
Accrued liabilities	1,624	1,297
Share-based compensation	3,384	—
Charitable contributions	1,587	2,053
State tax benefit	—	171
Alternative minimum tax credits	99	9,901
Valuation allowance	(163,900)	(137,381)
	9,600	9,041
Deferred income tax liabilities:		
Unrealized commodity derivative gains	—	(6,116)
Share-based compensation	—	(1,607)
Prepaid expenses	(1,200)	(1,318)
	(1,200)	(9,041)
Net deferred income tax assets (liabilities)	8,400	—
Net current deferred tax asset	8,400	—
Noncurrent deferred tax asset	$ —	$ —

The Company has net operating loss carryovers as of December 31, 2010 of $196.8 million for federal income tax purposes and $170.2 million for financial reporting purposes. The difference of $26.6 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. 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 2030. The Company provided a valuation allowance against its net deferred tax assets of $137.4 million as of December 31, 2010, since it cannot conclude that it is more likely than not that $137.4 million of the net deferred tax assets will be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods.

7. INCOME TAXES (Continued)

The Company's federal income tax returns for the 2003, 2004 and 2005 tax years have been examined by the U.S. Internal Revenue Service ("IRS"). In the second quarter of 2010, the IRS adjusted the Company's taxable income for the tax years 2005 through 2008 for disallowed deductions from the 2003 and 2004 examinations (no adjustments resulted from the 2005 examination). As part of that process with the IRS, the Company carried back net operating losses ("NOL") to tax years 2003 through 2005, which resulted in federal tax refunds of $8.6 million. Although the IRS did not examine the 2006 through 2008 tax years, it did conduct an analysis of significant transactions and other significant income and deductions for those years in connection with the Company's NOL carryback claims. The 2007 through 2010 tax years remain open to examination by the IRS.

During the third quarter of 2010, the California Franchise Tax Board ("FTB") completed an examination of the Company's 2003 and 2004 California income tax returns. No adjustments resulted from this examination other than adjustments related to the finalization of the federal examinations discussed above, which the Company had previously provided for in its liability for uncertain state tax positions. The 2006 through 2010 tax years remain open to examination by the various state jurisdictions.

Due to the finalization of the 2003, 2004 and 2005 IRS examinations, the NOL carryback claims filed with the IRS and the finalization of the 2003 and 2004 FTB examinations, the Company believes that it has no liability for uncertain tax positions.

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

	Years Ended December 31,	
	2009	2010
Balance at beginning of period	$200	$ 200
Additions based on tax positions related to the current year	—	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	—
Settlements	—	(200)
Balance at end of period	$200	$ —

The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in interest expense. The Company recognized interest expense of $0.3 million during the year ended December 31, 2009 related to the settlement of the 2003 and 2004 IRS examinations and $0.1 million during the year ended December 31, 2010 related to the settlement of the 2003 and 2004 FTB examinations.

8. CAPITAL STOCK

The Company had 61.3 million shares of common stock issued or reserved for issuance at December 31, 2010. At December 31, 2010, the Company had 56.2 million common shares issued and outstanding, of which 2.6 million shares are restricted stock granted under the Company's 2005 stock incentive plan. At December 31, 2010, the Company had approximately 1.1 million options outstanding

8. CAPITAL STOCK (Continued)

and 3.3 million shares available to be issued pursuant to awards under its stock incentive plans, including the 2008 Employee Stock Purchase Plan.

In February 2011, the Company sold 4.0 million shares of common stock in a public offering at $18.75 per share and received approximately $71.4 million in net proceeds, after underwriting discounts and estimated expenses. The underwriters have the option to purchase up to 0.6 million additional shares to cover any over-allotments.

9. SHARE-BASED PAYMENTS

The Company has granted options to directors, certain employees and officers of the Company other than its CEO, under its 2000 and 2005 Stock Plans (the "Stock Plans"). As of December 31, 2010, there are a total of 1,093,758 options outstanding with a weighted average exercise price of $13.07 ($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 typically have a maximum life of 10 years. The options will generally vest upon a change in control of the Company.

In 2009 the Company implemented a non-compensatory Employee Stock Purchase Plan (the "ESPP"), authorizing 1.5 million shares of common stock to be issued under the ESPP. Participation in the ESPP is open to all employees, other than executive officers, who meet limited qualifications. Under the terms of the ESPP, employees are able to purchase Company stock at a 5% discount as determined by the fair market value of the Company's stock on the last trading day of each purchase period. Individual employees are limited to $25,000 of common stock purchased in any calendar year.

As of December 31, 2010, there were a total of 2,603,250 shares of restricted stock outstanding under the Company's 2005 stock incentive plan, including 859,517 shares granted to its CEO. The restricted shares generally have a requisite service period of four years. The grant date fair value of restricted stock subject to service conditions only is determined by the Company's closing stock price on the day prior to the date of grant. The vesting of 1,475,029 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 derived using a Monte Carlo technique. The weighted average fair value of 954,065 awards with market conditions granted in February 2010 was estimated to be $10.65 per share. The estimated grant date fair values of restricted share awards are recognized as expense over the requisite service periods. The Company's total shareholder return for the measurement period of December 31, 2009 through December 31, 2010 was below the minimum threshold, therefore, none of the market based restricted shares will vest for this measurement period.

9. SHARE-BASED PAYMENTS (Continued)

The Company recognized total share-based compensation costs as follows (in thousands):

	Years Ended December 31,		
	2008	2009	2010
General and administrative expense	$ 5,030	$ 3,890	$ 6,930
Oil and natural gas production expense	680	700	1,150
Total share-based compensation costs	5,710	4,590	8,080
Less: share-based compensation costs capitalized	(2,646)	(1,766)	(2,427)
Share-based compensation expensed	$ 3,064	$ 2,824	$ 5,653

As of December 31, 2010, there was $0.1 million of total unrecognized compensation cost related to stock options which is expected to be amortized over a weighted-average period of 0.4 years and $16.3 million of total unrecognized compensation cost related to restricted stock which is expected to be amortized over a weighted-average period of 2.9 years.

The following summarizes the Company's stock option activity for the years ended December 31, 2008, 2009 and 2010:

	Years Ended December 31,						
	2008		2009		2010		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value of Options(1) (in thousands)
Outstanding, start of period	4,159,463	$ 9.19	3,504,263	$ 9.16	3,301,903	$ 8.92	
Granted	—	—	—	—	—	—	
Exercised	(450,460)	$ 6.59	(66,560)	$10.23	(2,103,195)	$ 6.79	
Cancelled	(204,740)	$15.50	(135,800)	$11.46	(104,950)	$ 8.50	
Outstanding, end of period	3,504,263	$ 9.16	3,301,903	$ 8.92	1,093,758	$13.07	$5,886
Exercisable, end of period	2,683,110	$ 8.77	3,128,153	$ 8.50	1,045,258	$12.90	$5,806

(1) The intrinsic value of a stock option is the amount by which the market value exceeds the exercise price.

9. SHARE-BASED PAYMENTS (Continued)

Additional information related to options outstanding at December 31, 2010 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 . . .	141,301	4.1	$ 6.04	141,301	4.1	$ 6.04
$8.00–$8.68 . . .	233,537	3.3	$ 8.26	233,537	3.3	$ 8.26
$10.67–$14.97 . .	240,000	5.4	$12.77	219,000	5.3	$12.56
$15.00–$20.00 . .	478,920	5.5	$17.64	451,420	5.5	$17.60
	1,093,758	4.8	$13.07	1,045,258	4.8	$12.90

The aggregate intrinsic value of options exercised in 2008, 2009 and 2010 was $7.1 million, $0.2 million and $23.3 million, respectively.

The following summarizes the Company's unvested stock option award activity for the year ended December 31, 2010.

Non-vested stock options	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2010	173,750	$7.54
Granted	—	—
Vested	(117,760)	$7.53
Forfeited	(7,490)	$7.98
Non-vested at December 31, 2010	48,500	$7.48

The following summarizes the Company's unvested restricted stock award activity for the years ended December 31, 2008, 2009 and 2010.

	Years Ended December 31,					
	2008		2009		2010	
Non-vested restricted stock	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Non-vested, start of period	370,785	$14.32	851,545	$12.65	1,594,156	$ 7.20
Granted	553,693	$11.74	895,376	$ 2.94	1,860,435	$11.81
Vested	(36,891)	$15.52	(92,410)	$13.82	(589,134)	$ 9.10
Forfeited	(36,042)	$13.37	(60,355)	$10.86	(262,207)	$10.75
Non-vested, end of period	851,545	$12.65	1,594,156	$ 7.20	2,603,250	$ 9.70

10. RELATED PARTY TRANSACTIONS

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 (the Company's current Chief Executive Officer) and an affiliate of the stockholder, including a ground lease and a development agreement relating to the property. The fair value of the property at the date of the dividend was estimated to be $5.0 million after taking into consideration the encumbrance for the ground lease and other factors. In December 2008, the Company repurchased the Bluffs Property from the affiliate of the stockholder for $5.3 million. The Company intends to continue its oil and gas operations on the property. An independent third party appraisal was obtained which valued the unencumbered land in excess of the purchase price. As a result of the transaction, the ground lease and the development agreement were both cancelled and the remaining unamortized leasehold interest of $4.7 million was recorded to property, plant and equipment.

In December 2008, the Company entered into an agreement with an affiliate of its Chief Executive Officer, pursuant to which the affiliate paid to the Company $0.9 million which equaled the amount of profits the affiliate was deemed to have realized under Section 16(b) of the Securities and Exchange Act of 1934, as amended, with respect to transactions involving the Company's common stock.

In 2006, the Company paid a dividend consisting of 100% of its membership interest in 6267 Carpinteria Avenue, LLC ("6267 Carpinteria") to its then sole stockholder, a trust controlled by the Company's Chief Executive Officer. 6267 Carpinteria owns the office building and related land used by the Company in Carpinteria, California. 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 $1.2 million per year through 2019.

11. COMMITMENTS

Leases—The Company has entered into lease agreements for office space, an office building, and a parcel of land adjacent to Ellwood pier used for pier access. As of December 31, 2010, future minimum lease payments under operating leases that have initial or remaining non-cancelable terms in excess of one year are $2.7 million in 2011, $2.7 million in 2012, $2.9 million in 2013, $2.0 million in 2014, $1.9 million in 2015 and $8.3 million thereafter. Net rent expense incurred for office space and the office building was $3.4 million, $3.8 million and $2.5 million in 2008, 2009 and 2010, respectively.

12. CONTINGENCIES

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

12. CONTINGENCIES (Continued)

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 grounds 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 2011. The Company vigorously defended the actions, and will continue to do so until they are resolved. Certain defendants have made claims for indemnity for events occurring prior to 1995, which the Company is disputing. The Company cannot predict the cost of these indemnity claims 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 judgment, 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. That decision was upheld on appeal. 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, the Company will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

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

In 2004 the California State Lands Commission (the "SLC") initiated an audit of the Company's royalty payments for the period from August 1, 1997 through December 31, 2003 on oil and gas produced from the South Ellwood Field, State Leases 3120 and 3240 (the "Leases"). The audit period

12. CONTINGENCIES (Continued)

was subsequently extended through September 2009. In December 2009, the Company was notified that the SLC's audit for the period January 2004 through September 2009 (the "Audit Period") indicated that the Company underpaid royalties due on oil and gas production from the Leases during the Audit Period by approximately $5.8 million. Based on the Company's review of the SLC's audit contentions and additional historical records, the Company believes that it may have overpaid royalties due on oil and gas production during the Audit Period and for prior periods and may be owed a refund of such overpayments. The Company believes the position of the SLC is without merit and it intends to vigorously contest the audit findings and to enforce its rights for refunds of royalties it may have overpaid during the Audit Period and prior periods. The Company has not accrued any amounts related to the SLC audit contentions or potential refunds.

Other

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

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2009 and 2010 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Year Ended December 31, 2009:				
Revenues	$57,890	$ 62,395	$69,710	$80,499
Income (loss) from operations	(1,494)	5,956	7,974	20,624
Net income (loss)	25,205	(59,477)	(5,272)	(7,754)
Basic earnings per common share	$ 0.49	$ (1.17)	$ (0.10)	$ (0.15)
Diluted earnings per common share	$ 0.49	$ (1.17)	$ (0.10)	$ (0.15)

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Year Ended December 31, 2010:				
Revenues	$82,756	$70,058	$70,412	$72,066
Income (loss) from operations	27,638	12,402	15,956	16,939
Net income (loss)	43,988	3,709	15,388	4,435
Basic earnings per common share	$ 0.83	$ 0.07	$ 0.28	$ 0.08
Diluted earnings per common share	$ 0.81	$ 0.07	$ 0.28	$ 0.08

13. QUARTERLY FINANCIAL DATA (UNAUDITED) (Continued)

During the quarter ended December 31, 2009, the Company recognized a loss on the extinguishment of debt of $7.9 million related to the refinancing of the $150 million senior notes which occurred in October 2009.

14. 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 the FASB guidance regarding Oil and Gas Reserve Estimation and Disclosures. At December 31, 2010, 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, 2008, 2009 and 2010 were prepared by DeGolyer and MacNaughton, independent petroleum reserve engineers.

Capitalized Costs of Oil and Natural Gas Properties

	As of December 31,		
	2008	2009	2010
		(in thousands)	
Unevaluated properties(1)	$ 30,228	$ 31,934	$ 42,686
Properties subject to amortization	1,641,571	1,640,967	1,734,190
Total capitalized costs	1,671,799	1,672,901	1,776,876
Accumulated depreciation, depletion and amortization	(351,334)	(1,073,664)	(1,147,688)
Impairment	(641,000)	—	—
Net capitalized costs	$ 679,465	$ 599,237	$ 629,188

(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 three years.

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, 2008, 2009 and 2010 include capitalized general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $18.8 million, $25.1 million and $22.7 million, respectively. Costs incurred also include

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

asset retirement costs of $24.2 million, $6.6 million and $(5.0) million during the years ended December 31, 2008, 2009 and 2010, respectively.

	Years Ended December 31,		
	2008	2009	2010
		(in thousands)	
Property acquisition and leasehold costs:			
Unevaluated property	$ 20,561	$ 8,972	$ 22,673
Proved property	23,035	22,784	1,048
Exploration costs	117,905	61,547	88,966
Development costs	178,767	97,782	102,283
Total costs incurred	$340,268	$191,085	$214,970

Estimated Net Quantities of Natural Gas and Oil Reserves

In January 2010, the FASB issued an ASU to amend existing oil and gas reserve accounting and disclosure guidance to align its requirements with the SEC's revised rules regarding oil and gas reserve reporting requirements. The significant revisions involve revised definitions of oil and gas producing activities, changing the pricing used to estimate reserves at period end to a twelve month arithmetic average of the first day of the month prices and additional disclosure requirements. In contrast to the SEC rule, the FASB does not permit the disclosure of probable and possible reserves in the supplemental oil and gas information in the notes to the financial statements. The amendments are effective for annual reporting periods ending on or after December 31, 2009. Application of the revised rules is prospective and companies were not required to change prior period presentation to conform to the amendments. Application of the amended guidance has only resulted in changes to the prices used to determine proved reserves at December 31, 2009 and 2010, which did not result in a significant change to the Company's proved oil and natural gas reserves.

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

The following table sets forth the Company's net proved reserves, including changes, proved developed reserves and proved undeveloped reserves (all within the United States) at the end of each of the three years in the periods ended December 31, 2008, 2009 and 2010.

	Crude Oil, Liquids and Condensate (MBbls)			Natural Gas (MMcf)		
	2008(1)	2009(2)	2010(3)	2008(1)	2009(2)	2010(3)
Beginning of the year reserves	64,176	58,159	51,966	214,605	236,166	278,082
Revisions of previous estimates	(5,202)	3,723	(1,783)	(4,880)	7,965	(12,097)
Extensions and discoveries(4)	3,177	874	—	47,223	38,532	27,749
Purchases of reserves in place	99	—	53	2,268	20,548	—
Production	(4,091)	(3,402)	(2,792)	(23,050)	(24,748)	(23,196)
Sales of reserves in place	—	(7,388)	(4,873)	—	(381)	(15,375)
End of year reserves	58,159	51,966	42,571	236,166	278,082	255,163
Proved developed reserves:						
Beginning of year	44,730	34,468	29,309	96,522	107,418	126,671
End of year	34,468	29,309	22,270	107,418	126,671	122,928
Proved undeveloped reserves:						
Beginning of year	19,446	23,691	22,657	118,083	128,749	151,411
End of year	23,691	22,657	20,301	128,749	151,411	132,235

(1) Unescalated year-end posted prices of (i) \$44.60 per Bbl for oil and natural gas liquids and \$5.62 per MMBtu for natural gas were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at prices of \$36.54 per Bbl for oil, \$35.96 per Bbl for natural gas liquids and \$5.35 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2008.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of \$61.04 per Bbl for oil and natural gas liquids and \$3.87 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at prices of \$51.15 per Bbl for oil, \$37.98 per Bbl for natural gas liquids and \$3.80 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2009.

(3) Unescalated twelve month arithmetic average of the first day of the month posted prices of \$79.43 per Bbl for oil and natural gas liquids and \$4.38 per MMBtu for natural gas were adjusted in note (1) above to arrive at prices of \$69.18 per Bbl for oil, \$59.85 per Bbl for natural gas liquids and \$4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

(4) Extensions for the years ended December 31, 2008, 2009 and 2010 include 4,962 MMcf, 32,001 MMcf and 8,748 MMcf, respectively, resulting from the Company's infill program in the Sacramento Basin.

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

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 information disclosed, as prescribed by the Oil and Gas Reserve Estimation and Disclosure guidance issued by the FASB, 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 the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves as of December 31, 2009 and 2010. The estimated future cash flows for the year ended December 31, 2008 are compiled by applying the year-end crude oil and natural gas prices 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.

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

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,		
	2008	2009	2010
		(in thousands)	
Future cash inflows	$ 3,387,228	$ 3,682,214	$ 4,037,386
Future production costs	(1,652,888)	(1,490,694)	(1,348,007)
Future development and abandonment costs	(636,285)	(676,801)	(620,073)
Future income taxes	(10,576)	(229,549)	(462,093)
Future net cash flows	1,087,479	1,285,170	1,607,213
10% annual discount for estimated timing of cash flows	(477,383)	(592,365)	(704,312)
Standardized measure of discounted future net cash flows	$ 610,096	$ 692,805	$ 902,901

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

	Years Ended December 31,		
	2008	2009	2010
		(in thousands)	
Beginning of the year	$ 1,655,641	$ 610,096	$ 692,805
Changes in prices and production costs	(1,599,448)	214,179	465,538
Revisions of previous quantity estimates	(60,099)	59,878	(65,495)
Changes in future development costs	(92,391)	(11,270)	11,724
Development costs incurred during the period	56,328	49,194	50,740
Extensions, discoveries and improved recovery, net of related costs	110,378	47,177	55,269
Sales of oil and natural gas, net of production costs	(400,456)	(158,659)	(190,550)
Accretion of discount	238,875	61,011	84,065
Net change in income taxes	697,089	(101,663)	(117,547)
Sale of reserves in place	—	(55,600)	(71,765)
Purchases of reserves in place	4,766	15,737	1,144
Production timing and other	(587)	(37,275)	(13,027)
End of year	$ 610,096	$ 692,805	$ 902,901

15. GUARANTOR FINANCIAL INFORMATION

All subsidiaries of the Company other than Ellwood Pipeline Inc. ("Guarantors") have fully and unconditionally guaranteed, on a joint and several basis, the Company's obligations under its 11.50% senior notes. Ellwood Pipeline, Inc. 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, 2010. 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.

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS AT DECEMBER 31, 2009 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 418	$ 1	$ —	$ —	$ 419
Accounts receivable	29,453	3,939	461	—	33,853
Inventories	5,813	326	—	—	6,139
Other current assets	4,276	—	—	—	4,276
Income taxes receivable	3,116	—	—	—	3,116
Deferred income taxes	8,400	—	—	—	8,400
Commodity derivatives	34,611	—	—	—	34,611
TOTAL CURRENT ASSETS	86,087	4,266	461	—	90,814
PROPERTY, PLANT & EQUIPMENT, NET	697,270	(80,955)	3,115	—	619,430
COMMODITY DERIVATIVES	18,720	—	—	—	18,720
INVESTMENTS IN AFFILIATES	512,074	—	—	(512,074)	—
OTHER	10,235	344	—	—	10,579
TOTAL ASSETS	$1,324,386	$ (76,345)	$ 3,576	$(512,074)	$ 739,543
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 52,129	$ 4,726	$ —	$ —	$ 56,855
Interest payable	4,885	—	—	—	4,885
Commodity and interest derivatives	49,709	—	—	—	49,709
TOTAL CURRENT LIABILITIES:	106,723	4,726	—	—	111,449
LONG-TERM DEBT	695,029	—	—	—	695,029
COMMODITY AND INTEREST DERIVATIVES	15,076	—	—	—	15,076
ASSET RETIREMENT OBLIGATIONS	84,925	6,638	922	—	92,485
INTERCOMPANY PAYABLES (RECEIVABLES)	597,129	(549,473)	(47,656)	—	—
TOTAL LIABILITIES	1,498,882	(538,109)	(46,734)	—	914,039
TOTAL STOCKHOLDERS' EQUITY	(174,496)	461,764	50,310	(512,074)	(174,496)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,324,386	$ (76,345)	$ 3,576	$(512,074)	$ 739,543

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS AT DECEMBER 31, 2010 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 5,024	$ —	$ —	$ —	$ 5,024
Accounts receivable	29,082	121	399	—	29,602
Inventories	6,229	—	—	—	6,229
Other current assets	4,585	—	—	—	4,585
Income taxes receivable	931	—	—	—	931
Deferred income taxes	—	—	—	—	—
Commodity derivatives	26,407	—	—	—	26,407
TOTAL CURRENT ASSETS	72,258	121	399	—	72,778
PROPERTY, PLANT & EQUIPMENT, NET	825,844	(183,940)	6,140	—	648,044
COMMODITY DERIVATIVES	21,462	—	—	—	21,462
INVESTMENTS IN AFFILIATES	520,958	—	—	(520,958)	—
OTHER	8,578	61	—	—	8,639
TOTAL ASSETS	$1,449,100	$(183,758)	$ 6,539	$(520,958)	$750,923
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 45,346	$ 50	$ —	$ —	$ 45,396
Interest payable	5,538	—	—	—	5,538
Commodity and interest derivatives	33,483	—	—	—	33,483
TOTAL CURRENT LIABILITIES:	84,367	50	—	—	84,417
LONG-TERM DEBT	633,592	—	—	—	633,592
COMMODITY AND INTEREST DERIVATIVES	23,430	—	—	—	23,430
ASSET RETIREMENT OBLIGATIONS	91,127	1,604	990	—	93,721
INTERCOMPANY PAYABLES (RECEIVABLES)	700,821	(650,346)	(50,475)	—	—
TOTAL LIABILITIES	1,533,337	(648,692)	(49,485)	—	835,160
TOTAL STOCKHOLDERS' EQUITY	(84,237)	464,934	56,024	(520,958)	(84,237)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,449,100	$(183,758)	$ 6,539	$(520,958)	$750,923

VENOCO, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
YEARS ENDED DECEMBER 31, 2008, 2009 AND 2010

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2008
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 413,815	$140,455	$ —	$ —	$ 554,270
Other	3,121	30	5,451	(4,999)	3,603
Total revenues	416,936	140,485	5,451	(4,999)	557,873
EXPENSES:					
Lease operating expense	87,201	44,432	2,140	—	133,773
Production and property taxes	7,852	7,853	26	—	15,731
Transportation expense	8,990	24	—	(4,703)	4,311
Depletion, depreciation and amortization	110,344	24,047	92	—	134,483
Impairment of oil and natural gas properties	641,000	—	—	—	641,000
Accretion of asset retirement obligations	3,460	680	63	—	4,203
General and administrative, net of amounts capitalized	39,792	3,309	296	(296)	43,101
Total expenses	898,639	80,345	2,617	(4,999)	976,602
Income from operations	(481,703)	60,140	2,834	—	(418,729)
FINANCING COSTS AND OTHER:					
Interest expense, net	57,260	(18)	(3,193)	—	54,049
Amortization of deferred loan costs	3,344	—	—	—	3,344
Interest rate derivative losses, net	20,567	—	—	—	20,567
Commodity derivative losses (gains), net	(116,757)	—	—	—	(116,757)
Total financing costs and other	(35,586)	(18)	(3,193)	—	(38,797)
Equity in subsidiary income	41,034	—	—	(41,034)	—
Income (loss) before income taxes	(405,083)	60,158	6,027	(41,034)	(379,932)
Income tax provision (benefit)	(13,951)	22,860	2,291	—	11,200
Net income (loss)	$(391,132)	$ 37,298	$ 3,736	$(41,034)	$(391,132)

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2009
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$235,702	$31,461	$ —	$ —	$267,163
Other	2,810	114	5,667	(5,260)	3,331
Total revenues	238,512	31,575	5,667	(5,260)	270,494
EXPENSES:					
Lease operating expense	81,284	11,935	1,994	—	95,213
Production and property taxes	9,494	537	97	—	10,128
Transportation expense	8,025	77	—	(4,939)	3,163
Depletion, depreciation and amortization	78,544	7,527	155	—	86,226
Accretion of asset retirement obligations	5,256	456	53	—	5,765
General and administrative, net of amounts capitalized	34,058	2,881	321	(321)	36,939
Total expenses	216,661	23,413	2,620	(5,260)	237,434
Income from operations	21,851	8,162	3,047	—	33,060
FINANCING COSTS AND OTHER:					
Interest expense, net	44,669	(6)	(3,679)	—	40,984
Amortization of deferred loan costs	2,862	—	—	—	2,862
Interest rate derivative losses, net	16,676	—	—	—	16,676
Loss on extinguishment of debt	8,493	—	—	—	8,493
Commodity derivative losses (gains), net	25,743	—	—	—	25,743
Total financing costs and other	98,443	(6)	(3,679)	—	94,758
Equity in subsidiary income	9,234	—	—	(9,234)	—
Income (loss) before income taxes	(67,358)	8,168	6,726	(9,234)	(61,698)
Income tax provision (benefit)	(20,060)	3,104	2,556	—	(14,400)
Net income (loss)	$(47,298)	$ 5,064	$ 4,170	$(9,234)	$(47,298)

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2010
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$280,028	$10,580	$ —	$ —	$290,608
Other	4,273	82	4,986	(4,657)	4,684
Total revenues	284,301	10,662	4,986	(4,657)	295,292
EXPENSES:					
Lease operating expenses	79,624	2,724	1,907	—	84,255
Production and property taxes	6,153	405	143	—	6,701
Transportation expense	13,401	13	—	(4,312)	9,102
Depletion, depreciation and amortization	76,105	1,856	543	—	78,504
Accretion of asset retirement obligations	5,914	259	68	—	6,241
General and administrative, net of amounts capitalized	35,220	2,235	444	(345)	37,554
Total expenses	216,417	7,492	3,105	(4,657)	222,357
Income from operations	67,884	3,170	1,881	—	72,935
FINANCING COSTS AND OTHER:					
Interest expense, net	44,418	(1)	(3,833)	—	40,584
Amortization of deferred loan costs	2,362	—	—	—	2,362
Interest rate derivative losses, net	31,818	—	—	—	31,818
Commodity derivative losses (gains), net	(68,049)	—	—	—	(68,049)
Total financing costs and other	10,549	(1)	(3,833)	—	6,715
Equity in subsidiary income	5,509	—	—	(5,509)	—
Income (loss) before income taxes	62,844	3,171	5,714	(5,509)	66,220
Income tax provision (benefit)	(4,676)	1,205	2,171	—	(1,300)
Net income (loss)	$ 67,520	$ 1,966	$ 3,543	$(5,509)	$ 67,520

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2008 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 111,964	$ 94,169	$ 6,246	$—	$ 212,379
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(272,641)	(38,514)	(18)	—	(311,173)
Acquisitions of oil and natural gas properties	(11,857)	(2,422)	—	—	(14,279)
Expenditures for property and equipment and other	(7,253)	(156)	—	—	(7,409)
Net cash provided by (used in) investing activities	(291,751)	(41,092)	(18)	—	(332,861)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	60,277	(54,049)	(6,228)	—	—
Proceeds from long-term debt	260,052	—	—	—	260,052
Principal payments on long-term debt	(169,892)	—	—	—	(169,892)
Payments for deferred loan costs	(963)	—	—	—	(963)
Proceeds from derivative premium financing	17,993	—	—	—	17,993
Proceeds from stock incentive plans and other	3,748	—	—	—	3,748
Net cash provided by (used in) financing activities	171,215	(54,049)	(6,228)	—	110,938
Net increase (decrease) in cash and cash equivalents	(8,572)	(972)	—	—	(9,544)
Cash and cash equivalents, beginning of period	8,762	973	—	—	9,735
Cash and cash equivalents, end of period	$ 190	$ 1	$ —	$—	$ 191

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2009 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 88,414	$ 23,804	$ 6,473	$—	$ 118,691
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(160,069)	(12,699)	(2,056)	—	(174,824)
Acquisitions of oil and natural gas properties	(22,794)	—	—	—	(22,794)
Expenditures for property and equipment and other	(1,802)	(186)	—	—	(1,988)
Proceeds from sale of oil and natural gas properties	—	197,653	—	—	197,653
Net cash provided by (used in) investing activities	(184,665)	184,768	(2,056)	—	(1,953)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	212,989	(208,572)	(4,417)	—	—
Proceeds from long-term debt	276,562	—	—	—	276,562
Principal payments on long-term debt	(382,280)	—	—	—	(382,280)
Payments for deferred loan costs	(5,221)	—	—	—	(5,221)
Payments to retire debt	(6,627)	—	—	—	(6,627)
Proceeds from stock incentive plans and other	1,056	—	—	—	1,056
Net cash provided by (used in) financing activities	96,479	(208,572)	(4,417)	—	(116,510)
Net increase (decrease) in cash and cash equivalents	228	—	—	—	228
Cash and cash equivalents, beginning of period	190	1	—	—	191
Cash and cash equivalents, end of period	$ 418	$ 1	$ —	$—	$ 419

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS FOR THE YEAR ENDED DECEMBER 31, 2010 (in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 149,248	$ 5,037	$ 6,388	$—	$ 160,673
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(203,814)	(1,001)	(3,568)	—	(208,383)
Acquisitions of oil and natural gas properties	(4,112)	—	—	—	(4,112)
Expenditures for property and equipment and other	(3,238)	—	—	—	(3,238)
Proceeds from sale of oil and natural gas properties	8,476	98,961	—	—	107,437
Net cash provided by (used in) investing activities	(202,688)	97,960	(3,568)	—	(108,296)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	105,818	(102,998)	(2,820)	—	—
Proceeds from long-term debt	135,000	—	—	—	135,000
Principal payments on long-term debt	(197,035)	—	—	—	(197,035)
Payments for deferred loan costs	(396)	—	—	—	(396)
Proceeds from stock incentive plans and other	14,659	—	—	—	14,659
Net cash provided by (used in) financing activities	58,046	(102,998)	(2,820)	—	(47,772)
Net increase (decrease) in cash and cash equivalents	4,606	(1)	—	—	4,605
Cash and cash equivalents, beginning of period	418	1	—	—	419
Cash and cash equivalents, end of period	$ 5,024	$ —	$ —	$—	$ 5,024

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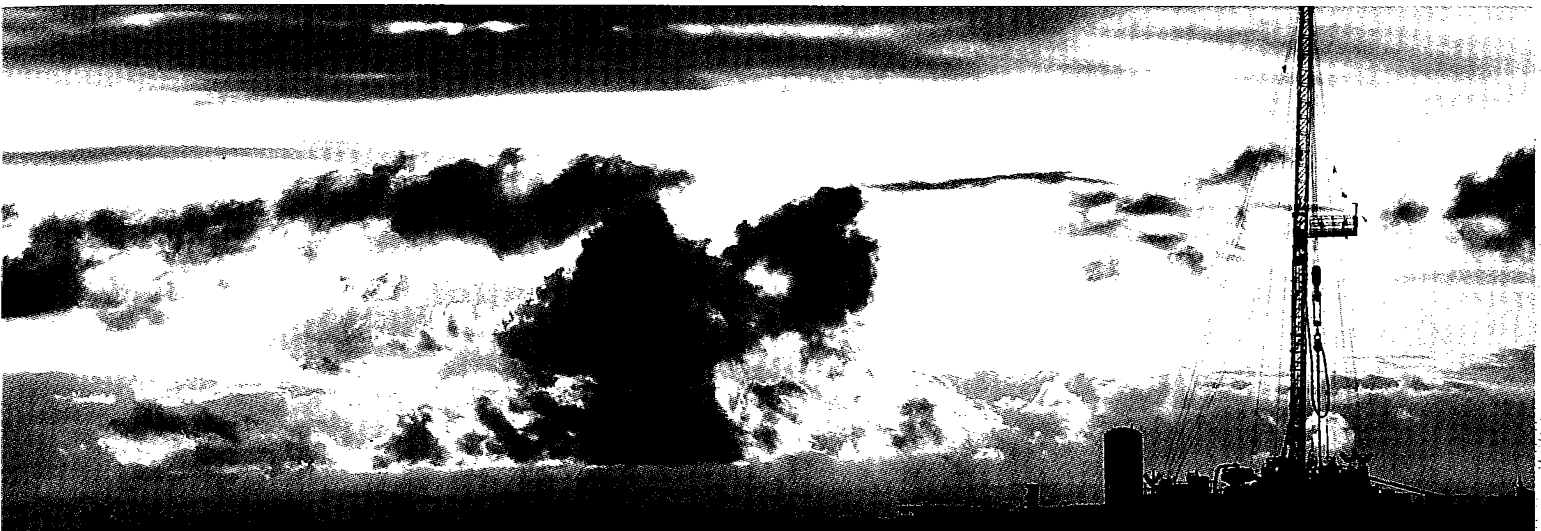

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Directors and Officers

Timothy Marquez
Chairman and Chief Executive Officer

Timothy A. Ficker
Chief Financial Officer

Terry L. Anderson
General Counsel and Secretary

Douglas Griggs
Chief Accounting Officer

Ed O'Donnell
Senior Vice President,
Southern California Operations

Terry Sherban
Vice President, Acquisitions

Ed McLaughlin
Vice President, Corporate Development

Michael D. Wracher
Vice President, Sacramento Basin & Exploration

Michael G. Edwards
Vice President,
Corporate & Investor Relations

Joel L. Reed, Lead Director
Principal – Relational Advisors

Donna Lucas, Director
CEO/President – Lucas Public Affairs

J.C. "Mac" McFarland, Director
Principal – McFarland Advisors, Inc.

Dr. M.W. Scoggins, Director
President – Colorado School of Mines

Mark Snell, Director
CFO – Sempra Energy

Richard S. Walker, Director
Executive VP & Managing Director –
DHR International

Corporate Offices

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Stock Information

Exchange: NYSE
Ticker: VQ
CUSIP: 92275P307

Independent Registered Public Accounting Firm

Ernst & Young LLP
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 stockholder accounts:

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 2010 (including financial statements and schedules) to any stockholder who requests one. Requests should be directed to Venoco, Inc., Attention: Secretary, 370 17th Street, Suite 3900, Denver, Colorado 80202-1370. Copies of the 10-K and all exhibits thereto may also be obtained from our website.

Code of Business Conduct and Ethics

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

Annual Meeting

The meeting will be held at 7:30 a.m. Mountain Time on Wednesday, June 8, 2011, at the Four Seasons Hotel, 1111 14th Street, Denver, Colorado.

VENOCO, INC.

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