

ENCORE ACQUISITION CO

Form 10-K

February 24, 2009

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

or

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

For the transition period from to

Commission File Number: 001-16295

ENCORE ACQUISITION COMPANY

(Exact name of registrant as specified in its charter)

Delaware

State or other jurisdiction
of incorporation or organization

777 Main Street, Suite 1400, Fort Worth, Texas

(Address of principal executive offices)

75-2759650

(I.R.S. Employer
Identification No.)

76102

(Zip Code)

Registrant's telephone number, including area code: (817) 877-9955

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange
Rights to Purchase Series A Junior Participating Preferred Stock	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 Act. Yes ☐ No ☒

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

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

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

Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input type="checkbox"/>
		(Do not check if a smaller reporting company)	

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity of the registrant was last sold as of June 30, 2008 (the last business day of the registrant's most recently completed second fiscal quarter)

\$ 3,715,001,806

Number of shares of Common Stock, \$0.01 par value, outstanding as of February 18, 2009

51,819,037

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant's 2009 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

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GLOSSARY

The following are abbreviations and definitions of certain terms used in this annual report on Form 10-K (the Report). The definitions of proved developed reserves, proved reserves, and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/D. One Bbl per day.

Bcf. One billion cubic feet, used in reference to natural gas.

BOE. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

BOE/D. One BOE per day.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Council of Petroleum Accountants Societies (COPAS). A professional organization of oil and gas accountants that maintains consistency in accounting procedures and interpretations, including the procedures that are part of most joint operating agreements. These procedures establish a drilling rate and an overhead rate to reimburse the operator of a well for overhead costs, such as accounting and engineering.

Delay Rentals. Fees paid to the lessor of an oil and natural gas lease during the primary term of the lease prior to the commencement of production from a well.

Developed Acreage. The number of acres allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Hole or Unsuccessful Well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production costs.

EAC. Encore Acquisition Company, a publicly traded Delaware corporation, together with its subsidiaries.

ENP. Encore Energy Partners LP, a publicly traded Delaware limited partnership, together with its subsidiaries.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously producing oil or natural gas in another reservoir, or to extend a known reservoir.

Farm-out. Transfer of all or part of the operating rights from the working interest holder to an assignee, who assumes all or some of the burden of development, in return for an interest in the property. The assignor usually retains an overriding royalty, but may retain any type of interest.

FASB. Financial Accounting Standards Board.

Field. An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

GAAP. Accounting principles generally accepted in the United States.

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Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which an entity owns a working interest.

Horizontal Drilling. A drilling operation in which a portion of a well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Lease Operations Expense (LOE). All direct and allocated indirect costs of producing oil and natural gas after completion of drilling and before removal of production from the property. Such costs include labor, superintendence, supplies, repairs, maintenance, and direct overhead charges.

LIBOR. London Interbank Offered Rate.

MBbl. One thousand Bbls.

MBOE. One thousand BOE.

MBOE/D. One thousand BOE per day.

Mcf. One thousand cubic feet, used in reference to natural gas.

Mcf/D. One Mcf per day.

Mcfe. One Mcf equivalent, calculated by converting oil to natural gas equivalent at a ratio of one Bbl of oil to six Mcf of natural gas.

Mcfe/D. One Mcfe per day.

MMBbl. One million Bbls.

MMBOE. One million BOE.

MMBtu. One million British thermal units. One British thermal unit is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

MMcf. One million cubic feet, used in reference to natural gas.

Natural Gas Liquids (NGLs). The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Net Acres or Net Wells. Gross acres or wells, as the case may be, multiplied by the working interest percentage owned by an entity.

Net Production. Production owned by an entity less royalties, net profits interests, and production due others.

Net Profits Interest. An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

NYMEX. New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

Oil. Crude oil, condensate, and NGLs.

Operator. The entity responsible for the exploration, development, and production of an oil or natural gas well or lease.

Present Value of Future Net Revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, net of estimated future production and development costs, using prices and costs as of the date of estimation without future escalation, without

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giving effect to commodity derivative activities, non-property related expenses such as general and administrative expenses, debt service, depletion, depreciation, and amortization, and income taxes, discounted at an annual rate of 10 percent.

Production Margin. Oil and natural gas wellhead revenues less production expenses.

Productive Well. A producing well or a well capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Proved Developed Reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of crude oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required for recompletion. Proved undeveloped reserves include unrealized production response from enhanced recovery techniques that have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

SEC. The United States Securities and Exchange Commission.

Secondary Recovery. Enhanced recovery of oil or natural gas from a reservoir beyond the oil or natural gas that can be recovered by normal flowing and pumping operations. Secondary recovery techniques involve maintaining or enhancing reservoir pressure by injecting water, gas, or other substances into the formation. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding.

SFAS. Statement of Financial Accounting Standards.

Standardized Measure. Future cash inflows from proved oil and natural gas reserves, less future production costs, development costs, net abandonment costs, and income taxes, discounted at 10 percent per annum to reflect the timing of future net cash flows. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of estimated future income taxes.

Successful Well. A well capable of producing oil and/or natural gas in commercial quantities.

Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gases are used as the injectant.

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Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Unit. A specifically defined area within which acreage is treated as a single consolidated lease for operations and for allocations of costs and benefits without regard to ownership of the acreage. Units are established for the purpose of recovering oil and natural gas from specified zones or formations.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil or natural gas lease that gives the owner the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the production and development costs.

Workover. Operations on a producing well to restore or increase production.

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References in this Report to EAC, we, our, us, or similar terms refer to Encore Acquisition Company and its subsidiaries. References in this Report to ENP refers to Encore Energy Partners LP and its subsidiaries. The financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. This Report contains forward-looking statements, which give our current expectations and forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by us or on our behalf. Please read Item 1A. Risk Factors for a description of various factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined above under the caption Glossary. In addition, all production and reserve volumes disclosed in this Report represent amounts net to us, unless otherwise noted.

PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

General

Our Business. We are a Delaware corporation engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, we have acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, and reengineering or expanding existing waterflood projects. Our properties and our oil and natural gas reserves are located in four core areas:

the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota;

the Permian Basin of West Texas and southeastern New Mexico;

the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins in Wyoming, Montana, and North Dakota, and the Paradox Basin in southeastern Utah; and

the Mid-Continent area, which includes the Arkoma and Anadarko Basins in Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Mississippi Salt Basin.

Proved Reserves. Our estimated total proved reserves at December 31, 2008 were 134.5 MMBbls of oil and 307.5 Bcf of natural gas, based on December 31, 2008 spot market prices of \$44.60 per Bbl for oil and \$5.62 per Mcf for natural gas. On a BOE basis, our proved reserves were 185.7 MMBOE at December 31, 2008, of which approximately 72 percent was oil and approximately 80 percent was proved developed. Based on 2008 production, our ratio of reserves to production was approximately 12.9 years for total proved reserves and 10.3 years for proved developed reserves as of December 31, 2008.

Most Valuable Asset. The CCA represented approximately 40 percent of our total proved reserves as of December 31, 2008 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future CCA exploitation and production through primary, secondary, and tertiary recovery techniques.

Drilling. In 2008, we drilled 88 gross (67.8 net) operated productive wells and participated in drilling 194 gross (37.0 net) non-operated productive wells for a total of 282 gross (104.8 net) productive wells. Also in 2008, we drilled

7 gross (4.9 net) operated dry holes and participated in drilling another 6 gross (1.9 net) dry holes for a total of 13 gross (6.8 net) dry holes. This represents a success rate of over 95 percent during 2008. We invested \$619.0 million in development, exploitation, and exploration activities in 2008, of which \$14.7 million related to exploratory dry holes.

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Oil and Natural Gas Reserve Replacement. Our average reserve replacement for the three years ended December 31, 2008 was 125 percent. The following table sets forth the calculation of our reserve replacement for the periods indicated:

	Year Ended December 31,			Three-Year
	2008	2007	2006	Average
	(In MBOE, except percentages)			
Acquisition Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	1,303	43,146	64	14,838
Divided by:				
Production	14,446	13,539	11,244	13,076
Acquisition Reserve Replacement	9%	319%	1%	113%
Development Reserve Replacement:				
Changes in Proved Reserves:				
Extensions, discoveries, and improved recovery	19,952	15,983	27,504	21,146
Revisions of previous estimates	(52,432)	896	(7,461)	(19,666)
Total development program	(32,480)	16,879	20,043	1,480
Divided by:				
Production	14,446	13,539	11,244	13,076
Development Reserve Replacement	(225)%	125%	178%	11%
Total Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	1,303	43,146	64	14,838
Extensions, discoveries, and improved recovery	19,952	15,983	27,504	21,146
Revisions of previous estimates	(52,432)	896	(7,461)	(19,666)
Total reserve additions	(31,177)	60,025	20,107	16,318
Divided by:				
Production	14,446	13,539	11,244	13,076
Total Reserve Replacement	(216)%	443%	179%	125%

During the three years ended December 31, 2008, we invested \$1.0 billion in acquiring proved oil and natural gas properties and leasehold acreage and \$1.3 billion on development, exploitation, and exploration.

Given the inherent decline of reserves resulting from production, we must more than offset produced volumes with new reserves in order to grow. Management uses reserve replacement as an indicator of our ability to replenish annual production volumes and grow our reserves. Management believes that reserve replacement is relevant and useful information as it is commonly used to evaluate the performance and prospects of entities engaged in the production and sale of depleting natural resources. It should be noted that reserve replacement is a statistical indicator that has

limitations. As an annual measure, reserve replacement is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. The predictive and comparative value of reserve replacement is also limited for the same reasons. In addition, since reserve replacement does not consider the cost or timing of future production of new reserves or the prices used to determine period end reserve volumes, it cannot be used as a measure of value creation. Reserve replacement does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop. The lower commodity prices and higher service costs at December 31, 2008 had the effect of decreasing the economic life of our oil and natural gas properties and making development of some previously recorded undeveloped reserves uneconomic.

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Encore Energy Partners. As of February 18, 2009, we owned 20,924,055 of ENP's outstanding common units, representing an approximate 62 percent limited partner interest. Through our indirect ownership of ENP's general partner, we also hold all 504,851 general partner units, representing a 1.5 percent general partner interest in ENP. As we control ENP's general partner, ENP's financial position, results of operations, and cash flows are consolidated with ours.

In February 2008, we sold certain oil and natural gas producing properties and related assets in the Permian and Williston Basins to ENP. The consideration for the sale consisted of approximately \$125.3 million in cash and 6,884,776 common units representing limited partner interests in ENP.

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP. The purchase price was \$49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately \$3 million).

Financial Information About Operating Segments. We have operations in only one industry segment: the oil and natural gas exploration and production industry in the United States. However, we are organizationally structured along two operating segments: EAC Standalone and ENP. The contribution of each operating segment to revenues and operating income (loss), and the identifiable assets and liabilities attributable to each operating segment, are set forth in Note 18 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Business Strategy

Our primary business objective is to maximize shareholder value by growing production, repaying debt or repurchasing shares of our common stock, prudently investing internally generated cash flows, efficiently operating our properties, and maximizing long-term profitability. Our strategy for achieving this objective is to:

Maintain a development program to maximize existing reserves and production. Our technological expertise, combined with our proficient field operations and reservoir engineering, has allowed us to increase production on our properties through infill, offset, and re-entry drilling, workovers, and recompletions. Our plan is to maintain an inventory of exploitation and development projects that provide a good source of future production.

Utilize enhanced oil recovery techniques to maximize existing reserves and production. We budget a portion of internally generated cash flows for secondary and tertiary recovery projects that are longer-term in nature to increase production and proved reserves on our properties. Throughout our Williston and Permian Basin properties, we have successfully used waterfloods to increase production. On certain of our non-operated properties in the Rockies, a tertiary recovery technique that uses carbon dioxide instead of water is being used successfully. Throughout our Bell Creek properties, we have successfully used a polymer injection program to increase our production. We believe that these enhanced oil recovery projects will continue to be a source of reserve and production growth.

Expand our reserves, production, and development inventory through a disciplined acquisition program. Using our experience, we have developed and refined an acquisition program designed to increase our reserves and complement our core properties. We have a staff of engineering and geoscience professionals

who manage our core properties and use their experience and expertise to target and evaluate attractive acquisition opportunities. Following an acquisition, our technical professionals seek to enhance the value of the new assets through a proven development and exploitation program. We will continue to evaluate acquisition opportunities with the same disciplined commitment to acquire assets that fit our existing portfolio of properties and create value for our shareholders.

Explore for reserves. We believe exploration programs can provide a rate of return comparable to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into

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development arrangements to explore in areas that complement our existing portfolio of properties. Successful exploration projects would expand our existing fields and could set up multi-well exploitation projects in the future.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2008, we operated properties representing approximately 79 percent of our proved reserves, which allows us to better control expenses, capital allocation, operate in a safe manner, and control timing of investments.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. One challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our development inventory. Changing commodity prices and increased costs of goods and services affect the rate of return on property acquisitions, and the amount of our internally generated cash flows, and, in turn, can affect our capital budget. For example, if cash flow is invested in periods of higher commodity prices, a subsequent decline in commodity prices could result in a lower rate of return, if any. In addition to commodity price risk, we face strong competition from other independents and major oil and natural gas companies. Our views and the views of our competitors about future commodity prices affect our success in acquiring properties and the expected rate of return on each acquisition. For more information on the challenges to implementing our strategy and achieving our goals, please read Item 1A. Risk Factors.

Operations

Well Operations

In general, we seek to be the operator of wells in which we have a working interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oilfield service equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities.

As of December 31, 2008, we operated properties representing approximately 79 percent of our proved reserves. As the operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities on our properties. We also own working interests in properties that are operated by third parties, and are required to pay our share of production, exploitation, and development costs. Please read Properties Nature of Our Ownership Interests. During 2008, 2007, and 2006, our costs for development activities on non-operated properties were approximately 22 percent, 40 percent, and 47 percent, respectively, of our total development costs. We also own royalty interests in wells operated by third parties that are not burdened by production or capital costs; however, we have little or no control over the implementation of projects on these properties.

Natural Gas Gathering

We own and operate a network of natural gas gathering systems in our Elk Basin area of operation. These systems gather and transport our natural gas and a small amount of third-party natural gas to larger gathering systems and intrastate, interstate, and local distribution pipelines. Our network of natural gas gathering systems permits us to transport production from our wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to our wells. Our ownership and control of these lines enables us to:

realize faster connection of newly drilled wells to the existing system;

control pipeline operating pressures and capacity to maximize our production;

control compression costs and fuel use;

maintain system integrity;

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control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and

track sales volumes and receipts closely to assure all production values are realized.

Seasonal Nature of Business

Oil and gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is typically in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating.

Production and Price History

The following table sets forth information regarding our net production volumes, average realized prices, and average costs per BOE for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Total Production Volumes:			
Oil (MBbls)	10,050	9,545	7,335
Natural gas (MMcf)	26,374	23,963	23,456
Combined (MBOE)	14,446	13,539	11,244
Average Daily Production Volumes:			
Oil (Bbls/D)	27,459	26,152	20,096
Natural gas (Mcf/D)	72,060	65,651	64,262
Combined (BOE/D)	39,470	37,094	30,807
Average Realized Prices:			
Oil (per Bbl)	\$ 89.30	\$ 58.96	\$ 47.30
Natural gas (per Mcf)	8.63	6.26	6.24
Combined (per BOE)	77.87	52.66	43.87
Average Costs per BOE:			
Lease operations expense	\$ 12.12	\$ 10.59	\$ 8.73
Production, ad valorem, and severance taxes	7.66	5.51	4.43
Depletion, depreciation, and amortization	15.80	13.59	10.09
Impairment of long-lived assets	4.12		
Exploration	2.71	2.05	2.71
Derivative fair value loss (gain)	(23.97)	8.31	(2.17)
General and administrative	3.35	2.89	2.06
Provision for doubtful accounts	0.14	0.43	0.18
Other operating expense	0.90	1.26	0.71
Marketing loss (gain)	(0.06)	(0.11)	0.09

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The following table sets forth information relating to productive wells in which we owned a working interest at December 31, 2008. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of productive wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest. As of December 31, 2008, we owned a working interest in 5,774 gross wells. We also hold royalty interests in units and acreage beyond the wells in which we own a working interest.

	Oil Wells			Natural Gas Wells		
	Gross Wells(a)	Net Wells	Average Working Interest	Gross Wells(a)	Net Wells	Average Working Interest
CCA	743	659	89%	22	6	27%
Permian Basin	1,967	769	39%	634	314	50%
Rockies	1,437	837	58%	60	45	75%
Mid-Continent	235	141	60%	676	181	27%
Total	4,382	2,406	55%	1,392	546	39%

(a) Our total wells include 3,094 operated wells and 2,680 non-operated wells. At December 31, 2008, 52 of our wells had multiple completions.

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The following table sets forth information relating to our leasehold acreage at December 31, 2008. Developed acreage is assigned to productive wells. Undeveloped acreage is acreage held under lease, permit, contract, or option that is not in a spacing unit for a producing well, including leasehold interests identified for exploitation or exploratory drilling. As of December 31, 2008, our undeveloped acreage in the Rockies represented approximately 60 percent of our total net undeveloped acreage. Our current leases expire at various dates between 2009 and 2028, with leases representing \$18.6 million of cost set to expire in 2009 if not developed.

	Gross Acreage	Net Acreage
CCA:		
Developed	117,209	109,775
Undeveloped	150,283	117,793
	267,492	227,568
Permian Basin:		
Developed	66,280	45,173
Undeveloped	21,564	17,232
	87,844	62,405
Rockies:		
Developed	231,846	156,350
Undeveloped	809,323	574,323
	1,041,169	730,673
Mid-Continent:		
Developed	79,231	41,122
Undeveloped	344,963	245,472
	424,194	286,594
Total:		
Developed	494,566	352,420
Undeveloped	1,326,133	954,820
	1,820,699	1,307,240

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The following table sets forth information with respect to wells completed during the periods indicated, regardless of when development was initiated. This information should not be considered indicative of future performance, nor should a correlation be assumed between productive wells drilled, quantities of reserves discovered, or economic value.

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	186	73	165	62	182	72
Dry holes	5	3	5	3	4	3
	191	76	170	65	186	75
Exploratory Wells:						
Productive	96	32	63	21	71	19
Dry holes	8	4	5	3	14	8
	104	36	68	24	85	27
Total:						
Productive	282	105	228	83	253	91
Dry holes	13	7	10	6	18	11
	295	112	238	89	271	102

Present Activities

As of December 31, 2008, we had a total of 63 gross (31.6 net) wells that had begun drilling and were in varying stages of drilling operations, of which 31 gross (17.9 net) were development wells. As of December 31, 2008, we had a total of 29 gross (14.7 net) wells that had reached total depth and were in the process of being completed pending first production, of which 19 gross (13.7 net) were development wells.

Delivery Commitments and Marketing Arrangements

Our oil and natural gas production is generally sold to marketers, processors, refiners, and other purchasers that have access to nearby pipeline, processing, and gathering facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where it is aggregated and sold to various markets and downstream purchasers. Our production sales agreements generally contain customary terms and conditions for the oil and natural gas industry, provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

The marketing of our CCA oil production is mainly dependent on transportation through the Bridger, Poplar, and Butte Pipelines to markets in the Guernsey, Wyoming area. Alternative transportation routes and markets have been developed by moving a portion of the crude oil production through the Enbridge Pipeline to the Clearbrook, Minnesota hub. To a lesser extent, our production also depends on transportation through the Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on the Platte Pipeline are oversubscribed and have been subject to apportionment since December 2005, we were allocated sufficient pipeline capacity to move our crude oil production effective January 1, 2007. Enbridge Pipeline completed an expansion, which moved the total Rockies area pipeline takeaway closer to a balancing point with increasing production volumes and thereby provided greater stability to oil differentials in the area. In spite of the increase in capacity, the Enbridge Pipeline continues to run at full capacity and is scheduled to complete an additional expansion by the beginning of 2010. However, further

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restrictions on available capacity to transport oil through any of the above-mentioned pipelines, any other pipelines, or any refinery upsets could have a material adverse effect on our production volumes and the prices we receive for our production.

The difference between quoted NYMEX market prices and the price received at the wellhead for oil and natural gas production is commonly referred to as a differential. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have affected this differential. We cannot accurately predict future crude oil and natural gas differentials. Increases in the percentage differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows. The following table illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices by quarter for 2008, as well as our expected differentials for the first quarter of 2009:

	First Quarter of 2008	Second Quarter of 2008	Actual Third Quarter of 2008	Fourth Quarter of 2008	Forecast First Quarter of 2009
Oil wellhead to NYMEX percentage	91%	94%	91%	80%	78%
Natural gas wellhead to NYMEX percentage	103%	102%	93%	86%	103%

Principal Customers

For 2008, our largest purchasers were Eighty-Eight Oil and Tesoro, which accounted for approximately 14 percent and 12 percent, respectively, of our total sales of oil and natural gas production. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. Management believes that the loss of any one purchaser would not have a material adverse effect on our ability to market our oil and natural gas production.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independents and major oil and natural gas companies in acquiring properties, contracting for development equipment, and securing trained personnel. Many of these competitors have resources substantially greater than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for, and purchase a greater number of properties or prospects than our resources will permit.

We are also affected by competition for rigs and the availability of related equipment. The oil and natural gas industry has experienced shortages of rigs, equipment, pipe, and personnel, which has delayed development and exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases, and development rights, and we may not be able to compete satisfactorily when attempting to acquire additional properties.

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The following table sets forth the net production, proved reserve quantities, and PV-10 of our properties by principal area of operation as of and for the periods indicated:

	2008 Net Production				Proved Reserve Quantities at December 31, 2008				PV-10 at December 31, 2008	
	Oil	Natural Gas	Total	Percent	Oil	Natural Gas	Total	Percent	Amount(a) (In thousands)	Percent
	(MBbls)	(MMcf)	(MBOE)		(MBbls)	(MMcf)	(MBOE)			
CA	4,146	978	4,309	30%	71,892	13,327	74,113	40%	\$ 550,734	39%
Permian Basin	1,246	12,442	3,320	23%	19,736	161,720	46,689	25%	362,000	26%
Rockies	4,256	1,870	4,567	32%	40,074	16,552	42,833	23%	326,196	23%
Mid-Continent	402	11,084	2,250	15%	2,750	115,921	22,070	12%	170,019	12%
Total	10,050	26,374	14,446	100%	134,452	307,520	185,705	100%	\$ 1,408,949	100%

- (a) Giving effect to commodity derivative contracts, our PV-10 would increase by \$339.1 million at December 31, 2008. Standardized Measure at December 31, 2008 was \$1.2 billion. Standardized Measure differs from PV-10 by \$189.0 million because Standardized Measure includes the effects of future net abandonment costs and future income taxes. Since we are taxed at the corporate level, future income taxes are determined on a combined property basis and cannot be accurately subdivided among our core areas. Therefore, we believe PV-10 provides the best method for assessing the relative value of each of our areas.

The estimates of our proved oil and natural gas reserves are based on estimates prepared by Miller and Lents, Ltd. (Miller and Lents), independent petroleum engineers. Guidelines established by the SEC regarding our PV-10 were used to prepare these reserve estimates. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and estimates of other engineers might differ materially from those included herein. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions based on the results of drilling, testing, and production activities. Accordingly, reserve estimates and their PV-10 are inherently imprecise, subject to change, and should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

During 2008, we filed the estimates of our oil and natural gas reserves as of December 31, 2007 with the U.S. Department of Energy on Form EIA-23. As required by Form EIA-23, the filing reflected only gross production that comes from our operated wells at year-end. Those estimates came directly from our reserve report prepared by Miller and Lents.

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CCA Properties

Our initial purchase of interests in the CCA was in 1999, and we continue to acquire additional working interests. As of December 31, 2008, we operated virtually all of our CCA properties with an average working interest of approximately 89 percent in the oil wells and 27 percent in the natural gas wells.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the two-to-six-mile-wide crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 120 continuous miles along the crest of the CCA across five counties in two states. Primary producing reservoirs are the Red River, Stony Mountain, Interlake, and Lodgepole formations at depths of between 7,000 and 9,000 feet. Our fields in the CCA include the North Pine, South Pine, Cabin Creek, Coral Creek, Little Beaver, Monarch, Glendive North, Glendive, Gas City, and Pennel fields.

Our CCA reserves are primarily produced through waterfloods. Our average daily net production from the CCA remained approximately constant at 12,153 BOE/D in the fourth quarter of 2008 as compared to 12,080 BOE/D in the fourth quarter of 2007. We have been able to maintain or grow production through a combination of:

effective management of the existing wellbores;

addition of strategically positioned horizontal and vertical wellbores;

re-entry horizontal drilling using existing wellbores;

waterflood enhancements;

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extensional drilling; and

other enhanced oil recovery techniques.

In 2008, we drilled 10 gross wells in the CCA, some of which were horizontal re-entry wells that (1) reestablished production from non-producing wells, (2) added additional production to existing producing wells, or (3) served as injection wells for secondary and tertiary recovery projects. We invested \$37.3 million, \$41.6 million, and \$103.9 million in capital projects in the CCA during 2008, 2007, and 2006, respectively.

The CCA represents approximately 40 percent of our total proved reserves as of December 31, 2008 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future exploitation of and production from this area.

We pursued HPAI in the CCA beginning in 2002 because CO₂ was not readily available and HPAI was an attractive alternative. The initial project was successful and continues to be successful; however, the political environment is changing in favor of CO₂ sequestration. We believe this will increase the amount of CO₂ available to be used in tertiary recovery projects. Although CO₂ is currently not readily available, we believe we will be able to secure an economical source of CO₂ in the future. Therefore, we have made a strategic decision to move away from HPAI and focus on CO₂.

Existing HPAI project areas in the CCA are in Pennel and Cedar Creek fields. In both fields, HPAI wells will be converted to water injection in three to four phases over a period of approximately 18 months. Priority will be largely based on economics of incremental production uplift and air injection utilization. We anticipate that we will continue injecting air in a small number of HPAI patterns beyond the planned 18-month conversion period. We expect to realize significant LOE savings while achieving current production estimates.

Net Profits Interest. A major portion of our acreage position in the CCA is subject to net profits interests ranging from one percent to 50 percent. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering operating expense, overhead expense, interest expense, and development costs. The amounts of reserves and production attributable to net profits interests are deducted from our reserves and production data, and our revenues are reported net of net profits interests. The reserves and production attributed to net profits interests are calculated by dividing estimated future net profits interests (in the case of reserves) or prior period actual net profits interests (in the case of production) by commodity prices at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributable to the net profits interests and will have an inverse effect on our reported reserves and production. For 2008, 2007, and 2006, we reduced revenue for net profits interests by \$56.5 million, \$32.5 million, and \$23.4 million, respectively.

Permian Basin Properties

West Texas. Our West Texas properties include seventeen operated fields, including the East Cowden Grayburg Unit, Fuhrman-Mascho, Crockett County, Sand Hills, Howard Glasscock, Nolley, Deep Rock, and others; and seven non-operated fields. Production from the central portion of the Permian Basin comes from multiple reservoirs, including the Grayburg, San Andres, Glorieta, Clearfork, Wolfcamp, and Pennsylvanian zones. Production from the

southern portion of the Permian Basin comes mainly from the Canyon, Devonian, Ellenberger, Mississippian, Montoya, Strawn, and Wolfcamp formations with multiple pay intervals.

In March 2006, we entered into a joint development agreement with ExxonMobil Corporation (ExxonMobil) to develop legacy natural gas fields in West Texas. The agreement covers certain formations in the Parks, Pegasus, and Wilshire Fields in Midland and Upton Counties, the Brown Bassett Field in Terrell County, and Block 16, Coyanosa, and Waha Fields in Ward, Pecos, and Reeves Counties. Targeted formations include the Barnett, Devonian, Ellenberger, Mississippian, Montoya, Silurian, Strawn, and Wolfcamp horizons.

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Under the terms of the agreement, we have the opportunity to develop approximately 100,000 gross acres. We earn 30 percent of ExxonMobil's working interest and 22.5 percent of ExxonMobil's net revenue interest in each well drilled. We operate each well during the drilling and completion phase, after which ExxonMobil assumes operational control of the well.

In July 2008, we earned the right to participate in all fields by drilling the final well of the 24-well commitment phase and are entitled to a 30 percent working interest in future drilling locations. We also have the right to propose and drill wells for as long as we are engaged in continuous drilling operations.

We have entered into a side letter agreement with ExxonMobil to: (1) combine a group of specified fields into one development area, and extend the period within which we must drill a well in this development area and one additional development area in order to be considered as conducting continuous drilling operations; (2) transfer ExxonMobil's full working interest in a specified well along with a majority of its net royalty interest to us, while reserving its portion of an overriding royalty interest; (3) allow ExxonMobil to participate in any re-entry of the specified well under the original terms of a subsequent well (as defined in the joint development agreement), in which they will pay their proportional share of agreed costs incurred; and (4) reduce the non-consent penalty for 10 specified wells from 200 percent to 150 percent in exchange for ExxonMobil agreeing not to elect the carry for reduced working interest option for these wells.

Average daily production for our West Texas properties increased 19 percent from 7,122 BOE/D in the fourth quarter of 2007 to 8,497 BOE/D in the fourth quarter of 2008. We believe these properties will be an area of growth over the next several years. During 2008, we drilled 36 gross wells and invested approximately \$203.8 million of capital to develop these properties.

In 2009, we intend to drill approximately 7 gross wells and invest approximately \$51 million of net capital in the development areas. We anticipate operating one to two rigs in West Texas for most of 2009.

New Mexico. We began investing in New Mexico in May 2006 with the strategy of deploying capital to develop low-to medium-risk development projects in southeastern New Mexico where multiple reservoir targets are available. Average daily production for these properties decreased 14 percent from 7,793 Mcfe/D in the fourth quarter of 2007 to 6,732 Mcfe/D in the fourth quarter of 2008. During 2008, we drilled 8 gross operated wells and invested approximately \$39.7 million of capital to develop these properties.

Mid-Continent Properties

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP for \$49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately \$3 million).

Oklahoma, Arkansas, and Kansas. We own various interests, including operated, non-operated, royalty, and mineral interests, on properties located in the Anadarko Basin of western Oklahoma and the Arkoma Basin of eastern Oklahoma and western Arkansas. Our average daily production for these properties decreased 5 percent from 8,555 Mcfe/D in the fourth quarter of 2007 to 8,159 Mcfe/D for the fourth quarter of 2008. During 2008, we drilled 52 gross wells and invested \$29.9 million of development and exploration capital in these properties.

North Louisiana Salt Basin and East Texas Basin. Our North Louisiana Salt Basin and East Texas Basin properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired primarily in the Elm Grove and Overton acquisitions in 2004 and development in the Stockman and Danville fields in east Texas. Our interests acquired in the Elm Grove acquisition are located in the Elm Grove Field in Bossier Parish, Louisiana, and include non-operated working interests ranging from one percent to 47 percent across 1,800 net acres in 15 sections.

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Our East Texas and North Louisiana properties are in the same core area and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the Travis Peak and Lower Cotton Valley formations at depths ranging from 8,000 to 11,500 feet.

In the fourth quarter of 2008, we began our Haynesville shale drilling program with the spudding of the first Haynesville shale well at the Greenwood Waskom field in Caddo Parish, Louisiana. This well reached total depth in January 2009 ahead of schedule. We plan to complete the well with an 11 stage fracture stimulation in the first quarter of 2009 and have recently spud our second horizontal well in the area. Since entering the Haynesville play, we have accumulated over 18,000 acres.

Tuscaloosa Marine Shale. Since entering into the Tuscaloosa Marine Shale, we have accumulated over 290,000 gross (220,000 net) acres, the majority of which is locked up through the end of 2010. During 2008, we drilled 4 gross wells at a drilling cost of over \$11 million per well. As a result of the significant decline in commodity prices during the second half of 2008, we recorded a \$59.5 million impairment on these wells and have approximately \$15 million of net unproved costs remaining in these properties.

During 2008, we drilled 95 gross wells and invested approximately \$147.6 million of capital to develop our Mid-Continent properties. Average daily production for these properties increased 81 percent from 20,038 Mcfe/D in the fourth quarter of 2007 to 36,239 Mcfe/D for the fourth quarter of 2008. We drilled 8 gross operated wells in the Stockman and Danville fields.

Rockies Properties

Big Horn Basin. In March 2007, ENP acquired the Big Horn Basin properties, which are located in the Big Horn Basin in northwestern Wyoming and south central Montana. The Big Horn Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. The Big Horn Basin is a prolific basin and has produced over 1.8 billion Bbls of oil since its discovery in 1906.

ENP also owns and operates (1) the Elk Basin natural gas processing plant near Powell, Wyoming, (2) the Clearfork crude oil pipeline extending from the South Elk Basin Field to the Elk Basin Field in Wyoming, (3) the Wildhorse natural gas gathering system that transports low sulfur natural gas from the Elk Basin and South Elk Basin fields to our Elk Basin natural gas processing plant, and (4) a natural gas gathering system that transports higher sulfur natural gas from the Elk Basin Field to our Elk Basin natural gas processing facility.

Average daily production for these properties decreased slightly from 4,255 BOE/D in the fourth quarter of 2007 to 4,212 BOE/D in the fourth quarter of 2008. During 2008, ENP drilled 3 gross wells and invested approximately \$10.8 million of capital to develop these properties.

Williston Basin. Our Williston Basin properties have historically consisted of working and overriding royalty interests in several geographically concentrated fields. The properties are located in western North Dakota and eastern Montana, near our CCA properties. In April 2007, we acquired additional properties in the Williston Basin including 50 different fields across Montana and North Dakota. As part of this acquisition, we also acquired approximately 70,000 net unproved acres in the Bakken play of Montana and North Dakota. Since the acquisition, we have increased our acreage position in the Bakken play to approximately 300,000 acres. During 2008, we drilled and completed twelve wells in the Bakken and Sanish. The average seven day initial production rate of these wells was 411 BOE/D. Also during 2008, we re-fraced a total of six wells in North Dakota. The average thirty-day uplift in production rate

for these re-frac wells was 118 BOE/D. In the first quarter of 2009, we plan to complete our first Sanish well in the Almond prospect. The Almond prospect contains 70,000 net acres and is located near the northeast border of Mountrail County, North Dakota.

Average daily production for our Rockies properties increased nine percent from 6,363 BOE/D in the fourth quarter of 2007 to 6,919 BOE/D in the fourth quarter of 2008. During 2008, we drilled 59 gross wells and invested approximately \$125.6 million of capital to develop our Rockies properties.

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Bell Creek. Our Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate seven production units in Bell Creek, each with a 100 percent working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces oil. We have successfully implemented a polymer injection program on both injection and producing wells on our Bell Creek properties whereby a polymer is injected into a well to reduce the amount of water cycling in the higher permeability interval of the reservoir, reducing operating costs and increasing reservoir recovery. This process is generally more efficient than standard waterflooding.

We invested \$11.5 million of capital to develop these properties in 2008. Average daily production from these properties decreased seven percent from 958 BOE/D in the fourth quarter of 2007 to 890 BOE/D in the fourth quarter of 2008.

In 2009, we plan to initiate a CO₂ pilot in Bell Creek. We believe the field is an excellent candidate for CO₂ tertiary recovery and are attempting to procure a CO₂ source.

Paradox Basin. The Paradox Basin properties, located in southeast Utah's Paradox Basin, are divided between two prolific oil producing units: the Ratherford Unit and the Aneth Unit. In 2008, the operator continued the implementation of a tertiary project in the Aneth Unit. We believe these properties have additional potential in horizontal redevelopment, secondary development, and tertiary recovery potential.

Average daily production for these properties decreased approximately eight percent from 688 BOE/D in the fourth quarter of 2007 to 631 BOE/D in the fourth quarter of 2008. During 2008, we invested approximately \$8.0 million of capital to develop these properties.

Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with standards generally accepted in the oil and natural gas industry.

Our properties are subject, in one degree or another, to one or more of the following:

royalties, overriding royalties, net profits interests, and other burdens under oil and natural gas leases;

contractual obligations, including, in some cases, development obligations arising under joint operating agreements, farm-out agreements, production sales contracts, and other agreements that may affect the properties or their titles;

liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors, and contractual liens under joint operating agreements;

pooling, unitization, and communitization agreements, declarations, and orders; and

easements, restrictions, rights-of-way, and other matters that commonly affect property.

We believe that the burdens and obligations affecting our properties do not in the aggregate materially interfere with the use of the properties. As previously discussed, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

We have granted mortgage liens on substantially all of our oil and natural gas properties in favor of Bank of America, N.A., as agent, to secure borrowings under our revolving credit facility. These mortgages and the revolving credit facility contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type.

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Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. These laws and regulations may, among other things:

require the acquisition of various permits before development commences;

require the installation of pollution control equipment;

enjoin some or all of the operations of facilities deemed in non-compliance with permits;

restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with oil and natural gas development, production, and transportation activities;

restrict the way in which wastes are handled and disposed;

limit or prohibit development activities on certain lands lying within wilderness, wetlands, areas inhabited by threatened or endangered species, and other protected areas;

require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells;

impose substantial liabilities for pollution resulting from operations; and

require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement for operations affecting federal lands or leases.

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in indirect compliance costs or additional operating restrictions, including costly waste handling, disposal, and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a discussion of relevant environmental and safety laws and regulations that relate to our operations.

Waste Handling. The Resource Conservation and Recovery Act (RCRA), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous solid wastes. Under the auspices of the federal Environmental Protection Agency (the EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are regulated under RCRA 's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of

wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils that may be regulated as hazardous wastes.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where

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the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although petroleum, including crude oil, and natural gas are excluded from CERCLA's definition of hazardous substance, in the course of our ordinary operations, we generate wastes that may fall within the definition of a hazardous substance. We believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, yet hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

ENP's Elk Basin assets have been used for oil and natural gas exploration and production for many years. There have been known releases of hazardous substances, wastes, or hydrocarbons at the properties, and some of these sites are undergoing active remediation. The risks associated with these environmental conditions, and the cost of remediation, were assumed by ENP, subject only to limited indemnity from the seller of the Elk Basin assets. Releases may also have occurred in the past that have not yet been discovered, which could require costly future remediation. In addition, ENP assumed the risk of various other unknown or unasserted liabilities associated with the Elk Basin assets that relate to events that occurred prior to ENP's acquisition. If a significant release or event occurred in the past, the liability for which was not retained by the seller or for which indemnification from the seller is not available, it could adversely affect our results of operations, financial position, and cash flows.

ENP's Elk Basin assets include a natural gas processing plant. Previous environmental investigations of the Elk Basin natural gas processing plant indicate historical soil and groundwater contamination by hydrocarbons and the presence of asbestos-containing material at the site. Although the environmental investigations did not identify an immediate need for remediation of the suspected historical contamination, the extent of the contamination is not known and, therefore, the potential liability for remediating this contamination may be significant. In the event ENP ceased operating the gas plant, the cost of decommissioning it and addressing the previously identified environmental conditions and other conditions, such as waste disposal, could be significant. ENP does not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future nor a need to commence remedial activities at this time. However, a regulatory agency could require ENP to investigate and remediate any contamination even while the gas plant remains in operation. As of December 31, 2008, ENP has recorded \$4.4 million as future abandonment liability for decommissioning the Elk Basin natural gas processing plant. Due to the significant level of uncertainty associated with the known and unknown environmental liabilities at the gas plant, ENP's estimate of the future abandonment liability includes a large contingency. ENP's estimates of the future abandonment liability and compliance costs are subject to change and the actual cost of these items could vary significantly from those estimates.

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Water Discharges. The Clean Water Act (CWA), and analogous state laws, impose strict controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control, and countermeasure requirements of CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations.

The primary federal law for oil spill liability is the Oil Pollution Act (OPA), which addresses three principal areas of oil pollution prevention, containment, and cleanup. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Air Emissions. Oil and natural gas exploration and production operations are subject to the federal Clean Air Act (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including oil and natural gas exploration and production facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Permits and related compliance obligations under CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and natural gas exploration and production operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the atmosphere. In response to such studies, Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Supreme Court's holding in *Massachusetts* that greenhouse gases fall under CAA's definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under various CAA programs, including those used in oil and natural gas exploration and production operations. It is

not possible to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and natural gas exploration and production business. However, future laws and regulations could result in increased

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compliance costs or additional operating restrictions and could have a material adverse effect on our business, financial position, demand for our operations, results of operations, and cash flows.

Activities on Federal Lands. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Our current exploration and production activities and planned exploration and development activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of our oil and natural gas projects.

Occupational Safety and Health Act (OSH Act) and Other Laws and Regulation. We are subject to the requirements of OSH Act and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The Occupational Safety and Health Administration's hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities during 2008, and, as of the date of this Report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2009. However, accidental spills or releases may occur in the course of our operations, and we may incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, the passage of more stringent laws or regulations in the future may have a negative impact on our business, financial condition, or results of operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities, and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures

could be substantial.

Development and Production. Our operations are subject to various types of regulation at the federal, state, and local levels. These types of regulation include requiring permits for the development of wells, development bonds, and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

location of wells;

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methods of developing and casing wells;

surface use and restoration of properties upon which wells are drilled;

plugging and abandoning of wells; and

notification of surface owners and other third parties.

State laws regulate the size and shape of development and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts in order to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

Interstate Crude Oil Transportation. ENP's Clearfork crude oil pipeline is an interstate common carrier pipeline, which is subject to regulation by the Federal Energy Regulatory Commission (the "FERC") under the Interstate Commerce Act (the "ICA") and the Energy Policy Act of 1992 ("EP Act 1992"). The ICA and its implementing regulations give the FERC authority to regulate the rates ENP charges for service on that interstate common carrier pipeline and generally require the rates and practices of interstate oil pipelines to be just, reasonable, and nondiscriminatory. The ICA also requires ENP to maintain tariffs on file with the FERC that set forth the rates ENP charges for providing transportation services on its interstate common carrier liquids pipeline as well as the rules and regulations governing these services. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months and require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. EP Act 1992 deemed certain rates in effect prior to its passage to be just and reasonable and limited the circumstances under which a complaint can be made against such grandfathered rates. EP Act 1992 and its implementing regulations also allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. In addition, the FERC retains cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach.

Natural Gas Gathering. Section 1(b) of the Natural Gas Act ("NGA"), exempts natural gas gathering facilities from the jurisdiction of the FERC. ENP owns a number of facilities that it believes would meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC's jurisdiction. In the states in which ENP operates, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirement and complaint-based rate regulation.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since the FERC has taken a less stringent approach to regulation of the offshore gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. ENP's gathering operations could be adversely affected should they become subject to the application of state or federal regulation of rates and services. ENP's gathering operations also may be or become subject to safety and operational

regulations relating to the design, installation, testing, construction, operation, replacement, and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on ENP's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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Sales of Natural Gas. The price at which we buy and sell natural gas is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms, and cost of pipeline transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations, and we note that some of the FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with which we compete.

The Energy Policy Act of 2005 (EP Act 2005) gave the FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended NGA to prohibit market manipulation and also amended NGA and the Natural Gas Policy Act of 1978 (NGPA) to increase civil and criminal penalties for any violations of NGA, NGPA, and any rules, regulations, or orders of the FERC to up to \$1,000,000 per day, per violation. In 2006, the FERC issued a rule regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC's jurisdiction, to defraud, make an untrue statement, or omit a material fact, or engage in any practice, act, or course of business that operates or would operate as a fraud. This rule works together with the FERC's enhanced penalty authority to provide increased oversight of the natural gas marketplace.

State Regulation. The various states regulate the development, production, gathering, and sale of oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Reduced rates or credits may apply to certain types of wells and production methods.

In addition to production taxes, Texas and Montana each impose ad valorem taxes on oil and natural gas properties and production equipment. Wyoming imposes an ad valorem tax on the gross value of oil and natural gas production in lieu of an ad valorem tax on the underlying oil and natural gas properties. Wyoming also imposes an ad valorem tax on production equipment. North Dakota imposes an ad valorem tax on gross oil and natural gas production in lieu of an ad valorem tax on the underlying oil and gas leases or on production equipment used on oil and gas leases.

States also regulate the method of developing new fields, the spacing and operation of wells, and the prevention of waste of oil and natural gas resources. States may regulate rates of production and establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but they may do so in the future. The effect of these regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

Federal, State, or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Federal Bureau of Land Management, Minerals Management Service, and other agencies.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our ability to conduct

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operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

As of December 31, 2008, we had a staff of 394 persons, including 34 engineers, 17 geologists, and 14 landmen, none of which are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Principal Executive Office

Our principal executive office is located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other filings with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with or furnish such material to the SEC. In addition, you may read and copy any materials that we file with the SEC at its public reference room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Information concerning the operation of the public reference room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like us, that file electronically with the SEC.

We have adopted a code of business conduct and ethics that applies to all directors, officers, and employees, including our principal executive and financial officers. The code of business conduct and ethics is available on our website. In the event that we make changes in, or provide waivers from, the provisions of this code of business conduct and ethics that the SEC or the NYSE require us to disclose, we intend to disclose these events on our website.

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this Report. In 2008, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE's Listed Company Manual. In 2009, we expect to submit this certification to the NYSE after our annual meeting of stockholders.

Our board of directors (the Board) has four standing committees: (1) audit; (2) compensation; (3) nominating and corporate governance; and (4) special stock award. Our Board committee charters, code of business conduct and ethics, and corporate governance guidelines are available on our website and are also available in print upon written request to: Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

The information on our website or any other website is not incorporated by reference into this Report.

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ITEM 1A. RISK FACTORS

You should carefully consider each of the following risks and all of the information provided elsewhere in this Report. If any of the risks described below or elsewhere in this Report were actually to occur, our business, financial condition, results of operations, or cash flows could be materially and adversely affected. In that case, we may be unable to pay interest on, or the principal of, our debt securities, the trading price of our common stock could decline, and you could lose all or part of your investment.

Oil and natural gas prices are very volatile. A decline in commodity prices could materially and adversely affect our financial condition, results of operations, liquidity, and cash flows.

The oil and natural gas markets are very volatile, and we cannot accurately predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control, such as:

overall domestic and global economic conditions;

weather conditions;

political and economic conditions in oil and natural gas producing countries, including those in the Middle East, Africa, and South America;

actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;

the impact of U.S. dollar exchange rates on oil and natural gas prices;

technological advances affecting energy consumption and energy supply;

domestic and foreign governmental regulations and taxation;

the impact of energy conservation efforts;

the proximity, capacity, cost, and availability of oil and natural gas pipelines and other transportation facilities;

the availability of refining capacity; and

the price and availability of alternative fuels.

The worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over \$140 per Bbl to below \$39 per Bbl in mid-February 2009 and natural gas prices have declined from over \$13 per Mcf to below \$4.25 per Mcf over the

same period. In addition, the forecasted prices for 2009 have also declined. Notwithstanding significant declines in oil and natural gas prices since July 2008, there has not been a corresponding decrease in oilfield service costs as of February 2009. If oilfield service costs remain elevated in relation to prevailing oil and natural gas prices, our results of operations and cash flows could be adversely affected.

Our revenue, profitability, and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;

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reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and

result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

An increase in the differential between benchmark prices of oil and natural gas and the wellhead price we receive could adversely affect our financial condition, results of operations, and cash flows.

The prices that we receive for our oil and natural gas production sometimes trade at a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. For example, the oil production from our Elk Basin assets has historically been sold at a higher discount to NYMEX as compared to our Permian Basin assets due to competition from Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, and corresponding deep pricing discounts by regional refiners. Increases in differentials could significantly reduce our cash available for development of our properties and adversely affect our financial condition, results of operations, and cash flows.

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

It is not possible to measure underground accumulations of oil or natural gas in an exact way. In estimating our oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to oil and natural gas prices, production levels, capital expenditures, operating and development costs, the effects of regulation, and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classification of reserves based on risk of recovery, and our estimates of the future net cash flows from our reserves could change significantly.

Our Standardized Measure is calculated using prices and costs in effect as of the date of estimation, less future development, production, abandonment, and income tax expenses, and discounted at 10 percent per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. The Standardized Measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of estimate. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing of development expenditures.

The timing of both our production and our incurrence of expenses in connection with the development, production, and abandonment of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating

discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

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Our oil and natural gas reserves naturally decline and the failure to replace our reserves could adversely affect our financial condition.

Because our oil and natural gas properties are a depleting asset, 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. We may not be able to develop, find, or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition, and results of operations.

We need to make substantial capital expenditures to maintain and grow our asset base. If lower oil and natural gas prices or operating difficulties result in our cash flows from operations being less than expected or limit our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop, or acquire additional reserves.

Price declines may result in a write-down of our asset carrying values, which could have a material adverse effect on our results of operations and limit our ability to borrow funds under our revolving credit facility.

Declines in oil and natural gas prices may result in our having to make substantial downward revisions to our estimated reserves. If this occurs, or if our estimates of development costs increase, production data factors change, or development results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties and goodwill. If we incur such impairment charges, it could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our revolving credit facility. In addition, any write-downs that result in a reduction in our borrowing base could require prepayments of indebtedness under our revolving credit facility.

If we do not make acquisitions, our future growth could be limited.

Acquisitions are an essential part of our growth strategy, and our ability to acquire additional properties on favorable terms is important to our long-term growth. We may be unable to make acquisitions because we are:

unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;

unable to obtain financing for these acquisitions on economically acceptable terms; or

outbid by competitors.

Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. If we are unable to acquire properties containing proved reserves, our total level of proved reserves could decline as a result of our production. Future acquisitions could result in our incurring additional debt, contingent liabilities, and expenses, all of which could have a material adverse effect on our financial condition and results of operations. Furthermore, our financial position and results of operations may fluctuate significantly from period to period based on whether significant acquisitions are completed in particular periods.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

the validity of our assumptions about reserves, future production, revenues, capital expenditures, and operating costs, including synergies;

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an inability to integrate the businesses we acquire successfully;

a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;

a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

the assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which our indemnity is inadequate;

the diversion of management's attention from other business concerns;

an inability to hire, train, or retain qualified personnel to manage and operate our growing business and assets;

natural disasters;

the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation, or restructuring charges;

unforeseen difficulties encountered in operating in new geographic areas; and

customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

A substantial portion of our producing properties is located in one geographic area and adverse developments in any of our operating areas would negatively affect our financial condition and results of operations.

We have extensive operations in the CCA. Our CCA properties represented approximately 40 percent of our proved reserves as of December 31, 2008 and accounted for 30 percent of our 2008 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the CCA would materially affect our results of operations and cash flows.

Our commodity derivative contract activities could result in financial losses or could reduce our income and cash flows. Furthermore, in the future our commodity derivative contract positions may not adequately protect us from

changes in commodity prices.

To reduce our exposure to fluctuations in the price of oil and natural gas, we enter into derivative arrangements for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual prices we realize on our production. Changes in oil and natural gas prices could result in losses under our commodity derivative contracts.

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Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the notional amount of our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from the sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our derivative activities are subject to the following risks:

a counterparty may not perform its obligation under the applicable derivative instrument, which risk may have been exacerbated by the worldwide financial and credit crisis; and

there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received, which may result in payments to our derivative counterparty that are not accompanied by our receipt of higher prices from our production in the field.

In addition, certain commodity derivative contracts that we may enter into may limit our ability to realize additional revenues from increases in the prices for oil and natural gas.

We have oil and natural gas commodity derivative contracts covering a significant portion of our forecasted production for 2009. These contracts are intended to reduce our exposure to fluctuations in the price of oil and natural gas. We have a much smaller commodity derivative contract portfolio covering our forecasted production for 2010, 2011, and 2012, and no commodity derivative contracts covering production beyond 2012. After 2009 and unless we enter into new commodity derivative contracts, our exposure to oil and natural gas price volatility will increase significantly each year as our commodity derivative contracts expire. We may not be able to obtain additional commodity derivative contracts on acceptable terms, if at all. Our failure to mitigate our exposure to commodity price volatility through commodity derivative contracts could have a negative effect on our financial condition and results of operation and significantly reduce our cash flows.

The counterparties to our derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

As of December 31, 2008, we were entitled to future payments of approximately \$387.6 million from counterparties under our commodity derivative contracts. The worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

We have limited control over the activities on properties we do not operate.

Other companies operated approximately 21 percent of our properties (measured by total reserves) and approximately 46 percent of our wells as of December 31, 2008. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in development or acquisition activities and lead to

unexpected future costs.

Our development and exploratory drilling efforts may not be profitable or achieve our targeted returns.

Development and exploratory drilling and production activities are subject to many risks, including the risk that we will not discover commercially productive oil or natural gas reserves. In order to further our development efforts, we acquire both producing and unproved properties as well as lease undeveloped acreage

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that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not be required to impair our initial investments.

In addition, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us will be productive, or that we will recover all or any portion of our investment in such unproved property or wells. The costs of drilling and completing wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions, and shortages or delays in the delivery of equipment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient commercial quantities to cover the development, operating, and other costs. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas, and our ability to add reserves at an acceptable cost.

Seismic technology does not allow us to obtain conclusive evidence that oil or natural gas reserves are present or economically producible prior to spudding a well. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The use of seismic data and other technologies also requires greater up-front costs than development on proved properties.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

The cost of developing, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. If commodity prices decline, the cost of developing, completing and operating a well may not decline in proportion to the prices that we receive for our production, resulting in higher operating and capital costs as a percentage of oil and natural gas revenues. For instance, oil and natural gas prices declined from record levels in early July 2008 of over \$140 per Bbl and \$13 per Mcf, respectively, to below \$39 per Bbl and \$4.25 per Mcf, respectively, in mid-February 2009. Notwithstanding significant declines in oil and natural gas prices since July 2008, there has not been a corresponding decrease in oilfield service costs as of February 2009. If oilfield service costs remain elevated in relation to prevailing oil and natural gas prices, our results of operations and cash flows could be adversely affected. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil and natural gas as we had estimated. Furthermore, our development and production operations may be curtailed, delayed, or canceled as a result of other factors, including:

higher costs, shortages, or delivery delays of rigs, equipment, labor, or other services;

unexpected operational events and/or conditions;

reductions in oil and natural gas prices;

increases in severance taxes;

limitations in the market for oil and natural gas;

adverse weather conditions and natural disasters;

facility or equipment malfunctions, and equipment failures or accidents;

title problems;

pipe or cement failures and casing collapses;

compliance with environmental and other governmental requirements;

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environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases;

lost or damaged oilfield development and service tools;

unusual or unexpected geological formations, and pressure or irregularities in formations;

loss of drilling fluid circulation;

fires, blowouts, surface craterings, and explosions;

uncontrollable flows of oil, natural gas, or well fluids; and

loss of leases due to incorrect payment of royalties.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

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

A significant portion of our production and reserves rely on secondary and tertiary recovery techniques. If production response is less than forecasted for a particular project, then the project may be uneconomic or generate less cash flow and reserves than we had estimated prior to investing capital. Risks associated with secondary and tertiary recovery techniques include, but are not limited to, the following:

lower than expected production;

longer response times;

higher operating and capital costs;

shortages of equipment; and

lack of technical expertise.

If any of these risks occur, it could adversely affect our financial condition or results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells, gathering systems, pipelines, and other facilities, such as leaks, explosions, mechanical problems, and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our

operations, and substantial revenue losses. The location of our wells, gathering systems, pipelines, and other facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could significantly increase the level of damages resulting from these risks.

We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets due to weather and adverse economic conditions have made it more difficult for us to obtain certain types of coverage. We may not be able to obtain the levels or types of insurance we would otherwise

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have obtained prior to these market changes, and our insurance may contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, and results of operations.

Our development, exploitation, and exploration operations require substantial capital, and we may be unable to obtain needed financing on satisfactory terms.

We make and will continue to make substantial capital expenditures in development, exploitation, and exploration projects. For example, our Board approved a \$310 million capital budget for 2009, excluding proved property acquisitions. We intend to finance these capital expenditures through operating cash flows. However, additional financing sources may be required in the future to fund our capital expenditures. Financing may not continue to be available under existing or new financing arrangements, or on acceptable terms, if at all. If additional capital resources are not available, we may be forced to curtail our development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Shortages of rigs, equipment, and crews could delay our operations.

Higher oil and natural gas prices generally increase the demand for rigs, equipment, and crews and can lead to shortages of, and increasing costs for, development equipment, services, and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of I. Jon Brumley, our Chairman of the Board, Jon S. Brumley, our Chief Executive Officer and President, and other key personnel. The loss of the services of any of these persons could adversely affect our business, and we do not have employment agreements with, and do not maintain key person insurance on the lives of, any of these persons.

Our development success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for experienced geologists, engineers, and other professionals is extremely intense and the cost of attracting and retaining technical personnel has increased significantly in recent years. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed. Furthermore, escalating personnel costs could adversely affect our results of operations and financial condition.

Our business depends in part on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production and could harm our business.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipelines, oil and natural gas gathering systems, and processing facilities. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage, or lack of contracted capacity on such systems.

The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity could reduce our ability to market our oil and natural gas production and harm our business.

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Competition in the oil and natural gas industry is intense, and many of our competitors have greater resources than we do. As a result, we may be unable to effectively compete with larger competitors.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major and large independent oil and natural gas companies, and possess and employ financial, technical, and personnel resources substantially greater than us. Those companies may be able to develop and acquire more prospects and productive properties than our resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Some of our competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national, or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for, and purchase a greater number of properties than our resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local, and other laws and regulations. Our inability to compete effectively could have a material adverse impact on our business activities, financial condition, and results of operations.

We are subject to complex federal, state, local, and other laws and regulations that could adversely affect the cost, manner, or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate, and abandon oil and natural gas wells and related pipeline and processing facilities. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, state, and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state, and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition, and results of operations. Please read Items 1 and 2. Business and Properties Environmental Matters and Regulation and Other Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

We have significant indebtedness and may incur significant additional indebtedness, which could negatively impact our financial condition, results of operations, and business prospects.

As of December 31, 2008, we had total consolidated debt of \$1.3 billion and \$615 million of consolidated available borrowing capacity under our revolving credit facility. We have the ability to incur additional debt under our revolving credit facilities, subject to borrowing base limitations. Our future indebtedness could have important consequences to us, including:

our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions, or other purposes may not be available on favorable terms, if at all;

covenants contained in future debt arrangements may require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

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we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and

our debt level will make us more vulnerable to competitive pressures, or a downturn in our business or the economy in general, than our competitors with less debt.

Our ability to service our indebtedness depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory, and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

In addition, we are not currently permitted to offset the value of our commodity derivative contracts with a counterparty against amounts that may be owing to such counterparty under our revolving credit facilities.

We are unable to predict the impact of the recent downturn in the credit markets and the resulting costs or constraints in obtaining financing on our business and financial results.

U.S. and global credit and equity markets have recently undergone significant disruption, making it difficult for many businesses to obtain financing on acceptable terms. In addition, equity markets are continuing to experience wide fluctuations in value. If these conditions continue or worsen, our cost of borrowing may increase, and it may be more difficult to obtain financing in the future. In addition, an increasing number of financial institutions have reported significant deterioration in their financial condition. If any of the financial institutions are unable to perform their obligations under our revolving credit agreements and other contracts, and we are unable to find suitable replacements on acceptable terms, our results of operations, liquidity and cash flows could be adversely affected. We also face challenges relating to the impact of the disruption in the global financial markets on other parties with which we do business, such as customers and suppliers. The inability of these parties to obtain financing on acceptable terms could impair their ability to perform under their agreements with us and lead to various negative effects on us, including business disruption, decreased revenues, and increases in bad debt write-offs. A sustained decline in the financial stability of these parties could have an adverse impact on our business, results of operations, and liquidity.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas production activities. In addition, we often indemnify sellers of oil and natural gas properties for environmental liabilities they or their predecessors may have created. These costs and liabilities could arise under a wide range of federal, state, and local environmental and safety laws and regulations, which have become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, imposition of cleanup and site restoration costs, liens and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint, and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations, or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our profitability and our ability to make distributions to unitholders could be adversely affected.

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ITEM 1B. *UNRESOLVED STAFF COMMENTS*

There were no unresolved SEC staff comments as of December 31, 2008.

ITEM 3. *LEGAL PROCEEDINGS*

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on our results of operations or financial position.

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

There were no matters submitted to a vote of stockholders during the fourth quarter of 2008.

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Our common stock, par value \$0.01 per share, is listed on the NYSE under the symbol EAC. The following table sets forth high and low sales prices of our common stock for the periods indicated:

	High	Low
<u>2008</u>		
Quarter ended December 31	\$ 41.05	\$ 17.89
Quarter ended September 30	\$ 79.62	\$ 36.84
Quarter ended June 30	\$ 77.35	\$ 38.45
Quarter ended March 31	\$ 40.74	\$ 26.10
<u>2007</u>		
Quarter ended December 31	\$ 38.55	\$ 30.59
Quarter ended September 30	\$ 33.00	\$ 25.79
Quarter ended June 30	\$ 29.96	\$ 24.21
Quarter ended March 31	\$ 26.50	\$ 21.74

On February 18, 2009, the closing sales price of our common stock as reported by the NYSE was \$23.09 per share, and we had approximately 387 shareholders of record. This number does not include owners for whom common stock may be held in street name.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In October 2008, we announced that the Board authorized a share repurchase program of up to \$40 million of our common stock. As of December 31, 2008, we had repurchased and retired 620,265 shares of our outstanding common stock for approximately \$17.2 million, or an average price of \$27.68 per share, under the share repurchase program. The following table summarizes purchases of our common stock during the fourth quarter of 2008:

			Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs
Month	Total Number of Shares Purchased	Average Price Paid per Share		

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October	620,265	\$	27.68	620,265	
November(a)	4,753	\$	21.31		
December		\$			
Total	625,018	\$	27.63	620,265	\$ 22,830,139

(a) During the fourth quarter of 2008, certain employees directed us to withhold 4,753 shares of common stock to satisfy minimum tax withholding obligations in conjunction with vesting of restricted shares.

Dividends

No dividends have been declared or paid on our common stock. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of the Board after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The

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declaration and payment of dividends is restricted by our existing revolving credit facility and the indentures governing our senior subordinated notes. Future debt agreements may also restrict our ability to pay dividends.

Stock Performance Graph

The following graph compares our cumulative total stockholder return during the period from January 1, 2004 to December 31, 2008 with total stockholder return during the same period for the Independent Oil and Gas Index and the Standard & Poor's 500 Index. The graph assumes that \$100 was invested in our common stock and each index on January 1, 2004 and that all dividends, if any, were reinvested. The following graph is being furnished pursuant to SEC rules and will not be incorporated by reference into any filing under the Securities Act of 1933 or the Exchange Act except to the extent we specifically incorporate it by reference.

**Comparison of Total Return Since January 1, 2004 Among Encore
Acquisition Company, the Standard & Poor's 500 Index, and the
Independent Oil and Gas Index**

Table of Contents**ENCORE ACQUISITION COMPANY****ITEM 6. SELECTED FINANCIAL DATA**

The following selected consolidated financial and operating data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data :

	Year Ended December 31,(f)				
	2008	2007	2006	2005	2004
	(In thousands, except per share amounts)				
Consolidated Statements of Operations Data:					
Revenues(a):					
Oil	\$ 897,443	\$ 562,817	\$ 346,974	\$ 307,959	\$ 220,649
Natural gas	227,479	150,107	146,325	149,365	77,884
Marketing(b)	10,496	42,021	147,563		
Total revenues	1,135,418	754,945	640,862	457,324	298,533
Expenses:					
Production:					
Lease operations(c)	175,115	143,426	98,194	69,744	47,807
Production, ad valorem, and severance taxes	110,644	74,585	49,780	45,601	30,313
Depletion, depreciation, and amortization	228,252	183,980	113,463	85,627	48,522
Impairment of long-lived assets(g)	59,526				
Exploration	39,207	27,726	30,519	14,443	3,935
General and administrative(c)	48,421	39,124	23,194	17,268	12,059
Marketing(b)	9,570	40,549	148,571		
Derivative fair value loss (gain)(d)	(346,236)	112,483	(24,388)	5,290	5,011
Loss on early redemption of debt				19,477	
Provision for doubtful accounts	1,984	5,816	1,970	231	
Other operating	12,975	17,066	8,053	9,254	5,028
Total expenses	339,458	644,755	449,356	266,935	152,675
Operating income	795,960	110,190	191,506	190,389	145,858
Other income (expenses):					
Interest	(73,173)	(88,704)	(45,131)	(34,055)	(23,459)
Other	3,898	2,667	1,429	1,039	240
Total other expenses	(69,275)	(86,037)	(43,702)	(33,016)	(23,219)

Income before income taxes and minority interest	726,685	24,153	147,804	157,373	122,639
Income tax provision	(241,621)	(14,476)	(55,406)	(53,948)	(40,492)
Minority interest in loss (income) of consolidated partnership	(54,252)	7,478			
Net income	\$ 430,812	\$ 17,155	\$ 92,398	\$ 103,425	\$ 82,147
Net income per common share:					
Basic	\$ 8.24	\$ 0.32	\$ 1.78	\$ 2.12	\$ 1.74(e)
Diluted	\$ 8.07	\$ 0.32	\$ 1.75	\$ 2.09	\$ 1.72(e)
Weighted average common shares outstanding:					
Basic	52,270	53,170	51,865	48,682	47,090(e)
Diluted	53,414	54,144	52,736	49,522	47,738(e)

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	Year Ended December 31,(f)					
	2008	2007	2006	2005	2004	
	(In thousands, except per unit amounts)					
Total Production Volumes:						
Oil (Bbls)	10,050	9,545	7,335	6,871	6,679	
Natural gas (Mcf)	26,374	23,963	23,456	21,059	14,089	
Combined (BOE)	14,446	13,539	11,244	10,381	9,027	
Average Realized Prices:						
Oil (\$/Bbl)	\$ 89.30	\$ 58.96	\$ 47.30	\$ 44.82	\$ 33.04	
Natural gas (\$/Mcf)	8.63	6.26	6.24	7.09	5.53	
Combined (\$/BOE)	77.87	52.66	43.87	44.05	33.07	
Average Costs per BOE:						
Lease operations	\$ 12.12	\$ 10.59	\$ 8.73	\$ 6.72	\$ 5.30	
Production, ad valorem, and severance taxes	7.66	5.51	4.43	4.39	3.36	
Depletion, depreciation, and amortization	15.80	13.59	10.09	8.25	5.38	
Impairment of long-lived assets	4.12					
Exploration	2.71	2.05	2.71	1.39	0.44	
General and administrative	3.35	2.89	2.06	1.67	1.33	
Derivative fair value loss (gain)	(23.97)	8.31	(2.17)	0.51	0.56	
Provision for doubtful accounts	0.14	0.43	0.18	0.02		
Other operating expense	0.90	1.26	0.72	0.89	0.56	
Marketing loss (gain)	(0.06)	(0.11)	0.09			
Consolidated Statements of Cash Flows Data:						
Cash provided by (used in):						
Operating activities	\$ 663,237	\$ 319,707	\$ 297,333	\$ 292,269	\$ 171,821	
Investing activities	(728,346)	(929,556)	(397,430)	(573,560)	(433,470)	
Financing activities	65,444	610,790	99,206	281,842	262,321	
Proved Reserves:						
Oil (Bbls)	134,452	188,587	153,434	148,387	134,048	
Natural gas (Mcf)	307,520	256,447	306,764	283,865	234,030	
Combined (BOE)	185,705	231,328	204,561	195,698	173,053	
Consolidated Balance Sheets Data:						
Working capital	\$ 188,678	\$ (16,220)	\$ (40,745)	\$ (56,838)	\$ (15,566)	
Total assets	3,633,195	2,784,561	2,006,900	1,705,705	1,123,400	
Long-term debt	1,319,811	1,120,236	661,696	673,189	379,000	
Stockholders equity	1,314,128	948,155	816,865	546,781	473,575	

(a) For 2008, 2007, 2006, 2005, and 2004, we reduced oil and natural gas revenues for net profits interests by \$56.5 million, \$32.5 million, \$23.4 million, \$21.2 million, and \$12.6 million, respectively.

- (b) In 2006, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases assisted us in marketing our production by decreasing our dependence on individual markets. These activities allowed us to aggregate larger volumes, facilitated our efforts to maximize the prices we received for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled us to reach other markets. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March

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2007, ENP acquired a natural gas pipeline as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets. Marketing expenses include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of equity crude, the revenues of which are included in our oil revenues instead of marketing revenues.

- (c) On January 1, 2006, we adopted the provisions of SFAS No. 123R, *Share-Based Payment* (SFAS 123R). Due to the adoption of SFAS 123R, non-cash equity-based compensation expense for 2005 and 2004 has been reclassified to allocate the amount to the same respective income statement lines as the respective employees cash compensation. This resulted in increases in LOE of \$1.3 million and \$0.7 million during 2005 and 2004, respectively, increases in general and administrative (G&A) expense of \$2.6 million and \$1.1 million during 2005 and 2004, respectively.
- (d) During July 2006, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivative contracts which were previously accounted for as hedges. From that point forward, all mark-to-market gains or losses on all commodity derivative contracts are recorded in Derivative fair value loss (gain) while in periods prior to that point, only the ineffective portions of commodity derivative contracts which were designated as hedges were recorded in Derivative fair value loss (gain).
- (e) Adjusted for the effects of the 3-for-2 stock split in July 2005.
- (f) We acquired certain oil and natural gas properties and related assets in the Big Horn and Williston Basins in March 2007 and April 2007, respectively. We also acquired Crusader Energy Corporation in October 2005 and Cortez Oil & Gas, Inc. in April 2004. The operating results of these acquisitions are included in our Consolidated Statements of Operations from the date of acquisition forward. We disposed of certain oil and natural gas properties and related assets in the Mid-Continent in June 2007. The operating results of this disposition are included in our Consolidated Statements of Operations through the date of disposition.
- (g) During 2008, circumstances indicated that the carrying amounts of certain oil and natural gas properties, primarily four wells in the Tuscaloosa Marine Shale, may not be recoverable. We compared the assets' carrying amounts to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net carrying amounts of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of \$59.5 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

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

The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes and supplementary data thereto included in Item 8. Financial Statements and Supplementary Data. The following discussion and analysis contains forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Actual results could differ materially from those discussed in the forward-looking statements. We do not undertake to update, revise, or correct any of the forward-looking information unless required to do so under federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Information Concerning Forward-Looking Statements and Item 1A. Risk Factors.

Introduction

In this management's discussion and analysis of financial condition and results of operations, the following are discussed and analyzed:

Overview of Business

2008 Highlights

Recent Developments

2009 Outlook

Results of Operations

Comparison of 2008 to 2007

Comparison of 2007 to 2006

Capital Commitments, Capital Resources, and Liquidity

Changes in Prices

Critical Accounting Policies and Estimates

New Accounting Pronouncements

Information Concerning Forward-Looking Statements

Overview of Business

We are a Delaware corporation engaged in the acquisition, development, exploitation, exploration, and production of oil and natural gas reserves from onshore fields in the United States. Our business strategies include:

Maintaining an active development program to maximize existing reserves and production;

Utilizing enhanced oil recovery techniques to maximize existing reserves and production;

Expanding our reserves, production, and development inventory through a disciplined acquisition program;

Exploring for reserves; and

Operating in a cost effective, efficient, and safe manner.

At December 31, 2008, our oil and natural gas properties had estimated total proved reserves of 134.5 MMBbls of oil and 307.5 Bcf of natural gas, based on December 31, 2008 spot market prices of \$44.60

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per Bbl of oil and \$5.62 per Mcf of natural gas. On a BOE basis, our proved reserves were 185.7 MMBOE at December 31, 2008, of which approximately 72 percent was oil and approximately 80 percent was proved developed. Based on 2008 production, our ratio of reserves to production was approximately 12.9 years for total proved reserves and 10.3 years for proved developed reserves as of December 31, 2008.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Average NYMEX oil prices strengthened in the first half of 2008 to record levels, but have since experienced a significant deterioration. In addition, our oil wellhead differentials to NYMEX improved in 2008 as we realized 90 percent of the average NYMEX oil price, as compared to 88 percent in 2007. Average NYMEX natural gas prices strengthened in the first half of 2008 to their highest levels since 2005, but have since experienced a significant deterioration. Our natural gas wellhead differentials to NYMEX deteriorated slightly in 2008 as we realized 95 percent of the average NYMEX natural gas price, as compared to 98 percent in 2007. Commodity prices are influenced by many factors that are outside of our control. We cannot accurately predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by entering into commodity derivative contracts for a portion of our forecasted future production. For a discussion of factors that influence commodity prices and risks associated with our commodity derivative contracts, please read Item 1A. Risk Factors.

During 2008, we did not make a significant acquisition of proved reserves. Instead, we acquired unproved acreage in our core areas, continued to make significant investments within our core areas to develop proved undeveloped reserves and increase production from proved developed reserves through various recovery techniques, and made significant investments for exploration within our areas of unproved acreage. We continue to believe that a portfolio of long-lived quality assets will position us for future success.

In May 2008, we announced that our Board had authorized our management team to explore a broad range of strategic alternatives to further enhance shareholder value, including, but not limited to, a sale or merger of the company. In conjunction, our Board approved a retention plan for all of our then-current employees, excluding members of our strategic team, providing for the payment of four months of base salary or base rate of pay, as applicable, upon the completion of the strategic alternatives process, subject to continued employment. This bonus was paid in August 2008.

In July 2008, our Board and management team decided that a sale or merger of the company was not currently in the best interest of our shareholders. In conjunction, our Board approved a separate retention plan for all of our then-current employees, excluding our Chairman and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment.

Our 2008 results of operations include approximately \$7.6 million of pre-tax expense related to the four-month retention plan and approximately \$6.9 million of pre-tax expense related to the eight-month retention plan.

2008 Highlights

Our financial and operating results for 2008 included the following:

Our oil and natural gas revenues increased 58 percent to \$1.1 billion as compared to \$712.9 million in 2007 as a result of increased production volumes and higher average realized prices.

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Our average realized oil price increased 51 percent to \$89.30 per Bbl as compared to \$58.96 per Bbl in 2007. Our average realized natural gas price increased 38 percent to \$8.63 per Mcf as compared to \$6.26 per Mcf in 2007.

Our average daily production volumes increased six percent to 39,470 BOE/D as compared to 37,094 BOE/D in 2007. Oil represented 70 percent and 71 percent of our total production volumes in 2008 and 2007, respectively.

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Our production margin (defined as oil and natural gas wellhead revenues less production expenses) increased 54 percent to \$842.0 million as compared to \$548.5 million in 2007. Total oil and natural gas wellhead revenues per BOE increased by 38 percent while total production expenses per BOE increased by 23 percent. On a per BOE basis, our production margin increased 44 percent to \$58.29 per BOE as compared to \$40.52 per BOE for 2007.

We reported record net income for 2008, which increased to \$430.8 million (\$8.07 per diluted share) from the \$17.2 million (\$0.32 per diluted share) reported for 2007.

We invested \$775.9 million in oil and natural gas activities (excluding asset retirement obligations of \$0.6 million), of which \$618.5 million was invested in development, exploitation, and exploration activities, yielding 282 gross (104.8 net) productive wells, and \$157.4 million was invested in acquisitions, primarily of unproved acreage.

Recent Developments

In January 2009, we sold certain oil and natural gas producing properties and related assets in the Arkoma Basin and royalty interest properties in Oklahoma as well as 10,300 unleased mineral acres to ENP. The sales price was \$49 million in cash, subject to customary adjustments (including a reduction in the purchase price for acquisition-related commodity derivative premiums of approximately \$3 million).

2009 Outlook

For 2009, the Board has approved a \$310 million capital budget for oil and natural gas related activities, excluding proved property acquisitions. We expect to fund our 2009 capital expenditures within cash flows from operations and use the additional cash flows from operations to reduce our debt levels. The following table represents the components of our 2009 capital budget (in thousands):

Drilling	\$ 215,000
Improved oil recovery, workovers	60,000
Land, seismic, and other	35,000
Total	\$ 310,000

The prices we receive for our oil and natural gas production are largely based on current market prices, which are beyond our control. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects based on management's outlook of future commodity prices. If NYMEX prices continue to trend downward, we may further reevaluate our capital projects. Since the end of 2008, oil NYMEX prices have declined from \$44.60 per Bbl to below \$39.00 per Bbl in mid-February 2009 and natural gas NYMEX prices have declined from \$5.62 per Mcf to below \$4.25 per Mcf over the same period. The price risk on a significant portion of our forecasted oil and natural gas production for 2009 is mitigated using commodity derivative contracts. Please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our commodity derivative contracts. We intend to continue to enter into commodity derivative

transactions to mitigate the impact of price volatility on our oil and natural gas revenues. Significant factors that will impact near-term commodity prices include the following:

the duration and severity of the worldwide economic recession;

political developments in Iraq, Iran, Venezuela, Nigeria, and other oil-producing countries;

the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas;

Russia's increasing position as a major supplier of natural gas to world markets;

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the level of economic growth in China, India, and other developing countries;

concerns that major oil fields throughout the world have reached peak production;

the level of interest rates;

oilfield service costs;

the potential for terrorist activity; and

the value of the U.S. dollar relative to other currencies.

We expect to continue to pursue asset acquisitions, but expect to confront intense competition for these assets from third parties.

First Quarter 2009 Outlook

We expect our total average daily production volumes to be approximately 39,900 to 41,100 BOE/D in the first quarter of 2009, net of average daily net profits production volumes of approximately 900 to 1,100 BOE/D. We expect our oil wellhead differentials as a percentage of NYMEX to widen in the first quarter of 2009 to a negative 22 percent as compared to the negative 20 percent differential we realized in the fourth quarter of 2008. We expect our natural gas wellhead differentials as a percentage of NYMEX to improve in the first quarter of 2009 to a positive three percent as compared to the negative 14 percent differential we realized in the fourth quarter of 2008.

In the first quarter of 2009, we expect our LOE to average \$12.75 to \$13.25 per BOE, including approximately \$2.5 million (\$0.68 per BOE) for retention bonuses related to the strategic alternatives process to be paid in August 2009. We expect our production taxes to average approximately 9.5 percent of wellhead revenues in the first quarter of 2009. In the first quarter of 2009, we expect our depletion, depreciation, and amortization (DD&A) expense to average \$18.00 to \$18.50 per BOE. In the first quarter of 2009, we expect our G&A expense to average \$3.50 to \$4.00 per BOE, including approximately \$1.7 million (\$0.46 per BOE) for retention bonuses related to the strategic alternatives process to be paid in August 2009.

During the first quarter of 2009, we expect our effective tax rate to be approximately 38 percent, 95 percent of which is expected to be deferred.

We do not expect to reduce our total debt levels during the first quarter of 2009.

Table of Contents**ENCORE ACQUISITION COMPANY**Results of Operations**Comparison of 2008 to 2007**

Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period's respective production volumes and average prices:

	Year Ended December 31,		<i>Increase</i>	
	2008	2007	\$	%
Revenues (in thousands):				
Oil wellhead	\$ 900,300	\$ 606,112	\$ 294,188	
Oil commodity derivative contracts	(2,857)	(43,295)	40,438	
Total oil revenues	\$ 897,443	\$ 562,817	\$ 334,626	59%
Natural gas wellhead	\$ 227,479	\$ 160,399	\$ 67,080	
Natural gas commodity derivative contracts		(10,292)	10,292	
Total natural gas revenues	\$ 227,479	\$ 150,107	\$ 77,372	52%
Combined wellhead	\$ 1,127,779	\$ 766,511	\$ 361,268	
Combined commodity derivative contracts	(2,857)	(53,587)	50,730	
Total combined oil and natural gas revenues	\$ 1,124,922	\$ 712,924	\$ 411,998	58%
Average realized prices:				
Oil wellhead (\$/Bbl)	\$ 89.58	\$ 63.50	\$ 26.08	
Oil commodity derivative contracts (\$/Bbl)	(0.28)	(4.54)	4.26	
Total oil revenues (\$/Bbl)	\$ 89.30	\$ 58.96	\$ 30.34	51%
Natural gas wellhead (\$/Mcf)	\$ 8.63	\$ 6.69	\$ 1.94	
Natural gas commodity derivative contracts (\$/Mcf)		(0.43)	0.43	
Total natural gas revenues (\$/Mcf)	\$ 8.63	\$ 6.26	\$ 2.37	38%
Combined wellhead (\$/BOE)	\$ 78.07	\$ 56.62	\$ 21.45	
Combined commodity derivative contracts (\$/BOE)	(0.20)	(3.96)	3.76	
Total combined oil and natural gas revenues (\$/BOE)	\$ 77.87	\$ 52.66	\$ 25.21	48%
Total production volumes:				
Oil (MBbls)	10,050	9,545	505	5%
Natural gas (MMcf)	26,374	23,963	2,411	10%

Combined (MBOE)	14,446	13,539	907	7%
Average daily production volumes:				
Oil (Bbl/D)	27,459	26,152	1,307	5%
Natural gas (Mcf/D)	72,060	65,651	6,409	10%
Combined (BOE/D)	39,470	37,094	2,376	6%
Average NYMEX prices:				
Oil (per Bbl)	\$ 99.75	\$ 72.45	\$ 27.30	38%
Natural gas (per Mcf)	\$ 9.04	\$ 6.86	\$ 2.18	32%

Oil revenues increased 59 percent from \$562.8 million in 2007 to \$897.4 million in 2008 as a result of an increase in our average realized oil price and an increase in oil production volumes of 505 MBbls. The

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increase in oil production volumes contributed approximately \$32.1 million in additional oil revenues and was primarily the result of a full year of production from our Big Horn Basin acquisition in March 2007 and our Williston Basin acquisition in April 2007, as well as our development program in the Bakken.

Our average realized oil price increased \$30.34 per Bbl from 2007 to 2008 primarily as a result of an increase in our average realized oil wellhead price, which increased oil revenues by approximately \$262.1 million, or \$26.08 per Bbl. Our average realized oil wellhead price increased primarily as a result of the increase in the average NYMEX price from \$72.45 per Bbl in 2007 to \$99.75 per Bbl in 2008.

During July 2006, we elected to discontinue hedge accounting prospectively for all remaining commodity derivative contracts which were previously accounted for as hedges. While this change had no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. As a result, oil revenues for 2008 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately \$2.9 million, or \$0.28 per Bbl, while 2007 included approximately \$43.3 million, or \$4.54 per Bbl, of net losses.

Our average daily production volumes were decreased by 1,530 BOE/D and 1,466 BOE/D in 2008 and 2007, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by \$55.3 million and \$31.9 million in 2008 and 2007, respectively.

Natural gas revenues increased 52 percent from \$150.1 million in 2007 to \$227.5 million in 2008 as a result of an increase in our average realized natural gas price and an increase in natural gas production volumes of 2,411 MMcf. The increase in natural gas production volumes contributed approximately \$16.1 million in additional natural gas revenues and was primarily the result of our development program in our Permian Basin and Mid-Continent regions.

Our average realized natural gas price increased \$2.37 per Mcf from 2007 to 2008 primarily as a result of an increase in our average realized natural gas wellhead price, which increased natural gas revenues by approximately \$50.9 million, or \$1.94 per Mcf. Our average realized natural gas wellhead price increased primarily as a result of the increase in the average NYMEX price from \$6.86 per Mcf in 2007 to \$9.04 per Mcf in 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for 2007 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately \$10.3 million, or \$0.43 per Mcf.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2008	2007
Oil wellhead (\$/Bbl)	\$ 89.58	\$ 63.50
Average NYMEX (\$/Bbl)	\$ 99.75	\$ 72.45
Differential to NYMEX	\$ (10.17)	\$ (8.95)
Oil wellhead to NYMEX percentage	90%	88%

Natural gas wellhead (\$/Mcf)	\$ 8.63	\$ 6.69
Average NYMEX (\$/Mcf)	\$ 9.04	\$ 6.86
Differential to NYMEX	\$ (0.41)	\$ (0.17)
Natural gas wellhead to NYMEX percentage	95%	98%

Our oil wellhead price as a percentage of the average NYMEX price was 90 percent in 2008 as compared to 88 percent in 2007. Our natural gas wellhead price as a percentage of the average NYMEX price was 95 percent in 2008 as compared to 98 percent in 2007.

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Marketing revenues and expenses. In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets. Marketing expenses include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of oil production, the revenues of which are included in our oil revenues instead of marketing revenues. The following table summarizes our marketing activities for the periods indicated:

	Year Ended December 31,		Decrease	
	2008	2007	\$	%
	(In thousands, except per BOE amounts)			
Marketing revenues	\$ 10,496	\$ 42,021	\$ (31,525)	(75)%
Marketing expenses	9,570	40,549	(30,979)	(76)%
Marketing gain	\$ 926	\$ 1,472	\$ (546)	(37)%
Marketing revenues per BOE	\$ 0.72	\$ 3.10	\$ (2.38)	(77)%
Marketing expenses per BOE	0.66	2.99	(2.33)	(78)%
Marketing gain, per BOE	\$ 0.06	\$ 0.11	\$ (0.05)	(45)%

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Year Ended December 31,		Increase/(Decrease)	
	2008	2007	\$	%
Expenses (in thousands):				
Production:				
Lease operations	\$ 175,115	\$ 143,426	\$ 31,689	
Production, ad valorem, and severance taxes	110,644	74,585	36,059	
Total production expenses	285,759	218,011	67,748	31%
Other:				
Depletion, depreciation, and amortization	228,252	183,980	44,272	
Impairment of long-lived assets	59,526		59,526	
Exploration	39,207	27,726	11,481	
General and administrative	48,421	39,124	9,297	

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Derivative fair value loss (gain)	(346,236)	112,483	(458,719)	
Provision for doubtful accounts	1,984	5,816	(3,832)	
Other operating	12,975	17,066	(4,091)	
Total operating	329,888	604,206	(274,318)	(45)%
Interest	73,173	88,704	(15,531)	
Income tax provision	241,621	14,476	227,145	
Total expenses	\$ 644,682	\$ 707,386	\$ (62,704)	(9)%

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	Year Ended December 31,		Increase/(Decrease)	
	2008	2007	\$	%
Expenses (per BOE):				
Production:				
Lease operations	\$ 12.12	\$ 10.59	\$ 1.53	
Production, ad valorem, and severance taxes	7.66	5.51	2.15	
Total production expenses	19.78	16.10	3.68	23%
Other:				
Depletion, depreciation, and amortization	15.80	13.59	2.21	
Impairment of long-lived assets	4.12		4.12	
Exploration	2.71	2.05	0.66	
General and administrative	3.35	2.89	0.46	
Derivative fair value loss (gain)	(23.97)	8.31	(32.28)	
Provision for doubtful accounts	0.14	0.43	(0.29)	
Other operating	0.90	1.26	(0.36)	
Total operating	22.83	44.63	(21.80)	(49)%
Interest	5.07	6.55	(1.48)	
Income tax provision	16.73	1.07	15.66	
Total expenses	\$ 44.63	\$ 52.25	\$ (7.62)	(15)%

Production expenses. Total production expenses increased 31 percent from \$218.0 million in 2007 to \$285.8 million in 2008 as a result of higher total production volumes and an increase in the per BOE rate.

Production expense attributable to LOE increased \$31.7 million from \$143.4 million in 2007 to \$175.1 million in 2008 as a result of a \$1.53 increase in the average per BOE rate, which contributed approximately \$22.1 million of additional LOE, and an increase in production volumes, which contributed approximately \$9.6 million of additional LOE. The increase in our average LOE per BOE rate was attributable to:

increases in prices paid to oilfield service companies and suppliers;

increases in natural gas prices resulting in higher electricity costs and gas plant fuel costs;

higher compensation levels for engineers and other technical professionals; and

an increase of (1) approximately \$4.7 million (\$0.32 per BOE) for retention bonuses paid in August 2008 and (2) approximately \$4.1 million (\$0.28 per BOE) for retention bonuses to be paid in August 2009, related to our strategic alternatives process.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) increased \$36.1 million from \$74.6 million in 2007 to \$110.6 million in 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained approximately constant at 9.8 percent in 2008 as compared to 9.7 percent in 2007.

DD&A expense. DD&A expense increased \$44.3 million from \$184.0 million in 2007 to \$228.3 million in 2008 as a result of a \$2.21 increase in the per BOE rate, which contributed approximately \$32.0 million of additional DD&A expense, and an increase in production volumes, which contributed approximately \$12.3 million of additional DD&A expense. The increase in our average DD&A per BOE rate was attributable to higher costs incurred resulting from increases in rig rates, pipe costs, and acquisition costs and the decrease in our total proved reserves to 185.7 MMBOE as of December 31, 2008 as compared to 231.3 MMBOE as of December 31, 2007.

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Impairment of long-lived assets. During 2008, circumstances indicated that the carrying amounts of certain oil and natural gas properties, primarily four wells in the Tuscaloosa Marine Shale, may not be recoverable. We compared the assets' carrying amounts to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net carrying amounts of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of \$59.5 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

Exploration expense. Exploration expense increased \$11.5 million from \$27.7 million in 2007 to \$39.2 million in 2008. During 2008, we expensed 8 exploratory dry holes totaling \$14.7 million. During 2007, we expensed 5 exploratory dry holes totaling \$14.7 million. Impairment of unproved acreage increased \$9.4 million from \$10.8 million in 2007 to \$20.2 million in 2008, primarily due to our larger unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table illustrates the components of exploration expenses for the periods indicated:

	Year Ended December 31,		
	2008	2007	Increase
	(In thousands)		
Dry holes	\$ 14,683	\$ 14,673	\$ 10
Geological and seismic	2,851	1,455	1,396
Delay rentals	1,482	784	698
Impairment of unproved acreage	20,191	10,814	9,377
Total	\$ 39,207	\$ 27,726	\$ 11,481

G&A expense. G&A expense increased \$9.3 million from \$39.1 million in 2007 to \$48.4 million in 2008, primarily due to:

a full year of ENP public entity expenses;

higher activity levels;

increased personnel costs due to intense competition for human resources within the industry; and

an increase of (1) approximately \$2.9 million for retention bonuses paid in August 2008 and (2) approximately \$2.8 million for retention bonuses to be paid in August 2009, related to our strategic alternatives process;

partially offset by a \$3.1 million decrease in non-cash equity-based compensation.

Derivative fair value loss (gain). During 2008, we recorded a \$346.2 million derivative fair value gain as compared to a \$112.5 million derivative fair value loss in 2007, the components of which were as follows:

	Year Ended December 31,		<i>Increase/ (Decrease)</i>
	2008	2007	
	(In thousands)		
Ineffectiveness on designated derivative contracts	\$ 372	\$	\$ 372
Mark-to-market loss (gain) on derivative contracts	(365,495)	36,272	(401,767)
Premium amortization	62,352	41,051	21,301
Settlements on commodity derivative contracts	(43,465)	35,160	(78,625)
Total derivative fair value loss (gain)	\$ (346,236)	\$ 112,483	\$ (458,719)

The change in our derivative fair value loss (gain) was a result of the addition of commodity derivative contracts in the first part of 2008 when prices were high and the significant decrease in prices during the end of 2008, which favorably impacted the fair values of those contracts.

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During 2009, 2010, and 2011, we expect to make payments for deferred premiums of commodity derivative contracts of \$67.0 million, \$15.7 million, and \$0.9 million, respectively.

Provision for doubtful accounts. In 2008 and 2007, we recorded a provision for doubtful accounts of \$2.0 million and \$5.8 million, respectively, for the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense decreased \$4.1 million from \$17.1 million in 2007 to \$13.0 million in 2008, primarily due to a \$7.4 million loss on the sale of certain Mid-Continent properties in 2007, partially offset by a \$3.4 million increase during 2008 in third-party transportation costs to move our production to markets outside the immediate area of production.

Interest expense. Interest expense decreased \$15.5 million from \$88.7 million in 2007 to \$73.2 million in 2008, primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP's IPO to reduce weighted average outstanding borrowings on our revolving credit facilities, (2) a reduction in LIBOR, and (3) our use of interest rate swaps to fix the rate on a portion of outstanding borrowings on ENP's revolving credit facility. The weighted average interest rate for all long-term debt for 2008 was 5.6 percent as compared to 6.9 percent for 2007.

The following table illustrates the components of interest expense for the periods indicated:

	Year Ended December 31,		Increase/ (Decrease)
	2008	2007	
	(In thousands)		
6.25% Notes	\$ 9,727	\$ 9,705	\$ 22
6.0% Notes	18,550	18,517	33
7.25% Notes	10,996	10,988	8
Revolving credit facilities	31,038	46,085	(15,047)
Other	2,862	3,409	(547)
Total	\$ 73,173	\$ 88,704	\$ (15,531)

Minority interest. As of December 31, 2008, public unitholders owned approximately 37 percent of ENP's common units. We consolidate ENP's results of operations in our consolidated financial statements and show the public ownership as minority interest. Minority interest in income of ENP was approximately \$54.3 million for 2008 as compared to a loss of \$7.5 million for 2007.

Income taxes. In 2008, we recorded an income tax provision of \$241.6 million as compared to \$14.5 million in 2007. In 2008, we had income before income taxes, net of minority interest, of \$672.4 million as compared to \$31.6 million in 2007. Our effective tax rate decreased to 35.9 percent in 2008 as compared to 45.8 percent in 2007 primarily due to the 2007 recognition of non-deductible deferred compensation.

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Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period's respective production volumes and average prices:

	Year Ended December 31,		<i>Increase/ (Decrease)</i>	
	2007	2006	\$	%
Revenues (in thousands):				
Oil wellhead	\$ 606,112	\$ 399,180	\$ 206,932	
Oil commodity derivative contracts	(43,295)	(52,206)	8,911	
Total oil revenues	\$ 562,817	\$ 346,974	\$ 215,843	62%
Natural gas wellhead	\$ 160,399	\$ 154,458	\$ 5,941	
Natural gas commodity derivative contracts	(10,292)	(8,133)	(2,159)	
Total natural gas revenues	\$ 150,107	\$ 146,325	\$ 3,782	3%
Combined wellhead	\$ 766,511	\$ 553,638	\$ 212,873	
Combined commodity derivative contracts	(53,587)	(60,339)	6,752	
Total combined oil and natural gas revenues	\$ 712,924	\$ 493,299	\$ 219,625	45%
Average realized prices:				
Oil wellhead (\$/Bbl)	\$ 63.50	\$ 54.42	\$ 9.08	
Oil commodity derivative contracts (\$/Bbl)	(4.54)	(7.12)	2.58	
Total oil revenues (\$/Bbl)	\$ 58.96	\$ 47.30	\$ 11.66	25%
Natural gas wellhead (\$/Mcf)	\$ 6.69	\$ 6.59	\$ 0.10	
Natural gas commodity derivative contracts (\$/Mcf)	(0.43)	(0.35)	(0.08)	
Total natural gas revenues (\$/Mcf)	\$ 6.26	\$ 6.24	\$ 0.02	0%
Combined wellhead (\$/BOE)	\$ 56.62	\$ 49.24	\$ 7.38	
Combined commodity derivative contracts (\$/BOE)	(3.96)	(5.37)	1.41	
Total combined oil and natural gas revenues (\$/BOE)	\$ 52.66	\$ 43.87	\$ 8.79	20%
Total production volumes:				
Oil (MBbls)	9,545	7,335	2,210	30%
Natural gas (MMcf)	23,963	23,456	507	2%
Combined (MBOE)	13,539	11,244	2,295	20%

Average daily production volumes:

Oil (Bbl/D)	26,152	20,096	6,056	30%
Natural gas (Mcf/D)	65,651	64,262	1,389	2%
Combined (BOE/D)	37,094	30,807	6,287	20%

Average NYMEX prices:

Oil (per Bbl)	\$ 72.45	\$ 66.26	\$ 6.19	9%
Natural gas (per Mcf)	\$ 6.86	\$ 7.17	\$ (0.31)	(4)%

Oil revenues increased \$215.8 million from \$347.0 million in 2006 to \$562.8 million in 2007, primarily due to an increase in oil production volumes and an increase in our average realized oil price. Our production volumes increased 2,210 MBbls from 2007 to 2008, which contributed approximately \$120.3 million in

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additional oil revenues. The increase in production volumes was the result of our Big Horn Basin acquisition in March 2007, our Williston Basin acquisition in April 2007, and our development program.

Our average realized oil price increased \$11.66 per Bbl primarily as a result of an increase in our average realized wellhead price, which increased oil revenues by \$86.7 million, or \$9.08 per Bbl. Our average realized oil wellhead price increased primarily as a result of the increase in the average NYMEX price from \$66.26 per Bbl in 2006 to \$72.45 per Bbl in 2007. In addition, as a result of our discontinuance of hedge accounting in July 2006, oil revenues for 2007 included amortization of net losses of certain commodity derivative contracts that were previously designated as hedges of approximately \$43.3 million, or \$4.54 per Bbl, while 2006 included approximately \$52.2 million, or \$7.12 per Bbl, of net losses.

Our oil wellhead revenue was reduced by \$31.9 million and \$22.8 million in 2007 and 2006, respectively, for net profits interests related to our CCA properties.

Natural gas revenues increased \$3.8 million from \$146.3 million in 2006 to \$150.1 million in 2007, primarily due to an increase in production volumes of 507 MMcf, which contributed approximately \$3.3 million in additional natural gas revenues. The increase in natural gas production volumes was the result of our West Texas joint development agreement with ExxonMobil and our development program in the Mid-Continent area, partially offset by natural gas production sold in conjunction with our Mid-Continent asset disposition in 2007.

Our average realized natural gas price increased \$0.02 per Mcf primarily as a result of an increase in our wellhead price, which increased natural gas revenues by \$2.6 million, or \$0.10 per Mcf. Our average natural gas wellhead price increased as a result of the tightening of our natural gas differential despite decreases in the overall market price for natural gas, as reflected in the decrease in the average NYMEX price from \$7.17 per Mcf in 2006 to \$6.86 per Mcf in 2007. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for 2007 included amortization of net losses of certain commodity derivative contracts that were previously designated as hedges of approximately \$10.3 million, or \$0.43 per Mcf, while 2006 included approximately \$8.1 million, or \$0.35 per Mcf, of net losses.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2007	2006
Oil wellhead (\$/Bbl)	\$ 63.50	\$ 54.42
Average NYMEX (\$/Bbl)	\$ 72.45	\$ 66.26
Differential to NYMEX	\$ (8.95)	\$ (11.84)
Oil wellhead to NYMEX percentage	88%	82%
Natural gas wellhead (\$/Mcf)	\$ 6.69	\$ 6.59
Average NYMEX (\$/Mcf)	\$ 6.86	\$ 7.17
Differential to NYMEX	\$ (0.17)	\$ (0.58)
Natural gas wellhead to NYMEX percentage	98%	92%

Our oil wellhead price as a percentage of the average NYMEX price tightened to 88 percent in 2007 as compared to 82 percent in 2006. Our natural gas wellhead price as a percentage of the average NYMEX price improved to 98 percent in 2007 as compared to 92 percent in 2006. The differential improved because of efforts to reduce natural gas transportation and gathering costs.

Marketing revenues and expenses. In 2006, we purchased third-party oil Bbls from counterparties other than to whom the Bbls were sold for aggregation and sale with our own production in various markets. These purchases assisted us in marketing our production by decreasing our dependence on individual markets. These

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activities allowed us to aggregate larger volumes, facilitated our efforts to maximize the prices we received for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled us to reach other markets.

In 2007, we discontinued purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change allowed us to focus on the marketing of our own production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

The following table summarizes our marketing activities for the periods indicated:

	Year Ended December 31,		<i>Increase/(Decrease)</i>	
	2007	2006	\$	%
	(In thousands, except per BOE amounts)			
Marketing revenues	\$ 42,021	\$ 147,563	\$ (105,542)	(72)%
Marketing expenses	40,549	148,571	(108,022)	(73)%
Marketing gain (loss)	\$ 1,472	\$ (1,008)	\$ 2,480	(246)%
Marketing revenues per BOE	\$ 3.10	\$ 13.12	\$ (10.02)	(76)%
Marketing expenses per BOE	2.99	13.21	(10.22)	(77)%
Marketing gain (loss), per BOE	\$ 0.11	\$ (0.09)	\$ 0.20	(222)%

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Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Year Ended December 31,		<i>Increase/ (Decrease)</i>	
	2007	2006	\$	%
Expenses (in thousands):				
Production:				
Lease operations	\$ 143,426	\$ 98,194	\$ 45,232	
Production, ad valorem, and severance taxes	74,585	49,780	24,805	
Total production expenses	218,011	147,974	70,037	47%
Other:				
Depletion, depreciation, and amortization	183,980	113,463	70,517	
Exploration	27,726	30,519	(2,793)	
General and administrative	39,124	23,194	15,930	
Derivative fair value loss (gain)	112,483	(24,388)	136,871	
Provision for doubtful accounts	5,816	1,970	3,846	
Other operating	17,066	8,053	9,013	
Total operating	604,206	300,785	303,421	101%
Interest	88,704	45,131	43,573	
Income tax provision	14,476	55,406	(40,930)	
Total expenses	\$ 707,386	\$ 401,322	\$ 306,064	76%
Expenses (per BOE):				
Production:				
Lease operations	\$ 10.59	\$ 8.73	\$ 1.86	
Production, ad valorem, and severance taxes	5.51	4.43	1.08	
Total production expenses	16.10	13.16	2.94	22%
Other:				
Depletion, depreciation, and amortization	13.59	10.09	3.50	
Exploration	2.05	2.71	(0.66)	
General and administrative	2.89	2.06	0.83	
Derivative fair value loss (gain)	8.31	(2.17)	10.48	
Provision for doubtful accounts	0.43	0.18	0.25	
Other operating	1.26	0.71	0.55	
Total operating	44.63	26.74	17.89	67%
Interest	6.55	4.01	2.54	
Income tax provision	1.07	4.93	(3.86)	

Total expenses	\$	52.25	\$	35.68	\$	16.57	46%
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Production expenses. Total production expenses increased \$70.0 million from \$148.0 million in 2006 to \$218.0 million in 2007 due to higher total production volumes and a \$2.94 increase in production expenses per BOE. Our production margin increased by \$142.8 million (35 percent) to \$548.5 million in 2007 as compared to \$405.7 million in 2006. Total production expenses per BOE increased by 22 percent while total oil and natural gas wellhead revenues per BOE increased by 15 percent. On a per BOE basis, our production margin increased 12 percent to \$40.52 per BOE for 2007 as compared to \$36.08 per BOE for 2006.

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Production expense attributable to LOE increased \$45.2 million from \$98.2 million in 2006 to \$143.4 million in 2007, primarily as a result of a \$1.86 increase in the average per BOE rate, which contributed approximately \$25.2 million of additional LOE, and higher production volumes, which contributed approximately \$20.0 million of additional LOE. The increase in our average LOE per BOE rate was attributable to:

increases in prices paid to oilfield service companies and suppliers;

increased operational activity to maximize production;

HPAI expenses at the CCA; and

higher salary levels for engineers and other technical professionals.

Production expense attributable to production taxes increased \$24.8 million from \$49.8 million in 2006 to \$74.6 million in 2007. The increase was primarily due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.7 percent in 2007 as compared to 9.0 percent in 2006 as a result of higher rates in the states where the properties associated with our Big Horn Basin and Williston Basin asset acquisitions are located.

DD&A expense. DD&A expense increased \$70.5 million from \$113.5 million in 2006 to \$184.0 million in 2007 due to a \$3.50 increase in the per BOE rate and higher production volumes. The per BOE rate increased due to the higher cost basis of the properties associated with our Big Horn Basin and Williston Basin asset acquisitions, development of proved undeveloped reserves, and higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately \$47.3 million, while the increase in production volumes resulted in additional DD&A expense of approximately \$23.2 million.

Exploration expense. Exploration expense decreased \$2.8 million from \$30.5 million in 2006 to \$27.7 million in 2007. During 2007, we expensed 5 exploratory dry holes totaling \$14.7 million. During 2006, we expensed 14 exploratory dry holes totaling \$17.3 million. The following table details our exploration expenses for the periods indicated:

	Year Ended December 31,		Increase/ (Decrease)
	2007	2006	
	(In thousands)		
Dry holes	\$ 14,673	\$ 17,257	\$ (2,584)
Geological and seismic	1,455	1,720	(265)
Delay rentals	784	670	114
Impairment of unproved acreage	10,814	10,872	(58)
Total	\$ 27,726	\$ 30,519	\$ (2,793)

G&A expense. G&A expense increased \$15.9 million from \$23.2 million in 2006 to \$39.1 million in 2007, primarily due to:

a \$6.4 million increase in non-cash equity-based compensation expense;

increased staffing to manage our larger asset base;

higher activity levels; and

increased personnel costs due to intense competition for human resources within the industry.

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Derivative fair value loss (gain). During 2007, we recorded a \$112.5 million derivative fair value loss as compared to a \$24.4 million derivative fair value gain in 2006, the components of which were as follows:

	Year Ended December 31, 2007 2006 (In thousands)		Increase/ (Decrease)
Ineffectiveness on designated cash flow hedges	\$	\$ 1,748	\$ (1,748)
Mark-to-market loss (gain) on commodity derivative contracts	36,272	(31,205)	67,477
Premium amortization	41,051	13,926	27,125
Settlements on commodity derivative contracts	35,160	(8,857)	44,017
Total derivative fair value loss (gain)	\$ 112,483	\$ (24,388)	\$ 136,871

Provision for doubtful accounts. Provision for doubtful accounts increased \$3.8 million from \$2.0 million in 2006 to \$5.8 million in 2007, primarily due to an increase in the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense increased \$9.0 million from \$8.1 million in 2006 to \$17.1 million in 2007, primarily due to a \$7.4 million loss on the sale of certain Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of production.

Interest expense. Interest expense increased \$43.6 million from \$45.1 million in 2006 to \$88.7 million in 2007, primarily due to additional debt used to finance the Big Horn Basin and Williston Basin asset acquisitions. The weighted average interest rate for all long-term debt for 2007 was 6.9 percent as compared to 6.1 percent for 2006.

The following table illustrates the components of interest expense for the periods indicated:

	Year Ended December 31, 2007 2006 (In thousands)		Increase/ (Decrease)
6.25% Notes	\$ 9,705	\$ 9,684	\$ 21
6.0% Notes	18,517	18,418	99
7.25% Notes	10,988	10,984	4
Revolving credit facilities	46,085	3,609	42,476
Other	3,409	2,436	973
Total	\$ 88,704	\$ 45,131	\$ 43,573

Minority interest. As of December 31, 2007, public unitholders in ENP had a limited partner interest of approximately 40 percent. We consolidate ENP in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest loss in ENP was \$7.5 million for 2007.

Income taxes. During 2007, we recorded an income tax provision of \$14.5 million as compared to \$55.4 million in 2006. Our effective tax rate increased to 45.8 percent in 2007 as compared to 37.5 percent in 2006 primarily due to a permanent rate adjustment for ENP's management incentive units, a state rate adjustment due to larger apportionment of future taxable income to states with higher tax rates, and permanent timing adjustments that will not reverse in future periods.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments. Our primary needs for cash are:

Development, exploitation, and exploration of oil and natural gas properties;

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Acquisitions of oil and natural gas properties;

Funding of necessary working capital; and

Contractual obligations.

Development, exploitation, and exploration of oil and natural gas properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Development and exploitation	\$ 362,111	\$ 270,016	\$ 253,484
Exploration	256,437	97,453	95,205
Total	\$ 618,548	\$ 367,469	\$ 348,689

Our development and exploitation expenditures primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital for 2008 yielded 186 gross (73.4 net) successful wells and 5 gross (3.1 net) dry holes. Our exploration expenditures primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for 2008 yielded 96 gross (31.4 net) successful wells and 8 gross (3.8 net) dry holes. Please read Items 1 and 2. Business and Properties Development Results for a description of the areas in which we drilled wells during 2008.

Acquisitions of oil and natural gas properties and leasehold acreage. The following table summarizes our costs incurred (excluding asset retirement obligations) related to oil and natural gas property acquisitions for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Acquisitions of proved property	\$ 28,729	\$ 787,988	\$ 4,486
Acquisitions of leasehold acreage	128,635	52,306	24,462
Total	\$ 157,364	\$ 840,294	\$ 28,948

In March 2007, Encore Operating and OLLC acquired oil and natural gas properties in the Big Horn Basin, including properties in the Elk Basin and the Gooseberry fields for approximately \$393.6 million. In April 2007, we acquired oil

and natural gas properties in the Williston Basin for approximately \$392.1 million.

During 2008, our capital expenditures for leasehold acreage costs totaled \$128.6 million, \$45.2 million of which related to the exercise of preferential rights in the Haynesville area and the remainder of which related to the acquisition of unproved acreage in various areas. During 2007, our capital expenditures for leasehold acreage costs totaled \$52.3 million, \$16.1 million of which related to the Williston Basin asset acquisition and the remainder of which related to the acquisition of unproved acreage in various areas. During 2006, our capital expenditures for leasehold acreage costs totaled \$24.5 million, all of which related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. As of December 31, 2008 and 2007, our working capital (defined as total current assets less total current liabilities) was \$188.7 million and negative \$16.2 million, respectively. The increase in 2008 as compared to 2007 was primarily attributable to a decrease in commodity prices at December 31, 2008 as compared to December 31, 2007, which positively impacted the fair value of our outstanding commodity derivative contracts.

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For 2009, we expect working capital to remain positive, primarily due to the fair value of our outstanding derivative contracts. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and reduce outstanding borrowings and related interest expense under our revolving credit facility. However, we have availability under our revolving credit facility to fund our obligations as they become due. We do not plan to pay cash dividends in the foreseeable future. Our production volumes, commodity prices, and differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by production volumes and commodity prices. Given our current commodity derivative contracts, assuming constant or increasing production volumes, our operating cash flow should remain positive in 2009.

The Board approved a capital budget of \$310 million for 2009, excluding proved property acquisitions. The level of these and other future expenditures are largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow and borrowings under our revolving credit facility.

Off-balance sheet arrangements. We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. We have no off-balance sheet arrangements that are material to our financial position or results of operations.

Contractual obligations. The following table illustrates our contractual obligations and commitments at December 31, 2008:

Contractual Obligations and Commitments	Maturity Date	Total	Payments Due by Period			
			2009	2010 -	2012 -	Thereafter
				2011	2013	
(In thousands)						
6.25% Notes(a)	4/15/2014	\$ 201,563	\$ 9,375	\$ 18,750	\$ 18,750	\$ 154,688
6.0% Notes(a)	7/15/2015	426,000	18,000	36,000	36,000	336,000
7.25% Notes(a)	12/1/2017	247,875	10,875	21,750	21,750	193,500
Revolving credit facilities(a)	3/7/2012	789,626	19,885	39,770	729,971	
Commodity derivative contracts(b)						
Interest rate swaps		4,342	1,269	3,071	2	
Capital lease obligations		1,747	466	932	349	
Development commitments(c)		134,860	134,860			