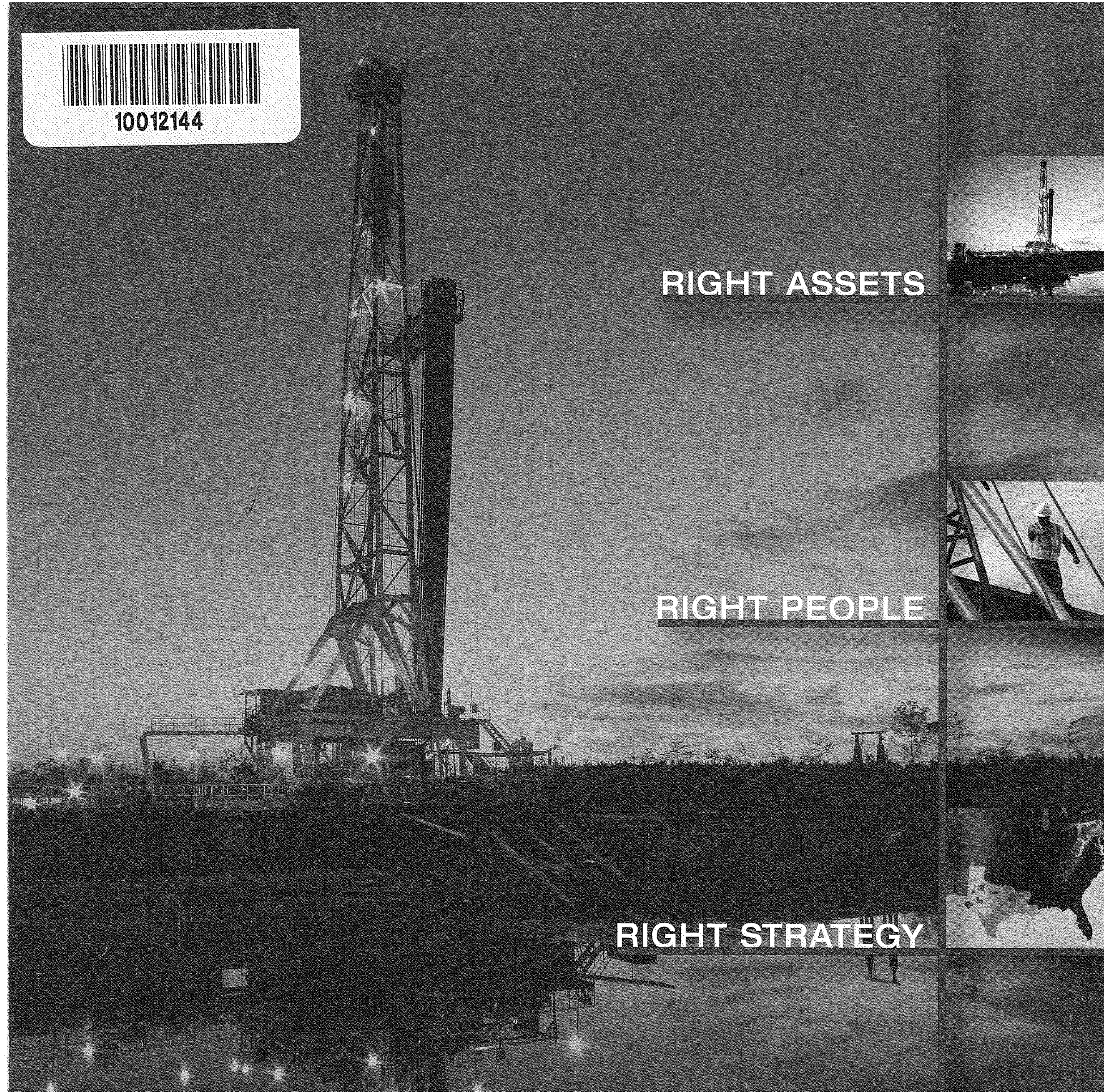
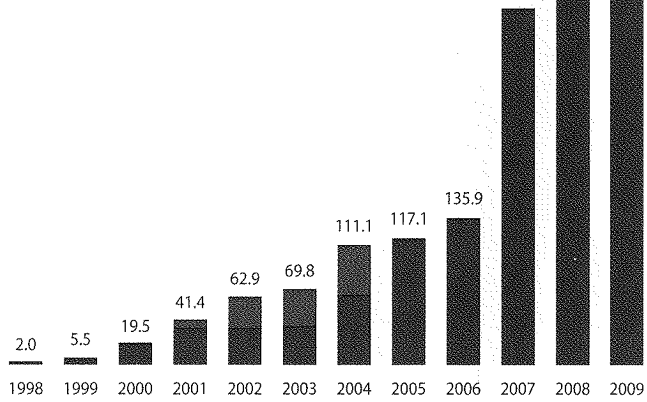


EXCO RESOURCES, INC.

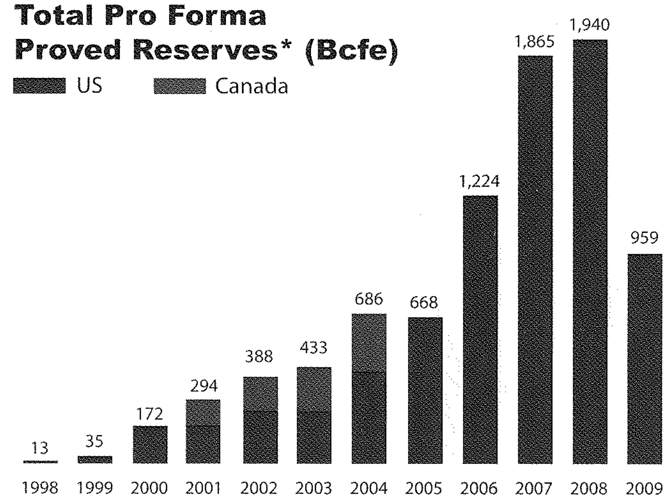
ANNUAL REPORT 2009

Daily Pro Forma Production* (Mmcfed)



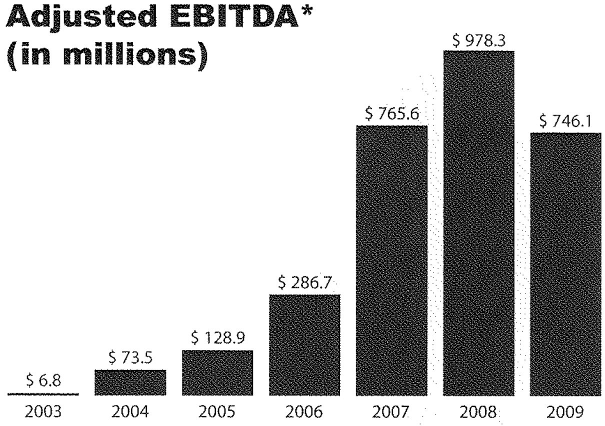
We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Daily production in 2005 is pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.

Total Pro Forma Proved Reserves* (Bcfe)



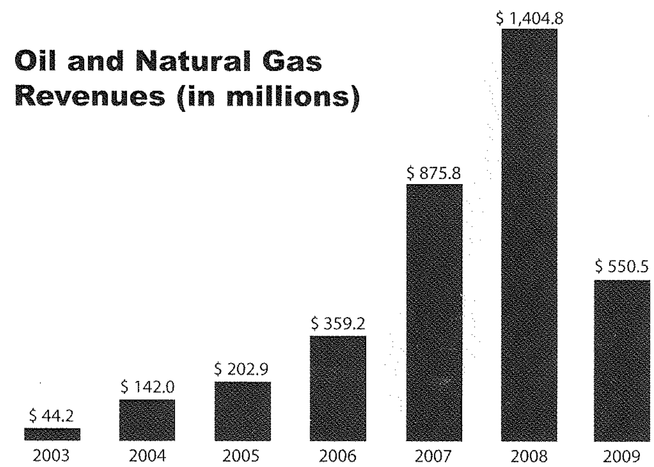
** We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Total proved reserves in 2005 are pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.*

Adjusted EBITDA* (in millions)



** See our website at www.excoresources.com under Investor Relations for a reconciliation of this non-GAAP measure.*

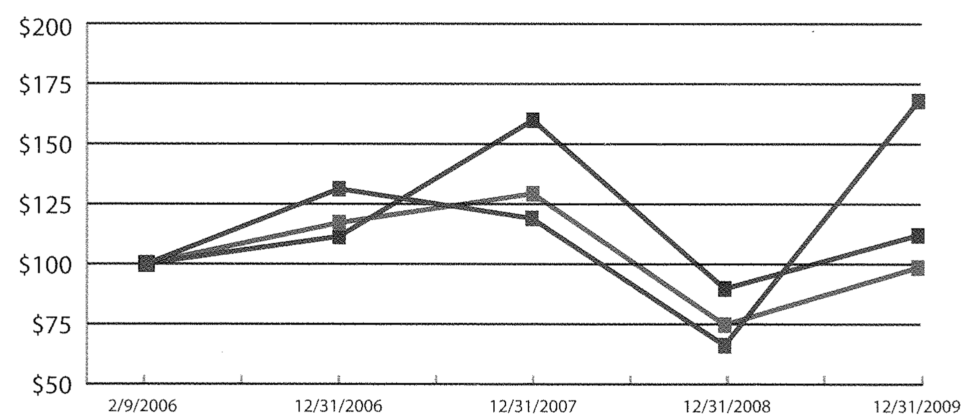
Oil and Natural Gas Revenues (in millions)



EXCO's Common Stock Performance

The graph to the right compares the cumulative total return (what $100 invested on February 9, 2006, the date of our IPO, would be worth on December 31, 2009) on the company's common stock with the cumulative total return on the NYSE Market Index and the Crude Petroleum and Natural Gas SIC Code Index.

These historical comparisons are not a forecast of the future performance of our common stock or the referenced indexes.



	Period Ended				
	2/9/2006	12/31/2006	12/31/2007	12/31/2008	12/31/2009
EXCO Resources, Inc.	$ 100.00	$ 129.58	$ 118.62	$ 69.43	$ 163.13
Crude Petroleum & Natural Gas	$ 100.00	$ 110.79	$ 155.74	$ 91.13	$ 111.51
NYSE Market Index	$ 100.00	$ 116.85	$ 127.21	$ 77.27	$ 99.13

Financial Highlights

(in millions, except production, wells drilled, productive wells, reserves and prices)

	Years ended December 31,					
Results of Operations*	*Non-GAAP combined 2005*	*2006*	*2007*	*2008*	*2009*	*2008-2009 Change*
Oil and natural gas revenues						
(before effects of derivative financial instruments)	$ 202.9	$ 359.2	$ 875.8	$ 1,404.8	$ 550.5	-61%
Midstream revenues	$ -	$ 8.1	$ 18.8	$ 85.4	$ 35.3	-59%
Adjusted EBITDA	$ 128.9	$ 286.7	$ 765.6	$ 978.3	$ 746.1	-24%
Net income (loss) available to common shareholders	$ 1.2	$ 139.0	$ (83.3)	$ (1,810.5)	$ (496.8)	73%
Net cash flow provided by (used in) operating activities	$ (72.9)	$ 227.7	$ 577.8	$ 975.0	$ 433.6	-56%
Total production (Bcfe)	23.5	49.6	121.3	144.6	128.2	-11%
Productive wells drilled (gross)	108	367	495	467	101	-78%
Drilling success rate	97%	98%	98%	98%	98%	0%
Total acreage (gross)	1.0	1.5	1.8	2.1	1.2	-43%
Total productive wells (gross)	6,468	8,964	10,312	13,213	7,843	-41%

Financial Position*	*2005*	*2006*	*2007*	*2008*	*2009*	*2008-2009 Change*
Total assets	$1,530.5	$ 3,707.1	$ 5,955.8	$ 4,822.4	$ 2,358.9	-51%
Long-term debt, less current maturities	$ 461.8	$ 2,081.7	$ 2,099.2	$ 3,019.7	$ 1,196.3	-60%
Shareholders' equity	$ 370.9	$ 1,179.9	$ 1,115.7	$ 1,332.5	$ 859.6	-35%
Total proved reserves (Bcfe)**	442	1,224	1,865	1,940	959	-51%
Pre-tax present value, discounted at 10%	$1,248.6	$ 1,606.0	$ 3,945.9	$ 2,473.5	$ 747.7	-70%
SEC reserve prices utilized:***						
Oil (per Bbl)	$ 61.03	$ 60.82	$ 95.92	$ 44.60	$ 61.18	37%
Natural gas (per Mmbtu)	$ 10.08	$ 5.64	$ 6.80	$ 5.71	$ 3.87	-32%

* See our website at www.excoresources.com under Investor Relations for a reconciliation of non-GAAP measures, certain definitions, and explanations of and assumptions used in certain calculations.
** Does not include our wholly-owned Canadian subsidiary, Addison Energy Inc., that was sold in February 2005.
*** The SEC reserve prices utilized are adjusted for geographical and historical differentials.

Mission Statement and Guiding Principles

Mission Statement

EXCO Resources, Inc. is a natural gas and oil company engaged in the exploration, exploitation, development and production of onshore natural gas and oil properties. Our operations are focused in certain key natural gas and oil producing regions of the United States.

Our primary goal is to build value for our shareholders by enhancing the value of our assets through efficient operations, a high technology drilling program, development of our properties and exploitation of unproved upside.

Guiding Principles

At EXCO we achieve our mission within the framework established by our guiding principles.

Ethics: We are committed to transparency and conducting our business ethically and lawfully. We are accountable by taking responsibility for our actions and results.

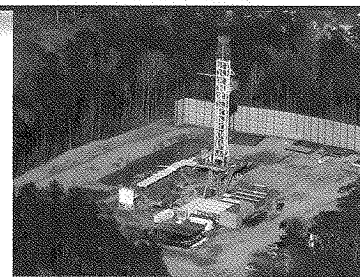
Safety: We provide a safe place to work and protect our environment.

Teamwork: We create a work environment that encourages teamwork and cooperation by treating each other with respect and understanding.

Technology: We pursue continuous improvement by encouraging technological innovation in the achievement of our goals.

Growth: We work to produce a high return and deliver on commitments to our shareholders.

Letter to Shareholders



To Our Fellow Shareholders,

For EXCO, 2009 was a highly successful year of transformation. Historically, EXCO based much of its growth on acquisitions. Over the years we assembled acreage in our core operating areas, two of which turned out to contain what many believe will be the most prolific natural gas finds in U.S. history—the Haynesville and Marcellus shale plays. With the tremendous exploration and development opportunities in these two plays we elected to divest various non-strategic properties across our portfolio which resulted in our exit from Ohio, Northwest Pennsylvania, the Rockies, and our Mid-Continent Division, among others. As a result, using year-end NYMEX strip pricing, we ended 2009 with 1.3 Tcfe of proved reserves with significant upside potential consisting of 1.8 Tcfe of probable and possible reserves and 12.8 Tcfe of potential resources. As of February 2010 we hold approximately 54,000 net acres in the Haynesville play and approximately 343,000 net acres in the Marcellus play.

We are also very excited about our joint ventures in East Texas / North Louisiana with BG Group plc, or BG Group. BG Group, which has complementary skills to EXCO, has supplemented our team with 13 secondees who have experience in upstream and midstream operations. As part of the joint venture arrangement, our finding and development costs on deep wells in the joint venture will be significantly lower going forward with BG Group paying 75% of EXCO's share of drilling and completion costs up to $400 million.

EXCO's focus on financial flexibility was realized through the combination of asset sales and joint venture proceeds resulting in $2.1 billion of proceeds which enabled us to reduce our outstanding debt by 60%. This has "right sized" our balance sheet to better support our drilling program while still providing capacity under our revolving credit facility for additional acreage purchases and opportunistic acquisitions of assets in our core areas.

Throughout 2009, we focused on hiring additional technical experts who are able to support our plan of drilling more than 100 operated horizontal Haynesville / Bossier shale wells, 11 operated horizontal Marcellus shale wells and 36 Canyon Sand wells in 2010, with the size of our technical team nearly doubling since January 2008.

Our drilling success in the Haynesville shale has exceeded our expectations. In February 2010, we had 13 operated horizontal rigs drilling. We have averaged an initial production rate of 22.8 Mmcf / d in DeSoto Parish, and we plan to complete 20-30 wells per quarter throughout 2010. Our operations team has been very successful in reducing the average number of days from spud to rig release by nearly 50%. We have recently drilled our first full-length lateral Marcellus shale well in central Pennsylvania and are making preparations to complete the well. We are very excited about our early Haynesville drilling results and prospects for the Marcellus shale.

With the significant increase in our production levels in the Haynesville shale, our marketing team and the midstream team of TGGT Holdings, in which we own a 50% interest, are diligently working to secure sufficient pipeline capacity to meet our delivery needs both now and in the future. This has led to expansion of our existing gathering systems in 2009, with additional capacity increases slated for 2010 as well. This will increase the number of market outlets available for our production which will allow our marketing team to negotiate the best prices possible for our natural gas. In Pennsylvania and West Virginia, the pipeline infrastructure is less developed throughout the region. As a result, to ensure there is sufficient future capacity to meet our production delivery requirements we are working with major marketing entities to move our gas until firm transportation capacity is available on the interstate markets.

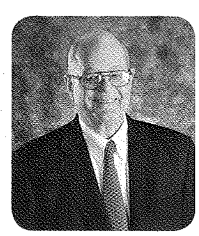
As in previous years, we continue to hedge a substantial portion of our future expected production. Our hedging strategy has resulted in a $1.22 per Mcfe increase in the average realized price received for our production over the last three years. We will actively monitor our debt levels and adjust our hedge exposure appropriately to continue protecting our cash flows from significant fluctuations in natural gas and oil prices.

We have assembled a talented team of employees who are dedicated to growing EXCO efficiently and effectively in an effort to maximize value for our shareholders. Our Haynesville shale results are just one example of our tremendous success. EXCO truly has the "Right Assets, Right People and Right Strategy."

On behalf of all of the employees of EXCO, we thank you for your continued support of our efforts to build a world class exploration and production company. We look forward to serving you in 2010.

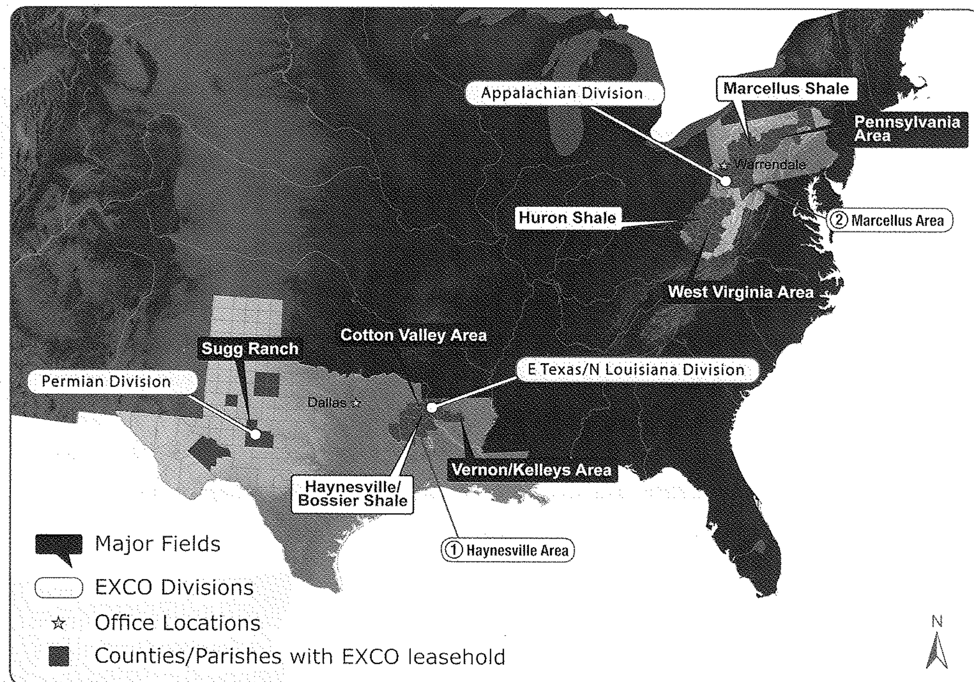
Thank you,

Douglas H. Miller
Chairman of the Board
and Chief Executive Officer



Stephen F. Smith
Vice Chairman of the
Board, President and
Chief Financial Officer

Areas of Operation



(1) Haynesville Area:

- 100% drilling success rate
- Significant production growth
- Existing infrastructure and access to multiple markets
- Readily available field services

(2) Marcellus Area:

- 343,000 net acres
- Massive reserve potential
- Great proximity to Northeast markets
- Very attractive returns

Forward-looking Statements, and SEC and NYSE Certifications

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements included in our Annual Report on Form 10-K for the year ended December 31, 2009, and our other periodic filings with the SEC.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

SEC and NYSE Certifications

The Form 10-K, included herein, which was filed by the company with the Securities and Exchange Commission (SEC) for the fiscal year ending December 31, 2009, includes, as exhibits, the certifications of our chief executive officer, chief financial officer and chief accounting officer required to be filed with the SEC. Our chief executive officer also filed his 2009 annual CEO certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

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, 2009

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 ~~0-9204~~ 1-32743

EXCO RESOURCES, INC.
(Exact name of Registrant as specified in its charter)

Texas	**74-1492779**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
12377 Merit Drive, Suite 1700, LB 82 Dallas, Texas	**75251**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(214) 368-2084**

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $0.001 par value	New York Stock Exchange

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

None

(Title of class)

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 ☒

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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant is required to submit and post such files). YES ☐ NO ☐

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 ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of February 12, 2010, the registrant had 212,054,805 outstanding shares of common stock, par value $.001 per share, which is its only class of common stock. As of the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates was $1,803,590,000.

For purposes of this calculation only, affiliates include all shares held by all officers, directors and 10% or greater shareholders.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to shareholders in connection with its 2010 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

TABLE OF CONTENTS

EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc. and its consolidated subsidiaries.

We have provided definitions of terms commonly used in the oil and natural gas industry in the "Glossary of selected oil and natural gas terms" beginning on page 29.

EXCO Resources, a Texas corporation incorporated in October 1955, is an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties. Our principal operations are conducted in key North American oil and natural gas areas including East Texas, North Louisiana, Appalachia and the Permian. In addition to our oil and natural gas producing operations, we own a 50% interest in a midstream joint venture in the East Texas/North Louisiana area. As of December 31, 2009, our Proved Reserves were approximately 1.0 Tcfe, of which 96.5% were natural gas and 67.1% were Proved Developed Reserves. As of December 31, 2009, the PV-10 and the Standardized Measure of our Proved Reserves was $747.7 million (see "—Summary of geographic areas of operations" for a reconciliation of PV-10 to Standardized Measure of Proved Reserves). For the year ended December 31, 2009, we produced 128.2 Bcfe of oil and natural gas. Based on December 2009 average daily production of 224.0 Mmcfe per day, this translates to a reserve life of approximately 11.7 years.

Our business strategy

Historically, we used acquisitions of producing properties with additional development drilling and workover opportunities and vertical drilling of development wells in established producing areas as our vehicle for growth. As a result of our acquisitions, we have accumulated an inventory of drilling locations and acreage holdings with significant potential in the Haynesville/Bossier and Marcellus shale resource plays. This shale potential has allowed us to shift our focus to exploit these shales primarily through horizontal drilling. Future acquisitions are likely to be focused on increasing our shale resource holdings in the East Texas/North Louisiana and Appalachian areas. We will continue to develop certain vertical drilling opportunities in East Texas, North Louisiana, Appalachia and Permian as economic conditions permit.

We plan to achieve reserve, production and cash flow growth by executing our strategy as highlighted below:

- ***Develop our shale resource plays***

  We hold significant acreage positions in prominent shale plays in the United States. In East Texas and North Louisiana, we own approximately 53,900 net acres in the Haynesville/Bossier shale plays. During 2008, we conducted our initial technical evaluations and drilling of test wells in the Haynesville shale. In the fourth quarter of 2008, we drilled and completed our first horizontal well in the play. In 2009, we spud 43 operated horizontal wells and entered into a joint venture with affiliates of BG Group plc, or BG Group, to jointly develop this area. In addition to our operated drilling, we participated in 20 Haynesville horizontal wells operated by others.

  Our operational focus has yielded significant improvements in drilling and completion efficiencies in our Haynesville program. Our initial horizontal wells in the program required 72 days from spud to rig release. The amount of time to drill these wells has continued to improve and our most recent wells have averaged 37 days from spud to rig release, a 50% reduction over a one-year period. By utilizing dedicated fracture stimulation fleets, the consistency in and efficiency of our fracturing operations has improved. We continue to work very closely with our midstream operations to plan the drilling and completion timing of our new wells, which allows us to flow new completions to sales promptly after fracture stimulation.

In our Appalachia region, we hold approximately 343,000 net acres in the Marcellus and Huron shale resource plays. Our principal activities to date have been focused on technical evaluations of our acreage holdings, expansion of our technical staff, evaluation of test wells and our acreage position. Our significant held-by-production position allows us to dictate our continued enhancement of the pace of development in the Marcellus and Huron shales. We have commenced with a horizontal drilling program and plan to run one horizontal drilling rig during 2010 while continuing our technical evaluations in this large geographic area.

- ***Pursue joint venture opportunities***

  The shale resource plays are capital intensive and require significant expenditures for drilling, completing, treating and pipeline take-away capacity. In our Haynesville/Bossier shale play, we entered into joint venture transactions with BG Group to jointly develop the upstream assets and expand our midstream infrastructure. The Marcellus and Huron shale areas cover a geographic area which is significantly larger than the Haynesville/Bossier shale area. We intend to seek joint venture partners in these areas to enhance our financial flexibility while developing these assets at an accelerated pace.

- ***Expand our midstream assets***

  We jointly own a midstream company in our East Texas/North Louisiana operating area with BG Group. These assets enhance our ability to promptly hook-up our wells for delivery of our production to markets. We are presently completing construction of a 36-inch diameter 29-mile header system in DeSoto Parish, Louisiana and expanding our other gathering systems in East Texas and North Louisiana to facilitate the rapid production growth resulting from our Haynesville shale drilling program. In Appalachia, we intend to pursue similar midstream expansions as part of our operating strategy. These expansions will also provide opportunities to transport third party gas and generate incremental gathering and transportation fee income.

- ***Exploit our multi-year development inventory***

  Our prior strategy of acquiring producing properties created a portfolio with a multi-year inventory of shale and conventional drilling locations and exploitation projects. This inventory consists of step-out drilling, infill drilling, exploratory drilling, workovers and recompletions. In 2009, we drilled and completed 41 horizontal wells with a 100% drilling success rate. Despite reducing our vertical drilling program in 2009 from prior years due to low commodity prices, we still participated in the drilling and completion of 62 vertical wells with a 96.8% success rate. As of December 31, 2009, we have identified 11,856 drilling locations and 1,497 exploitation projects across our portfolio.

- ***Maintain financial flexibility***

  We employ the use of debt and equity, along with a comprehensive derivative financial instrument program, to support our business strategy. This approach enhances our ability to execute our business plan over the entire commodity price cycle, protect our returns on investments and manage our capital structure. Our derivative financial instruments contributed $478.5 million of cash settlements which offset low commodity prices during 2009. During 2009, our joint venture strategy and divestiture program resulted in a reduction of debt from $3.0 billion at the beginning of 2009 to $1.2 billion by the end of 2009 (prior to receipt of $53.8 million of acreage reimbursements from our joint venture partner subsequent to December 31, 2009).

- ***Actively manage our portfolio and associated costs***

  We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs, properties that are not within our core geographic operating areas and properties that are not strategic. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives. During 2009, we completed asset divestitures, excluding the joint venture transactions with BG Group, totaling approximately $1.1 billion of proceeds. The divestiture program resulted in our exiting a number of areas, including the Mid-Continent operating area and our operations in the state of Ohio.

- ***Seek acquisitions that meet our strategic and financial objectives in our core operating areas***

  Historically, we have maintained a disciplined acquisition process to identify and acquire properties in our core operating areas that have established production histories and value enhancement potential through development drilling and exploitation projects. Our shale resource plays have created a shift in our acquisition focus from producing properties to opportunistic acreage acquisitions with additional shale potential. Acreage acquisitions differ from our prior strategy of acquiring producing properties as the acreage does not result in immediate production and cash flows or provide an incremental borrowing base increase under our credit agreements. As a result, our acreage acquisition strategy will be dependent on our available borrowing base.

- ***Identify and exploit upside opportunities on our acquired properties***

  Our acquisitions and their resulting shale upside have led to significant reserve addition opportunities above those identified at the date of acquisition. In our East Texas/North Louisiana area, we plan to aggressively drill horizontal wells, implement down spacing of wells, and recomplete existing wells to enhance our production and reserve position. In Appalachia, our focus will be directed toward unconventional drilling and exploitation of the Marcellus shale resource play. We continue to exploit our Permian assets, which have resulted in higher oil production than originally expected.

Our strengths

We have a number of strengths that we believe will help us successfully execute our strategy.

- ***High quality asset base in attractive regions***

  We own, and plan to maintain, a geographically diversified reserve base. Our principal operations are in the East Texas/North Louisiana, Appalachia and Permian areas. Our properties are generally characterized by:

  - long reserve lives;
  - exploration opportunities;
  - a multi-year inventory of development drilling and exploitation projects;
  - high drilling success rates;
  - a high natural gas concentration; and
  - significant unproved reserves and resources.

- ***Skilled technical personnel with supplemental support and expertise from our joint venture partner***

  Our acquisitions and hiring programs have provided us with skilled multi-disciplined technical and operational personnel who have allowed us to rapidly ramp up our horizontal drilling program. In addition, our access to BG Group's personnel in the East Texas/North Louisiana area supplement our execution strategy.

- ***Shale resource plays***

  Our Haynesville, Bossier, Marcellus and Huron shale resource plays present significant opportunities to grow our reserves with low finding and development costs. Since the majority of the acreage in these areas is held-by-production, we are not forced to commit large amounts of capital over a short period of time to avoid lease expirations.

- ***Experienced management team with significant employee ownership***

  Our management team has led both public and private oil and natural gas companies over the past 20 years and has an average of over 26 years of industry experience in exploring, acquiring, developing and exploiting oil and natural gas properties. Our management team first purchased a significant ownership interest in us in December 1997, and since then we have achieved substantial growth in reserves and production. Since the beginning of 1998, we have increased our Proved Reserves from approximately 4.7 Bcfe to approximately 1.0 Tcfe for December 2009, and our average daily production increased from less than 1 Mmcfe per day in 1997 to 224.0 Mmcfe per day for December 31, 2009. As of February 10, 2010, our named executives (excluding our outside directors) own approximately 4.6% of our issued and outstanding common stock and exercisable stock options and our outside directors and/or their affiliated investment funds own approximately 28.1% of our issued and outstanding common stock and exercisable stock options, which aligns their objectives with those of our shareholders.

- ***Operational control***

  We operate a significant portion of our properties, coupled with significant held-by-production acreage, which permits us to manage our operating costs and better control capital expenditures as well as the timing of development and exploitation activities. As of December 31, 2009, we operated 7,416 gross wells which represented approximately 97.0% of our Proved Reserves.

Plans for 2010

Our efforts in 2009 were primarily focused on ramping up our drilling activities in the Haynesville shale, de-leveraging our balance sheet and executing our divestiture program to allow for increased attention on exploitation of our shale play assets. Commodity prices were substantially lower in 2009 compared with 2008 and presented significant challenges to economically develop our portfolio. However, the impacts of these lower commodity prices were substantially mitigated by our derivative financial instruments program.

The closing of our upstream and midstream joint venture transactions with BG Group, coupled with our successful divestiture program, provided us with cash to execute our horizontal drilling program in East Texas/ North Louisiana, strategically add to our acreage position and reduce our debt by $1.8 billion. In addition to the cash received from BG Group in connection with the upstream joint venture transaction, BG Group also agreed to fund $400.0 million of capital development attributable to our 50% interest in the venture, or the BG Carry, with BG Group paying 75% of our share of drilling and completion costs in the Haynesville/Bossier shales until the $400.0 million funding is satisfied. The BG Carry applies only to drilling and completion activities below the Cotton Valley formation, particularly focusing on the Haynesville/Bossier shales. Other expenditures are shared equally between EXCO and BG Group.

Our plans for 2010 are focused on the Haynesville/Bossier and Marcellus shales. Budgeted capital expenditures for 2010 total $471.4 million, of which $409.4 million, or 86.8%, is allocated to our East Texas/ North Louisiana and Appalachia regions. In East Texas and North Louisiana, capital expenditures in the area of mutual interest with BG Group, or BG AMI, are expected to total $740.8 million, with EXCO's share being approximately $165.3 million, which reflects the favorable impact of $205.1 million to be funded pursuant to the BG Carry. In Appalachia, our planned capital expenditures total $154.2 million.

The 2010 capital budget includes $39.1 million for midstream activities, which includes a $7.8 million contribution to TGGT Holdings, LLC, or TGGT. TGGT is the newly formed midstream joint venture owned equally by EXCO and BG Group. TGGT owns the midstream assets located within the BG AMI in East Texas and North Louisiana. The TGGT capital budget for 2010 is $101.0 million, $50.5 million net to EXCO's interest. This budget will be mostly funded by internal TGGT cash flow. In addition, the management of TGGT is evaluating several expansion projects which, if approved, will require additional capital contributions.

We expect commodity prices, particularly for natural gas, to be volatile and this volatility may have an impact on our drilling activities. We have consistently used derivative financial instruments as a strategy to mitigate commodity price volatility and we expect to continue to enter into derivative financial instruments as opportunities arise.

Significant activities during 2009

Haynesville shale

In the fourth quarter of 2008, we completed our first horizontal well in the Haynesville shale. In 2009, we significantly expanded our activities in this area, both internally during the first and second quarters and jointly with BG Group beginning in the third quarter, to become a significant operator in the play. We spud 43 operated horizontal wells in 2009 and completed and turned to sales 25 wells. We are presently operating 13 drilling rigs in the area. In DeSoto Parish, Louisiana, where we have focused our 2009 drilling, our average initial production rate per well has averaged 22.8 Mmcf per day. The addition of BG Group as a strategic partner will allow us to accelerate drilling in the area in 2010 and beyond. Another strategic component in the Haynesville area is our ownership interest in TGGT. The integration with TGGT provides us with timely well connections and priority pipeline space to deliver our production to market.

Marcellus shale

Our efforts in 2009 in the Marcellus shale were focused on testing and evaluating our shale holdings to determine the best areas and techniques for development. This consisted of drilling and coring vertical test wells, analyzing cores and logs, testing stimulation methods and solving future marketing, logistics and regulatory issues associated with this shale play. As a result of these efforts, we have shifted our focus to horizontal well drilling primarily in central Pennsylvania, where we are beginning a horizontal drilling program. We are also planning expansion of our midstream assets in the area to accommodate the expected future natural gas production from both EXCO and third party development.

Joint ventures and divestiture program

A summary of our joint venture and divestiture activities during 2009 is presented on the following table. Proceeds from the transactions were used to reduce our debt and fund our capital program.

(in thousands)	Proceeds(1)
Operating division	
East Texas/North Louisiana	
BG Upstream Transaction	$ 713,779
BG Midstream Transaction	269,237
East Texas Transaction	154,299
Other East Texas/North Louisiana	22,327
Mid-Continent	
Mid-Continent Transaction	197,730
Sheridan Transaction(2)	531,351
Other Mid-Continent	5,482
Appalachia	
EnerVest Transaction(2)(3)	129,737
Permian	40,042
Total joint ventures and divestitures	$2,063,984

(1) Net of selling expenses.

(2) Subject to final closing adjustments.

(3) Pending receipt of an additional $13.1 million of consents.

On August 11, 2009, we closed a sale of properties located in East Texas, or the East Texas Transaction, with Encore Operating, LP, or Encore. Pursuant to the East Texas Transaction, we sold all of our interests in certain oil and natural gas properties located in our Overton Field and Gladewater area of East Texas. We received $154.3 million in cash, after final closing adjustments.

On August 11, 2009, we closed a sale of properties located in Texas and Oklahoma, or the Mid-Continent Transaction, with Encore. Pursuant to the Mid-Continent Transaction, we sold all of our interests in certain oil and natural gas properties located in our Mid-Continent operating area. We received $197.7 million in cash, after final closing adjustments.

On August 14, 2009, we closed a sale and joint development transaction with BG Group for the sale of an undivided 50% of our interest in the BG AMI, which included most of our oil and natural gas assets in East Texas and North Louisiana (excluding the Vernon Field, Gladewater area, Overton Field and Redland Field), or the BG Upstream Transaction. The BG Upstream Transaction includes agreements for the joint development and operation of our Haynesville and Bossier shales as well as the shallow Cotton Valley and other formations located in the BG AMI. We received $713.8 million in cash, after final closing adjustments necessary to reflect the January 1, 2009 effective date. Pursuant to this transaction, BG Group will also fund $400.0 million of capital development attributable to our 50% interest, with BG Group paying 75% of our share of drilling and completion costs on the deep rights (Haynesville and Bossier shales) until the $400.0 million commitment is satisfied. Under the terms of the agreement, BG Group's funding of the $400.0 million commitment will be satisfied solely through drilling of deep right wells as defined in the agreement. As of December 31, 2009, the remaining balance of the BG Carry was approximately $367.7 million.

In addition, on August 14, 2009, we closed the sale of 50% of our membership interest in TGGT to an affiliate of BG Group which now holds most of our East Texas and North Louisiana midstream assets, or the BG Midstream Transaction. Our Vernon Field midstream assets were excluded from the BG Midstream Transaction. Pursuant to the contribution agreement, we contributed TGG Pipeline, Ltd., or TGG, which owns an intrastate pipeline in East Texas and a gathering system in North Louisiana and Talco Midstream Assets, Ltd., or Talco, which owns gathering assets in East Texas and North Louisiana, to TGGT. BG Group contributed $269.2 million in cash, after final closing adjustments, to TGGT and we received those funds from TGGT as a special distribution at closing. EXCO Operating Company, LP, or EXCO Operating, now owns 50% of TGGT and the affiliate of BG Group owns 50% of TGGT. The effective date of this transaction was also January 1, 2009.

The total cash proceeds of $983.0 million from the BG Upstream Transaction and the BG Midstream Transaction were used to repay EXCO Operating's $300.0 million senior unsecured term credit agreement, or the Term Credit Agreement, create an evergreen escrow funding account to develop the Haynesville operations, and provide a working capital contribution to TGGT, with the remainder applied to the outstanding balances under EXCO Operating's credit agreement.

On November 10, 2009, we closed the sale of our remaining assets in our Mid-Continent operating area to Sheridan Holding Company I, LLC, or the Sheridan Transaction, for $531.4 million, subject to final closing adjustments. The sale was effective as of October 1, 2009.

On November 24, 2009, we closed the sale of certain Ohio and Northwestern Pennsylvania producing assets to EV Energy Partners, L.P., along with certain institutional partnerships managed by EnerVest, Ltd., or the EnerVest Transaction, for $129.7 million, subject to final closing adjustments. In connection with the closing, the parties agreed to hold back approximately $13.1 million of the properties pending the receipt of required consents from third parties necessary to transfer such properties. The sale was effective as of September 1, 2009.

During the year, we also closed sales of other non-strategic assets across all of our operating areas, resulting in net cash proceeds of approximately $67.9 million after final closing adjustments.

Acreage acquisitions

As part of our ongoing shale-focused strategy, we acquired acreage within the BG AMI in the Haynesville/Bossier shale play throughout 2009. A substantial amount of this acreage was acquired in the fourth quarter, where we completed acquisitions of undeveloped acreage and other assets for approximately $251.5 million. Pursuant to terms contained within the agreement in the BG Upstream Transaction, we offered BG Group 50% of these acquisitions under terms identical to our acquisition agreements. BG Group has 60 days to elect to participate for their share of acquisitions. BG has elected to acquire their 50% interest in all cases in which the election period has been completed.

In our Appalachia region, we completed acreage acquisitions totaling $6.6 million in 2009.

Debt reduction

During 2009, we reduced our consolidated debt to $1.2 billion as of December 31, 2009 from $3.0 billion as of December 31, 2008. The reductions were the result of our successful joint venture transactions with BG Group and our divestiture program. The joint ventures and divestitures also affected the borrowing bases in our two revolving credit agreements. A summary of our outstanding long-term debt as of December 31, 2009 and 2008 is as follows:

(in thousands)	December 31, 2009	December 31, 2008
EXCO Resources Credit Agreement	$ 81,486	$1,048,951
EXCO Operating Credit Agreement	666,078	1,218,485
Term Credit Agreement	—	300,000
7 1/4% Senior Notes due January 15, 2011	444,720	444,720
Unamortized premium on 7 1/4% Senior Notes due January 15, 2011	3,993	7,582
Total debt	$1,196,277	$3,019,738

As of December 31, 2009, we had cash and cash equivalents of $68.4 million and $58.9 million of restricted cash. The restricted cash is principally comprised of our share of an evergreen escrow account with BG Group which is used to fund our share of operations and development within the BG AMI.

A summary of each of our revolving credit agreements, senior notes and other debt is presented below.

EXCO Resources credit agreement. The EXCO Resources credit agreement, as amended, or the EXCO Resources Credit Agreement, matures on March 30, 2012 and had a borrowing base of $450.0 million as of December 31, 2009.

EXCO Operating credit agreement. The EXCO Operating credit agreement, as amended, or the EXCO Operating Credit Agreement, matures on March 30, 2012 and had a borrowing base of $850.0 million as of December 31, 2009.

7 1/4% senior notes due January 15, 2011. EXCO has issued 7 1/4% senior notes due January 15, 2011, or the Senior Notes, totaling $444.7 million as of December 31, 2009. Interest is payable semi-annually on January 15 and July 15 of each year. We presently have sufficient borrowing capacity under the EXCO Resources Credit Agreement and the EXCO Operating Credit Agreement to pay the Senior Notes.

Term Credit Agreement. In connection with the closings of the BG Upstream Transaction and the BG Midstream Transaction, the Term Credit Agreement was paid in full on August 14, 2009. The Term Credit Agreement was due and payable on January 15, 2010. As a result of the early payment of the Term Credit Agreement, EXCO Operating avoided payment of a $9.0 million duration fee that would have been due on September 15, 2009.

Summary of geographic areas of operations

The following tables set forth summary operating information attributable to our principal geographic areas of operation:

Areas	Total Proved Reserves (Bcfe)(1)	PV-10 (in millions)(1)(2)	Average December daily net production (Mmcfe)	Reserve life (years)(3)
East Texas/North Louisiana	630.0	$562.7	168.0	10.3
Appalachia	264.8	107.3	38.0	19.1
Permian and other	64.0	77.7	18.0	9.7
Total	958.8	$747.7	224.0	11.7

Areas	Identified drilling locations(4)	Identified exploitation projects(5)	Total gross acreage	Total net acreage(6)
East Texas/North Louisiana	3,798	930	266,047	155,945
Appalachia	7,592	537	726,499	654,168
Permian and other	466	30	190,059	137,420
Total	11,856	1,497	1,182,605	947,533

(1) The total Proved Reserves and PV-10 for non-shale properties, excluding future plugging and abandonment costs, of the Proved Reserves, as used in this table, were prepared by Lee Keeling and Associates, Inc., or Lee Keeling, an independent petroleum engineering firm located in Tulsa, Oklahoma. The total Proved Reserves and PV-10 for our shale properties, excluding future plugging and abandonment costs, as used in the table, were prepared by Haas Petroleum Engineering Services, Inc., or Haas Engineering, an independent petroleum engineering firm located in Dallas, Texas. For each area set forth in the table, the Proved Reserves were extracted from the reports from Lee Keeling and Haas Engineering by our internal engineers. The estimated future plugging and abandonment costs necessary to compute PV-10 were computed internally.

(2) The PV-10 data used in this table is based on the simple average spot prices for the trailing twelve month period using the first day of each month beginning on January 1, 2009 and ended on December 1, 2009, of $3.87 per Mmbtu for natural gas and $61.18 per Bbl for oil, in each case adjusted for geographical and historical differentials. Market prices for oil and natural gas are volatile. See "Item 1A. Risk factors—Risks relating to our business." We believe that PV-10 before income taxes, while not a financial measure in accordance with generally accepted accounting principles, or GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total Standardized Measure, a measure recognized under GAAP, for our Proved Reserves as of December 31, 2009 was $747.4 million. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," or ASC 932. The 32.2% decrease in the natural gas price at December 31, 2009 compared with December 31, 2008 resulted in significantly lower future net revenues and future net cash flows. Our existing net operating loss carry-forwards combined with reduced cash flows eliminated estimated future taxable income. The amount of estimated future plugging and abandonment costs, the PV-10 of these costs and the Standardized Measure were determined by us. We do not designate our derivative financial instruments as hedges and accordingly, do not include the impact of derivative financial instruments when computing the Standardized Measure. The following table provides a reconciliation of our PV-10 to our Standardized Measure as of December 31, 2009.

(in millions)	At December 31, 2009	2008	2007
PV-10	$747.7	$2,473.5	$ 3,945.9
Future income taxes	—	(649.8)	(1,857.5)
Discount of future income taxes at 10% per annum	—	412.6	1,030.5
Standardized Measure	$747.7	$2,236.3	$ 3,118.9

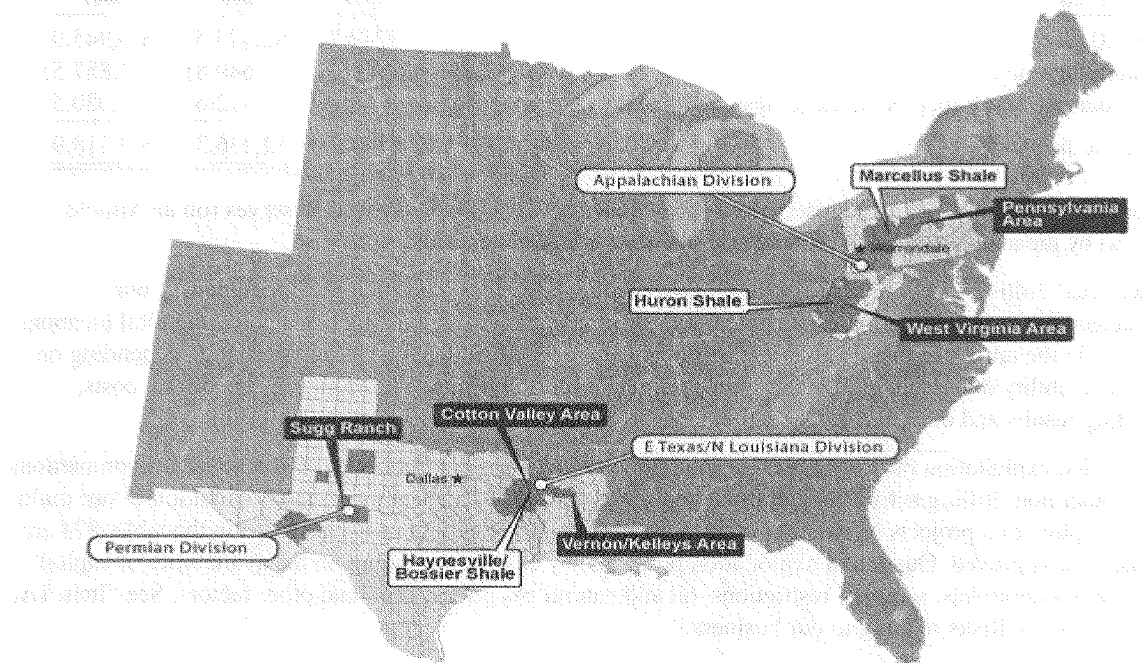
(3) For purposes of this table, the reserve life is calculated by dividing the Proved Reserves (on an Mmcfe basis) by the annualized daily production volumes for December 2009.

(4) Identified drilling locations represent total gross drilling locations identified and scheduled by our management as an estimation of our multi-year drilling activities on existing acreage. Of the total locations shown in the table, 1,726 are classified as proved. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors. See "Item 1A. Risk factors—Risks relating to our business."

(5) Identified exploitation projects represent total gross exploitation projects, such as workovers, recompletions, and other non-drilling activities, identified and scheduled by our management as an estimation of our multi-year exploitation projects on existing acreage. Of the total exploitation projects shown in the table, 874 are classified as proved. Our actual exploitation projects may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs and other factors. See "Item 1A. Risk factors—Risks relating to our business."

(6) Includes 38,638, 95,851 and 25,557 net acres with leases expiring in 2010, 2011 and 2012, respectively. Net acreage at December 31, 2009 reflects a reduction of 7,341 acres that BG Group elected to acquire after December 31, 2009, pursuant to the BG AMI.

Our development and exploitation project areas



East Texas/North Louisiana

The East Texas/North Louisiana area is comprised of the Cotton Valley Sand trend, which covers portions of the East Texas Basin and the Northern Louisiana Salt Basin, and the Haynesville shale play that rapidly developed in northwest Louisiana and East Texas beginning in 2008. EXCO operates or participates in over 1,300 total wells in the area and has significant operations base and infrastructure in East Texas and North Louisiana. We are targeting tight gas sand reservoirs along the Cotton Valley Sand trend at depths of approximately 6,500 to 15,000 feet. Operations in the area are generally characterized by long-lived reserves, high drilling success rates and wells with relatively high initial production rates. Due to the tight nature of the reservoirs, development programs are mostly focused on infill development drilling and extension of field limits. The Haynesville/Bossier shale plays lie beneath the Cotton Valley. Our Haynesville shale targets are approximately 12,000 feet true vertical depth and developed with horizontal wells that are typically approximately 16,500 feet measured depth. Based on our 2009 results we have realized in the shale play, the majority of our focus in this area will be on horizontal shale development drilling.

Haynesville/Bossier shale

In the Haynesville/Bossier shale resource play in the East Texas/Northwest Louisiana area we hold approximately 53,900 net acres. The core area of the Haynesville shale is located in Desoto and Caddo Parishes in Louisiana and Harrison and Panola Counties in Texas. A large percentage of our core area acreage is held by our existing Cotton Valley, Hosston and Travis Peak production. During the fourth quarter of 2009, we acquired 14,700 net acres in several transactions, all located in the core area of the shale play. This additional acreage is complementary to our existing acreage, operations and pipeline infrastructure and provides significant additional development potential in the play.

Our development program in the Haynesville shale play has transitioned from a vertical testing and data acquisition program to a full horizontal development drilling program. In early 2009 we were running 4 operated horizontal rigs in the play and we exited 2009 with 12 operated horizontal rigs. In 2009, we spud 43 operated horizontal wells and by year end had 25 of those wells completed and flowing to sales. Our first horizontal well, the Oden 30H #6 in DeSoto Parish, Louisiana has performed exceptionally well, having produced 3.2 Bcf of natural gas during its first year of production. EXCO operated wells in the DeSoto Parish have averaged initial production rates of approximately 23 Mmcf per day. We also participated in 12 outside operated horizontal Haynesville wells that were completed and turned to sales in 2009. At year end 2009, we had 12 operated horizontal rigs drilling. We are adding two additional horizontal drilling rigs in the first quarter of 2010, which will bring our operated rig count to 14. We plan to drill 102 operated horizontal wells and participate in 23 non-operated horizontal wells in 2010. At year end 2009, we had Proved Reserves of 153.8 Bcfe and 38 gross producing wells in the Haynesville shale. As of February 12, 2010, our operated Haynesville shale production was approximately 318.2 Mmcf per day gross (85.0 Mmcf per day net). We expect significant production and reserve growth with our Haynesville shale development program in 2010 and beyond.

The Bossier shale section overlies the Haynesville shale. In 2009, we initiated a Bossier shale testing program. We have acquired core in the Bossier shale in different wells and have rock mechanics testing and other reservoir engineering studies ongoing. We have completed testing of the Bossier shale across our acreage by utilizing the vertical Haynesville test wells drilled during 2008. The Bossier shale has up to five times the thickness of the Haynesville shale in the DeSoto Parish area, and may hold significant reserve potential. Based on the test results acquired to date in these vertical wells, we are now drilling our first Bossier horizontal test and expect to complete it in the first quarter of 2010. We are planning a total of seven Bossier horizontal tests across our acreage in East Texas and North Louisiana in our 2010 development plan. These seven Bossier horizontal tests are included in the total of 102 horizontals shale wells planned for the year.

We have a strong commitment to technical evaluations to improve our understanding of these shale plays, and have made appropriate investments to reduce risks. We are members of a major shale consortium, reservoir engineering consortium and several other engineering and geoscience study projects. We are acquiring 2-D seismic data over a regional area, are currently shooting a 168 square mile 3-D seismic survey and have initiated a 20 section microseismic fracture stimulation monitoring project.

Vernon/Kelleys Fields

The Vernon Field, located in Jackson Parish, Louisiana, is our largest producing field, accounting for approximately 27.4% of our company production at year end 2009. The field produces from the Lower Cotton Valley and Bossier Sand formations at depths ranging from 12,000 to 15,000 feet. At year end 2009, we had Proved Reserves of 316.3 Bcfe and 402 gross producing wells. A focus on maintaining base production levels and lowering our operating expenses is a priority. We gather and treat our own natural gas and have access to numerous transmission lines in the area. The Kelleys Field is located north of the Vernon Field. In 2009, we drilled and completed seven gross wells in the two fields. We have plans to drill seven wells in 2010.

East Texas/North Louisiana Cotton Valley Area

Within our Cotton Valley Area, we are active in Harrison, Panola, Rusk, Upshur and Gregg Counties in Texas, primarily across four fields—Danville, Waskom, Oak Hill and Minden. We are also active in Caddo and DeSoto Parishes Louisiana, primarily in four fields—Holly, Kingston, Caspiana and Longwood. At year end 2009, we had Proved Reserves in the Cotton Valley and shallower horizons of 157.1 Bcfe and 903 gross producing wells. We are primarily focused on developing Cotton Valley sands at depths ranging from approximately 10,400 to 11,000 feet and the Travis Peak and Hosston Sands at approximately 7,800 to 10,000 feet. Our natural gas is gathered through gathering lines operated by TGGT. We drilled and completed 19 wells in 2009 across the Cotton Valley area. Our plans for 2010 include a horizontal testing program in the Cotton Valley including six tests across our acreage to evaluate the feasibility of a larger scale horizontal program for 2011 and beyond. We are also planning to conduct 28 recompletions in the area, primarily targeting the Hosston interval.

Appalachia

The Appalachian Basin includes portions of the states of Kentucky, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee, and covers an area of over 185,000 square miles. It is the most mature oil and natural gas producing region in the United States, first establishing oil production in 1859. The Appalachian Basin is strategically located near high energy demand areas with limited supply. As a result, the natural gas produced from the area typically commands a higher wellhead price relative to other North American areas.

Although the Appalachian Basin has sedimentary formations indicating the potential for deposits of oil and natural gas reserves up to depths of 30,000 feet or more, most production in this area has traditionally been derived from relatively shallow, low porosity and permeability sand and shale formations at depths of 1,000 to 8,000 feet. Operations in the area are generally characterized by long reserve lives, high drilling success rates and a large number of low productivity wells in these shallow formations. In the Appalachian Basin, there are over 200,000 producing wells and more than 5,000 operators with most being relatively small, private enterprises. Our operations in the area have included maintaining our existing production base from our shallow wells. We believe that the number of wells and operators presents a significant consolidation opportunity. We also believe the Marcellus shale development presents a significant growth opportunity for us.

Marcellus Shale Resource Play

During 2009, we focused on testing and evaluating our Marcellus fairway acreage, which we define as being geologically over-pressured. Our net acreage in the play totals approximately 343,000 acres, all of which is located in Pennsylvania and West Virginia. Of our total acreage, approximately 186,000 acres are located in the over-pressured fairway. Approximately 70% of our Marcellus shale fairway acreage is held by shallow production. Testing of the Marcellus shale has been conducted on 6 vertical wells and 2 horizontal wells. In the fourth quarter, we began the early stages of development drilling of the Marcellus shale play in central Pennsylvania with the spudding of a horizontal well. We continue to hire technical personnel to support the development of this play in five distinct team areas covering our entire Marcellus shale fairway acreage position.

Pennsylvania Area

The Pennsylvania Area encompasses 23 of the counties in the state. At December 31, 2009 we had Proved Reserves of 153.2 Bcfe and 3,776 gross producing wells. Drilling, completion and production activities target the Marcellus shale and the Upper Devonian Venango, Bradford and Elk sandstone groups at depths of 1,800 to 8,100 feet. We plan to use one operated horizontal drilling rig to drill and complete 11 gross (11.0 net) horizontal wells. We also plan to drill and complete 5 gross (5.0 net) vertical wells targeting the Marcellus shale and 6 gross (6.0 net) wells in 2010 targeting the shallower Upper Devonian reservoirs.

West Virginia Area

The West Virginia Area includes 29 counties stretching from the northern to the southern areas of the state. At December 31, 2009 we had Proved Reserves of 104.7 Bcfe and 2,273 gross producing wells. Drilling, completion and production activities target the Marcellus shale and the multiple, laterally stratified reservoirs of the Mississippian and Devonian formations found at depths ranging from 1,500 to 8,100 feet. During 2010, we currently plan to drill 1 gross (1.0 net) operated vertical well and participate in 4 gross (0.6 net) horizontal wells operated by others targeting the Marcellus Shale.

Permian

The Permian Basin, located in West Texas and the adjoining area of southeastern New Mexico, is best known as a mature oil focused basin exploited with waterflood and other enhanced oil recovery techniques. Our activities are focused on conventional oil and natural gas properties. With the use of 3-D seismic, we are targeting prolific reservoirs with potential for multi-pay horizons. The properties are characterized by long reserve lives and low operating costs.

Sugg Ranch Field

The Sugg Ranch Field is located primarily in Irion County, Texas. We have a total working interest of 97% in the property. At December 31, 2009, we had Proved Reserves of 57.7 Bcfe and 281 gross producing wells. Production is primarily from the Canyon Sand from depths of 6,700 to 7,900 feet. We currently plan to use one operated, vertical rig to drill 36 wells in 2010.

Our oil and natural gas reserves

Changes in our Proved Reserves for the year ended December 31, 2009 were impacted by the following significant factors and events:

- significant additions of new Proved Reserves arising from our drilling of horizontal wells in the Haynesville shale. After the impact of the BG Upstream Transaction discussed below, we have 153.8 Bcfe of Proved Reserves in the Haynesville shale play as of December 31, 2009 compared with 14.1 Bcfe at December 31, 2008;
- our BG Upstream Transaction resulted in the sale of an undivided 50% of our oil land natural gas assets in East Texas/North Louisiana, with the exception of our Vernon Field in Jackson Parish, Louisiana. The BG Upstream Transaction also included an undivided 50% of our Haynesville/Bossier shale play and the BG Carry, which will reduce development costs by $400.0 million;
- our 2009 divestiture activities, including the BG Upstream Transaction and included sales resulting in an exit from our Mid-Continent and Ohio regions, reduced Proved Reserves by approximately 790.4 Bcfe; and
- a 32.2% decrease in the price of natural gas used in determining Proved Reserves at December 31, 2009 compared with December 31, 2008.

The following table summarizes Proved Reserves at December 31, 2009, 2008 and 2007. This information was prepared in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC.

	At December 31,		
	2009	2008	2007
Oil (Mmbbls)			
Developed	3.5	14.8	15.2
Undeveloped	2.0	6.0	5.7
Total	5.5	20.8	20.9
Natural Gas (Bcf)			
Developed	622.2	1,354.8	1,228.8
Undeveloped	303.6	460.3	510.9
Total	925.8	1,815.1	1,739.7
Equivalent reserves (Bcfe)			
Developed	643.2	1,443.6	1,320.0
Undeveloped	315.6	496.3	545.1
Total	958.8	1,939.9	1,865.1
PV-10 (in millions)(1)			
Developed	$649.8	$2,375.7	$3,369.2
Undeveloped	97.9	97.8	576.7
Total	$747.7	$2,473.5	$3,945.9
Standardized Measure (in millions)(2)	$747.7	$2,236.3	$3,118.9

(1) The PV-10 data does not include the effects of income taxes or derivative financial instruments, and is based on the following average and spot prices, in each case adjusted for historical differentials.

(2) There is no difference in Standardized Measure and PV-10 as of December 31, 2009 as the impacts of lower natural gas prices, net cash flows and net operating loss carry-forwards eliminated estimated future income taxes.

	Average and spot price(a)	
Date	**Natural gas (per Mmbtu)**	**Oil (per Bbl)**
December 31, 2009	$3.87	$61.18
December 31, 2008	5.71	44.60
December 31, 2007	6.80	95.92

(a) The prices for 2009 are the average spot prices for the trailing twelve month period per Mmbtu at Henry Hub and per Bbl at Cushing, Oklahoma, using the first day of each month beginning on January 1, 2009 and ended December 1, 2009. The prices for 2008 and 2007 represent the December 31 spot price per Mmbtu at Henry Hub and per Bbl at Cushing, Oklahoma in each respective year.

We believe that PV-10 before income taxes, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions due to tax characteristics, which can differ significantly, among comparable companies. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with ASC 932. The following table provides a reconciliation of our PV-10 to our Standardized Measure:

(in millions)	
PV-10	$747.7
Future income taxes	—
Discount of future income taxes at 10% per annum	—
Standardized Measure	$747.7

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with rules and regulations promulgated by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls include documented process workflows, qualified professional engineering and geological personnel with specific reservoir experience and investment in on-going education with emphasis on emerging technologies. These emerging technologies are of particular importance as they relate to our shale plays. We also retain outside independent engineering firms to prepare estimates of our Proved Reserves. We work closely with these firms and management is responsible for providing accurate operating, economic and technical data to these outside firms. Our internal audit function routinely tests our processes and controls and estimated Proved Reserve computations. Senior management reviews and approves our reserve estimates, whether prepared internally or by third parties.

The estimates of Proved Reserves and future net cash flow attributable to our interests, presented as of December 31, 2009, 2008 and 2007 have been prepared by Lee Keeling, our external engineers for our non-shale properties, and Haas Engineering our external engineers for our shale properties for 2009. Lee Keeling and Haas Engineering are independent petroleum engineering firms that perform a variety of reserve engineering and valuation assessments for public and private companies, financial institutions and institutional investors. Lee Keeling has performed these services for over 50 years and Haas Engineering was founded in 1980. We selected Haas Engineering to prepare our estimates of Proved Reserves for our shale properties based upon their specific experience in performing services to industry peers with shale operations. Our internal technical employees responsible for reserve estimates and interaction with our independent engineers include corporate officers with petroleum and other engineering degrees, professional certifications and industry experience similar to those of our independent engineering firms. The estimates of future plugging and abandonment costs necessary to compute PV-10 and Standardized Measure were computed internally. Estimates of oil and natural gas reserves are projections based on a process involving an independent third party engineering firm's extensive visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely on various assumptions, including definitions and economic assumptions required by the SEC, including the use of constant oil and natural gas pricing, use of current and constant operating costs and future capital costs. We also make assumptions relating to availability of funds and timing of capital expenditures for development of our proved undeveloped reserves. The production profiles in the Haynesville shale are in their early stages. As a result, the assumptions used for our Haynesville well and reservoir characteristics and performance are subject to further refinement as more production history is accumulated. These reports should not be construed as the current market value of our Proved Reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See "Note 21. Supplemental information relating to oil and natural gas producing activities (unaudited)" of the notes to our consolidated financial statements for additional information regarding our oil and natural gas reserves and our Standardized Measure.

Lee Keeling and Haas Engineering also examined our estimates with respect to reserve categorization, using the definitions for Proved Reserves set forth in SEC Regulation S-X Rule 4-10(a) and SEC staff interpretations and guidance. In preparing an estimate of our Proved Reserves and future net cash flows attributable to our interests, Lee Keeling and Haas Engineering did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of the examination something came to the attention of Lee Keeling or Haas Engineering which brought into question the validity or sufficiency of any such information or data, Lee Keeling or Haas Engineering did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Lee Keeling and Haas Engineering determined that our estimates of Proved Reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of Proved Reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

Management's discussion and analysis of oil and natural gas reserves

The following discussion and analysis of our proved oil and natural gas reserves and changes in our Proved Reserves is intended to provide additional guidance on the operational activities, transactions, economic and other factors which significantly impacted the determination of our estimate of Proved Reserves as of December 31, 2009 and changes in our Proved Reserves during 2009. This discussion and analysis should be read in conjunction with our supplemental oil and gas disclosures relating to oil and natural gas producing activities included in Note 21. Supplemental information relating to oil and natural gas producing activities (unaudited) of the notes to our consolidated financial statements and the uncertainties inherent in the estimation of oil and natural gas reserves discussed under "risk factors" included elsewhere in this Annual Report on Form 10-K. The following table summarizes the significant changes in our Proved Reserves from January 1, 2009 to December 31, 2009.

(in thousands)	Oil (Bbls)	Natural gas (Mcf)	Equivalent natural gas (Mcfe)
Proved developed	3,505	622,160	643,190
Proved undeveloped	2,013	303,568	315,646
Total	5,518	925,728	958,836
The changes in reserves for the year are as follows:			
January 1, 2009	20,801	1,815,138	1,939,944
Purchase of reserves in place	—	8,065	8,065
Extensions and discoveries	202	240,844	242,056
Revisions of previous estimates:			
Changes in price	(1,482)	(249,948)	(258,840)
Changes in performance	124	(54,613)	(53,869)
Sales of reserves in place	(12,556)	(715,023)	(790,359)
Production	(1,571)	(118,735)	(128,161)
December 31, 2009	5,518	925,728	958,836

Current year oil and natural gas production

Total oil and natural gas production in 2009 was 128.2 Bcfe, which includes approximately 14.3 Bcfe in production from 2009 extensions and discoveries that were not reflected in our beginning of the year Proved Reserves.

Sales of reserves in place

During 2009, we implemented a program to divest certain non-strategic oil and natural gas assets and to seek a joint venture partner to facilitate more rapid development of our shale resources in East Texas/North Louisiana. These divestitures, including the BG Upstream Transaction significantly reduced our Proved Reserves. A total of 790.4 Bcfe were sold in these transactions, representing approximately 40% of our beginning of the year total Proved Reserves. The divestiture program, which included an exit from several operating areas, including our Mid-Continent region and operations in the state of Ohio, provided substantial liquidity to fund our Haynesville development program and Marcellus testing program. The BG Upstream Transaction provided additional liquidity with which to further develop our streamlined asset portfolio.

New discoveries and extensions

EXCO had extensions and discoveries of 242.1 Bcfe of Proved Reserves additions in 2009. Approximately 204.7 Bcfe, or 84.6%, of the extensions and discoveries, were from our Haynesville shale play efforts. The majority of EXCO's Haynesville shale development has been concentrated in 89 contiguous sections in DeSoto Parish, Louisiana, where our drilling results have been the most successful. We have booked an average of two and one-half proved undeveloped offsetting locations adjacent to each producing horizontal well drilled in the

Haynesville shale play. EXCO's Proved Undeveloped Reserves, or PUD Reserves, represent 32.9% of our total Proved Reserves with the Haynesville shale representing about 38.1% of our total PUD Reserves at year end.

Revisions of previous estimates

Revisions in 2009 include negative revisions due to prices and other economic factors of 258.8 Bcfe. Net negative revisions resulting from performance issues totaled 53.9 Bcfe, primarily due to decreases of 65.0 Bcfe in our Appalachia division, which were partially offset by positive revisions in East Texas/North Louisiana and Permian of 11.1 Bcfe. The primary factor in the revisions due to prices was the use at December 31, 2009 of the simple average of the trailing twelve month spot price (using the price on the first day of the month) for natural gas pursuant to the new SEC rules. Such average gas price of $3.87 per Mmbtu represented a 32.2% decrease from the December 31, 2008 spot natural gas price of $5.71 per Mmbtu.

Proved undeveloped reserves

The following table summarizes the changes in our proved undeveloped reserves for the year ended December 31, 2009:

	Mmcfe
Proved undeveloped reserves at beginning of year	496,325
Purchases of proved undeveloped reserves in place	7,431
Sales of proved undeveloped reserves in place	(191,419)
New discoveries and extensions(1)	167,858
Undeveloped reserves transferred to developed	(21,619)
Revisions of previous estimates or proved undeveloped reserves(2)	(142,930)
Proved undeveloped reserves at end of year	315,646

(1) Substantially all of the discoveries and extensions of proved undeveloped reserves in 2009 occurred in our East Texas/North Louisiana region, primarily in our Haynesville shale play.

(2) Negative revisions in our proved undeveloped reserves resulted from pricing and costs (94.4%) and from performance and other factors (5.6%) with over 75% of the revisions occurring in our East Texas/North Louisiana region.

During 2009, we incurred a total of $299.8 million in various development and exploration activities which resulted in total discoveries and extensions of approximately 242.1 Bcfe. Most of these additions were in the Haynesville shale play in East Texas/North Louisiana in areas in which minimal proved undeveloped reserves were attributed as of the beginning of the year, but which became proved during the year.

Impacts of 2009 changes in reserves on depletion rate and statements of operations

For the year ended December 31, 2009, a combination of factors resulted in significant impact on our full cost pool and our depreciation, depletion and amortization rate for the year.

Prices and costs

Prices for oil and natural gas used in determining Proved Reserves at December 31, 2009 using the new SEC rules based on the simple average of spot prices on the first day of the trailing twelve months beginning January 1, 2009 and ending on December 1, 2009, were down 32.2% for natural gas and up 37.2% for oil when compared with the year-end December 31, 2008 spot prices. The overall impact of prices and costs resulted in a decrease in our reserves by approximately 287.1 Bcfe, primarily resulting from the decrease in the natural gas prices. Our oil reserves at December 31, 2009 represent only 3.5% of our total reserves, therefore the increase in oil prices did not have a significant impact on our overall reserves.

Between December 31, 2008 and March 31, 2009, the spot price for natural gas fell from $5.71 to $3.63 per Mmbtu, a $2.08 decrease, or 36.4%. As a result of this decrease, we incurred a ceiling test write-down of $1.3 billion for the quarter ended March 31, 2009. This ceiling write-down reduced the amortizable full cost pool and the depletion rate at March 31, 2009 by 37.5% to approximately $1.30 per Mcfe. No other ceiling test write-downs were incurred in 2009.

2009 divestitures and related gains on sales

As previously discussed, we had divestitures, including our BG Upstream Transaction, of Proved Reserves totaling approximately 790.4 Bcfe. On four of these sales transactions, aggregating 622.8 Bcfe, we recognized gains since reflecting the sales proceeds as a reduction in the full cost pool would have resulted in a significant alteration to the full cost pool. Divestitures in 2009 did not have a significant impact on our depletion rate after the first quarter ceiling test write-down. Our depletion rate for the last three quarters of 2009 averaged $1.32 per Mcfe.

BG Upstream Transaction—BG Carry

The impact from the BG Carry on our depletion rate began during the fourth quarter of 2009, where our depletion rate for the quarter decreased to $1.23 per Mcfe. Continued application of the remaining balance of $367.7 million of the BG Carry in 2010 and 2011 will reduce our capital requirements in the Haynesville/Bossier shale play exploitation and development and should continue to have a favorable impact on our overall full cost pool amortization rate.

Our production, prices and expenses

The following table summarizes revenues, net production of oil and natural gas sold, average sales price per unit of oil and natural gas and costs and expenses associated with the production of oil and natural gas.

(in thousands, except production and per unit amounts)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Revenues, production and prices:			
Oil:			
Revenue(1)	$ 84,397	$ 216,727	$117,073
Production sold (Mbbl)	1,571	2,236	1,645
Average sales price per Bbl(1)	$ 53.72	$ 96.93	$ 71.17
Natural gas:			
Revenue(1)	$466,108	$1,188,099	$758,714
Production sold (Mmcf)	118,736	131,159	111,419
Average sales price per Mcf(1)	$ 3.93	$ 9.06	$ 6.81
Costs and expenses:			
Average production cost per Mcfe	$ 1.38	$ 1.64	$ 1.39
General and administrative expense per Mcfe	$ 0.77	$ 0.61	$ 0.53
Depreciation, depletion and amortization per Mcfe	$ 1.72	$ 3.18	$ 3.10

(1) Excludes the effects of derivative cash settlements and derivative financial instruments.

Our interest in productive wells

The following table quantifies information regarding productive wells (wells that are currently producing oil or natural gas or are capable of production), including temporarily shut-in wells. The number of total gross oil and natural gas wells excludes any multiple completions. Gross wells refer to the total number of physical wells in which we hold a working interest, regardless of our percentage interest. A net well is not a physical well, but is a concept that reflects the actual total working interests we hold in all wells. We compute the number of net wells by totaling the percentage interests we hold in all our gross wells.

	At December 31, 2009					
	Gross wells(1)			Net wells		
Areas	Oil	Gas	Total	Oil	Gas	Total
East Texas/North Louisiana	62	1,264	1,326	30.6	707.8	738.4
Appalachia	365	5,793	6,158	359.2	5,234.2	5,593.4
Permian and other	270	89	359	242.0	50.5	292.5
Total	697	7,146	7,843	631.8	5,992.5	6,624.3

(1) As of December 31, 2009, we held interests in 23 gross wells with multiple completions.

As of December 31, 2009, we were the operator of 7,416 gross (6,524.7 net) wells, which represented approximately 97.0% of our Proved Reserves as of December 31, 2009.

Our drilling activities

In 2009, we shifted our drilling emphasis toward horizontal drilling in shale plays. Prior to 2009, our drilling emphasis was vertical development projects. The number and types of wells we drill will vary depending on the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests in each well, commodity prices, the estimated recoverable reserves attributable to each well and accessibility to the well site.

The following tables summarize our approximate gross and net interests in the wells we drilled during the periods indicated and refer to the number of wells completed at any time during the period, regardless of when drilling was initiated. At December 31, 2009, we had 15 gross (6.8 net) wells being drilled and 13 gross (6.6 net) wells being completed.

	Development Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2009	82	1	83	40.8	0.9	41.7
Year ended December 31, 2008	447	4	451	374.2	2.5	376.7
Year ended December 31, 2007	487	7	494	394.7	4.6	399.3

	Exploratory Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2009(1)	19	1	20	12.2	1.0	13.2
Year ended December 31, 2008	20	4	24	19.3	3.5	22.8
Year ended December 31, 2007	8	4	12	2.5	3.4	5.9

(1) Our classifications of exploratory wells for 2009 include Haynesville shale wells located outside of DeSoto Parish, Louisiana and all East Texas counties and all Marcellus shale wells. We also classify our Bossier shale test wells as exploratory projects. Haynesville shale drilling in DeSoto Parish, Louisiana has been classified as development.

Our developed and undeveloped acreage

Developed acreage includes those acres spaced or assignable to producing wells. Undeveloped acreage represents those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains Proved Reserves. The definitions of gross acres and net acres conform to how we determine gross wells and net wells. The following table sets forth our developed and undeveloped acreage at December 31, 2009:

	At December 31, 2009			
	Developed acreage		Undeveloped acreage	
Areas	Gross	Net(1)	Gross	Net(1)
East Texas/North Louisiana	166,219	88,469	99,828	67,476
Appalachia	376,705	335,351	349,794	318,817
Permian and other	28,532	18,829	161,527	118,591
Total	571,456	442,649	611,149	504,884

(1) Net acreage at December 31, 2009 reflects a reduction of 7,341 acres that BG Group elected to acquire after December 31, 2009, pursuant to the BG AMI.

The primary terms of our oil and natural gas leases expire at various dates. Much of our undeveloped acreage is held-by-production, which means that these leases are active as long as we produce oil or natural gas from the acreage. Upon ceasing production, these leases will expire. We have 38,638, 95,851 and 25,557 net acres with leases expiring in 2010, 2011 and 2012, respectively.

The undeveloped held-by-production acreage in many cases represents potential additional drilling opportunities through down-spacing and drilling of proved undeveloped and unproved locations in the same formation(s) already producing, as well as other non-producing formations, in a given oil or natural gas field without the necessity of purchasing additional leases or producing properties.

Sales of producing properties and undeveloped acreage

We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs, properties that are not within our core geographic operating areas and properties that are not strategic. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives.

Equity investment in midstream operations

On August 14, 2009, we closed the sale to an affiliate of BG Group of a 50% interest in TGGT, which now holds most of our previously owned East Texas/North Louisiana midstream assets. Pursuant to the contribution agreement, we contributed TGG, which owns an intrastate pipeline in East Texas and a gathering system in North Louisiana and Talco, which owns gathering assets in East Texas/North Louisiana, to TGGT. BG Group contributed \$269.2 million in cash to TGGT and we received those funds from TGGT as a special distribution at closing. EXCO Operating now owns 50% of TGGT and the affiliate of BG Group owns 50% of TGGT. The effective date of this transaction was January 1, 2009. We adopted the equity method of accounting for our interest in TGGT upon its formation. Prior to August 14, 2009, we treated our midstream operations as a separate segment of our business.

TGGT's midstream operations are principally designed to facilitate delivery of natural gas produced in the East Texas/North Louisiana region to markets. Revenues are derived from sales of natural gas purchased for resale and fees earned from gathering, transportation, treating and compression of natural gas. TGGT does not own any natural gas processing facilities.

In 2009, TGGT undertook a major expansion of its TGG system in North Louisiana in order to take advantage of the increasing opportunities for gathering of Haynesville/Bossier shale natural gas. The first phase of the expansion was the installation of a header system comprised of approximately 29 miles of 36-inch diameter pipe through the Holly field area, which is south of Shreveport. The header will primarily gather EXCO and BG Group produced natural gas but will also seek opportunities to gather natural gas from other producers in the area. The system provides producers with dehydration and amine treating facilities and has connections to major third party interstate pipelines. The majority of the system was completed in the fourth quarter of 2009, and the remaining pipe segment is scheduled to be completed in the first quarter of 2010. TGGT is currently in the process of evaluating additional opportunities associated with the expansion of this 29-mile pipeline system.

The East Texas TGG system, which gathers natural gas, has access to 12 interstate pipeline markets. The TGG system in East Texas has approximately 110 miles of pipeline comprised of 12, 16, and 20-inch diameter pipe with a current throughput capacity of approximately 390.0 Mmcf per day without compression. With compression, TGG throughput capacity in East Texas is estimated to be approximately 530.0 Mmcf per day.

TGGT also owns and operates Talco, a network of eight natural gas gathering systems comprised of approximately 615 miles of pipeline in their East Texas/North Louisiana area of operation, which gathers natural gas produced from the Holly/Caspiana field, Longwood/Waskom fields and other fields in East Texas and North Louisiana and transports the natural gas to TGG and larger gathering systems and intrastate, interstate and local distribution pipelines owned by third parties. Talco gathers natural gas through fixed fee arrangements pursuant to which the fee income represents an agreed rate per unit of throughput. The revenues earned from these arrangements are directly related to the volume of natural gas that flows through the systems and are not directly dependent on commodity prices.

Other gas gathering systems

A gathering system and treating facility in the area of our Vernon Field operations, or Vernon Gathering, gathers and transports natural gas from our Vernon Field and, to a lesser extent, natural gas from third-party producers. The gathering system transports natural gas to our Caney Lake facility where the natural gas is treated and delivered to interstate pipeline systems. During December 2009, average throughput in Vernon Gathering was approximately 113.0 Mmcf per day.

Our principal customers

For the year ended December 31, 2009, there were no sales to any individual customer which exceeded 10% of our consolidated revenues or was considered material to our operations. The loss of any significant customer may cause a temporary interruption in sales of, or lower price for, our oil and natural gas, but we believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and other services and securing trained personnel. Competition has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. Many of our competitors have financial, technical and personnel resources substantially larger 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 drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, proppant, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases. We are unable to predict when, or if, shortages may occur or how they will affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties and for undeveloped leases and drilling rights, and we cannot provide assurance that we will be able to compete satisfactorily.

Applicable laws and regulations

General

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, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Although the regulatory burden on the oil and 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 others in our industry with similar types, quantities and locations of production.

The following is a summary of the more significant existing environmental, safety and other laws and regulations to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Production regulation

Our production operations are subject to a number of regulations at federal, state and local levels. These regulations require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate, also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration 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 requiring production in a prorated, equitable system. 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, ad valorem or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

FERC matters

The availability, terms and cost of downstream transportation significantly affect sales of natural gas, oil and NGLs. With regard to natural gas, the interstate transportation and sale for resale is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. Federal and state regulations govern the rates and terms for access to intrastate natural gas pipeline transportation, while states alone regulate natural gas gathering activities. With regard to oil and NGLs, the rates and terms and conditions of service for interstate transportation is regulated by FERC. Tariffs for such transportation must be just and reasonable and not unduly discriminatory. Oil and NGL transportation that is not federally regulated is left to state regulation.

Wholesale prices for natural gas, oil and NGLs are not currently regulated and are determined by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. The Commodity Futures Trading Commission, or the CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical sales of natural gas, oil and NGLs, our gathering of any of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Federal, state or Indian oil and natural gas leases

In the event we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, or Minerals Management Service or other appropriate federal or state agencies.

Surface Damage Acts

In addition, eleven states and some tribal nations have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and specific expenses for exploration and activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

Other regulatory matters relating to our pipeline and gathering system assets

The pipelines we use to gather and transport our oil and natural gas are subject to regulation by the Department of Transportation, or DOT, under the Hazardous Liquid Pipeline Safety Act of 1979, as amended, or the HLPSA, with respect to oil, and the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and hazardous liquids pipeline facilities, including pipelines transporting crude oil. Where applicable, the HLPSA and NGPSA also require us and other pipeline operators to comply with regulations issued pursuant to these acts that are designed to permit access to and allow copying of records and to make certain reports available and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992, as reauthorized and amended, mandates requirements in the way that the energy industry ensures the safety and integrity of its pipelines. The law applies to natural gas and hazardous liquids pipelines, including some natural gas gathering pipelines. Central to the law are the requirements it places on each pipeline operator to prepare and implement an "integrity management program." The Pipeline Safety Act of 1992 mandates a number of other requirements, including increased penalties for violations of safety standards and qualification programs for employees who perform sensitive tasks. The DOT has established a number of rules carrying out the provisions of this act. The Pipeline and Hazardous Materials Safety Administration of DOT, or the PHMSA, has established a new risk-based approach to determine which gathering pipelines are subject to regulation, and what safety standards regulated pipelines must meet. We could incur significant expenses as a result of these laws and regulations.

U.S. federal taxation

The federal government may propose tax initiatives that affect us. We are unable to determine what effect, if any, future proposals would have on product demand or our results of operations.

U.S. environmental regulations

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Federal environmental statutes to which our domestic activities are subject include, but are not limited to:

- the Oil Pollution Act of 1990, or OPA;
- the Clean Water Act, or CWA;
- the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA;
- the Resource Conservation and Recovery Act, or RCRA;
- the Clean Air Act, or CAA; and
- the Safe Drinking Water Act, or SDWA.

Our domestic activities are subject to regulations promulgated under these statutes and comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Administrative, civil and criminal penalties may be imposed for non-compliance with environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before we undertake certain activities, limit or prohibit other activities because of protected areas or species, impose certain substantial liabilities for the clean-up of pollution, impose certain reporting requirements, regulate remedial plugging operations to prevent future contamination, and require substantial expenditures for compliance. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Under the CWA, which was amended and augmented by OPA, our release or threatened release of oil or hazardous substances into or upon waters of the United States, adjoining shorelines and wetlands and offshore areas could result in our being held responsible for: (1) the costs of removing or remediating a release; (2) administrative, civil or criminal fines or penalties; or (3) specified damages, such as loss of use, property damage and natural resource damages. The scope of our liability could be extensive depending upon the circumstances of the release. Liability can be joint and several and without regard to fault. The CWA also may impose permitting requirements for certain discharges into waters of the United States, including certain wetlands, of dredged materials, which may apply to various of our construction activities, as well as requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

CERCLA, as amended, and comparable state Superfund statutes, impose liability that is generally joint and several and that is retroactive for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on specified classes of persons for the release of a "hazardous substance" or under state law, other specified substances, into the environment. So-called potentially responsible parties, or PRPs, include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the Environmental Protection Agency, or 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 PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties not under our control, and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA currently exempts petroleum (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We cannot assure you that this exemption will be preserved in any future amendments of the act. Such amendments could have a material impact on our costs or operations. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA or regulated under similar state statutes. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA. We also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event hazardous substance contamination is discovered at a site on which we are or have been an owner or operator, we could be liable for costs of investigation and remediation and natural resource damages.

If substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Although we maintain insurance coverage we consider to be customary in the industry, we are not fully insured against all of these risks, either because insurance is not available or because of high premiums. Accordingly, we may be subject to liability or may lose substantial portions of properties due to hazards that cannot be insured against or have not been insured against due to prohibitive premiums or for other reasons. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

RCRA and comparable state and local programs impose requirements on the management, treatment, storage and disposal of both hazardous and nonhazardous solid wastes. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we own or lease, in addition to the locations where such wastes have been taken for disposal. In addition, many of these properties have been owned or operated by third parties. We have not had control over such parties' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We also generate hazardous and non-hazardous solid waste in our routine operations. It is possible that certain wastes generated by our operations, which are currently exempt from "hazardous waste" regulations under RCRA, may in the future be designated as "hazardous waste" under RCRA or other applicable state statutes and become subject to more rigorous and costly management and disposal requirements.

Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The CAA and analogous state laws require certain new and modified sources of air pollutants to obtain permits prior to commencing construction. Smaller sources may qualify for exemption from permit requirements through qualifications for permits by rule or general permits. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional operating permits. Federal and state laws designed to control hazardous (i.e., toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forgo construction, modification or operation of certain air emission sources.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at a majority of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in certain instances may require remediation. In some instances, we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. We do not believe the costs to be incurred by us for compliance and remediating previously or currently owned or operated properties will be material, but we cannot guarantee that result.

If in the course of our routine oil and natural gas operations surface spills and leaks occur, including casing leaks of oil or other materials, we may incur penalties and costs for waste handling, remediation and third party actions for damages. Moreover, we are only able to directly control the operations of the wells that we operate. Notwithstanding our lack of control over wells owned by us but operated by others, the failure of the operator to comply with applicable environmental regulations may be attributable to us and may impose legal liabilities upon us.

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act, or CZMA, was passed in 1972 to preserve and, where possible, restore the natural resources of the coastal zone of the United States. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development. States, such as Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. In the event our activities trigger these programs, this review of agency rules and actions may impact other agency permitting and review activities, resulting in possible delays or restrictions of our activities and adding an additional layer of review to certain activities undertaken by us.

We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program complying with current environmental laws and regulations. As these laws and regulations are frequently changed and are subject to interpretation, our assessment regarding the cost of compliance or the extent of liability risks may change in the future.

We are also unable to assure you that more stringent laws and regulations protecting the environment will not be adopted and that we will not incur material expenses in complying with them in the future. For example, on June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACES. The purpose of ACES is to control and reduce emissions of "greenhouse gases," or "GHGs," in the United States. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to warming of the Earth's atmosphere resulting in climatic changes. ACES would establish a cap on total emissions of GHGs from certain categories of emission sources in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACES, those categories of sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACES's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACES will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACES, the Senate legislation would need to be reconciled with ACES, and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance system that results in fewer allowances being issued over time, but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACES, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

The Environmental Protection Agency has also taken recent action related to greenhouse gases. On December 7, 2009, the U.S. Environmental Protection Agency, or "EPA," issued a notice of its finding and determination that emissions of carbon dioxide, methane, and other GHGs may reasonably be anticipated to endanger human health and the environment by, among other things, increasing ground-level ozone, altering the climate, contributing to a rise in sea levels, and harming water resources, agriculture, wildlife, and ecosystems. Once EPA promulgates regulations controlling GHG emissions, for example, regarding emissions from motor vehicles, which EPA has indicated may occur in 2010, EPA will be required to begin regulating emissions of GHGs under existing permitting provisions of the federal Clean Air Act. Those permitting provisions could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those permitting requirements. EPA has proposed a "Tailoring Rule" to regulate the permitting of GHG sources under the Clean Air Act's PSD and Title V programs. Although it may take EPA several years to adopt and impose regulations limiting stationary source emissions of GHGs, any limitation on emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. On September 22, 2009, EPA finalized a GHG reporting rule that will require large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, recordkeep and report emissions of GHGs associated with our operations.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance.

OSHA and other regulations

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the 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 OSHA and comparable requirements.

Title to our properties

When we acquire developed properties, we conduct a title investigation. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct little or no investigation of title other than a preliminary review of local mineral records. We do conduct title investigations and, in most cases, obtain a title opinion of local counsel before we begin drilling operations. We believe that the methods we utilize for investigating title prior to acquiring any property are consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire good title to properties. However, some title risks cannot be avoided, despite the use of customary industry practices.

Our properties are generally burdened by:

- customary royalty and overriding royalty interests;
- liens incident to operating agreements; and
- liens for current taxes and other burdens and minor encumbrances, easements and restrictions.

We believe that none of these burdens either materially detract from the value of our properties or materially interfere with property used in the operation of our business. Substantially all of our properties are pledged as collateral under our credit agreements.

Our employees

As of December 31, 2009, we employed 802 persons. None of our employees are represented by unions or covered by collective bargaining agreements. To date, we have not experienced any strikes or work stoppages due to labor problems, and we consider our relations with our employees to be good. We also utilize the services of independent consultants and contractors.

Forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- our future use of derivative financial instruments; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget" and other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial condition and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this Annual Report on Form 10-K, including, but not limited to:

- fluctuations in prices of oil and natural gas;
- imports of foreign oil and natural gas, including liquefied natural gas;
- future capital requirements and availability of financing;
- continued disruption of credit and capital markets and the ability of financial institutions to honor their commitments, such as the events which occurred during the third quarter of 2008 and thereafter, for an extended period of time;
- estimates of reserves and economic assumptions used in connection with our acquisitions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including our Marcellus shale play in Appalachia and the Haynesville/Bossier shale play in East Texas/North Louisiana;
- risks associated with the operation of natural gas pipelines and gathering systems;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;

- developments in oil-producing and natural gas-producing countries;
- title to our properties;
- litigation;
- competition;
- general economic conditions, including costs associated with drilling and operations of our properties;
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases;
- receipt and collectability of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- potential acts of terrorism;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates; and
- our ability to effectively integrate companies and properties that we acquire.

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Annual Report on Form 10-K. The risk factors noted in this Annual Report on Form 10-K and other factors noted throughout this Annual Report on Form 10-K provide examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement. Please see "Item 1A. Risk factors" for a discussion of certain risks of our business and an investment in our common stock.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices may also reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

Glossary of selected oil and natural gas terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

2-D seismic. Geophysical data that depict the subsurface strata in two dimensions

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

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

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Commercial Well; Commercially Productive Well. An oil and natural gas well which produces oil and natural gas in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Completion. The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Deterministic estimate. The method of estimating reserves or resources when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

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

Developed Reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate.

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

Downspacing Wells. Additional wells drilled between known producing wells to better exploit the reservoir.

Dry Hole; Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. As it relates to a resource, a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To maximize the ultimate recovery of oil or natural gas from the field by development wells, secondary recovery equipment or other suitable processes and technology.

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Fracture Stimulation. A stimulation treatment routinely performed involving the injection of water, sand and chemicals under pressure to stimulate hydrocarbon production in low-permeability reservoirs.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

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

Held-by-production. A provision in an oil, gas and mineral lease that perpetuates a company's right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or gas.

Horizontal Wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Infill drilling. Drilling of a well between known producing wells to better exploit the reservoir.

Initial production rate. Generally, the maximum 24 hour production volume from a well.

Mbbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmbbl. One million stock tank barrels.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcf/d. One million cubic feet of natural gas per day.

Mmcfe. One million cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmcfe/d. One million cubic feet equivalent per day calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmmbtu. One billion British thermal units.

NYMEX. New York Mercantile Exchange.

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.

Overriding royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

Present value of estimated future net revenues or PV-10. The present value of estimated future net revenues is an estimate of future net revenues from a property at the date indicated, without giving effect to derivative financial instrument activities, after deducting production and ad valorem taxes, future capital costs, abandonment costs and operating expenses, but before deducting future federal income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil and natural gas prices and operating and capital costs at the date indicated, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially.

Probabilistic estimate. The method of estimation of reserves or resources when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive Well. A productive well is a well that is not a dry well.

Proved Reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Recompletion. An operation within an existing well bore to make the well produce oil and/or gas from a different, separately producible zone other than the zone from which the well had been producing.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reserve Life. The estimated productive life, in years, of a proved reservoir based upon the economic limit of such reservoir producing hydrocarbons in paying quantities assuming certain price and cost parameters. For purposes of this Annual Report on Form 10-K, reserve life is calculated by dividing the Proved Reserves (on a Mmcfe basis) at the end of the period by the annualized average daily production volumes for December 2009.

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

Resources. All quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. It also includes all types of petroleum whether currently considered "conventional" or "unconventional."

Royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Spud. To start the well drilling process.

Standardized Measure of discounted future net cash flows or the Standardized Measure. Under the Standardized Measure, future cash flows for the year ended December 31, 2009 are estimated by applying the simple average spot prices for the trailing twelve month period using the first day of each month beginning on January 1, 2009 and ended December 1, 2009, adjusted for fixed and determinable escalations, to the estimated future production of year-end Proved Reserves. Spot prices used to compute estimated future cash flows for the years ended December 31, 2008 and 2007 were based on year-end spot prices for each respective year. Future cash inflows are reduced by estimated future production and development costs based on period-end and future plugging and abandonment costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Stock tank barrel. 42 U.S. gallons liquid volume.

Tcf. One trillion cubic feet of natural gas.

Tcfe. One trillion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

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 and natural gas regardless of whether such acreage contains Proved Reserves.

Undeveloped Reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct activities on the property and a share of production.

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

Available information

We make our filings with the SEC available, free of charge, on our website at *www.excoresources.com* as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

ITEM 1A. RISK FACTORS

The risk factors noted in this section and other factors noted throughout this Annual Report on Form 10-K, including those risks identified in "Item 7. Management's discussion and analysis of financial condition and results of operations" describe examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this Annual Report on Form 10-K.

Risks relating to our business

Fluctuations in oil and natural gas prices, which have been volatile at times, may adversely affect our revenues as well as our ability to maintain or increase our borrowing capacity, repay current or future indebtedness and obtain additional capital on attractive terms.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. We are particularly dependent on prices for natural gas. As of December 31, 2009, 96.5% of our Proved Reserves were natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Factors that affect the prices we receive for our oil and natural gas include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- political and economic conditions and events in foreign oil and natural gas producing nations, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the cost and availability of transportation and pipeline systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and refined products;
- concerns about global warming or other conservation initiatives and the extent of governmental price controls and regulation of production;
- weather;
- foreign and domestic government relations; and
- overall economic conditions, particularly the recent worldwide economic slowdown which has put downward pressure on oil and natural gas prices and demand.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. During 2009, the NYMEX price for natural gas has fluctuated from a high of $6.07 per Mmbtu to a low of $2.51 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $81.37 per Bbl to a low of $33.98 per Bbl. For the five years ended December 31, 2009, the NYMEX Henry Hub natural gas price ranged from a high of $15.38 per Mmbtu to a low of $2.51 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $145.29 per Bbl to a low of $33.87 per Bbl. On December 31, 2009, the spot market price for natural gas at Henry Hub was $5.79 per Mmbtu, a 1.4% increase from December 31, 2008. On December 31, 2009, the spot market price for crude oil at Cushing was $79.36 per Bbl, a 77.9% increase from December 31, 2008. In 2009, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $53.72 per Bbl and $3.93 per Mcf compared with 2008 average realized prices of $96.93 per Bbl and $9.06 per Mcf, respectively.

Our revenues, cash flow and profitability and our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms depend substantially upon oil and natural gas prices.

Changes in the differential between NYMEX or other benchmark prices of oil and natural gas and the reference or regional index price used to price our actual oil and natural gas sales could have a material adverse effect on our results of operations and financial condition.

The reference or regional index prices that we use to price our oil and natural gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and natural gas differentials. Changes in differentials between the benchmark price for oil and natural gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition.

There are risks associated with our drilling activity that could impact the results of our operations.

Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to identify and acquire properties and to drill and complete wells. Additionally, seismic technology does not allow us to know conclusively prior to drilling a well that oil or natural gas is present or economically producible. 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. We have experienced some delays in contracting for drilling rigs, obtaining fracture stimulation crews and materials, and increasing costs to drill wells. All of these risks could adversely affect our results of operations and financial condition.

Part of our strategy involves acquiring acreage and drilling in new or emerging shale resource plays. As a result, our drilling results in these areas are subject to more uncertainties than our drilling program in the more established shallower formations and may not meet our expectations for reserves or production.

The results of our drilling in new or emerging shale resource plays, such as the Haynesville/Bossier shale and the Marcellus shale, are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. In addition, part of our drilling strategy to maximize recoveries from the shale resource plays involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling of the Haynesville/Bossier shale and the Marcellus shale to date, as well as the industry's drilling and production history in these formations, is limited. In the past, we acquired producing oil and natural gas properties with established production histories which generated cash flow immediately upon closing the acquisition. Since we shifted our acquisition strategy to focus on acreage acquisitions in shale areas with Haynesville/Bossier and Marcellus potential, we now invest significant capital for acreage generally without any meaningful production or immediate cash flow. We must then incur significant additional costs to drill and properly develop the acreage we acquire in these shale areas. We may use bank debt to fund these acquisitions but we do not receive credit for borrowing base purposes until we drill wells and generate production.

Increased drilling in the Haynesville/Bossier shale formation may cause pipeline and gathering system capacity constraints that may limit our ability to sell natural gas and/or receive market prices for our gas.

The Haynesville shale wells we have drilled to date in and around our core area have reported very high initial production rates, implying potentially large reserves. If drilling in the Haynesville/Bossier shale continues to be successful, the amount of natural gas being produced in the area from these new wells, as well as natural gas produced from other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. If this occurs it will be necessary for new interstate and intrastate pipelines and gathering systems to be built.

Because of the current economic climate, certain pipeline projects that are planned for the Haynesville/Bossier shale area may not occur because the prospective owners of these pipelines may be unable to secure the necessary financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such event, this could result in wells being shut-in awaiting a pipeline connection or capacity and/or natural gas being sold at much lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

Our use of derivative financial instruments is subject to risks that our counterparties may default on their contractual obligations to us and may cause us to forego additional future profits or result in our making cash payments.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into derivative financial instrument arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our derivative financial instruments are subject to mark-to-market accounting treatment. The change in the fair market value of these instruments is reported as a non-cash item in our statement of operations each quarter, which typically result in significant variability in our net income. Derivative financial instruments expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to the derivative financial instrument contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in the derivative financial instrument agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments.

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our common stock. During the year ended December 31, 2009, we received cash payments to settle our derivative financial instrument contracts totaling $478.5 million. During the year ended December 31, 2008, we made cash payments to settle our oil and natural gas derivative financial instrument contracts totaling $109.3 million. For the year ended December 31, 2009, a $1.00 increase in the average commodity price per Mcfe would have resulted in an increase in cash settlement payments (or a decrease in settlements received) of approximately $96.9 million. As of December 31, 2009, the net unrealized gains on our oil and natural gas derivative financial instrument contracts were $159.9 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. In connection with acquisitions which included producing properties, we have, in certain instances, assumed derivative financial instruments covering a significant portion of estimated future production. We may incur significant unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place. See "—Item 7. Management's discussion and analysis of financial condition and results of operations—Our results of operations—Derivative financial instruments."

We have incurred a substantial amount of indebtedness to fund our acquisitions, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of December 31, 2009, our consolidated indebtedness was approximately $1.2 billion, a substantial reduction from our December 31, 2008 consolidated debt of approximately $3.0 billion as a result of proceeds received from our 2009 divestiture program and joint venture transactions. While our consolidated debt has been substantially reduced, our reserves, borrowing base, production and cash flows have also been reduced as a result of our divestitures and joint venture transactions. To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations. In addition, we expect to fund acreage acquisitions with debt, which may increase our outstanding debt without any corresponding borrowing base increases. If our operating cash flow and other capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. None of these remedies may, if necessary, be effected on commercially reasonable terms, or at all. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt under our credit facilities, which could cause us to default on our obligations and could impair our liquidity.

We may be unable to acquire or develop additional reserves, which would reduce our revenues and access to capital.

Our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire or develop additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number and attractiveness of properties for sale. If we are unable to conduct successful development activities or acquire properties containing Proved Reserves, our total Proved Reserves will generally decline as a result of production. Also, our production will generally decline. In addition, if our reserves and production decline, then the amount we are able to borrow under our credit agreements will also decline. We may be unable to locate additional reserves, drill economically productive wells or acquire properties containing Proved Reserves.

We may not identify all risks associated with the acquisition of oil and natural gas properties, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and Employee Retirement Security Act, or ERISA, liabilities, and other liabilities and other similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. Even a detailed review of properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity.

We may be unable to obtain additional financing to implement our growth strategy.

The growth of our business will require substantial capital on a continuing basis. Due to the amount of debt we have incurred, it may be difficult for us in the foreseeable future to obtain additional debt financing or to obtain additional secured financing other than purchase money indebtedness. If we are unable to obtain additional capital on satisfactory terms and conditions, we may lose opportunities to acquire oil and natural gas properties and businesses and, therefore, be unable to implement our growth strategy.

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other requirements may be adversely affected.

Section 404 of the Sarbanes-Oxley Act of 2002 requires companies subject to the act to disclose any material weaknesses discovered through management's assessments. We are required to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Prior to December 31, 2007, we were not required to make an assessment of the effectiveness of our internal control over financial reporting for that purpose.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our company's annual or interim financial statements will not be prevented or detected on a timely basis.

We will continue to monitor the effectiveness of these and other processes, procedures and controls and will make any further changes management determines appropriate, including to effect compliance with Section 404 of the Sarbanes-Oxley Act of 2002.

Any material weaknesses or other deficiencies in our internal control over financial reporting may affect our ability to comply with SEC reporting requirements and the New York Stock Exchange, or NYSE, listing standards or cause our financial statements to contain material misstatements, which could negatively affect the market price and trading liquidity of our common stock, cause investors to lose confidence in our reported financial information, as well as subject us to civil or criminal investigations and penalties.

There are inherent limitations in all internal control systems over financial reporting, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, does not expect that our internal controls and disclosure controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of our company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

We may encounter obstacles to marketing our oil and natural gas, which could adversely impact our revenues.

Our ability to market our oil and natural gas production will depend upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities. We are primarily dependent upon third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs, outages caused by accidents or other events, or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. We experienced production curtailments in East Texas/North Louisiana during 2009 and the Appalachian Basin during 2007, 2008 and 2009 resulting from capacity restraints and short term shutdowns of certain pipelines for maintenance purposes. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas, the value of our common stock and our ability to pay dividends on our company stock.

We may not correctly evaluate reserve data or the exploitation potential of properties as we engage in our acquisition, exploration, development and exploitation activities.

Our future success will depend on the success of our acquisition, exploration, development and exploitation activities. Our decisions to purchase, explore, develop or otherwise exploit properties or prospects 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, which could significantly reduce our ability to generate cash needed to service our debt and fund our capital program and other working capital requirements.

We cannot control the development of the properties we own but do not operate, which may adversely affect our production, revenues and results of operations.

As of December 31, 2009, third parties operate wells that represent approximately 3.0% of our Proved Reserves. As a result, the success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

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

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

Numerous uncertainties are inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves and the PV-10 and Standardized Measure of our proved oil and natural gas reserves. These estimates are based upon reports of our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC as to constant oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These estimates should not be construed as the current market value of our estimated Proved Reserves. The process of estimating oil and natural gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir. As a result, the estimates are inherently imprecise evaluations of reserve quantities and future net revenue. Our actual future production, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we have assumed in the estimates. Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of PV-10 and Standardized Measure described in this Annual Report on Form 10-K, and our financial condition. In addition, our reserves or PV-10 and Standardized Measure may be revised downward or upward, based upon production history, results of future exploitation and development activities, prevailing oil and natural gas prices and other factors. A material decline in prices paid for our production can adversely impact the estimated volumes of our reserves. Similarly, a decline in market prices for oil or natural gas may adversely affect our PV-10 and Standardized Measure. Any of these negative effects on our reserves or PV-10 and Standardized Measure may decrease the value of our common stock.

New SEC and GAAP reserve reporting requirements may affect the results of our reserve estimates and could change our relative positioning in the industry with regard to reserve estimates.

On December 31, 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting" amending and expanding its disclosure requirements for oil and natural gas producing companies. The new rules and disclosure requirements are effective as of December 31, 2009. On January 16, 2010, the Financial Accounting Standards Board adopted rules conforming GAAP to the new SEC definitions and rules. These changes are the first major modifications to the accounting-based reserve reporting requirements since 1982. Among other things, the new SEC rules modify various definitions impacting categories of oil and natural gas reserves and replace the previous pricing mechanism of using the last day of our fiscal year by using an average price mechanism based on the first day of the last twelve months for purposes of computing reserve quantities as of December 31, 2009 and subsequent periods. In addition, these new requirements not only require oil and gas companies to report Proved Reserves, but also permit voluntary disclosure of 'probable' and 'possible' reserves. While the new rules are intended to provide investors with a more complete picture of the reserves of reporting companies, and were made with an eye towards continuing to recognize new technologies and knowledge about the geometry and extent of oil and natural gas fields, these changes will potentially affect the results of our reserve estimates and application of these new reserve reporting rules by competitors may change our relative positioning in the industry as a whole with regards to reserve estimates.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fires, explosions and blowouts;
- pipe failures;
- abnormally pressured formations; and
- environmental accidents such as oil spills, gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

We have in the past experienced some of these events during our drilling, production and midstream operations. These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- environmental clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorneys' fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in our industry, we maintain insurance against some, but not all, of these risks. Our insurance may not be adequate to cover these potential losses or liabilities. Furthermore, insurance coverage may not continue to be available at commercially acceptable premium levels or at all. Due to cost considerations, from time to time we have declined to obtain coverage for certain drilling activities. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our results of operations and cash flow.

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 development and production operations are subject to complex and stringent laws and regulations. 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 comply 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, production and sale 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 see "Item 1. Business—Applicable laws and regulations" for a description of the laws and regulations that affect us.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama's proposed Fiscal Year 2011 Budget included proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the manufacturing deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation, or ACES. The purpose of ACES is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to warming of the Earth's atmosphere resulting in climatic changes. ACES would establish a cap on total emissions of GHGs from certain categories of emission sources in the United States and require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACES, those categories of sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACES's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. If enacted, the net effect of ACES would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACES, the Senate legislation would need to be reconciled with ACES, and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance system that results in fewer allowances being issued over time, but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACES, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

The U.S. Environmental Protection Agency, or "EPA," has also taken recent action related to greenhouse gases. On December 7, 2009, the EPA issued a notice of its finding and determination that emissions of carbon dioxide, methane, and other GHGs may reasonably be anticipated to endanger the public health and public welfare by, among other things, increasing ground-level ozone, altering the climate, contributing to a rise in sea levels, and harming water resources, agriculture, wildlife, and ecosystems. Once EPA promulgates regulations controlling GHG emissions, for example, regarding emissions from motor vehicles, which EPA has indicated may occur in 2010, EPA will be required to begin regulating emissions of GHGs under existing permitting provisions of the federal Clean Air Act. Those permitting provisions could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those permitting requirements. EPA has proposed a "Tailoring Rule" to regulate the permitting of GHG sources under the Clean Air Act's PSD and Title V programs. Although it may take EPA several years to adopt and impose regulations limiting stationary source emissions of GHGs, any limitation on emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. On September 22, 2009, EPA finalized a GHG reporting rule that will require large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, recordkeep and report emissions of GHGs associated with our operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Legislation has been proposed in Congress and by the Treasury Department to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. Under proposed legislation, OTC derivative dealers and other major OTC derivative market participants could be subjected to substantial supervision and regulation. The legislation generally would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, to mandate clearance of derivative contracts through registered derivative clearing organizations, and to impose conservative capital and margin requirements and strong business conduct standards on OTC derivative transactions. The CFTC has proposed regulations that would implement speculative limits on trading and positions in certain commodities. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or the CFTC may issue new regulations, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance.

Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures.

Our operations are subject to numerous U.S. federal, state and local laws and regulations relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. Regulation of GHG emissions by Congress, EPA, or various states in the United States in areas in which we conduct business could have an adverse effect on our operations and demand for the oil and natural gas that we produce.

Our business substantially depends on Douglas H. Miller, our Chief Executive Officer.

We are substantially dependent upon the skills of Mr. Douglas H. Miller. Mr. Miller has extensive experience in acquiring, financing and restructuring oil and natural gas companies. We do not have an employment agreement with Mr. Miller or maintain key man insurance. The loss of the services of Mr. Miller could hinder our ability to successfully implement our business strategy.

We may have write-downs of our asset values, which could negatively affect our results of operations and net worth.

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon oil and natural gas prices in the future, and at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. We have in the past, including 2008 and the first quarter of 2009, experienced ceiling test write-downs with respect to our oil and natural gas properties. Future non-cash ceiling test write-downs could negatively affect our results of operations and net worth.

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting units exceeds the estimated fair value of those reporting units, an impairment charge will occur, which would negatively impact our net worth.

We may experience a financial loss if any of our significant customers fail to pay us for our oil or natural gas.

Our ability to collect the proceeds from the sale of oil and natural gas from our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fails to pay us for any reason, we could experience a material loss. In addition, in recent years, a number of energy marketing and trading companies have discontinued their marketing and trading operations, which has significantly reduced the number of potential purchasers for our oil and natural gas production. This reduction in potential customers has reduced market liquidity and, in some cases, has made it difficult for us to identify creditworthy customers. We also sell a portion of our natural gas directly to end users. We may experience a material loss as a result of the failure of our customers to pay us for prior purchases of our oil or natural gas.

We may experience a decline in revenues if we lose one of our significant customers.

During 2009, there were no sales to any individual customer which exceeded more than 10% of our consolidated revenues. However, during 2008 and in previous years, sales to Crosstex Gulf Coast Marketing and Atmos Energy have exceeded a 10% threshold. We continue to sell substantial quantities of natural gas to these customers. As our volumes in the Haynesville shale grow, these customers and others are expected to become more significant. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

We have entered into significant natural gas firm transportation contracts primarily in East Texas and North Louisiana which require us to pay fixed amounts of money to the shippers regardless of quantities actually shipped. If we are unable to deliver the necessary quantities of natural gas to the shippers, our results of operations and liquidity could be adversely affected.

As of February 12, 2010, we were contractually committed to spend approximately $33.5 million in 2010 and over $300.0 million over the next ten years for firm transportation services. We may enter into additional firm transportation agreements as our development of our Haynesville, Bossier and Marcellus shale plays expand. We expect our production volumes, as well as our competitors, to increase significantly in the Haynesville and Marcellus shale areas. The use of firm transportation allows us priority space in a shippers' pipeline which we believe is a strategic advantage. In the event we encounter delays due to construction, interruptions of operations or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

Competition in our industry is intense and we may be unable to compete in acquiring properties, contracting for drilling equipment and hiring experienced personnel.

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and headcount substantially larger 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 financial or personnel resources will permit. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. We may experience difficulties in obtaining drilling rigs and other services in certain areas as well as an increase in the cost for these services and related material and equipment. We are unable to predict when, or if, such shortages may again occur or how such shortages and price increases will affect our development and exploitation program. Competition has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We are often outbid by competitors in our attempts to acquire properties or companies. All of these challenges could make it more difficult to execute our growth strategy and increase our costs.

If third-party pipelines or other facilities interconnected to our gathering and transportation pipelines become unavailable to transport or process natural gas, our revenues and cash flow could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options from our transportation and gathering pipelines for the benefit of our customers. Much of the natural gas transported by our pipelines must be treated or processed before delivery into a pipeline for natural gas. If the processing and treating plants to which we deliver natural gas were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, our customers would be unable to deliver natural gas to end markets. Either of such events could materially and adversely affect our business, results of operations and financial condition.

Risks relating to our indebtedness

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of February 12, 2010, we had approximately \$1.2 billion of indebtedness, including \$747.6 million of indebtedness which is subject to variable interest rates and \$444.7 million of senior notes with a near-term maturity of January 15, 2011. Our total interest expense, excluding amortization of deferred financing costs, on an annual basis based on current available interest rates would be approximately \$50.3 million and would change by approximately \$7.5 million for every 1% change in interest rates.

Our level of debt could have important consequences, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the indenture with Wilmington Trust Company, as trustee, or the Indenture, governing our senior notes and the agreements governing our other indebtedness;

- we may have difficulty borrowing money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations;
- the amount of our interest expense may increase because certain of our borrowings are at variable rates of interest;
- we will need to use a substantial portion of our cash flows to pay principal and interest on our debt, which will reduce the amount of money we have for operations, working capital, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will be unable to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our earnings will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money to service our debt, we may be required but unable to refinance all or part of our existing debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Further, failing to comply with the financial and other restrictive covenants in our credit agreements and the Indenture governing our senior notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

We may incur substantially more debt, which may intensify the risks described above, including our ability to service our indebtedness.

Together with our subsidiaries, we may incur substantially more debt in the future in connection with our exploration, exploitation, development, acquisitions of undeveloped acreage and production of oil and natural gas producing properties. The restrictions in our debt agreements on our incurrence of additional indebtedness are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. To the extent new indebtedness is added to our current indebtedness levels, the risks described above could substantially increase. Significant additions of undeveloped acreage financed with debt may result in increased indebtedness without any corresponding increase in borrowing base, which could curtail drilling and development of this acreage or could cause us to not comply with our debt covenants.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our senior notes and loans under our credit agreements, and to fund planned capital expenditures will depend on our ability to generate cash from operations and other resources in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, including the prices that we receive for oil and natural gas.

Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us in an amount sufficient to enable us to pay our indebtedness, including our senior notes and loans under our credit agreements, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. None of these remedies may, if necessary, be effected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, which could cause us to default on our obligations and could impair our liquidity.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our credit agreements contain a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

Also, our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit agreements and the Indenture governing our senior notes. A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit arrangements. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit arrangements. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

Risks relating to our common stock

Our stock price may fluctuate significantly.

Our common stock began trading on the NYSE on February 9, 2006. An active trading market may not be sustained. The market price of our common stock could fluctuate significantly as a result of:

- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;

- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Future sales of our common stock may cause our stock price to decline.

As of December 31, 2009, we had 211,905,509 shares of common stock outstanding. All shares are freely tradable by persons other than our affiliates. Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

The equity trading markets may be volatile, which could result in losses for our shareholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition.

Our articles of incorporation permit us to issue preferred stock that may restrict a takeover attempt that you may favor.

Our articles of incorporation permit our board to issue up to 10,000,000 shares of preferred stock and to establish by resolution one or more series of preferred stock and the powers, designations, preferences and participating, optional or other special rights of each series of preferred stock. The preferred stock may be issued on terms that are unfavorable to the holders of our common stock, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred stock to convert their shares into our common stock on terms that are dilutive to holders of our common stock. The issuance of preferred stock in future offerings may make a takeover or change in control of us more difficult.

We may reduce or discontinue paying our quarterly cash dividend if our board of directors determines that paying a dividend is no longer appropriate.

In October 2009, we commenced a $0.025 quarterly cash dividend program on shares of our common stock. Any future dividend payments will depend on our earnings, capital requirements, financial condition, prospects and other factors that our board of directors may deem relevant. At any time, our board of directors may decide to reduce or discontinue paying our quarterly cash dividend. If we do not pay dividends, our common stock may be less valuable because a return on your investment will only occur if our stock price appreciates. In addition, our credit agreements and the Indenture governing our senior notes restrict our ability to pay dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Corporate offices

We lease office space in Dallas, Texas; Akron, Ohio; Cranberry Township, Pennsylvania; Warrendale, Pennsylvania and The Woodlands, Texas. We also have small offices for technical and field operations in Texas, Louisiana, Ohio, Pennsylvania and West Virginia. The table below summarizes our material corporate leases. We plan to close our offices in The Woodlands, Texas and Akron, Ohio during 2010 and will consolidate functions into our Dallas, Texas and Warrendale, Pennsylvania locations.

Location	Approximate square footage	Approximate monthly payment	Expiration
Dallas, Texas	152,600	$207,300	June 30, 2015
Warrendale, Pennsylvania	56,000	$102,700	October 31, 2016
Cranberry Township, Pennsylvania	22,400	$ 27,900	February 28, 2013
Akron, Ohio	17,500	$ 49,500	February 28, 2010
The Woodlands, Texas	13,800	$ 28,700	June 30, 2012

Other

We have described our oil and natural gas properties, oil and natural gas reserves, acreage, wells, production and drilling activity in "Item 1. Business" of this Annual Report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

In the ordinary course of business, we are periodically a party to lawsuits and claims. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition.

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

Not applicable.

PART II

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

Market information for our common stock

Our common stock trades on the NYSE under the symbol "XCO." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the NYSE:

	Price Per Share		Dividends
	High	Low	declared
2009			
First Quarter	$12.52	$ 7.68	$ —
Second Quarter	16.66	9.28	—
Third Quarter	19.38	10.57	—
Fourth Quarter	22.52	14.91	0.050
2008			
First Quarter	$19.33	$13.94	$ —
Second Quarter	39.00	18.51	—
Third Quarter	40.93	14.00	—
Fourth Quarter	16.10	4.08	—

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 86 holders of record of our common stock on December 31, 2009 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders).

Our dividend policy

On October 1, 2009 our Board of Directors approved the commencement of a dividend program at an initial quarterly cash dividend rate of $0.025 per share of EXCO's common stock. The first quarterly dividend of $0.025 per share was paid on October 26, 2009 to holders of record on October 12, 2009. The second quarterly dividend of $0.025 per share was paid on December 15, 2009 to holders of record on November 30, 2009. Any future declaration of dividends, as well as the establishment of record and payment dates, is subject to the approval of EXCO's Board of Directors.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial and operating data. You should read this financial data in conjunction with "Item 7. Management's discussion and analysis of financial condition and results of operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information included in this Annual Report on Form 10-K. This information does not replace the consolidated financial statements.

The selected financial data for the 275 day period from January 1, 2005 to October 2, 2005 is referred to as Predecessor and represents the period of time when EXCO was privately held and owned by a different group of equity holders. On October 3, 2005, a group of investors and EXCO management completed an equity buyout of EXCO, which resulted in a change of control and a change in accounting basis. All periods subsequent to October 3, 2005 are referred to as Successor. We became a publicly traded company on February 14, 2006.

Selected consolidated financial and operating data

(in thousands, except per share amounts)	Successor: Year ended December 31, 2009	Successor: Year ended December 31, 2008	Successor: Year ended December 31, 2007	Successor: Year ended December 31, 2006	Successor: 90 day period from October 3 to December 31, 2005	Predecessor: 275 day period from January 1 to October 2, 2005
Statement of operations data(1):						
Revenues:						
Oil and natural gas	$ 550,505	$ 1,404,826	$ 875,787	$359,235	$ 70,061	$ 132,821
Midstream(2)	35,330	85,432	18,817	8,139	—	—
Total revenues	585,835	1,490,258	894,604	367,374	70,061	132,821
Costs and expenses:						
Oil and natural gas production(3)	177,629	238,071	168,999	68,517	8,949	22,157
Midstream operating expenses(2)	35,580	82,797	16,289	7,797	—	—
Gathering and transportation	18,960	14,206	10,210	1,615	—	—
Depreciation, depletion and amortization	221,438	460,314	375,420	135,722	14,071	24,687
Write-down of oil and natural gas properties	1,293,579	2,815,835	—	—	—	—
Accretion of discount on asset retirement obligations	7,132	6,703	4,878	2,014	226	617
General and administrative(4)	99,177	87,568	64,670	41,206	6,375	89,442
Gain on divestitures and other operating items	(676,434)	(2,692)	(3,997)	—	—	—
Total costs and expenses	1,177,061	3,702,802	636,469	256,871	29,621	136,903
Operating income (loss)	(591,226)	(2,212,544)	258,135	110,503	40,440	(4,082)
Other income (expense):						
Interest expense	(147,161)	(161,638)	(181,350)	(84,871)	(19,414)	(26,675)
Gain (loss) on derivative financial instruments(5)	232,025	384,389	26,807	198,664	(256)	(177,253)
Other income	126	1,289	6,160	2,466	2,374	7,096
Equity method loss in TGGT Holdings, LLC	(69)	—	—	—	—	—
Other equity method investment	—	—	—	1,593	837	—
Total other income (expense)	84,921	224,040	(148,383)	117,852	(16,459)	(196,832)
Income (loss) before income taxes	(506,305)	(1,988,504)	109,752	228,355	23,981	(200,914)
Income tax expense (benefit)	(9,501)	(255,033)	60,096	89,401	7,631	(63,698)
Income (loss) before discontinued operations	(496,804)	(1,733,471)	49,656	138,954	16,350	(137,216)
Discontinued operations:						
Income (loss) from discontinued operations	—	—	—	—	—	(4,403)
Gain on disposition of Addison Energy, Inc	—	—	—	—	—	175,717
Income tax expense	—	—	—	—	—	49,282
Income from discontinued operations	—	—	—	—	—	122,032
Net income (loss)	(496,804)	(1,733,471)	49,656	138,954	16,350	(15,184)
Preferred stock dividends	—	(76,997)	(132,968)	—	—	—
Net income (loss) available to common shareholders	$ (496,804)	$(1,810,468)	$ (83,312)	$138,954	$ 16,350	$ (15,184)
Basic income (loss) per share from discontinued operations	$ —	$ —	$ —	$ —	$ —	$ 1.05
Basic income (loss) per share available to common shareholder	$ (2.35)	$ (11.81)	$ (0.80)	$ 1.44	$ 0.35	$ (0.13)
Diluted income (loss) per share from discontinued operations	$ —	$ —	$ —	$ —	$ —	$ 1.05
Diluted income (loss) per share available to common shareholders	$ (2.35)	$ (11.81)	$ (0.80)	$ 1.41	$ 0.35	$ (0.13)
Weighted average common and common equivalent shares outstanding:						
Basic	211,266	153,346	104,364	96,727	47,222	116,504
Diluted	211,266	153,346	104,364	98,453	47,222	116,504

Selected consolidated financial and operating data (continued)

	Successor					Predecessor
	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006	90 day period from October 3 to December 31, 2005	275 day period from January 1 to October 2, 2005
Statement of cash flow data:						
Net cash provided by (used in):						
Operating activities	$ 433,605	$ 974,966	$ 577,829	$ 227,659	$ 8,177	$ (81,122)
Investing activities	1,235,275	(1,708,579)	(2,396,437)	(1,791,517)	(13,337)	337,880
Financing activities	(1,657,612)	735,242	1,851,296	1,359,727	(4,018)	(47,035)
Balance sheet data:						
Current assets	$ 402,088	$ 513,040	$ 311,300	$ 236,710	$ 342,525	n/a
Total assets	2,358,894	4,822,352	5,955,771	3,707,057	1,530,493	n/a
Current liabilities	212,914	322,873	278,167	190,924	465,725	n/a
Long-term debt, less current maturities	1,196,277	3,019,738	2,099,171	2,081,653	461,802	n/a
Shareholders' equity	859,588	1,332,501	1,115,742	1,179,850	370,882	n/a
Total liabilities and shareholders' equity	2,358,894	4,822,352	5,955,771	3,707,057	1,530,493	n/a

(1) We have completed numerous acquisitions and dispositions which impacts the comparability of the selected financial data between periods. See Note 4. Divestitures and acquisitions in our notes to consolidated financial statements.

(2) We designated a midstream segment during 2008. Upon closing of the BG Midstream Transaction on August 14, 2009 of 50% of our interest in our East Texas/North Louisiana midstream operations (excluding the Vernon Field midstream assets), our Midstream operations no longer meet the criteria to be designated as a separate business segment. Effective August 14, 2009, net operating activity for the Vernon Field midstream assets, including intercompany eliminations are reported as a component of "Gathering and transportation" expense.

(3) Share-based compensation pursuant to Financial Accounting Standards Board, or FASB, ASC Topic 718 Compensation—Stock Compensation, included in oil and natural gas production is $2.8 million, $4.2 million and $3.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(4) Share-based compensation pursuant to FASB ASC Topic 718 Compensation—Stock Compensation, included in general and administrative expenses is $16.2 million, $11.8 million and $9.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(5) We do not designate our derivative financial instruments as hedges and as a result the changes in the fair value of our derivative financial instruments are recognized directly in our statement of operations. See "Item 7. Managements' discussion and analysis of financial condition and results of operations—Critical accounting policies—Accounting for derivatives" for a description of this accounting method.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and the related notes to those statements included elsewhere in this Annual Report on Form 10-K. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our results and the timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under "risk factors" and elsewhere in this Annual Report on Form 10-K.

Overview and history

We are an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties. Our principal operations are conducted in the East Texas/North Louisiana, Appalachia and Permian producing areas. In addition to our oil and natural gas producing operations, we hold a 50% equity interest in a joint venture which owns gathering systems and pipelines in East Texas/North Louisiana. Our assets in East Texas/North Louisiana, including our equity interest in midstream operations, are owned by our subsidiary, EXCO Operating. Organizationally, EXCO Operating is an indirect wholly-owned subsidiary of EXCO Resources. EXCO Operating's debt is not guaranteed by EXCO Resources and EXCO Operating does not guarantee EXCO Resources' debt.

Historically, we used acquisitions and vertical drilling as our vehicle for growth. As a result of our acquisitions, we accumulated an inventory of drilling locations and acreage holdings with significant potential in the Haynesville/Bossier and Marcellus shale resource plays. This shale potential has allowed us to shift our focus to exploit these shales, primarily through horizontal drilling. Future acquisitions are likely to be focused on supplementing our shale resource holdings in the East Texas/North Louisiana and Appalachian areas. We will continue to develop certain vertical drilling opportunities in our East Texas/North Louisiana, Appalachia and Permian areas as industry economic conditions permit.

We currently have two credit agreements with a combined borrowing base of $1.3 billion, of which $747.6 million was drawn as of December 31, 2009. The EXCO Resources Credit Agreement has a borrowing base of $450.0 million and the EXCO Operating Credit Agreement has a borrowing base of $850.0 million. We expect to continue to grow by leveraging our management and technical team's experience, developing our shale resource plays, exploiting our multi-year inventory of development drilling locations, accumulating undeveloped acreage in shale areas, exploitation projects and entering into joint venture transactions. We employ the use of debt along with a comprehensive derivative financial instrument program to mitigate commodity price volatility to support our strategy.

As of December 31, 2009, the PV-10 and the Standardized Measure of our Proved Reserves was approximately $747.7 million (see "Item 1. Summary of geographic areas of operations" for a reconciliation of PV-10 to Standardized Measure of Proved Reserves). For the year ended December 31, 2009, we produced 128.2 Bcfe of oil and natural gas. Based on our December 2009 average daily production of 224.0 Mmcfe, this translates to a reserve life of approximately 11.7 years.

In 2009, we drilled 103 wells and completed 101 gross (53.0 net) wells with 98.1% drilling success rate. Our 2009 development, exploitation and other oil and natural gas property capital expenditures totaled $299.8 million. In addition, we leased $106.0 million of undeveloped acreage primarily in the Haynesville/Bossier shale resource play in East Texas/North Louisiana. Midstream capital expenditures, prior to the formation of TGGT, were $53.1 million and corporate capital expenditures totaled an additional $52.5 million. In addition, we completed $233.6 million of acquisitions, which were mostly undeveloped acreage in the Haynesville shale resource play.

During 2009, we also completed sales of certain non-strategic assets pursuant to a previously announced divestiture program and entered into joint venture transactions with BG Group, resulting in net cash proceeds of approximately $2.1 billion after closing adjustments.

The following table summarizes our 2009 divestitures and joint venture transactions:

(in thousands)	Proceeds (1)
Operating division	
East Texas/North Louisiana	
BG Upstream Transaction	$ 713,779
BG Midstream Transaction	269,237
East Texas Transaction	154,299
Other East Texas/North Louisiana	22,327
Mid-Continent	
Mid-Continent Transaction	197,730
Sheridan Transaction(2)	531,351
Other Mid-Continent	5,482
Appalachia	
EnerVest Transaction(2)(3)	129,737
Permian	40,042
Total joint ventures and divestitures	$2,063,984

(1) Net of selling expenses.

(2) Subject to final closing adjustments.

(3) Pending receipt of an additional $13.1 million of consents.

Our plans for 2010 are focused on the Haynesville/Bossier and Marcellus shales. Our budgeted capital expenditures total $471.4 million, of which $409.4 million is allocated to our East Texas/North Louisiana and Appalachia regions. In East Texas and North Louisiana, our capital expenditures in the BG AMI are expected to total $740.8 million, with EXCO's share being only $165.3 million, which reflects the favorable impact of the BG Carry. In Appalachia, our planned capital expenditures total $154.2 million.

The 2010 capital budget includes $39.1 million for midstream activities, including a $7.8 million equity contribution to TGGT. TGGT is the newly formed midstream joint venture owned equally by EXCO and BG Group. TGGT owns the midstream assets located within the BG AMI in East Texas and North Louisiana. The TGGT capital budget for 2010 is $101.0 million, $50.5 million net to EXCO's interest. This budget will be mostly funded by internal TGGT cash flow. The management of TGGT is also evaluating several expansion projects which, if approved, will require additional capital contributions.

Like all oil and natural gas production companies, we face the challenge of natural production declines. Oil and natural gas production from a given well naturally decreases over time. We attempt to overcome this natural decline by drilling to identify and develop additional reserves and add additional reserves through acquisitions. As of December 31, 2009, 96.5% of our estimated Proved Reserves were natural gas. Consequently, our results of operations are particularly impacted by natural gas markets.

Critical accounting policies

In response to the SEC's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified the most critical accounting policies used in the preparation of our consolidated financial statements. We determined the critical policies by considering accounting policies that involve the most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our Proved Reserves, accounting for business combinations, accounting for derivatives, share-based payments, our choice of accounting method for oil and natural gas properties, goodwill, asset retirement obligations and income taxes.

We prepared our consolidated financial statements for inclusion in this report in accordance with GAAP. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, and applying these rules and requirements requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP.

Estimates of Proved Reserves

The Proved Reserves data included in this Annual Report on Form 10-K was prepared in accordance with SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the technical qualifications, experience and judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate. The assumptions used for our Haynesville well and reservoir characteristics and performance are subject to further refinement as more production history is accumulated.

You should not assume that the present value of future net cash flows represents the current market value of our estimated Proved Reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from Proved Reserves according to the requirements in the SEC's Release No. 33-8995 Modernization of Oil and Gas Reporting, or Release No. 33-8995. Actual future prices and costs may be materially higher or lower than the prices and costs used in the preparation of the estimate. Further, the mandated discount rate of 10% may not be an accurate assumption of future interest rates.

Proved Reserves quantities directly and materially impact depletion expense. If the Proved Reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in the estimate of Proved Reserves may result from lower market prices, making it uneconomical to drill or produce from higher cost fields. In addition, a decline in Proved Reserves may impact the outcome of our assessment of our oil and natural gas properties and require an impairment of the carrying value of our oil and natural gas properties.

Proved Reserves are defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimates is a deterministic estimate or probabilistic estimate. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes both the area identified by drilling and limited by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and the project has been approved for development by all necessary parties and entities, including governmental entities.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Business combinations

For the periods covered by this Annual Report on Form 10-K, we use FASB ASC Subtopic 805-10 for Business Combinations to record our acquisitions of oil and natural gas properties or entities which we acquire beginning January 1, 2009. ASC 805-10 requires that acquired assets, identifiable intangible assets and liabilities be recorded at their fair value, with any excess purchase price being recognized as goodwill. Application of ASC 805-10 requires significant estimates to be made by management using information available at the time of acquisition. Since these estimates require the use of significant judgment, actual results could vary as the estimates are subject to changes as new information becomes available.

Accounting for derivatives

We use derivative financial instruments to protect against commodity price fluctuations and in connection with the incurrence of debt related to our acquisition activities. Our objective in entering into these derivative financial instruments is to manage price fluctuations and achieve a more predictable cash flow to fund our development, acquisition activities and support debt incurred with our acquisitions. These derivative financial instruments are not held for trading purposes. We do not designate our derivative financial instruments as hedging instruments and, as a result, we recognize the change in the derivative's fair value as a component of current earnings.

Share-based payments

We account for share-based payments to employees using the methodology prescribed in FASB ASC Topic 718 for Compensation—Stock Compensation Topic. At December 31, 2009, our employees and directors held options under EXCO's 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, to purchase 16,454,294 shares of EXCO common stock at prices ranging from $6.33 per share to $38.01 per share. The options expire ten years from the date of grant. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of grant. We use the Black-Scholes model to calculate the fair value of issued options. The gross fair value of the granted options using the Black-Scholes model range from $2.28 per share to $14.27 per share. ASC Topic 718 requires share-based compensation be recorded with cost classifications consistent with cash compensation. EXCO uses the full cost method to account for its oil and natural gas properties. As a result, part of our share-based payments are capitalized. Total share-based compensation for 2009 was $24.1 million, of which $5.1 million was capitalized as part of our oil and natural gas properties. In 2008 and 2007, a total of $20.0 million and $15.0 million, respectively, of share-based compensation was incurred, of which $4.0 million and $2.4 million, respectively, was capitalized.

Accounting for oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities require that we choose between two GAAP alternatives; the full cost method or the successful efforts method.

We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs of oil and natural gas properties. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Unproved property costs are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess possible impairment or the need to transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus costs of acquired proved and unproved leaseholds.

During April 2008 we initiated leasing projects to acquire shale drilling rights in both our Appalachia and East Texas/North Louisiana operating areas. In accordance with our policy and FASB ASC Subtopic 835-20 for Capitalization of Interest, we began capitalizing interest on unproved properties.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs are divided by the total quantity of Proved Reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

Under the full cost method of accounting, sales, dispositions and other oil and natural gas property retirements are generally accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the relationship between capitalized costs and Proved Reserves. During 2009, our BG Upstream Transaction, Mid-Continent Transaction, East Texas Transaction and Sheridan Transaction resulted in significant alterations to our full cost depletion pool and we determined that gain recognition was appropriate for these transactions. Gain or loss recognition on divestiture or abandonment of oil and natural gas properties where disposition would result in a significant alteration of the depletion rate requires allocation of a portion of the amortizable full cost pool based on the relative estimated fair value of the disposed oil and natural gas properties to the estimated fair value of total Proved Reserves. As discussed under "Estimates of Proved Reserves," estimating oil and natural gas reserves involves numerous assumptions.

Prior to our December 31, 2009 adoption of Release No. 33-8995, at the end of each quarterly period the unamortized cost of oil and natural gas properties, net of related deferred income taxes, was limited to the full cost ceiling, computed as the sum of the estimated future net revenues from our Proved Reserves using period-end prices, discounted at 10%, and adjusted for related income tax effects (ceiling test). In the event our capitalized costs exceeded the ceiling limitation at the end of the reporting period, we subsequently evaluated the limitation for price changes occurring after the balance sheet date to assess impairment. Beginning December 31, 2009, Release No. 33-8995 requires that the full cost ceiling be computed as the sum of the estimated future net revenues from Proved Reserves using the average, first-day-of-the-month price during the previous 12-month period, discounted at 10% and adjusted for related income tax effects. The new rule no longer allows a company to subsequently evaluate the limitation for subsequent prices changes. Under full cost accounting rules, any ceiling test write-downs of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedges, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computation. As a result, decreases in commodity prices which contribute to ceiling test write-downs may be offset by mark-to-market gains which are not reflected in our ceiling test results.

For the year 2007, we sought and received exemptions from the Securities and Exchange Commission, or the SEC, in July 2007 to exclude three significant proved oil and natural gas property acquisitions which closed in late 2006 and during the first half of 2007 from our ceiling test computation for a period of 12 months from the closing date of each acquisition. There were no ceiling test exemptions in effect for any acquisitions for the years ended December 31, 2009 and 2008.

The quarterly calculation of the ceiling test is based upon estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Goodwill

A change in control transaction involving an equity buyout on October 3, 2005, required the application of the purchase method of accounting pursuant to ASC 805-10 and goodwill of $220.0 million was recognized. Additional goodwill of $250.1 million was recognized from our 2006 acquisitions.

The BG Upstream Transaction, the East Texas Transaction, the Mid-Continent Transaction and the Sheridan Transaction each caused significant alterations to our depletion rate and we therefore evaluated the goodwill associated with these properties. As a result of our analysis, we eliminated $177.6 million of goodwill by reducing the gains associated with these transactions. In addition, the BG Midstream Transaction triggered the write off of $11.4 million of goodwill against the associated gain and the transfer of $11.4 million of goodwill to the TGGT investment.

As of December 31, 2009, our consolidated goodwill totals $269.7 million. Not all of our goodwill is currently deductible for income tax purposes. Furthermore, in accordance with FASB ASC Topic 350-Intangibles —Goodwill and Other, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are subject to various assumptions and judgments. We use a combination of valuation techniques, including discounted cash flow projections and market comparable analyses to evaluate our goodwill for possible impairment. Actual future results of these assumptions could differ as a result of economic changes which are not within our control. Losses, if any, resulting from impairment tests will be reflected in operating income in the statement of operations. As of December 31, 2009, we did not have any impairment of our goodwill.

Asset retirement obligations

We follow FASB ASC Subtopic 410-20 for Asset Retirement Obligations to account for legal obligations associated with the retirement of long-lived assets. ASC 410-20 requires these obligations be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. We periodically assess the estimated costs of our asset retirement obligations and adjust the liability according to these estimates.

Accounting for income taxes

Income taxes are accounted for using the liability method of accounting in accordance FASB ASC Topic 740 for Income Taxes. We must make certain estimates related to the reversal of temporary differences, and actual results could vary from those estimates. Deferred taxes are recorded to reflect the tax benefits and consequences of future years' differences between the tax basis of assets and liabilities and their financial reporting basis. We record a valuation allowance to reduce deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Recent accounting pronouncements

On January 21, 2010, the Financial Accounting Standards Board, or the FASB, issued Accounting Standards Update No. 2010-06—Fair Value Measurement and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements, or ASU 2010-06. ASU 2010-06 requires transfers, and the reasons for the transfers, between Levels 1 and 2 be disclosed, Level 3 reconciliations for fair value measurements using significant unobservable inputs should be presented on a gross basis, the fair value measurement disclosure should be reported for each class of asset and liability, and disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring will be required for fair value measurements that fall in either Level 2 or 3. The update will be effective for interim and annual reporting periods beginning after December 15, 2009. This update will require us to update our disclosures on derivatives, but will have no impact to our financial position.

On April 1, 2009, the FASB issued FASB ASC Subtopic 805-20 for Business Combinations. ASC 805-20 amends and clarifies FASB SFAS No. 141 (revised 2007), "Business Combinations," to give guidance on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This pronouncement was effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted ASC 805-20 on January 1, 2009.

In March 2008, the FASB issued FASB ASC Section 815-10-65 for Derivatives and Hedging. ASC 815-10-65 requires enhanced disclosure about the fair value of derivative instruments and their gains or losses in tabular format and information about credit-risk-related contingent features in derivative agreements, counterparty credit risk, and the company's strategies and objectives for using derivative instruments. ASC 815-10-65 is effective for financial statements issued for fiscal years beginning after November 15, 2008, and as such, was adopted by us on January 1, 2009. See "Note 9. Derivative financial instruments and fair value measurements" for the impact to our disclosures.

On December 31, 2008, the SEC issued Release No. 33-8995, amending its oil and natural gas reporting requirements for oil and natural gas producing companies. On January 16, 2010, the Financial Accounting Standards Board, or the FASB, issued Update No. 2010-03—Extractive Activities—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures, or Update No. 2010-03, to align the oil and gas reserve estimation and disclosure requirements of the Codification with Release No. 33-8995.

The effective date of the new accounting and disclosure requirements is for annual reports filed for fiscal years ending on or after December 31, 2009. Companies are not permitted to comply at an earlier date.

Among other things, Release No. 33-8995 and the Update No. 2010-03:

- Revises a number of definitions relating to oil and natural gas reserves to make them consistent with the Petroleum Resource Management System, which includes certain non-traditional resources in proved reserves;
- Permits the use of new technologies for determining oil and natural gas reserves;
- Requires the use of the simple average spot prices for the trailing twelve month period using the first day of each month in the estimation of oil and natural gas reserve quantities and, for companies using the full cost method of accounting, in computing the ceiling limitation test, in place of a single day price as of the end of the fiscal year;
- Permits the disclosure in filings with the SEC of probable and possible reserves and sensitivity of our proved oil and natural gas reserves to changes in prices;
- Requires additional disclosures (outside of the financial statements) regarding the status of undeveloped reserves and changes in status of these from period to period; and
- Requires a discussion of the internal controls in place in the reserve estimation process and disclosure of the technical qualifications of the technical person having primary responsibility for preparing the reserve estimates.

The impact of the adoption of this statement can be seen in our disclosures in Item 1. Business. The change in the calculation of pricing resulted in prices of $3.87 per Mmbtu for Henry Hub and $61.18 per Bbl for Cushing, Oklahoma instead of the December 31, 2009 spot price of $5.79 per Mmbtu for Henry Hub and $79.36 per Bbl for Cushing, Oklahoma.

Our results of operations

A summary of key financial data for 2009, 2008 and 2007 related to our results of operations for the years then ended is presented below.

(dollars in thousands, except per unit price)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Production:					
Oil (Mbbls)	1,571	2,236	1,645	(665)	591
Natural gas (Mmcf)	118,736	131,159	111,419	(12,423)	19,740
Total production (Mmcfe)(1)	128,162	144,575	121,289	(16,413)	23,286
Oil and natural gas revenues before derivative financial instrument activities:					
Oil	$ 84,397	$ 216,727	$ 117,073	$ (132,330)	$ 99,654
Natural gas	466,108	1,188,099	758,714	(721,991)	429,385
Total oil and natural gas	$ 550,505	$ 1,404,826	$ 875,787	$ (854,321)	$ 529,039
Midstream operations:(2)					
Midstream revenues (before intersegment eliminations)	$ 76,478	$ 147,636	$ 45,763	$ (71,158)	$ 101,873
Midstream operating expenses (before intersegment eliminations)	56,372	112,705	22,276	(56,333)	90,429
Midstream operating profit (before intersegment eliminations)	20,106	34,931	23,487	(14,825)	11,444
Intersegment eliminations	(20,356)	(32,296)	(20,959)	11,940	(11,337)
Midstream operating profit (after intersegment eliminations)	$ (250)	$ 2,635	$ 2,528	$ (2,885)	$ 107
Oil and natural gas derivative financial instruments:					
Cash settlements on derivative financial instruments	$ 478,463	$ (109,300)	$ 108,413	$ 587,763	$ (217,713)
Non-cash change in fair value of derivative financial instruments	(246,438)	493,689	(81,606)	(740,127)	575,295
Total derivative financial instrument activities	$ 232,025	$ 384,389	$ 26,807	$ (152,364)	$ 357,582
Average sales price (before cash settlements of derivative financial instruments):					
Oil (Bbl)	$ 53.72	$ 96.93	$ 71.17	$ (43.21)	$ 25.76
Natural gas (per Mcf)	3.93	9.06	6.81	(5.13)	2.25
Natural gas equivalent (per Mcfe)	4.30	9.72	7.22	(5.42)	2.50
Costs and expenses:					
Oil and natural gas operating costs(3)	$ 138,659	$ 161,172	$ 115,719	$ (22,513)	$ 45,453
Production and ad valorem taxes	38,970	76,899	53,280	(37,929)	23,619
Gathering and transportation	18,960	14,206	10,210	4,754	3,996
Depletion	196,515	435,595	357,902	(239,080)	77,693
Depreciation and amortization	24,923	24,719	17,518	204	7,201
General and administrative(4)	99,177	87,568	64,670	11,609	22,898
Interest expense, including impacts of interest rate swaps	147,161	161,638	181,350	(14,477)	(19,712)
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 1.08	$ 1.11	$ 0.95	$ (0.03)	$ 0.16
Production and ad valorem taxes	0.30	0.53	0.44	(0.23)	0.09
Gathering and transportation	0.15	0.10	0.08	0.05	0.02
Depletion	1.53	3.01	2.95	(1.48)	0.06
Depreciation and amortization	0.19	0.17	0.15	0.02	0.02
General and administrative	0.77	0.61	0.53	0.16	0.08
Net income (loss)	$(496,804)	$(1,733,471)	$ 49,656	$1,236,667	$(1,783,127)
Preferred Stock dividends	—	(76,997)	(132,968)	76,997	55,971
Income (loss) available to common shareholders	$(496,804)	$(1,810,468)	$ (83,312)	$1,313,664	$(1,727,156)

(1) Mmcfe is calculated by converting one barrel of oil into six Mcf of natural gas.

(2) Upon closing the BG Midstream Transaction on August 14, 2009, our midstream operations no longer met the criteria to be designated as a separate business segment. Our 50% interest in TGGT is accounted for using the equity method of accounting. Effective August 14, 2009, all operating activity, including intersegment eliminations, for the Vernon Field midstream assets is reported as a component in "Gathering and transportation" expense.

(3) Share-based compensation, pursuant to FASB ASC Topic 718, included in oil and natural gas operating costs, is $2.8 million, $4.2 million and $3.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(4) Share-based compensation, pursuant to FASB ASC Topic 718, included in general and administrative expenses is $16.2 million, $11.8 million and $9.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. See "Note 2. Summary of significant accounting policies—Stock options" in the notes to our consolidated financial statements included in this Annual Report on Form 10-K.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2009, 2008 and 2007.

The comparability of our results of operations for 2009, 2008 and 2007 is impacted by:

- the BG Upstream Transaction;
- 2009 divestures;
- other dispositions of oil and natural gas properties;
- fluctuations in oil and natural gas prices, which impact our oil and natural gas reserves, revenues, cash flows and net income or loss;
- the impact of our 2009 natural gas production volumes from our horizontal drilling activities in the Haynesville shale;
- mark-to-market accounting used for our derivative financial instruments gains or losses;
- changes in Proved Reserves and production volumes, including the impact of the 2009 SEC rules, and their impact on depletion;
- the impact of ceiling test write-downs in 2009 and 2008;
- gains on sales of assets in 2009;
- the impact of the BG Midstream Transaction and related adoption of the equity method of accounting for our investment in TGGT;
- significant changes in the amount of our long-term debt and the conversion of $2.0 billion of preferred stock into common stock in July 2008; and
- significant acquisitions of producing oil and natural gas properties acquired in 2007 and 2008.

General

The availability of a ready market for oil and natural gas and the prices of oil and natural gas are dependent upon a number of factors that are beyond our control. These factors include, among other things:

- the level of domestic production and economic activity, particularly the recent worldwide economic recession which continues to affect oil and natural gas prices and demand;
- the level of domestic and international industrial demand for manufacturing operations;
- the availability of imported oil and natural gas;
- actions taken by foreign oil producing nations;
- the cost and availability of natural gas pipelines with adequate capacity and other transportation facilities;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and refined products;
- the extent of governmental regulation and taxation (under both present and future legislation) of the production, refining, transportation, pricing, use and allocation of oil, natural gas, refined products and substitute fuels; and
- trends in fuel use and government regulations that encourage less fuel use and encourage or mandate alternative fuel use.

Accordingly, in light of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we cannot accurately predict the prices or marketability of oil and natural gas from any producing well in which we have or may acquire an interest.

Marketing arrangements and backlog

We produce oil and natural gas. We do not refine or process the oil or natural gas we produce. We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our contracts are based on NYMEX pricing, which is typically calculated as the average of the daily closing prices of oil to be delivered one month in the future. We also sell a portion of our oil at F.O.B. field prices posted by the principal purchaser of oil where our producing properties are located. Our sales contracts are of a type common within the industry, and we usually negotiate a separate contract for each property. Generally, we sell our oil to purchasers and refiners near the areas of our producing properties.

We sell the majority of our natural gas under individually negotiated gas purchase contracts using market sensitive pricing. Our sales contracts vary in length from spot market sales of a single day to term agreements that may extend for a year or more. Our natural gas customers include utilities, natural gas marketing companies and a variety of commercial and industrial end users. The natural gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market varies daily, reflecting changing market conditions.

For the year ended December 31, 2009, there were no sales to any individual customer which exceeded 10% of our consolidated revenues or were considered material to our operations. For the year ended December 31, 2008, sales to a natural gas marketing company, Crosstex Gulf Coast Marketing, and to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, accounted for approximately 12.0% and 11.2%, respectively, of total consolidated revenues. For the year ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for approximately 18.9% and 11.4%, respectively, of total consolidated revenues. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas, but we believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

We may be unable to market all of the oil and natural gas we produce. If our oil and natural gas can be marketed, we may be unable to negotiate favorable price and contractual terms. Changes in oil or natural gas prices may significantly affect our revenues, cash flows, the value of our oil and natural gas properties and the estimates of recoverable oil and natural gas reserves. Further, significant declines in the prices of oil or natural gas may have a material adverse effect on our business and on our financial condition.

We engage in oil and natural gas production activities in geographic regions where, from time to time, the supply of oil or natural gas available for delivery exceeds the demand. In this situation, companies purchasing oil or natural gas in these areas reduce the amount of oil or natural gas that they purchase from us. If we cannot locate other buyers for our production or for any of our newly discovered oil or natural gas reserves, we may shut-in our oil or natural gas wells for periods of time. If this occurs, we may incur additional payment obligations under our oil and natural gas leases and, under certain circumstances, the oil and natural gas leases might be terminated. Recent economic conditions related to the liquidity and creditworthiness of our purchasers may expose us to risk with respect to the ability to collect payments for the oil and natural gas we deliver.

Summary

For the years ended December 31, 2009, 2008 and 2007, we had net losses available to common shareholders of $496.8 million, $1.8 billion and $83.3 million, respectively.

During 2009, we closed divestiture and joint venture transactions totaling approximately $2.1 billion. Upon closing these transactions, we no longer operate in the Mid-Continent, Rockies and Ohio regions. Our current primary focus is the exploration and exploitation of the Haynesville/Bossier shales in East Texas/North Louisiana and the Marcellus shale in Appalachia.

Our results of operations for 2009 were impacted by the BG Upstream Transaction, the BG Midstream Transaction, the East Texas Transaction, the Mid-Continent Transaction, the Sheridan Transaction and the EnerVest Transaction. The impacts of these transactions include the following:

- we recognized gains from our joint venture transactions with BG Group, the East Texas Transaction, the Mid-Continent Transaction and the Sheridan Transaction in 2009 of $691.9 million.
- production, revenues, operating expenses and related severance and ad valorem taxes for 2009 reflect the significant joint ventures and divestitures with BG Group, Encore, and Sheridan, as well as other smaller sales completed during 2009. The significant divestitures and joint ventures occurred during the third and fourth quarters of 2009. The combination of these transactions had significant impacts on our operating statistics. Our average daily production volumes for December 2009, the first month in which we had operations which excluded these transactions, was 224.0 Mmcfe per day, which would result in annualized production of 81.8 Bcfe compared with reported 2009 production of 128.2 Bcfe and 2008 production of 144.6 Bcfe; and
- we discontinued reporting our midstream operations as a separate business segment on August 14, 2009 as a result of the BG Midstream Transaction. We now report our 50% equity in net income or loss from TGGT in Equity method loss in TGGT Holdings, LLC in our Condensed Consolidated Statements of Operations.

In addition, the impact of acquisitions, fluctuations in oil and natural gas prices, ceiling test write-downs and derivative financial instruments are significant to our results of operations. Acquisitions of producing oil and natural gas properties in 2008 and 2007 significantly increased our production, revenues and operating costs. There were large fluctuations in oil and natural gas prices during 2008 and 2009. In 2008, we received average oil prices of $96.93 per Bbl compared to $53.72 per Bbl in 2009 and in 2008 average natural gas prices of $9.06 per Mcfe compared to $3.93 per Mcfe in 2009. As a result of the decrease in natural gas prices from the end of 2008 and into 2009, we recognized write-downs to our full cost pool of $2.8 billion in 2008 and $1.3 billion in 2009. There were no write-downs required in 2007. In addition, we do not designate our derivative financial instruments as hedges. Therefore, we mark the non-cash changes in the fair value of our unsettled derivative financial instruments to market at the end of each reporting period. Due to significant fluctuations in the price of oil and natural gas during 2009, 2008 and 2007, the impacts of derivative financial instruments, including cash settlements or receipts with our counterparties and the non-cash mark-to-market impacts, totaled net gains of $232.0 million, $384.4 million and $26.8 million for 2009, 2008 and 2007, respectively.

Oil and natural gas revenues, production and prices

The following table presents our revenues, production and prices by major producing areas for the years ended December 31, 2009, 2008, 2007:

	Year ended December 31,								
	2009			2008			Year to date change		
(dollars in thousands, except per unit rate)	Production (Mmcfe)	Revenue	$/Mmcfe	Production (Mmcfe)	Revenue	$/Mmcfe	Production (Mmcfe)	Revenue	$/Mmcfe
Producing region:									
East Texas/North Louisiana	82,138	$315,710	$3.84	87,540	$ 802,579	$ 9.17	(5,402)	$(486,869)	$(5.33)
Mid-Continent	18,013	84,179	4.67	24,239	243,148	10.03	(6,226)	(158,969)	(5.36)
Appalachia	19,184	91,832	4.79	20,899	209,221	10.01	(1,715)	(117,389)	(5.22)
Permian and other	8,827	58,784	6.66	11,897	149,878	12.60	(3,070)	(91,094)	(5.94)
Total	128,162	$550,505	$4.30	144,575	$1,404,826	$ 9.72	(16,413)	$(854,321)	$(5.42)

(dollars in thousands, except per unit rate)	Year ended December 31, 2008 Production (Mmcfe)	Revenue	\$/Mmcfe	2007 Production (Mmcfe)	Revenue	\$/Mmcfe	Year to date change Production (Mmcfe)	Revenue	\$/Mmcfe
Producing region:									
East Texas/North Louisiana	87,540	\$ 802,579	\$ 9.17	78,312	\$528,947	\$6.75	9,228	\$273,632	\$2.42
Mid-Continent	24,239	243,148	10.03	19,271	148,586	7.71	4,968	94,562	2.32
Appalachia	20,899	209,221	10.01	15,661	121,994	7.79	5,238	87,227	2.22
Permian and other	11,897	149,878	12.60	8,045	76,260	9.48	3,852	73,618	3.12
Total	144,575	\$1,404,826	\$ 9.72	121,289	\$875,787	\$7.22	23,286	\$529,039	\$2.50

Total oil and natural gas revenues for 2009 were \$550.5 million compared with \$1.4 billion for 2008 and \$875.8 million for 2007. For 2009, natural gas represented 84.7% of our oil and natural gas revenues and 92.6% of equivalent production. For 2008, natural gas represented 84.6% of our oil and natural gas revenues and 90.7% of equivalent production and for 2007, natural gas represented 86.6% of our oil and natural gas revenues and 91.9% of equivalent production.

Our equivalent production volumes for 2009 were 128.2 Bcfe compared with 144.6 Bcfe for 2008, a decrease of 11.4% due primarily to our 2009 divestitures, including the BG Upstream Transaction, which were partially offset by increased production volumes from Haynesville drilling results.

Production in our East Texas/North Louisiana region for 2009 was 82.1 Bcfe compared with 87.5 Bcfe in 2008. Divestures in 2009 impacting our East Texas/North Louisiana region included our East Texas Transaction and the BG Upstream Transaction. Our East Texas/North Louisiana production was also impacted as a result of production declines in our Vernon Field due to suspension of vertical drilling operations in the area. These decreases were almost offset, however, by increased production in our Haynesville area, which we began actively drilling in late 2008, and the addition of the Danville Field in East Texas, which we acquired in July 2008.

Our Mid-Continent region was sold in 2009. Our production in Appalachia in 2009 of 19.2 Bcfe compared with 20.9 Bcfe in 2008, was the result of normal declines impacted by suspension of drilling operations and the EnverVest Transaction. Our production declines in Permian were a result of normal declines, suspension of drilling operations and the divesture of our Vinegarone Field.

Our equivalent production volumes for 2008 were 144.6 Bcfe compared with 121.3 Bcfe for 2007, an increase of 19.2%, due to our 2008 Appalachian Acquisition and the Danville Acquisition, combined with full year 2008 production impacts from the 2007 Vernon Acquisition and the Southern Gas Acquisition. The Appalachian Acquisition and the Danville Acquisition contributed 7.7 Bcfe of production to our 2008 total volumes. Production increases of approximately 10.2 Bcfe in 2008 include the impact of a full year production from the Vernon Acquisition and the Southern Gas Acquisition compared with a partial year in 2007.

For 2009, our average price received for natural gas was \$3.93 per Mcf compared with \$9.06 per Mcf in 2008 and \$6.81 per Mcf in 2007. The 2009 average price received for oil was \$53.72 per Bbl compared to \$96.93 per Bbl for 2008. The average price per Bbl for 2007 was \$71.17. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, estimates of oil and natural gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms. Market conditions involving over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Changes in oil and natural gas prices have a significant impact on our oil and natural gas revenues, cash flows, quantities of estimated Proved Reserves and related liquidity. The decline from the 2008 prices to the 2009 prices was a result of a commodity price decline that started at end of the third quarter of 2008 and continued through 2009. Assuming our 2009 production levels, a change of \$0.10 per Mcf of natural gas sold would result in an annual increase or decrease in revenues and cash flow of approximately \$11.9 million and a change of \$1.00 per Bbl of oil sold would result in an annual increase or decrease in revenues and cash flow of approximately \$1.6 million without considering the effects of derivative financial instruments.

In 2008, our revenues (before the impact of derivative financial instruments) increased to $1.4 billion from $875.8 million for 2007. The total increase of $529.0 million was attributable to an increase of $236.0 million from increased volumes primarily due to 2008 and 2007 acquisitions along with an increase in our realized price per Mcfe, which increased revenue by $293.0 million.

During 2008 we closed the Appalachian Acquisition, which included shallow natural gas properties located primarily in our central Pennsylvania operating area and the Danville Acquisition, which included producing oil and natural gas properties, acreage and other assets in Gregg, Rusk and Upshur counties of Texas. The Appalachian Acquisition and the Danville Acquisition increased our production in our Appalachia and East Texas/North Louisiana areas by 4.6 Bcfe and 3.1 Bcfe, respectively, during 2008. In addition, the impact of a full year of production in 2008 compared with a partial year in 2007 from the Vernon Acquisition increased volumes in East Texas/North Louisiana by 4.4 Bcfe. Volumes in the Mid-Continent area from the Southern Gas Acquisition increased by 5.7 Bcfe during 2008.

In January 2007, we completed the sale of our producing properties and undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado. This transaction included substantially all of our producing assets in Colorado. In May 2007, we sold a group of properties acquired in the Southern Gas Acquisition. While this sale, which provided proceeds of approximately $235.5 million, was substantial, it did not impact our results of operations as we did not hold the properties for a period of time sufficient to impact our operating results. In July 2007, we completed the sale of substantially all of our interest in the Cement Field located in our Mid-Continent area. In October 2007, we completed the purchase of an additional 45% ownership interest in approximately 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand Field in West Texas located in our Permian area. We also completed several small sales of producing properties and acreages throughout 2007. The Vernon Acquisition and the Southern Gas Acquisition significantly increased our production in the East Texas/North Louisiana and Mid-Continent areas during 2007.

Midstream revenues

Until our adoption of the equity method of accounting in connection with the BG Midstream Transaction in August 2009, our midstream revenues were principally derived from three of our wholly-owned subsidiaries: TGG, which owns an intrastate pipeline in East Texas and a gathering system in North Louisiana, Talco, which owns gathering systems in East Texas and North Louisiana and Vernon Gathering. Revenues in our midstream segment were derived from sales of natural gas purchased for resale and fees earned from gathering, transportation, treating and compression of natural gas. We do not own any natural gas processing facilities.

On August 14, 2009, we closed the BG Midstream Transaction. TGGT now holds our East Texas/North Louisiana midstream assets, exclusive of the Vernon Field midstream assets. TGGT is accounted for using the equity method of accounting. The net operations of Vernon Gathering are now reflected in "Gathering and transportation" on our Condensed Consolidated Statements of Operations.

Prior to the sale on August 14, 2009, we evaluated our midstream operations as if they were a stand alone operation. Accordingly, the results of operations discussed below are prior to intersegment eliminations.

For the year ended December 31, 2009, midstream revenues were $76.5 million compared with $147.6 million for year ended December 31, 2008. The decrease in sales for 2009 is due to the combination of lower prices received in 2009 from the sales of natural gas we purchased for resale, lower condensate prices and the adoption of the equity method of accounting for TGGT's operations on August 14, 2009.

For the year ended December 31, 2008, midstream revenues were $147.6 million, a 222.6% increase over the year ended December 31, 2007 midstream revenues of $45.8 million. Increases in the sales of natural gas account for 80.9% of the increase in the midstream revenues and are primarily attributable to the New Waskom Acquisition and gathering assets acquired in the Danville Acquisition. These assets, which were not owned in 2007, contained several contracts whereby we purchase and resell natural gas produced by third-parties. The remaining increase in revenues was attributable to increases in drip sales and gathering fees associated with the 2008 acquisitions, as well as increased throughput on our midstream assets.

Oil and natural gas operating costs

Our oil and natural gas operating costs for 2009, 2008, and 2007 were $138.7 million, $161.2 million and $115.7 million, respectively. Absolute increases or decreases in total dollar value from year to year are due primarily to operating expenses incurred from our acquisitions or divestitures. Management believes that analyses on a per Mcfe basis provide a more meaningful measure than the absolute dollar increases since the divestures in 2009 and the acquisitions in 2008 and 2007 significantly impacted the absolute dollar amounts. The following tables summarize direct operating expenses and unit rates per Mcfe for 2009, 2008, and 2007:

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Lease operating expense	$124,703	$144,171	$104,002	$(19,468)	$40,169
Workovers	11,125	12,827	8,126	(1,702)	4,701
Stock-based compensation (non-cash)	2,831	4,174	3,591	(1,343)	583
Total oil and natural gas operating costs	$138,659	$161,172	$115,719	$(22,513)	$45,453

(per Mcfe)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Lease operating expense	$ 0.97	$ 0.99	$ 0.85	$ (0.02)	$ 0.14
Workovers	0.09	0.09	0.07	—	0.02
Stock-based compensation (non-cash)	0.02	0.03	0.03	(0.01)	—
Total oil and natural gas operating costs	$ 1.08	$ 1.11	$ 0.95	$ (0.03)	$ 0.16

On a per Mcfe basis, oil and natural gas operating costs for the year ended December 31, 2009 decreased by $0.03 per Mcfe from year ended December 31, 2008. Direct lease operating expenses per unit decreased by $0.02 per Mcfe, or 2.0%, for the year ended December 31, 2009, from the year ended December 31, 2008. These decreases are principally the result of divestitures in 2009 and lower operating costs in our East Texas/North Louisiana area where increasing volumes from Haynesville wells benefit the unit rate. Benefits from the Haynesville results are partially offset by declining volumes from our base production that tend to increase the unit rate.

On a per Mcfe basis, oil and natural gas operating expenses for the year ended December 31, 2008 increased $0.16 per Mcfe from year ended December 31, 2007. Direct lease operating expenses increased by $0.14 per Mcfe, or 16.5%, for the year ended December 31, 2008 from the year ended December 31, 2007. These increases were primarily the result of our acquisitions in 2008 and the general increase in the costs of goods and services used in our oil and natural gas operations, most notably chemicals, labor, utilities, motor fuel and utility costs. Workover expenses for the year ended December 31, 2008, on a Mcfe basis, increased $0.02 per Mcfe from the year ended December 31, 2007 due primarily to higher costs for rigs and services.

Midstream operating expenses

Our midstream operating expenses before intersegment elimination, which includes the cost of natural gas purchased and then resold, for the year ended December 31, 2009 decreased $56.3 million from the year ended December 31, 2008. The decrease in midstream operating expenses was primarily attributable to a decline in the prices we paid for the natural gas we purchased for resale along with the August 14, 2009 BG Midstream Transaction and related adoption of the equity method of accounting for TGGT's operations. These decreases were offset by increases in both operating expenses and gas purchases resulting from the 2008 New Waskom and Danville acquisitions as well as the expansion of our gathering and transportation facilities in the East Texas/ North Louisiana operating area in support of our Haynesville projects.

Our midstream operating expenses before intersegment eliminations for the year ended December 31, 2008 increased $90.4 million, or 406.0%, respectively, from the year ended December 31, 2007. The increase in midstream operating expenses for the year ended December 31, 2008 was primarily attributable to:

- increased cost of purchased gas of approximately $78.3 million due primarily to contracts assumed to purchase natural gas from our March 2008 New Waskom Acquisition; and

- increased operating expenses of approximately $10.2 million related to the March 2008 New Waskom Acquisition and increased Vernon Gathering operating expenses due to 2008 reflecting twelve months of operating costs and 2007 reflecting only nine months of operating costs.

Gathering and transportation

We report gathering and transportation costs in accordance with FASB Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of the transportation costs. Under the other arrangement, we sell oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation cost as gathering and transportation expense. Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative financial instruments, contain revenues which are reported under two separate bases. Gathering and transportation expenses totaled $19.0 million for year ended December 31, 2009, compared to $14.2 million for the year ended December 31, 2008 and $10.2 million for the year ended December 31, 2007.

As a result of the BG Midstream Transaction on August 14, 2009 our gathering system in Louisiana that supports our Vernon Field operations, which was previously reported within our midstream segment, is now reported net in "Gathering and transportation" on the Consolidated Statements of Operations.

We have entered into firm transportation agreements with pipeline companies to facilitate sales as we expand our Haynesville volumes. We expect our gathering and transportation expenses to increase significantly in 2010 and beyond.

Production and ad valorem taxes

Production and ad valorem taxes were $39.0 million, $76.9 million and $53.3 million for 2009, 2008, and 2007, respectively. However, on a percentage of revenue basis, before the impact of derivative financial instruments, production and ad valorem taxes were 7.1% of oil and natural gas sales, compared with 5.5% and 6.1% for 2007 and 2006, respectively. The increase in the percentage of revenue basis is primarily the result of the different taxing jurisdictions in which we operate. Production taxes are set by state and local governments and vary as to the tax rate and the value to which that rate is applied. In Louisiana, where a substantial percentage of our production is derived, severance taxes are levied on a per Mcf basis. Therefore, the resulting dollar value of production is not sensitive to changes in prices for natural gas. The rate in Louisiana, whether stated on a per Mcfe basis or as a percentage of revenues, is also complicated by certain severance tax holidays on deep wells. Approval of these holidays is on a well by well basis, and credits are not recognized until approvals are received. Accordingly, a 50% decline in the average sales price per Mcf in Louisiana would double the effective production tax rate as a percentage of revenue. In our other operating areas, production taxes are predominantly price dependent. Ad valorem assessments also vary widely.

In addition to our existing production and ad valorem taxes on current properties, we may be subject to new taxes or changes to existing rates in the future. The state of Louisiana raised its severance tax rate to $0.33 per Mcf from $0.29 per Mcf effective July 1, 2009. In addition, the Commonwealth of Pennsylvania, which does not currently have ad valorem or severance taxes on oil and natural gas reserves or production, is currently studying different tax proposals impacting the oil and natural gas industry.

Overall, our production and ad valorem tax rates per Mcfe were $0.30 per Mcfe for 2009, $0.53 per Mcfe for 2008 and $0.44 per Mcfe for 2007. The following tables present our severance and ad valorem taxes on a per Mcfe basis and percentage of revenue basis for our significant producing regions.

	Year ended December 31,									
	2009					2008				
(dollars in thousands, except per unit rate)	Revenue	Production (Mmcfe)	Production and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe	Revenue	Production (Mmcfe)	Production and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe
Producing region:										
East Texas/North Louisiana	$ 315,710	82,138	$24,162	7.7%	$0.29	$ 802,579	87,540	$40,227	5.0%	$0.46
Mid-Continent	84,179	18,013	6,588	7.8%	0.37	243,148	24,239	18,415	7.6%	0.76
Appalachia	91,832	19,184	2,562	2.8%	0.13	209,221	20,899	5,545	2.7%	0.27
Permian and other	58,784	8,827	5,658	9.6%	0.64	149,878	11,897	12,712	8.5%	1.07
Total	$ 550,505	128,162	$38,970	7.1%	$0.30	$1,404,826	144,575	$76,899	5.5%	$0.53

	Year ended December 31,									
	2008					2007				
(dollars in thousands, except per unit rate)	Revenue	Production (Mmcfe)	Production and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe	Revenue	Production (Mmcfe)	Production and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe
Producing region:										
East Texas/North Louisiana	$ 802,579	87,540	$40,227	5.0%	$0.46	$ 528,947	78,312	$32,375	6.1%	$0.41
Mid-Continent	243,148	24,239	18,415	7.6%	0.76	148,586	19,271	10,469	7.0%	0.54
Appalachia	209,221	20,899	5,545	2.7%	0.27	121,994	15,661	4,099	3.4%	0.26
Permian and other	149,878	11,897	12,712	8.5%	1.07	76,260	8,045	6,337	8.3%	0.79
Total	$1,404,826	144,575	$76,899	5.5%	$0.53	$ 875,787	121,289	$53,280	6.1%	$0.44

Depreciation, depletion and amortization

The following table presents our depreciation, depletion and amortization expenses for the years ended December 31, 2009, 2008 and 2007. The depreciation, depletion and amortization rate per Mcfe produced varies significantly for each of the periods presented due to the various divestures, acquisitions and ceiling test write-downs incurred in 2008 and 2009. The 2007 Vernon Acquisition and the Southern Gas Acquisition, both of which included significant proved developed producing properties, increased the depreciation, depletion and amortization rate to $3.10 per Mcfe in 2007. The Appalachian Acquisition and the Danville Acquisition, along with a full year of activity related to the 2007 acquisitions, initially increased the depreciation, depletion and amortization rate in 2008; however, these acquisitions were offset by the ceiling test write-downs in 2008. The annual 2008 depreciation, depletion and amortization rate was $3.18 per Mcfe, approximately 2.6% higher than 2007. The depletion rate was further reduced in 2009 by the first quarter 2009 ceiling test write-downs and the divestures during year, resulting in an annual depreciation, depletion and amortization rate of $1.72 per Mcfe in 2009, approximately 45.9% lower than 2008.

(dollars in thousands, except per unit rate)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Depreciation, depletion and amortization costs:					
Depletion expense	$196,515	$435,595	$357,902	$(239,080)	$77,693
Depreciation and amortization expense	$ 24,923	$ 24,719	$ 17,518	$ 204	$ 7,201
Depletion calculated rate per Mcfe	$ 1.53	$ 3.01	$ 2.95	$ (1.48)	$ 0.06
Depreciation and amortization calculated rate per Mcfe	$ 0.19	$ 0.17	$ 0.15	$ 0.02	$ 0.02
Consolidated depreciation, depletion and amortization rate per Mcfe	$ 1.72	$ 3.18	$ 3.10	$ (1.46)	$ 0.08

Accretion of discount on asset retirement obligations increased to $7.1 million in 2009 from $6.7 million in 2008 and $4.9 million in 2007. The increase in 2009 from 2008 and in 2008 from 2007 is due to the combination of significant well additions and related plugging liabilities in connection with our 2008 and 2007 acquisitions and increased estimates for the costs to plug and abandon properties. The increased estimates for plugging and abandoning properties reflect increased costs for labor, rig rates and materials used in those operations. The impact of our 2009 divestitures on accretion expenses in not significant as the divestitures occurred throughout 2009.

Write-down of oil and natural gas properties

For the year ended December 31, 2009, we recognized a ceiling test write-down of $1.3 billion. For the year ended December 31, 2008, we recognized ceiling test write-downs of $2.8 billion to our proved oil and natural gas properties. There were no ceiling test write-downs in 2007.

As discussed above, prior to our December 31, 2009 adoption of Release No. 33-8995, we were required by the SEC to compute the after-tax present value of our proved oil and natural gas properties using spot market prices for oil and natural gas at our balance sheet date. The prices used to compute our first quarter write-down were $3.63 per Mmbtu for natural gas and $49.64 per Bbl of oil as of March 31, 2009. Beginning December 31, 2009, Release No. 33-8995 states that we are required to compute the present value of our proved oil and natural gas properties using the simple average spot price for the trailing twelve month period using the first day of each month. The average prices used to compute the present value of our properties were $3.87 per Mmbtu for natural gas and $61.18 per Bbl of oil for 2009. Natural gas, which is sold at other natural gas marketing hubs where we conduct operations, is subject to prices which reflect variables that can increase or decrease natural gas prices at these hubs such as market demand, transportation costs and quality of the natural gas being sold. Those differences are referred to as the basis differentials. Typically, basis differentials result in natural gas prices which are lower than Henry Hub, except in Appalachia, where we have typically received a premium to Henry Hub. We may face further ceiling test write-downs in future periods, depending on level of commodity prices, drilling results and well performance.

General and administrative expenses

The following table presents our general and administrative expenses for the years ended December 31, 2009, 2008 and 2007 and changes for each of the years then ended.

(in thousands, except per unit amounts)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
General and administrative costs:					
Gross general and administrative expense	$137,038	$123,981	$ 88,778	$13,057	$35,203
Operator overhead reimbursements	(24,600)	(24,902)	(18,413)	302	(6,489)
Capitalized acquisition and development charges	(13,261)	(11,511)	(5,695)	(1,750)	(5,816)
Net general and administrative expense	$ 99,177	$ 87,568	$ 64,670	$11,609	$22,898
General and administrative expense per Mcfe	$ 0.77	$ 0.61	$ 0.53	$ 0.16	$ 0.08

Net general and administrative expenses for the year ended December 31, 2009 were $99.2 million, or $0.77 per Mcfe, compared with $87.6 million, or $0.61 per Mcfe, in 2008, an increase of $11.6 million.

The primary components of the net increase of $11.6 million for the year ended December 31, 2009 were higher personnel costs of $16.4 million due to additional employees related to expansion of technical staff to exploit our shale resource asset base, $2.6 million in employee relocation and severance costs associated with our divestitures and office closures, $4.4 million in additional stock compensation expense related primarily to the acceleration of vesting of certain employees impacted by the divestitures and the impact the increase in our stock price had on the valuation of our December 2009 grants compared to the December 2008 grants and increased rent of $1.6 million resulting from our 2008 expansion.

These increases were offset by the following items:

- decreased legal fees of $4.4 million due to the first quarter 2008 cancellation of a proposed master limited partnership and reduced reserves for claims;
- decreased franchise and property taxes of $1.5 million due primarily to lower equity as a result of 2008 and 2009 ceiling test write-downs and recapitalization of our corporate structure;
- decreased information and technology costs of $1.6 million due primarily to prior year costs incurred in connection with additional personnel;
- recovery of $4.6 million of technical service costs from our service agreement with BG Group; and
- increased capitalized salary costs of $1.8 million due to the previously discussed expansion of technical personnel.

Net general and administrative expenses for the year ended December 31, 2008 were $87.6 million, or $0.61 per Mcfe, compared with $64.7 million, or $0.53 per Mcfe, in 2007, an increase of $22.9 million. Significant components of the increase for the year ended December 31, 2008 include the following items:

- increased personnel costs of $20.7 million due to increasing our net headcount by 185 employees related primarily to our acquisitions and expanding our technical and managerial staff to fully exploit our asset base;
- an increase in share-based compensation costs of $2.8 million due primarily to additional headcount;
- increased consulting and contract labor costs of $1.4 million due primarily to acquisitions and information technology-related support;
- increased information technology related costs of $2.3 million primarily due to the equipment and infrastructure requirements attributable to our increased headcount;
- increased legal fees of $2.0 million, including $3.7 million attributable to a write-off of our proposed master limited partnership offering, which was withdrawn in January 2008. The increase associated with this write-off was partially offset by lower external legal fees of approximately $1.7 million during the year ended December 31, 2008 when compared with the prior year;
- increases of $1.1 million in automobile expenses;
- increased occupancy costs of $0.7 million resulting from expansion of corporate facilities;
- increased franchise tax of $0.6 million due, primarily, to changes in the jurisdictional make-up of our properties; and
- other expenses related to the overall growth of our business.

Partially offsetting the increases in general and administrative expenses were operator overhead recoveries of $24.9 million and $18.4 million for the years ended December 31, 2008 and 2007, respectively. Additional offsets to general and administrative expenses were capitalized costs of $11.5 million and $5.7 million for the years ended December 31, 2008 and 2007, respectively.

Interest expense

Interest expense for the year ended December 31, 2009 was $147.2 million compared to $161.6 million for the same period in 2008. The decreased interest expense of $14.5 million is a result of $46.1 million decreased interest costs from our credit agreements due to the combination of significant reductions in outstanding debt beginning in the third quarter of 2009 and lower LIBO rates in 2009 compared to 2008, a $5.0 million decrease related to our interest rate swaps and a $2.0 million decrease related to a full year of capitalized interest. The decrease was offset by an increase of $9.0 million resulting primarily from the write-off of deferred financing fees related to the reduction of our debt on the credit agreements and $29.7 million of interest and deferred financing costs related to the Term Credit Agreement, which included a $15.0 million duration fee. We repaid the Term Credit Agreement in August 2009.

Interest expense for the year ended December 31, 2008 was $161.6 million compared to $181.3 million for the same period in 2007. The decrease of $19.7 million in 2008 when compared to 2007 reflects higher 2008 interest costs for the Term Credit Agreement of $26.9 million and settlements and non-cash changes in the fair value of interest swaps of $9.9 million which were more than offset by reductions of $50.2 million of prior year write-offs of deferred financing costs arising from early debt terminations, reduced interest on credit agreements of $1.7 million and $3.9 million of capitalized interest in 2008. There was no interest capitalized in 2007.

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Interest expense:					
7 1/4% senior notes due 2011	$ 28,653	$ 28,874	$ 28,922	$ (221)	$ (48)
EXCO Resources Credit Agreement	22,778	42,628	29,415	(19,850)	13,213
EXCO Operating Credit Agreement	26,456	52,717	68,462	(26,261)	(15,745)
Term Credit Agreement	18,833	13,337	—	5,496	13,337
Amortization and write-off of deferred financing costs on EXCO Resources Credit Agreement	8,632	1,956	1,519	6,676	437
Amortization of deferred financing costs on EXCO Operating Credit Agreement	5,362	3,014	2,619	2,348	395
Amortization of deferred financing costs on Term Credit Agreement	37,754	13,598	—	24,156	13,598
Amortization and write-off of deferred financing costs on EXCO Operating term loan	—	—	32,100	—	(32,100)
EXCO Operating term loan	—	—	18,140	—	(18,140)
Capitalized interest	(5,840)	(3,861)	—	(1,979)	(3,861)
Interest rate swaps settlements	12,180	(588)	—	12,768	(588)
Fair market value adjustment on interest rate swaps	(7,861)	9,878	—	(17,739)	9,878
Other interest expense	214	85	173	129	(88)
Total interest expense	$147,161	$161,638	$181,350	$(14,477)	$(19,712)

Derivative financial instruments

Our objective in entering into derivative financial instruments is to manage our exposure to commodity price and interest rate fluctuations, protect our returns on investments, service debt and achieve a more predictable cash flow in connection with our activities. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expenses due to changes in the fair value of our derivative financial instrument contracts. Cash charges or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration.

The following table presents our realized and unrealized gains and losses from our oil and natural gas derivative financial instruments, which are reported as a component of other income or expenses in our Condensed Consolidated Statements of Operations. We expect that our revenues will continue to be significantly impacted in future periods by changes in the value of our derivative financial instruments as a result of volatility in oil and natural gas prices and the amount of future production volumes subject to derivative financial instruments.

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Derivative financial instrument activities:					
Cash settlements on derivative financial instruments	$ 478,463	$(109,300)	$108,413	$ 587,763	$(217,713)
Non-cash change in fair value of derivative financial instruments	(246,438)	493,689	(81,606)	(740,127)	575,295
Total derivative financial instrument activities	$ 232,025	$ 384,389	$ 26,807	$(152,364)	$ 357,582

Our non-cash mark-to-market changes in the fair value of our oil and natural gas derivative financial instruments for the year ended December 31, 2009 resulted in a loss of $246.4 million compared to a gain of $493.7 million and a loss of $81.6 million for the years ended December 31, 2008 and 2007, respectively. The significant fluctuation was, again, attributable to high volatility in the prices for oil and natural gas between each of the years. The ultimate settlement amount of the unrealized portion of the derivative financial instruments is dependent on future commodity prices.

The use of derivative financial instruments allows us to limit the impacts of volatile price fluctuations associated with oil and natural gas. The following table presents our natural gas prices, before the impact of derivative financial instruments where average realized prices per Mcfe ranged from a high of $9.72 during the year end December 31, 2008 to a low of $4.30 during the year ended December 31, 2009 while the impact of cash settlements on derivatives decreased our price volatility from a high of $8.96 per Mcfe during the year ended December 31, 2008 to a low of $8.03 per Mcfe for the year ended December 31, 2009, respectively.

	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007	Year to year change 2009-2008	Year to year change 2008-2007
Realized pricing:					
Oil per Bbl	$53.72	$96.93	$71.17	$(43.21)	$25.76
Natural gas per Mcf	3.93	9.06	6.81	(5.13)	2.25
Natural gas equivalent per Mcfe	4.30	9.72	7.22	(5.42)	2.50
Effect of cash settlements on derivatives	3.73	(0.76)	0.89	4.49	(1.65)
Net price per Mcfe, including derivative financial instruments	$ 8.03	$ 8.96	$ 8.11	$ (0.93)	$ 0.85

Our cash settlements for 2009 increased our other income by $478.5 million, or $3.73 per Mcfe compared to cash settlements decreasing our other income by $109.3 million, or $0.76 per Mcfe, in 2008. The significant fluctuations between settlements of receipts on our derivative financial instruments demonstrates the aforementioned volatility in prices.

We expect to continue our comprehensive derivative financial instrument program as part of our overall acquisition and financing strategy to enhance our ability to execute our business plan over the entire commodity price cycle, protect our returns on investment, and manage our capital structure. In connection with our acquisitions, we typically hedge a portion of future production acquired in order to lessen the variability of our returns on shareholders' equity and to protect our shareholders' equity by supporting our ability to meet our debt service obligations and stabilize cash flows.

In January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBO rates ranging from 2.45% to 2.8%. For the year ended December 31, 2009, we had realized losses from settlements of $12.2 million and $2.0 million of cumulative non-cash unrealized losses attributable to our interest rate swaps. For the year ended December 31, 2008, we had realized gains from settlements of $0.6 million and $9.9 million of non-cash unrealized losses attributable to our interest rate swaps. Our interest rate derivative financial instruments terminated as of February 14, 2010.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2009, 2008 and 2007.

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
United States federal income taxes (benefit) at statutory rate of 35%	$(177,207)	$(695,977)	$38,413
Increases (reductions) resulting from:			
Goodwill	43,455	—	—
Adjustments to the valuation allowance	141,975	526,372	9,336
Non-deductible compensation	2,808	2,321	3,144
State tax rate change	—	—	3,078
State taxes net of federal benefit	(20,606)	(88,266)	4,423
Other	74	517	1,702
Total income tax provision	$ (9,501)	$(255,033)	$60,096

During 2009, our income tax rate was impacted by the recognition of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets and divestitures of properties.

During 2008, our income tax rate was impacted by the establishment of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets. Our deferred tax assets were offset by valuation allowances after testing to determine if the asset would meet a more likely than not criteria for realization pursuant to FASB ASC Topic 740- Income Taxes.

During 2007, our income tax rate was impacted by the substitution of a current federal net operating loss carryback for previously claimed foreign tax credits resulting from the 2005 sale of our Canadian subsidiary. The impact, net of a federal refund of $6.1 million, was an $11.0 million non-cash expense, principally related to foreign tax credits which are required since we no longer have any foreign operations.

Also, as a result of our 2007 acquisitions, our state effective rate increased which required us to change the rate in which we record our deferred tax assets and liabilities. This amount was recognized in our 2007 income tax expense as a current period expense and is presented as part of the "Other" line item presented above.

EXCO files income tax returns in the U.S. federal jurisdictions and various state jurisdictions. With few exceptions, EXCO is no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2004. The Internal Revenue Service, or IRS, completed its examination of EXCO's 2004 U.S. federal income tax return in January 2008. The result of the audit was an adjustment between U.S. and our Canadian subsidiary for a hedge recorded to the wrong entity. There was no material change to EXCO's financial position.

The Company adopted the provisions of FASB ASC Subtopic 740-10 for Income Taxes on January 1, 2007. As a result of ASC Subtopic 740-10, the Company recognized zero liabilities for unrecognized tax benefits. As of December 31, 2009, 2008 and 2007, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the current financials.

Liquidity, capital resources and capital commitments

Overview

Our financial strategy is to use a combination of cash flow from operations, bank financing, cash received from joint ventures, proceeds from sales of oil and natural gas properties and the issuance of equity and debt securities to fund our operations, conduct development and exploitation activities and to fund acquisitions. Prior to 2009, we used acquisitions of producing properties and vertical drilling of development wells in established basins as our primary vehicle for growth. These acquisitions provided us with substantial acreage with deep rights in shale resource plays, and our recent success using horizontal drilling in the Haynesville shale in East Texas/North Louisiana has created significant growth opportunities in the area, as well as in the Bossier shale play in East Texas/North Louisiana and the Marcellus shale play in Appalachia. These additional opportunities have resulted in a shift in our focus from an acquisition-oriented strategy to horizontal drilling, development and exploitation activities. As a result of the BG Upstream Transaction in August 2009, we increased our drilling and leasing activities within the BG AMI. Pursuant to the Joint Development Agreement, or JDA, with BG Group, BG Group also agreed to fund 75% of our 50% interest in deep drilling projects up to a total of $400.0 million. As a result of this carried amount, our required capital expenditures will be substantially reduced during the carried period, which we project will extend through 2011. As of December 31, 2009, approximately $367.7 million remains unfunded by BG Group under the carry provisions of the JDA.

Cash flows from operations and unused borrowing capacity under our revolving credit agreements represent the primary source of liquidity to fund our operations and our capital expenditure programs. The primary factors impacting our cash flow from operations include (i) levels of production from our oil and natural gas properties, (ii) prices we receive for sales of oil and natural gas production, including settlement proceeds or payments related to our oil and natural gas derivatives, (iii) operating costs of our oil and natural gas properties, (iv) costs for our general and administrative activities and (v) interest expense and other financing related costs. The following table presents our liquidity and financial position as of December 31, 2009 and February 12, 2010:

(in thousands)	December 31, 2009	February 12, 2010
Cash(1)	$ 127,316	$ 142,825
Borrowings under credit agreements	747,564	747,564
Senior Notes(2)	444,720	444,720
Total debt	1,192,284	1,192,284
Net debt	$1,064,968	$1,049,459
Consolidated borrowing base	$1,300,000	$1,300,000
Unused borrowing base(3)	$ 537,235	$ 537,235
Unused borrowing base plus cash(3)	$ 664,551	$ 680,060

(1) Includes restricted cash of $58.9 million at December 31, 2009 and $71.4 million at February 12, 2010.

(2) Excludes unamortized bond premium of $4.0 million.

(3) Net of $15.2 million in letters of credit.

Consistent with our strategy of acquiring and developing reserves, we have an objective of maintaining financing flexibility and the use of derivative financial instruments to mitigate price fluctuations Prices for natural gas experienced significant declines beginning in the third quarter of 2008 and remained at low levels throughout 2009. As a result of these low prices, we suspended many of our vertical drilling projects as economics did not meet our internal rate of return objectives. The following table presents a comparison of our existing 2010 capital budget to our 2009 activities.

(in thousands, except wells)	2010 planned gross wells	2010 capital budget	2009 actual spending	Year to year change 2010-2009
East Texas/North Louisiana	138	$255,133	$371,065	$(115,932)
Appalachia	27	154,246	32,173	122,073
Mid-Continent	—	—	8,282	(8,282)
Permian and other	40	29,163	20,692	8,471
Midstream	—	7,800	53,122	(45,322)
Corporate	—	25,044	26,198	(1,154)
Total	205	$471,386	$511,532	$ (40,146)

In the fourth quarter of 2008, we commenced a program to divest various oil and natural gas assets across our entire portfolio and engaged several different brokers to assist with these divestitures. This divestiture program, combined with the BG Upstream Transaction and the BG Midstream Transaction, resulted in cash proceeds of approximately $2.1 billion, after customary closing and post-closing adjustments and provided us with substantial liquidity. We used these proceeds to pay down debt on both of our revolving credit facilities and pay off our Term Credit Agreement. As of December 31, 2009, we had reduced our consolidated outstanding debt to $1.2 billion, a reduction of $1.8 billion from the December 31, 2008 debt levels. However, our oil and natural gas production, results of operations and future liquidity from operations will be reduced in the near term as a result of asset sales and the reduced interest in properties sold to the BG Group.

We generally do not establish a budget for acquisitions, as these tend to be opportunity driven. Historically, we have used the proceeds from the issuance of equity and debt securities and borrowings under our credit agreements to raise cash to fund acquisitions. Our ability to borrow from sources other than our credit agreements is subject to restrictions imposed by our lenders and the indenture governing our 7 1/4% Senior Notes due January 15, 2011, or Senior Notes, contains restrictions on incurring indebtedness and pledging our assets. In addition, disruptions in the credit and capital markets have limited the availability of financing to fund acquisitions. Any future acquisitions will more than likely be focused on supplementing our shale resource holdings in our East Texas/North Louisiana and Appalachia areas as economic conditions permit.

As of December 31, 2009, the aggregate borrowing bases under our credit agreements, after the October 2009 borrowing base redeterminations, totaled $1.3 billion, of which $747.6 million was drawn. In addition, we have $444.7 million outstanding under our Senior Notes due on January 11, 2011.

The U.S. House of Representatives has adopted legislation to control and reduce GHGs. The U.S. Senate is working on similar legislation. Although it is not possible at this time to predict whether or when any such legislation will emerge from Congress, any laws or regulations that may be adopted to restrict or reduce GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. The EPA has also taken recent action related to GHGs that would require large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, recordkeep and report emissions of GHGs associated with our operations.

Recent events affecting liquidity

The capital and credit markets remained constrained and unpredictable throughout 2009. Actions taken by the United States government and Federal Reserve in 2008 and 2009 through enacted legislation and implementation of various programs have had only limited impact in stabilizing the credit markets and promoting liquidity in financial institutions. The impacts of these actions, some of which have not yet been fully implemented, on our industry and on us, are not determinable at this time, nor can we determine the length of time that credit markets will remain constrained, and the ultimate impact on our ability to access capital is expected to be equally uncertain.

In addition to the turmoil in the credit markets and related uncertainties, prices for natural gas suffered a precipitous decline beginning in the third quarter of 2008 and has continued throughout 2009. As of February 12, 2010, the spot prices for oil and natural gas were $74.13 per Bbl and $5.53 per Mmbtu compared with $79.36 per Bbl and $5.79 per Mmbtu as of December 31, 2009. NYMEX future prices for oil and natural gas have also remained depressed throughout 2009, reflecting anticipated decreased domestic and worldwide demand for oil and natural gas as a result of the global recession and uncertainties about the depth and length of the recession and the timing of a recovery. Each of the aforementioned events could impact our near-term, and perhaps long-term, liquidity and operating revenues resulting in changes to business plans or operations. As discussed in greater detail under "Item 3. Quantitative and Qualitative Disclosures About Market Risk," we use derivative financial instruments to mitigate commodity price fluctuations and interest rate fluctuations to manage our debt service requirements.

Our proposed capital budget for 2010 reflects targeted capital expenditures. As in 2009, our 2010 capital program will focus on Haynesville/Bossier shale plays in East Texas/North Louisiana and we will begin to exploit the Marcellus shale play in Appalachia. Our 2009 asset sales and reduced ownership interest in East Texas/North Louisiana properties arising from the BG Upstream Transaction, will impact our production volumes in future periods. However, the provision in the JDA for the BG Group to fund 75% of our share of drilling and development costs on new Haynesville and other deep rights wells spud after closing, up to a total of $400.0 million, will allow us to accelerate our development of the Haynesville shale play while continuing to reduce our development cost per Mcf. While our recent debt reduction combined with the value created by the carried portion of capital expenditures are favorable as they relate to our reliance on available credit, the credit markets remain an area of concern.

Our 7 ¼% senior notes with a principal balance of $444.7 million mature on January 15, 2011. We believe that our cash flows from operations and amounts available to us under our credit facilities will provide us with sufficient liquidity to pay-off the 7 ¼% senior notes at maturity. Alternatively, we believe current market conditions may provide an opportunity to refinance the Senior Notes if necessary.

Despite the ongoing problems and uncertainties existing in the capital and credit markets and commodity prices, we believe that our capital resources from existing cash balances, anticipated cash flow from operating activities, reduced capital expenditures and remaining borrowing capacity under our credit agreements will be adequate to meet the cash requirements to fund our operations, debt service obligations and our 2010 capital expenditure programs As discussed above, our 2009 divestiture program and BG Group joint venture transactions, generated approximately $2.1 billion is cash proceeds, which enabled us to reduce our bank debt by $1.8 billion during 2009 and will substantially reduce our debt service requirements in 2010. Our future cash flows are subject to a number of variables including production volumes, oil and natural gas prices and drilling and service costs.

Significant acreage acquisitions may also have an impact on our near term liquidity as these types of acquisitions may cause an increase in our outstanding debt without any immediate cash flows or increases in our borrowing base in our credit agreements.

Divestitures and related transactions

During 2009, we implemented our previously announced asset divestiture program to sell certain non-strategic oil and natural gas assets and pursue a potential joint venture to accelerate development of our considerable acreage holdings in East Texas/North Louisiana in the Haynesville and Bossier shale plays. The following table summarizes the results of our 2009 divestitures and joint venture transactions:

(in thousands)	Proceeds(1)
Operating division	
East Texas/North Louisiana	
BG Upstream Transaction	$ 713,779
BG Midstream Transaction	269,237
East Texas Transaction	154,299
Other East Texas / North Louisiana	22,327
Mid-Continent	
Mid-Continent Transaction	197,730
Sheridan Transaction(2)	531,351
Other Mid-Continent	5,482
Appalachia	
EnerVest Transaction(2)(3)	129,737
Permian	40,042
Total joint ventures and divestitures	$2,063,984

(1) Net of selling expenses.

(2) Subject to final closing adjustments.

(3) Pending receipt of an additional $13.1 million of consents.

Encore transactions

On August 11, 2009, we closed on sales of assets contained within the East Texas Transaction and the Mid-Continent Transaction with Encore for aggregate cash proceeds of approximately $352.0 million, after final closing adjustments. The oil and natural gas properties sold included (i) all of EXCO's interests in its Gladewater area and Overton field in Gregg, Upshur and Smith counties in East Texas, or the East Texas Properties, and (ii) certain oil and natural gas properties in the Mid-Continent region of Oklahoma, Kansas and the Texas Panhandle, or the Mid-Continent Sale, collectively the Encore Transactions.

BG Group transactions

On August 14, 2009, we closed on the BG Upstream Transaction and the BG Midstream Transaction representing the sale of an undivided 50% interest in certain oil and natural gas properties in East Texas/North Louisiana and a 50% interest in certain midstream operations, respectively, in East Texas/North Louisiana for aggregate proceeds of approximately $983.0 million, after final closing adjustments.

In addition, BG Group will fund 75% of our capital expenditures on certain drilling and completion activities within the AMI until the aggregate of such expenditures equals $400.0 million, or the BG Group Carry. The BG Group Carry is expected to be fully funded in 2011 or 2012. If BG Group defaults in the payment of the BG Group Carry, then EXCO has the right to require BG Group to reassign to EXCO a proportionate percentage of BG Group's interest in the deep rights within the AMI. Upon the reassignment, the BG Group Carry will terminate.

Other than the BG Group Carry, each party will be responsible for its share of the costs and expenses associated with exploring, developing and producing the oil and natural gas assets in the AMI. To facilitate funding these costs and expenses and to provide security to each party, BG Group and EXCO have agreed to fund periodically an escrow account created by the parties with an amount equal to estimates of certain future expenses for the following three month period. In addition to this three month deposit, EXCO has agreed to fund one additional month of development costs into the escrow account and three additional months of operating expenses into the escrow account.

Sheridan Transaction

On November 10, 2009 we closed on the sale of most of our remaining oil and natural gas assets located in the Mid-Continent region to Sheridan Holding Company I, LLC for cash proceeds of $531.4 million, subject to final closing adjustments. Proceeds from the sale were primarily used to reduce balance outstanding under the EXCO Resources Credit Agreement.

EnerVest Transaction

On November 24, 2009, we consummated the sale of certain Ohio and Northwestern Pennsylvania shallow producing oil and natural gas properties to EV Energy Partners, L.P. and related entities. Total cash proceeds from the sale were $129.7 million, subject to final closing adjustments and receipt of $13.1 million of properties sold subject to receipt of required consents. Proceeds from the sale were primarily used to reduce the balances outstanding under the EXCO Resources Credit Agreement.

Historical sources and uses of funds

Cash flows from operations

Our operating cash flows are driven by the quantities of our production of oil and natural gas and the prices received from the sale of this production and revenue generated from our midstream operating activities. Prices of oil and natural gas have historically been very volatile and can significantly impact the cash from the sale our oil and natural gas production. Use of derivative financial instruments help mitigate this price volatility. Cash expenses also impact our operating cash flow and consist primarily of oil and natural gas property operating costs, severance and ad valorem taxes, interest on our indebtedness, general and administrative expenses and taxes on income.

Net cash provided by operating activities was $433.6 million for the year ended December 31, 2009 compared with $975.0 million for the year ended December 31, 2008. The 55.5% decrease is attributable primarily to net cash from decreased production resulting from oil and natural gas property divestitures in 2009 and from lower average oil and natural gas prices in 2009 compared with average prices for the 2008 year. At December 31, 2009, our cash and cash equivalents balance was $68.4 million and our evergreen escrow account, which is principally used for Haynesville development operations, was $58.9 million. On February 12, 2010, our cash, cash equivalent and restricted cash balance was $142.8 million.

We began paying quarterly dividends of $0.025 per share on our common stock in the fourth quarter of 2009. During the fourth quarter we paid two dividends to our common shareholders which totaled $10.6 million.

Investing activities and transactions

In recent years, a significant amount of our growth has been through acquisitions of existing producing and non-producing oil and natural gas properties and related assets. These acquisitions have been funded to a great extent by borrowings under credit agreements and term loan agreements, as well as issuance of equity. As discussed above, the deterioration in the U.S. and worldwide credit and equity markets has significantly diminished our ability to fund additional growth in the near term through these capital sources.

Acquisitions and capital expenditures

The following table presents our capital expenditures and acquisitions for the years ended December 31, 2009, 2008 and 2007.

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Capital expenditures:			
Oil and natural gas property acquisitions(1)	$233,634	$ 700,174	$2,343,829
Midstream acquisitions	—	66,172	119,409
Lease purchases(1)	106,040	187,134	21,415
Development capital expenditures	299,837	693,173	446,675
Midstream capital additions	53,122	54,993	16,980
Corporate and other	52,533	53,834	31,419
Total capital expenditures	$745,166	$1,755,480	$2,979,727

(1) The year ended December 31, 2009 includes $251.5 million of lease purchases and property acquisitions included in the BG AMI. We offered BG Group 50% of those acquisitions which BG Group will reimburse us upon acceptance of these offers. As of December 31, 2009, BG Group had pending outstanding offers totaling $125.8 million for their 50% share of this acreage. In 2010, BG Group paid $53.8 million to us for those assets.

Our 2009 acquisitions emphasized undeveloped acreage. Our 2008 and 2007 acquisitions were principally producing and undeveloped oil and natural gas properties.

During 2008, we completed the acquisitions of oil and natural gas properties, undeveloped acreage and other oil and natural gas assets totaling $766.3 million. These acquisitions included the Appalachian Acquisition, the New Waskom Acquisition and the Danville Acquisition.

In addition to these acquisitions of producing oil and natural gas properties and midstream assets, during the second and third quarters of 2008, we conducted two leasing programs of undeveloped acreage in East Texas/ North Louisiana and Appalachia to exploit the Haynesville, Marcellus and Huron shales. In Appalachia, our existing shallow production areas and newly acquired leasehold interests hold deep rights in the Marcellus and Huron shale formations. Similarly, in East Texas/ North Louisiana, our existing production areas and newly acquired leasehold interests hold deep rights in the Haynesville/Bossier shale play. We spent approximately $64.9 million in the Haynesville/Bossier shale plays in East Texas/North Louisiana and approximately $92.1 million in the Marcellus and Huron shale plays in the Appalachia region of the United States during 2008.

During 2007, we consummated acquisitions of oil and natural gas properties and undeveloped acreage totaling $2.47 billion, including the Vernon Acquisition and the Southern Gas Acquisition.

2010 Capital budget

Our capital expenditures budget for 2010 will continue to emphasize development of our significant shale resources in the Haynesville Shale play in East Texas/North Louisiana in conjunction with our joint venture with BG Group and increased emphasis of our significant acreage holdings covering the Marcellus Shale play in Appalachia.

The 2010 capital expenditures emphasize horizontal shale development in East Texas/North Louisiana and in Appalachia. Presently, we have budgeted approximately $471.4 million for capital expenditures in 2010, of which we are contractually obligated to spend $70.7 million as of December 31, 2009. We expect to utilize our current cash balances, including funds which we have already placed in our restricted accounts to fund Haynesville development, cash flow generated from operations and available funds under our credit agreements in 2010 to fund capital expenditures and acquisitions, if any. The capital budget for 2010 reflects a 7.8% decrease from 2009 actual capital expenditures, excluding acquisitions of approximately $233.6 million. The 2010 capital budget of $471.4 million is net of approximately $205.1 million of BG Carry covering our interests in certain drilling and completion costs in East Texas/North Louisiana.

Future cash flows are subject to a number of variables including production volumes, fluctuations in oil and natural gas prices and our ability to service the debt incurred in connection with our acquisitions. If cash flows decline we may be required to further reduce our capital expenditure budget, which in turn may affect our production in future periods. Our cash flow from operations and other capital resources may not provide cash in sufficient amounts to maintain or initiate planned levels of capital expenditures.

Credit agreements and long-term debt

As of February 12, 2010, we have total debt outstanding aggregating $1.2 billion consisting of two credit agreements and Senior Notes of $444.7 million due in January 2011. Terms and considerations of each of the debt obligations are discussed below. We are presently in discussions with our banking group to consolidate our two credit agreements into one facility.

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement, pursuant to the fifth amendment effective on October 2, 2009, has a borrowing base of $450.0 million with commitments spread among a consortium of banks, none of which have commitments exceeding 10% of the aggregate commitment amount. The borrowing base is redetermined semi-annually, with EXCO and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are made on or about April 1 and October 1 of each year. Borrowings under the EXCO Resources Credit Agreement are collateralized by a first lien mortgage providing a security interest in our oil and natural gas properties. EXCO may have in place derivative financial instruments covering no more than 80% of its forecasted production from total Proved Reserves (as defined) for each of the first two years of the five year period commencing on the date of incurrence on each new derivative financial instrument and 70% of the forecasted production from total Proved Reserves for each of the third through fifth years of the five year period thereafter. EXCO is required to have mortgages in place covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The EXCO Resources Credit Agreement matures on March 30, 2012.

The fifth amendment to the EXCO Resources Credit Agreement, among other things, modified the terms and conditions under which EXCO is permitted to pay a cash dividend on its common stock. Pursuant to the fifth amendment, EXCO may declare and pay cash dividends on its common stock in an amount not to exceed $50.0 million in any four consecutive fiscal quarters, provided that as of each payment date and after giving effect to the dividend payment date, (i) no default has occurred and is continuing, (ii) EXCO has at least 10% of its borrowing base available under the EXCO Resources Credit Agreement, and (iii) payment of such dividend is permitted under EXCO's 7 1/4% Senior Notes Indenture.

The EXCO Resources Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The interest rate ranges from LIBOR plus 175 basis points, or bps, to LIBOR plus 250 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 75 bps to ABR plus 150 bps depending upon borrowing base usage.

On February 12, 2010, we had $81.5 million of outstanding indebtedness and $353.3 million of available borrowing capacity under the EXCO Resources Credit Agreement. On February 12, 2010, the one month LIBOR was 0.23%, which would result in an interest rate of approximately 1.98% on any new indebtedness we may incur under the EXCO Resources Credit Agreement.

As of December 31, 2009, EXCO was in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a consolidated current ratio (as defined) of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- not permit our ratio of consolidated funded indebtedness (as defined) to consolidated EBITDAX (as defined) to be greater than (i) 4.0 to 1.0 at the end of any fiscal quarter ending on or after December 31, 2008 up to and including December 31, 2009, (ii) 3.75 to 1.0 at the end of the fiscal quarter ending on

March 31, 2010 and (iii) 3.50 to 1.0 beginning with the quarter ending June 30, 2010 and each quarter end thereafter; and

- maintain a consolidated EBITDAX to consolidated interest expense (as defined) ratio of at least 2.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Resources Credit Agreement.

EXCO Operating Credit Agreement

The EXCO Operating Credit Agreement, as amended, currently has a borrowing base of $850.0 million with commitments spread among a consortium of banks, none of which have commitments exceeding 10% of the aggregate commitment amount. The borrowing base is redetermined semi-annually, with EXCO Operating and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are made on or about April 1 and October 1 of each year. The EXCO Operating Credit Agreement is secured by a first priority lien on the assets of EXCO Operating, including 100% of the equity of EXCO Operating's subsidiaries, and is guaranteed by all existing and future subsidiaries of EXCO Operating. EXCO Operating may have in place derivative financial instruments covering no more than 80% of the forecasted production from total Proved Reserves (as defined) for each of the first two years of the five year period commencing on the date of incurrence on each new derivative financial instrument and 70% of the forecasted production from total Proved Reserves for each of the third through fifth years of the five year period thereafter. EXCO Operating is required to have mortgages in place covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The EXCO Operating Credit Agreement matures on March 30, 2012.

On October 16, 2009, the lenders agreed to consents which (i) confirmed the borrowing base under the EXCO Operating Credit Agreement at $850.0 million until the next borrowing base redetermination date, (ii) provided for EXCO Operating to grant to lenders a first priority lien and security interest in all of its equity interest in TGGT, representing EXCO Operating's retained 50% interest in the midstream assets contributed in connection with the BG Midstream Transaction, and (iii) by November 30, 2009, consummate transactions to unwind oil and natural gas derivatives with respect to notional volumes of oil and natural gas with respect to sold production volumes which had been waived by a July 29, 2009 consent.

The EXCO Operating Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The interest rate ranges from LIBOR plus 175 bps to LIBOR plus 250 bps depending upon borrowing base usage. The facility also includes an ABR pricing alternative ranging from ABR plus 75 bps to ABR plus 150 bps depending upon borrowing base usage.

On February 12, 2010, we had $666.1 million of outstanding indebtedness and $183.9 million available borrowing capacity under the EXCO Operating Credit Agreement. On February 12, 2010, the one month LIBO rate was 0.23%, which would result in an interest rate of approximately 2.48% on any new indebtedness we may incur under the EXCO Operating Credit Agreement.

As of December 31, 2009, EXCO Operating was in compliance with the financial covenants contained in the EXCO Operating Credit Agreement, which require that EXCO Operating:

- maintain a consolidated current ratio (as defined) of at least 1.0 to 1.0 at the end of any fiscal quarter, beginning with the quarter ended September 30, 2007;

- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined) to be greater than 3.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended September 30, 2007; and

- not permit our interest coverage ratio (as defined) to be less than 2.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended September 30, 2007.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Operating Credit Agreement.

Term Credit Agreement

On December 8, 2008, EXCO Operating entered into a $300.0 million senior unsecured term credit agreement with an aggregate balance of $300.0 million. Net proceeds from the loan of $274.4 million, after bank fees and expenses, were used to repay and terminate an original $300.0 million senior unsecured term credit agreement that was scheduled to mature on December 15, 2008. In addition to the fees incurred upon the closing of the Term Credit Agreement, EXCO Operating provided for additional fees on unpaid principal amounts, or duration fees, as defined in the agreement. These included a 5% fee on the unpaid principal on June 15, 2009 and an additional 3% fee on any unpaid outstanding balance as of September 15, 2009. On June 15, 2009 we remitted the first duration fee payment of $15.0 million

In connection with the closings of the BG Upstream Transaction and the BG Midstream Transaction on August 14, 2009 and the East Texas Transaction on August 11, 2009, EXCO Operating repaid the Term Credit Agreement. As a consequence of the early payment of the unsecured term loan, EXCO Operating avoided payment of a $9.0 million duration fee that would have been due on September 15, 2009.

The unamortized balance of deferred financing costs attributable to the Term Credit Agreement of approximately $9.9 million was written off and is included in interest expense in the year ended December 31, 2009.

7 1/4% senior notes due January 15, 2011

As of December 31, 2009, $444.7 million in principal was outstanding on our Senior Notes. The unamortized premium on the Senior Notes at December 31, 2009 was $4.0 million. The estimated fair value of the Senior Notes, based on quoted market prices for the Senior Notes, was $445.8 million on December 31, 2009.

Interest is payable on the Senior Notes semi-annually in arrears on January 15 and July 15 of each year. Effective January 15, 2007, we may redeem some or all of the Senior Notes for the redemption price set forth in the Senior Notes. On January 15, 2010, we paid $16.1 million of interest on the Senior Notes. Another interest payment of $16.1 million will be due on July 15, 2010. We presently have sufficient borrowing capacity under the EXCO Resources Credit Agreement and the EXCO Operating Credit Agreement to pay the Senior Notes.

The indenture governing the Senior Notes contains covenants, which limit our ability and the ability of our guarantor subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred stock;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated debt;
- make investments;
- create liens on our assets;
- enter into sale/leaseback transactions;
- create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- engage in transactions with our affiliates;
- transfer or issue shares of stock of subsidiaries;
- transfer or sell assets; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

Preferred Stock

We paid cash dividends totaling $82.8 million to the holders of our Preferred Stock between January 1, 2008 and July 18, 2008, the date upon which the Preferred Stock was converted into our common stock. On July 18, 2008, we converted all outstanding shares of our Preferred Stock into a total of approximately 105.2 million shares of our common stock. The conversion of the Preferred Stock has the effect of increasing the book value of shareholders' equity by approximately $2.0 billion. We also paid all accrued but unpaid dividends in cash totaling approximately $12.8 million to the holders of the converted shares of Preferred Stock as of July 18, 2008. After July 18, 2008, dividends ceased to accrue on the Preferred Stock and all rights of the holders with respect to the Preferred Stock terminated, except for the right to receive the whole shares of common stock issuable upon conversion, accrued dividends through July 18, 2008 and cash in lieu of any fractional shares. The conversion of all outstanding shares of Preferred Stock into common stock eliminated our obligation to pay quarterly cash dividends of $35.0 million, resulting in annual dividend savings of $140.0 million.

Derivative financial instruments

We use oil and natural gas derivatives and financial risk management instruments to manage our exposure to commodity price and interest rate fluctuations. We do not designate these instruments as hedging instruments for financial accounting purposes, and, as a result, we recognize the change in the respective instruments' fair value currently in earnings, as a gain or loss on oil and natural gas derivatives and interest expense on financial risk management instruments.

Oil and natural gas derivatives

Our production is generally sold at prevailing market prices. However, we periodically enter into oil and natural gas contracts for a portion of our production when market conditions are deemed favorable and oil and natural gas prices exceed our minimum internal price targets.

Our objective in entering into oil and natural gas derivative contracts is to mitigate the impact of price fluctuations and achieve a more predictable cash flow associated with our acquisition activities and borrowings under our credit agreements. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. As of December 31, 2009, we had contracts in place for the volumes and prices shown below:

(in thousands, except prices)	NYMEX gas volume—Mmbtu	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Swaps:				
Q1 2010	15,915	$7.80	110	$114.96
Q2 2010	16,078	7.67	111	114.96
Q3 2010	16,240	7.67	113	114.96
Q4 2010	16,240	7.70	113	114.96
2011	12,775	7.48	456	116.00
2012	5,490	5.91	92	109.30
2013	5,475	5.99	—	—
2014	—	—	—	—

Interest rate swaps

In January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBO rates ranging from 2.45% to 2.8%. For the year ended December 31, 2009, we had realized losses from settlements of $12.2 million. The fair value of our interest rate swaps was a liability of $2.0 million as of December 31, 2009.

Off-balance sheet arrangements

None.

Contractual obligations and commercial commitments

The following table presents a summary of our contractual obligations at December 31, 2009:

	Payments due by period				
(in thousands)	**Less than one year**	**One to three years**	**Three to five years**	**More than five years**	**Total**
Long-term debt—Senior Notes(1)	$ —	$ 444,720	$ —	$ —	$ 444,720
Long-term debt—EXCO Resources Credit Agreement(2)	—	81,486	—	—	81,486
Long-term debt—EXCO Operating Credit Agreement(3)	—	666,078	—	—	666,078
Firm transportation services and other fixed commitments(4)	40,570	69,548	71,666	199,515	381,299
Operating leases	7,357	11,461	10,063	4,329	33,210
Drilling contracts	51,438	37,655	—	—	89,093
Total contractual obligations	$99,365	$1,310,948	$81,729	$203,844	$1,695,886

(1) Our Senior Notes are due on January 15, 2011. The annual interest obligation is $32.2 million.

(2) The EXCO Resources Credit Agreement matures on March 30, 2012.

(3) The EXCO Operating Credit Agreement matures on March 30, 2012.

(4) Firm transportation services reflect contracts whereby EXCO commits to transport a minimum quantity of natural gas on a shippers' pipeline. Other fixed commitments include salt water disposal arrangements. Whether or not EXCO delivers the minimum quantity, we pay the fee as if the quantities were delivered.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates charged on borrowings and earned on cash equivalent investments, and adverse changes in the market value of marketable securities. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

Commodity price risk

Our objective in entering into derivative financial instruments is to manage our exposure to commodity price and interest rate fluctuations, protect our returns on investments, and achieve a more predictable cash flow in connection with our acquisition activities and borrowings related to these activities. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense due to changes in the fair value of our derivative financial instrument contracts. Cash charges or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration.

Pricing for oil and natural gas is volatile. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, we recognize the change in the respective instrument's fair value currently in earnings, with respect to commodity derivatives, gains or losses on derivative financial instruments and with respect to interest rate swaps, as interest expense on financial risk management instruments.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production is volatile. The following table sets forth our oil and natural gas derivatives management activities as of December 31, 2009.

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2009
Natural gas:			
Swaps:			
2010	64,473	$ 7.71	$122,432
2011	12,775	7.48	14,305
2012	5,490	5.91	(3,153)
2013	5,475	5.99	(3,350)
2014	—		—
Total natural gas	88,213		130,234
Oil:			
Swaps:			
2010	447	114.96	14,442
2011	456	116.00	13,337
2012	92	109.30	1,850
2013	—	—	—
2014	—	—	—
Total oil	995		29,629
Total oil and natural gas derivatives			$159,863

At December 31, 2009, the average forward NYMEX oil prices per Bbl for calendar year 2010 and 2011 were $82.32 and $86.10, respectively, and the average forward NYMEX natural gas prices per Mmbtu for calendar 2010 and 2011 were $5.79 and $6.34, respectively. Our reported earnings and assets or liabilities for derivative financial instruments will continue to be subject to significant fluctuations in value due to price volatility.

Realized gains or losses from the settlement of our oil and natural gas derivatives are recorded in our financial statements as increases or decreases in other income or loss. For example, using the oil swaps in place as of December 31, 2009 for 2010, if the settlement price exceeds the actual weighted average strike price of $114.96 per Bbl, then a reduction in other income (expense) would be recorded for the difference between the settlement price and $114.96 per Bbl, multiplied by the hedged volume of 447 Mbbls. Conversely, if the settlement price is less than $114.96 per Bbl, then an increase in other income (expense) would be recorded for the difference between the settlement price and $114.96 per Bbl, multiplied by the hedged volume of 447 Mbbls. For example, for a hedged volume of 447 Mbbls, if the settlement price is $115.96 per Bbl then other income (expense) would decrease by $0.4 million. Conversely, if the settlement price is $113.96 per Bbl, oil and natural gas revenue would increase by $0.4 million.

Interest rate risk

At December 31, 2008, our exposure to interest rate changes related primarily to borrowings under our credit agreements and interest earned on our short-term investments. The interest rate is fixed at 7 ¼% on the $444.7 million outstanding on our Senior Notes. Interest is payable on borrowings under our credit agreements and the New Term Credit Agreement is based on a floating rate as more fully described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Our liquidity, capital resources and capital commitments." At December 31, 2009, we had $747.6 million in outstanding borrowings under our credit agreements. A 1% change in interest rates based on the variable borrowings as of December 31, 2009 would result in an increase or decrease in our interest costs of $7.5 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

In January 2008, we entered into financial risk management instruments to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBO rates ranging from 2.45% to 2.8%. The fair value of our interest rate swaps was a liability of $2.0 million as of December 31, 2009.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Contents

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Shareholders of
EXCO Resources, Inc.:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on management's assessment, management believes that, as of December 31, 2009, our internal control over financial reporting is effective based on those criteria.

The effectiveness of EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2009 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By: . /s/ DOUGLAS H. MILLER
Title: Chief Executive Officer

By: /s/ STEPHEN F. SMITH
Title: President and Chief Financial Officer

Dallas, Texas
February 24, 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
EXCO Resources, Inc.:

We have audited EXCO Resources, Inc.'s (the Company) internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). EXCO Resources, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, EXCO Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 24, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 24, 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
EXCO Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EXCO Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 24, 2010

EXCO Resources, Inc.

Consolidated balance sheets

(in thousands)	December 31, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 68,407	$ 57,139
Restricted cash	58,909	—
Accounts receivable, net:		
Oil and natural gas	56,485	130,970
Joint interest	47,104	22,807
Interest and other	10,832	5,895
Inventory	15,830	42,479
Derivative financial instruments	138,120	247,614
Other	6,401	6,136
Total current assets	402,088	513,040
Equity investment in TGGT Holdings, LLC	216,987	—
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties	492,882	481,596
Proved developed and undeveloped oil and natural gas properties	1,875,749	3,578,344
Accumulated depletion	(1,132,604)	(936,088)
Oil and natural gas properties, net	1,236,027	3,123,852
Gas gathering assets	180,506	485,201
Accumulated depreciation and amortization	(22,841)	(32,232)
Gas gathering assets, net	157,665	452,969
Office and field equipment, net	31,771	25,647
Deferred financing costs, net	7,602	62,884
Derivative financial instruments	34,677	173,003
Goodwill	269,656	470,077
Other assets	2,421	880
Total assets	$ 2,358,894	$4,822,352

See accompanying notes.

EXCO Resources, Inc.

Consolidated balance sheets

(in thousands, except per share and share data)	December 31, 2009	December 31, 2008
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 112,991	$ 172,400
Revenues and royalties payable	79,356	108,130
Accrued interest payable	16,193	28,746
Current portion of asset retirement obligations	900	1,830
Income taxes payable	210	160
Derivative financial instruments	3,264	11,607
Total current liabilities	212,914	322,873
Long-term debt	1,196,277	3,019,738
Deferred income taxes	—	9,371
Derivative financial instruments	11,688	12,590
Asset retirement obligations and other long-term liabilities	78,427	125,279
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, \$0.001 par value; authorized shares—10,000,000; none issued and outstanding	—	—
Common stock, \$0.001 par value; authorized shares—350,000,000; issued and outstanding shares—211,905,509 at December 31, 2009 and 210,968,931 at December 31, 2008	212	211
Additional paid-in capital	3,105,238	3,070,766
Accumulated deficit	(2,245,862)	(1,738,476)
Total shareholders' equity	859,588	1,332,501
Total liabilities and shareholders' equity	$ 2,358,894	$ 4,822,352

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of operations

(in thousands, except per share data)	Year ended December 31, 2009	2008	2007
Revenues:			
Oil and natural gas	$ 550,505	$ 1,404,826	$ 875,787
Midstream	35,330	85,432	18,817
Total revenues	585,835	1,490,258	894,604
Costs and expenses:			
Oil and natural gas production	177,629	238,071	168,999
Midstream operating	35,580	82,797	16,289
Gathering and transportation	18,960	14,206	10,210
Depreciation, depletion and amortization	221,438	460,314	375,420
Write-down of oil and natural gas properties	1,293,579	2,815,835	—
Accretion of discount on asset retirement obligations	7,132	6,703	4,878
General and administrative	99,177	87,568	64,670
Gain on divestitures and other operating items	(676,434)	(2,692)	(3,997)
Total cost and expenses	1,177,061	3,702,802	636,469
Operating income (loss)	(591,226)	(2,212,544)	258,135
Other income (expense):			
Interest expense	(147,161)	(161,638)	(181,350)
Gain on derivative financial instruments	232,025	384,389	26,807
Other income	126	1,289	6,160
Equity method loss in TGGT Holdings, LLC	(69)	—	—
Total other income (expense)	84,921	224,040	(148,383)
Income (loss) before income taxes	(506,305)	(1,988,504)	109,752
Income tax expense (benefit)	(9,501)	(255,033)	60,096
Net income (loss)	(496,804)	(1,733,471)	49,656
Preferred stock dividends	—	(76,997)	(132,968)
Net loss available to common shareholders	$ (496,804)	$(1,810,468)	$ (83,312)
Earnings (loss) per common share:			
Basic			
Net loss available to common shareholders	$ (2.35)	$ (11.81)	$ (0.80)
Weighted average common shares outstanding	211,266	153,346	104,364
Diluted			
Net loss available to common shareholders	$ (2.35)	$ (11.81)	$ (0.80)
Weighted average common and common equivalent shares outstanding	211,266	153,346	104,364

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of cash flows

(in thousands)	Year ended December 31, 2009	2008	2007
Operating Activities:			
Net income (loss)	$ (496,804)	$(1,733,471)	$ 49,656
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on sale of other assets	—	39	(941)
Depreciation, depletion and amortization	221,438	460,314	375,420
Stock option compensation expense	18,987	15,978	12,632
Accretion of discount on asset retirement obligations	7,132	6,703	4,878
Write-down of oil and natural gas properties	1,293,579	2,815,835	—
Gain on divestitures	(691,932)	—	—
Loss from equity investment in TGGT Holdings, LLC	69	—	—
Non-cash change in fair value of derivatives	238,577	(483,811)	81,606
Cash settlements of assumed derivatives	(182,952)	83,603	14,214
Deferred income taxes	(9,371)	(255,285)	66,171
Amortization of deferred financing costs, premium on 7 1/4% senior notes due 2011 and discount on long-term debt and Term Credit Agreement	48,159	15,195	10,332
Effect of changes, net of acquisition effects, in:			
Accounts receivable	34,998	7,884	(59,290)
Other current assets	(2,325)	1,734	(3,092)
Accounts payable and other current liabilities	(45,950)	40,248	26,243
Net cash provided by operating activities	433,605	974,966	577,829
Investing Activities:			
Additions to oil and natural gas properties, gathering systems and equipment	(664,292)	(1,004,792)	(654,982)
Property and midstream acquisitions	(68,404)	(719,330)	(2,191,987)
Proceeds from disposition of property and equipment	2,074,380	15,543	490,362
Restricted cash	(58,909)	—	—
Equity investment in TGGT Holdings, LLC	(47,500)	—	—
Advance payment on pending acquisition	—	—	(39,500)
Proceeds from sales of marketable securities	—	—	5,228
Other investing activities	—	—	(5,558)
Net cash provided by (used in) investing activities	1,235,275	(1,708,579)	(2,396,437)
Financing Activities:			
Borrowings under credit agreements	247,799	1,700,136	2,235,500
Repayments under credit agreements	(2,067,671)	(776,200)	(2,221,532)
Proceeds from issuance of common stock	10,361	14,777	4,162
Proceeds from issuance of Preferred Stock, net of underwriter's commissions and issuance costs	—	—	1,992,273
Payment of preferred stock dividends	—	(82,831)	(127,134)
Payment of common stock dividends	(10,582)	—	—
Settlements of derivative financial instruments with a financing element	182,952	(83,603)	(14,214)
Deferred financing costs and other	(20,471)	(37,037)	(17,759)
Net cash provided by (used in) financing activities	(1,657,612)	735,242	1,851,296
Net increase in cash	11,268	1,629	32,688
Cash at beginning of period	57,139	55,510	22,822
Cash at end of period	$ 68,407	$ 57,139	$ 55,510
Supplemental Cash Flow Information:			
Interest paid	$ 112,560	$ 134,087	$ 182,192
Income taxes received	$ —	$ —	$ (6,075)
Derivative financial instruments assumed in acquisitions	$ —	$ —	$ (102,219)
Supplemental non-cash investing:			
Capitalized stock compensation	$ 5,066	$ 4,060	$ 2,410
Capitalized interest	$ 5,840	$ 3,861	$ —
Issuance of common stock for director services	$ 59	$ 137	$ —
Value of shares received for sale of properties	$ —	$ —	$ 4,575

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of changes in shareholders' equity

(in thousands)	Common Stock Shares	Common Stock Amount	Additional paid-in capital	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2006	104,162	$104	$1,024,442	$ 155,304	$ 1,179,850
Issuance of common stock	417	1	4,161	—	4,162
Preferred stock dividends	—	—	—	(132,968)	(132,968)
Share-based compensation	—	—	15,042	—	15,042
Net income	—	—	—	49,656	49,656
Balance at December 31, 2007	104,579	$105	$1,043,645	$ 71,992	$ 1,115,742
Issuance of common stock	1,127	1	14,913	—	14,914
Preferred stock dividends	—	—	—	(76,997)	(76,997)
Conversion of preferred stock	105,263	105	1,992,170	—	1,992,275
Share-based compensation	—	—	20,038	—	20,038
Net loss	—	—	—	(1,733,471)	(1,733,471)
Balance at December 31, 2008	210,969	$211	$3,070,766	$(1,738,476)	$ 1,332,501
Issuance of common stock	936	1	10,419	—	10,420
Share-based compensation	—	—	24,053	—	24,053
Common stock dividends	—	—	—	(10,582)	(10,582)
Net loss	—	—	—	(496,804)	(496,804)
Balance at December 31, 2009	211,905	$212	$3,105,238	$(2,245,862)	$ 859,588

See accompanying notes.

EXCO Resources, Inc.

Notes to consolidated financial statements

1. Organization

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc., and its consolidated subsidiaries.

We are an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties. Our principal operations are conducted in the East Texas, North Louisiana, Appalachia, and Permian producing areas. In addition to our oil and natural gas producing operations, as of August 14, 2009, we hold a 50% equity interest in a midstream joint venture in the East Texas/North Louisiana area.

Our assets in East Texas/North Louisiana, including our equity interest in the midstream operations, are owned by our subsidiary, EXCO Operating Company, LP, and its subsidiaries, collectively, EXCO Operating. Organizationally, EXCO Operating is an indirect wholly-owned subsidiary of EXCO Resources. EXCO Operating's debt is not guaranteed by EXCO Resources and EXCO Operating does not guarantee EXCO Resources' debt. This structure allows us to maintain two separate credit agreements. We expect to continue to grow by leveraging our management and technical team's experience, developing our shale resource plays, exploiting our multi-year inventory of development drilling locations and exploitation projects and entering into beneficial joint development agreements. We employ the use of debt along with a comprehensive derivative financial instrument program to support our strategy. These approaches enhance our ability to execute our business plan over the entire commodity price cycle, protect our returns on investments, and manage our capital structure.

The accompanying consolidated balance sheets as of December 31, 2009 and 2008, results of operations, cash flows and changes in shareholders' equity for the years ended December 31, 2009, 2008 and 2007 are for EXCO and its subsidiaries. The consolidated financial statements and related footnotes are presented in accordance with generally accepted accounting principles, or GAAP, and therefore, all intercompany transactions have been eliminated.

On August 14, 2009, we closed the sale to an affiliate of BG Group plc, or BG Group, of a 50% interest in a newly formed company, TGGT Holdings, LLC, or TGGT, which now holds most of our East Texas/North Louisiana midstream assets, or the BG Midstream Transaction. As a result of the BG Midstream Transaction we no longer report our midstream operations as a separate business segment. Effective August 14, 2009, we account for the jointly-held midstream operations as an equity method investment. The net operations of our gathering system in Louisiana that supports our Vernon Field operations, which was previously reported within our midstream segment and was not included in the BG Midstream Transaction, is now reported in "Gathering and transportation" on the Consolidated Statement of Operations.

Beginning December 31, 2009, we reclassified certain items that relate to our operations from "Other income (expense)" into "Gain on divestiture and other operating items." Prior year amounts have been reclassified to conform to current year reporting.

2. Summary of significant accounting policies

Principles of consolidation

We consolidate all of our subsidiaries in the accompanying consolidated balance sheets as of December 31, 2009 and 2008 and the consolidated statements of operations and consolidated statements of cash flows for the years ended December 31, 2009, 2008 and 2007. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. All intercompany transactions and accounts have been eliminated.

Management estimates

In preparing financial statements in conformity with GAAP, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting periods. The more significant estimates pertain to proved oil and natural gas reserve volumes, future development costs, dismantlement and abandonment costs, share-based compensation expenses, estimates relating to oil and natural gas revenues and expenses, the fair market value of assets and liabilities acquired in business combinations, derivatives, goodwill and equity securities. Actual results may differ from management's estimates.

Cash equivalents

We consider all highly liquid investments with maturities of three months or less when purchased, to be cash equivalents.

Restricted Cash

The restricted cash on our balance sheet is comprised principally of our share of an evergreen escrow account with BG Group which is used to fund our share of operations and development within the area of mutual interest, or the BG AMI. Funds within the escrow account are restricted solely to drilling and operations within the BG AMI.

Concentration of credit risk and accounts receivable

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash, trade receivables and our derivative financial instruments. We place our cash with financial institutions which we believe have sufficient credit quality to minimize risk of loss. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. The majority of our accounts receivable are due from either purchasers of oil or natural gas or participants in oil and natural gas wells for which we serve as the operator. We have the right to offset future revenues against unpaid charges related to wells which we operate. Oil and natural gas receivables are generally uncollateralized. The allowance for doubtful accounts receivable aggregated $3.2 million and $2.5 million at December 31, 2009 and 2008, respectively. We place our derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with our counterparties on our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty. As of December 31, 2009, the estimated fair value of our derivative financial instruments had a net asset position of $157.8 million.

For the year ended December 31, 2009 there were no sales to any individual customer which exceeded 10% of our consolidated revenues. For the year ended December 31, 2008, sales to a natural gas marketing company, Crosstex Gulf Coast Marketing, and to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, accounted for approximately 12.0% and 11.2%, respectively, of total consolidated revenues. For the year ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for approximately 18.9% and 11.4%, respectively, of total consolidated revenues.

Derivative financial instruments

In connection with the incurrence of debt related to our exploration, exploitation, development, acquisition and producing activities, our management has adopted a policy of entering into oil and natural gas derivative financial instruments to mitigate the impacts of commodity price fluctuations and to achieve a more predictable cash flow. Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, Topic 815 requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its estimated fair value. ASC 815 requires that changes in the derivative's estimated fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments and, as a result, recognize the change in a derivative's estimated fair value currently in earnings as a component of other income or expense.

Oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities require that we choose between two GAAP alternatives; the full cost method or the successful efforts method. We use the full cost method of accounting, which involves capitalizing all exploration, exploitation, development and acquisition costs. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Unproved property costs, which totaled $492.9 million and $481.6 million as of December 31, 2009 and 2008, respectively, are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess for impairment and transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus acquired proved and unproved leaseholds.

When we acquire significant amounts of undeveloped acreage, we capitalize interest on the acquisition costs in accordance with FASB ASC Subtopic 835-20 for Capitalization of Interest. We began capitalizing interest in April 2008, upon identification and development of shale resource opportunities in the Haynesville and Marcellus areas. The cost of these projects, net of any amortized or transferred amounts into the depletable full cost pool was $280.6 million as of December 31, 2009. When the balance is moved to proved developed and undeveloped oil and natural gas properties, we will cease capitalizing interest.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool, excluding the book value of unproved properties, and all estimated future development costs are divided by the total estimated quantities of Proved Reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our exploration, exploitation and development activities.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss, unless the disposition would significantly alter the amortization rate and/or the relationship between capitalized costs and Proved Reserves. The impacts on our depletion rate from the BG Upstream Transaction, Encore Transactions, and Sheridan Transaction in 2009, as discussed in Note 4. Divestures and acquisitions, were considered significant and we recognized gains on these sales of $691.9 million.

Prior to our December 31, 2009 adoption of the SEC's Release No. 33-8995 Modernization of Oil and Gas Reporting, or Release No. 33-8995, at the end of each quarterly period the end of quarter unamortized cost of oil and natural gas properties, net of related deferred income taxes, was limited to the full cost ceiling, computed as the sum of the estimated future net revenues from our Proved Reserves using current period-end prices, discounted at 10%, and adjusted for related income tax effects (ceiling test). In the event our capitalized costs exceeded the ceiling limitation at the end of the reporting period, we subsequently evaluated the limitation for price changes that occurred after the balance sheet date to assess impairment. Beginning December 31, 2009, Release No. 33-8995 requires that the full cost ceiling be computed as the sum of the estimated future net revenues from Proved Reserves using the simple average spot price for the trailing month period using the first day of each month. The new rule no longer allows a company to use subsequent price increases to eliminate ceiling test write-downs based on prices used at year end. Under full cost accounting rules, any ceiling test write-downs of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedges, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computation. As a result, decreases in commodity prices which contribute to ceiling test write-downs may be offset by mark-to-market gains which are not reflected in our ceiling test results.

For the year 2007, we sought and received exemptions from the Securities and Exchange Commission, or the SEC to exclude three significant proved oil and natural gas property acquisitions from our ceiling test computation for a period of twelve months from the closing date of each acquisition. There were no exemptions in effect for any acquisitions for the years ended December 31, 2009 and 2008 ceiling test computations.

The ceiling test calculation is based upon estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Write-down of oil and natural gas properties

For the year ended December 31, 2009, we recognized a ceiling test write-down in the first quarter of 2009 of $1.3 billion to our proved oil and natural gas properties. For the twelve months ended December 31, 2008, we recognized ceiling test write-downs of $2.8 billion to our proved oil and natural gas properties. There were no ceiling test write-downs in 2007.

As discussed above, prior to our December 31, 2009 adoption of the SEC's Release No. 33-8995, we were required by the SEC to compute the after-tax present value of our proved oil and natural gas properties using spot market prices for oil and natural gas at our balance sheet date. The prices used to compute our first quarter write-down were the March 31, 2009 spot natural gas price at Henry Hub of $3.63 per Mmbtu of natural gas and the spot oil price at Cushing, Oklahoma of $49.64 per Bbl of oil. Beginning December 31, 2009, Release No. 33-8995 requires the present value of estimated Proved Reserves be computed using the simple average spot price for the trailing twelve month period using the first day of each month. These prices were $3.87 per Mmbtu for natural gas and $61.18 per Bbl of oil.

Gas gathering assets

Gas gathering assets are capitalized at cost and depreciated on a straight line basis over their estimated useful lives of 25 to 40 years.

Inventory

Inventory includes tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities and is carried at the lower of cost or market. The inventory is capitalized to our full cost pool or gathering system assets once it has been placed into service.

Office and field equipment

Office and field equipment are capitalized at cost and depreciated on a straight line basis over their estimated useful lives. Office and field equipment useful lives range from 3 to 15 years.

Goodwill

In accordance with FASB ASC Subtopic 350-20 for Intangibles-Goodwill and Other, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are performed as of December 31 of each year. Losses, if any, resulting from impairment tests will be reflected in operating income in the statement of operations. In a February 2005 letter to oil and natural gas companies, the SEC provided guidance concerning the treatment of goodwill in situations when a full cost company sells less than 25% of its proved oil and natural gas reserves in a cost pool, unless there is a significant alteration to the depletion rate as a result of the disposition. The guidance indicated that such dispositions may trigger a need to evaluate goodwill for impairment under ASC 350-20.

The BG Upstream Transaction, Encore Transactions, and Sheridan Transaction, as discussed in Note 4. Divestitures and acquisitions, caused significant alterations to our full cost pool and we therefore evaluated the goodwill associated with these properties. As a result of our analysis, we reduced $177.6 million of goodwill and computed gains on those transactions. In addition, the BG Midstream Transaction, as discussed in Note 4. Divestures and acquisitions, resulted in a reduction of $11.4 million of goodwill against the associated gain and the transfer of $11.4 million of goodwill to the equity investment in TGGT.

The balance of goodwill as of December 31, 2009 and 2008 was $269.7 million and $470.1 million, respectively.

Deferred abandonment and asset retirement obligations

We apply FASB ASC Subtopic 410-20 for Asset Retirement and Environmental Obligations to account for estimated future plugging and abandonment costs. ASC 410-20 requires legal obligations associated with the retirement of long-lived assets to be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Our asset retirement obligations primarily represents the present value of the estimated amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws.

The following is a reconciliation of our asset retirement obligations for the periods indicated:

(in thousands)	For the year ended December 31, 2009	For the year ended December 31, 2008	For the year ended December 31, 2007
Asset retirement obligations at beginning of period	$120,671	$ 84,370	$56,149
Activity during the period:			
Adjustment to liability due to acquisitions	389	15,128	23,293
Revisions in estimated assumptions	—	14,960	—
Reduction to retirement obligations due to divestitures	(58,501)	—	—
Liabilities incurred during period	879	4,222	5,127
Liabilities settled during period	(5,455)	(4,712)	(5,077)
Accretion of discount	7,132	6,703	4,878
Asset retirement obligations at end of period	65,115	120,671	84,370
Less current portion	900	1,830	1,656
Long-term portion	$ 64,215	$118,841	$82,714

We have no assets that are legally restricted for purposes of settling asset retirement obligations.

Revenue recognition and gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. A majority of our gas imbalances were concentrated in our Mid-Continent properties, which we sold during 2009, as discussed in Note 4. Divestitures and acquisitions. Gas imbalances at December 31, 2009, 2008, and 2007 were not significant.

Gathering and transportation

We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of the transportation costs. Under the other arrangement, we sell oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation cost as gathering and transportation expense. Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative financial instruments, include revenues which are reported under two separate bases.

As a result of the BG Midstream Transaction, the net operating results from our gathering system in North Louisiana that supports our Vernon Field operations, which was previously reported within our midstream segment, is now reported as a component of "Gathering and transportation" in the Consolidated Statement of Operations.

Gathering and transportation expenses totaled $19.0 million, $14.2 million and $10.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Capitalization of internal costs

We capitalize as part of our proved developed oil and natural gas properties a portion of salaries and related share-based compensation for employees who are directly involved in the acquisition and development of oil and natural gas properties. During the years ended December 31, 2009, 2008 and 2007, we capitalized $18.3 million, $15.5 million and $8.1 million, respectively. The capitalized amounts include $5.1 million, $4.0 million and $2.4 million of share-based compensation for the years ended December 31, 2009, 2008 and 2007, respectively. See Note 12. Stock options.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $24.6 million, $24.9 million and $18.4 million, for the years ended December 31, 2009, 2008 and 2007, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. Our share of these charges was $16.6 million, $17.0 million and $13.5 million for the years ended December 31, 2009, 2008 and 2007, respectively, and are classified as oil and natural gas production costs.

Environmental costs

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Income taxes

Income taxes are accounted for using the liability method of accounting in accordance with FASB ASC Topic 740 for Income Taxes, under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Earnings per share

We account for earnings per share in accordance with FASB ASC Subtopic 260-10 for Earnings Per Share. ASC 260-10 requires companies to present two calculations of earnings per share, or EPS; basic and diluted. Basic earnings per common share is based on the weighted average number of common shares outstanding during the period. Diluted earnings per common share is computed in the same manner as basic earnings per share after assuming issuance of common stock for all potentially dilutive equivalent shares, whether exercisable or not.

Stock options

We account for our stock-based compensation in accordance with FASB ASC Topic 718 for Compensation—Stock Compensation Topic. ASC 718 requires all share-based payments to employees, including grants of employee stock options, to be recognized in our consolidated statements of operations based on their estimated fair values. We recognize expense on a straight-line basis over the vesting period of the option.

Our 2005 Long-Term Incentive Plan, as amended, or the 2005 Incentive Plan, provides for the granting of options and other equity incentive awards to purchase up to 23,000,000 shares of our common stock. New shares will be issued for any awards exercised. Since the adoption of the 2005 Incentive Plan, EXCO has issued only stock options, although the plan allows for other share-based awards.

3. Recent accounting pronouncements

On January 21, 2010, the Financial Accounting Standards Board, or the FASB, issued Accounting Standards Update No. 2010-06—Fair Value Measurement and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements, or ASU 2010-06. ASU 2010-06 requires transfers, and the reasons for the transfers, between Levels 1 and 2 be disclosed, Level 3 reconciliations for fair value measurements using significant unobservable inputs should be presented on a gross basis, the fair value measurement disclosure should be reported for each class of asset and liability, and disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring will be required for fair value measurements that fall in either Level 2 or 3. The update will be effective for interim and annual reporting periods beginning after December 15, 2009. This update will require us to update our disclosures on derivatives, but will have no impact to our financial position.

On April 1, 2009, the FASB issued FASB ASC Subtopic 805-20 for Business Combinations. ASC 805-20 amends and clarifies FASB SFAS No. 141 (revised 2007), "Business Combinations," to give guidance on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This pronouncement was effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted ASC 805-20 on January 1, 2009.

In March 2008, the FASB issued FASB ASC Section 815-10-65 for Derivatives and Hedging. ASC 815-10-65 requires enhanced disclosure about the fair value of derivative instruments and their gains or losses in tabular format and information about credit-risk-related contingent features in derivative agreements, counterparty credit risk, and the company's strategies and objectives for using derivative instruments. ASC 815-10-65 is effective for financial statements issued for fiscal years beginning after November 15, 2008, and as such, was adopted by us on January 1, 2009. See "Note 9. Derivative financial instruments and fair value measurements" for the impact to our disclosures.

On December 31, 2008, the SEC issued Release No. 33-8995, amending its oil and natural gas reporting requirements for oil and natural gas producing companies. On January 16, 2010, the Financial Accounting Standards Board, or the FASB, issued Update No. 2010-03—Extractive Activities—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures, or Update No. 2010-03, to align the oil and gas reserve estimation and disclosure requirements of the Codification with Release No. 33-8995.

The effective date of the new accounting and disclosure requirements is for annual reports filed for fiscal years ending on or after December 31, 2009. Companies are not permitted to comply at an earlier date. Among other things, Release No. 33-8995 and the Update No. 2010-03:

- Revises a number of definitions relating to oil and natural gas reserves to make them consistent with the Petroleum Resource Management System, which includes certain non-traditional resources in proved reserves;
- Permits the use of new technologies for determining oil and natural gas reserves;

- Requires the use of the simple average spot price for the trailing twelve month period using the first day of each month the estimation of oil and natural gas reserve quantities and, for companies using the full cost method of accounting, in computing the ceiling limitation test, in place of a single day price as of the end of the fiscal year;
- Permits the disclosure in filings with the SEC of probable and possible reserves and sensitivity of our proved oil and natural gas reserves to changes in prices;
- Requires additional disclosures (outside of the financial statements) regarding the status of undeveloped reserves and changes in status of these from period to period; and
- Requires a discussion of the internal controls in place in the reserve estimation process and disclosure of the technical qualifications of the technical person having primary responsibility for preparing the reserve estimates.

The change in the calculation of pricing resulted in $3.87 per Mmbtu for Henry Hub and $61.18 per Bbl for Cushing, Oklahoma instead of the spot price of $5.79 per Mmbtu for Henry Hub and $79.36 per Bbl for Cushing, Oklahoma, which would have been applied using the old SEC rules.

4. Divestures and acquisitions

2009 Divestures and acquisitions

The following summarizes our 2009 divestitures:

(in thousands)	Proceeds(1)
Operating division	
East Texas/North Louisiana	
BG Upstream Transaction	$ 713,779
BG Midstream Transaction	269,237
East Texas Transaction	154,299
Other East Texas / North Louisiana	22,327
Mid-Continent	
Mid-Continent Transaction	197,730
Sheridan Transaction(2)	531,351
Other Mid-Continent	5,482
Appalachia	
EnerVest Transaction(2)(3)	129,737
Permian	40,042
Total joint ventures and divestitures	$2,063,984

(1) Net of selling expenses.

(2) Subject to final closing adjustments.

(3) Pending receipt of an additional $13.1 million of consents.

On August 11, 2009, we closed a sale of properties located in East Texas, or the East Texas Transaction, with Encore Operating, LP, or Encore. Pursuant to the East Texas Transaction, we sold all of our interests in certain oil and natural gas properties located in our Overton Field and Gladewater area of East Texas. We received $154.3 million in cash, after final closing adjustments.

On August 11, 2009, we closed a sale of properties located in Texas and Oklahoma, or the Mid-Continent Transaction, with Encore. Pursuant to the Mid-Continent Transaction, we sold all of our interests in certain oil and gas properties located in our Mid-Continent operating area. We received $197.7 million in cash, after final closing adjustments.

On August 14, 2009, we closed a sale and joint development transaction with BG Group for the sale of an undivided 50% of our interest in the BG AMI which included most of our oil and natural gas assets in East Texas/North Louisiana (excluding the Vernon Field, Gladewater area, Overton Field and Redland Field), or the BG Upstream Transaction. The BG Upstream Transaction includes agreements for the joint development and operation of our Haynesville and Bossier shales and certain other related natural gas assets located in the BG AMI. We received $713.8 million in cash, after final closing adjustments and adjustments necessary to reflect the January 1, 2009 effective date. Pursuant to this transaction, BG Group will also fund $400.0 million of capital development attributable to our 50% interest, with BG Group paying 75% of our share of drilling and completion costs on the deep rights (Haynesville and Bossier shales) until the $400.0 million commitment is satisfied. Under the terms of the agreement, BG Group funding of the $400.0 million commitment will be satisfied solely through drilling of deep right wells as defined in the agreement. As of December 31, 2009, BG Group's remaining obligation was approximately $367.7 million.

On August 14, 2009 we closed the sale to an affiliate of BG Group of a 50% interest in a newly formed company, TGGT Holdings, LLC, or TGGT, which now holds most of our East Texas/North Louisiana midstream assets, or the BG Midstream Transaction. Our Vernon Field midstream assets were excluded from the BG Midstream Transaction. Pursuant to a contribution agreement, we contributed TGG Pipeline, Ltd., or TGG, which owns an intrastate pipeline in East Texas and a gathering system in North Louisiana, and Talco Midstream Assets, Ltd., or Talco, which owns gathering assets in East Texas/North Louisiana, to TGGT. BG Group contributed $269.2 million in cash to TGGT and we received those funds from TGGT as a special distribution at closing. EXCO Operating now owns 50% of TGGT and an affiliate of BG Group owns 50% of TGGT. The effective date of this transaction was also January 1, 2009. We adopted the equity method of accounting for our interest in TGGT upon its formation. The BG Midstream Transaction resulted in recognition of a gain of $98.3 million, net of an allocated reduction of goodwill previously ascribed to our midstream business segment.

The total cash proceeds of $983.0 million from the BG Upstream Transaction and the BG Midstream Transaction were used to repay EXCO Operating's $300.0 million senior unsecured term credit agreement, or the Term Credit Agreement, creation of an evergreen escrow funding account to develop the Haynesville operations, and a working capital contribution to TGGT, with the remainder applied to the outstanding balances under the EXCO Operating credit agreement.

The BG Upstream Transaction, BG Midstream Transaction and the Encore Transactions resulted in a gain of $460.4 million, net of a reduction in goodwill, was recognized in connection with these transactions.

On November 10, 2009, we closed the sale of our remaining assets in our Mid-Continent operating area to Sheridan Holding Company I, LLC, or the Sheridan Transaction, for $531.4 million, subject to final closing adjustments. The sale was effective on October 1, 2009.

The Sheridan Transaction caused a significant alteration to our full cost pool and a gain, net of a reduction in goodwill, of $231.5 million was recognized.

On November 24, 2009, we closed the sale of our Ohio and certain Northwestern Pennsylvania producing assets to EV Energy Partners, L.P., or the EnerVest Transaction, along with certain institutional partnerships managed by EnerVest, Ltd., for $129.7 million, subject to final closing adjustments. In connection with the closing, the parties agreed to hold back approximately $13.1 million of the properties pending the receipt of required consents from third parties necessary to transfer such properties. The sale was effective on September 1, 2009. This transaction did not significantly alter our full cost pool, therefore all proceeds reduced the full cost pool.

During the year we also closed sales of certain non strategic assets, resulting in net cash proceeds of approximately $67.9 million after customary preliminary closing and post-closing adjustments. These transactions did not significantly alter our full cost pool, therefore all proceeds reduced the full cost pool.

During the fourth quarter of 2009 we completed acquisitions totaling $251.5 million. While the acquisitions contained a minor amount of proved oil and gas properties, the strategic objective of the acquisitions was for the expansion of acreage in our shale resource plays. Due to their location within the BG AMI, we offered BG Group the opportunity to participate for 50% of these acquisitions pursuant to our joint development agreement.

2008 Acquisitions

During 2008, we completed acquisitions of proved and unproved oil and natural gas properties, undeveloped acreage and other assets. A summary of these acquisitions and the values allocated to oil and natural gas properties and gathering facilities, net of contractual adjustments, is presented on the following table.

(in thousands)	Appalachian Acquisition	New Waskom Acquisition	Danville Acquisition	Other acquisitions	Total acquisitions
Purchase price calculations:					
Purchase price	$386,703	$55,198	$249,451	$74,075	$765,427
Acquisition related expenses	741	—	178	—	919
Total purchase price	$387,444	$55,198	$249,629	$74,075	$766,346
Allocation of purchase price:					
Proved oil and natural gas properties	$334,308	$ —	$199,183	$71,232	$604,723
Unproved oil and natural gas properties	44,797	—	42,391	(18)	87,170
Other property and equipment	2,517	—	656	—	3,173
Gulf Coast sale		—	—	6,471	6,471
Gas gathering and related facilities	19,876	55,198	11,042	—	86,116
Asset retirement obligations	(12,647)	—	(1,029)	—	(13,676)
Other liabilities, net	(1,407)	—	(2,614)	(3,610)	(7,631)
Total purchase price allocation	$387,444	$55,198	$249,629	$74,075	$766,346

On February 20, 2008, EXCO acquired shallow natural gas properties from EOG Resources, Inc. located primarily in EXCO's central Pennsylvania operating area, or the Appalachian Acquisition. The purchase price was $387.4 million and was financed with funds drawn under the EXCO Resources credit agreement.

On March 11, 2008, we acquired a gathering system in East Texas, or the New Waskom Acquisition, which contained 230 miles of pipeline and a gathering system at a cost of approximately $55.2 million. The New Waskom system is located primarily in Harrison and Panola Counties in East Texas and Caddo Parish in North Louisiana. The system has access to one plant and three interstate pipelines. The New Waskom Acquisition was funded with drawings under the EXCO Operating credit agreement.

On July 15, 2008, we acquired producing oil and natural gas properties, acreage and other assets in Gregg, Rusk and Upshur counties of Texas, or the Danville Acquisition, for approximately $249.6 million, net of closing adjustments. Funding for this acquisition was provided by the Term Credit Agreement.

In addition to the acquisitions detailed above, we also acquired additional incremental interest in wells we own in our East Texas/North Louisiana areas, along with additional Proved Reserves in our Mid-Continent area.

2007 Acquisitions

During 2007, we completed acquisitions of proved and unproved oil and natural gas properties and undeveloped acreage. A summary of these acquisitions and the values allocated to oil and natural gas properties and gathering facilities, net of contractual adjustments, is presented on the following table. As stated above, the Southern Gas Acquisition was not finalized until 2008.

(in thousands)	Vernon Acquisition	Southern Gas Acquisition(1)	Other acquisitions	Consolidated total
Purchase price calculations:				
Purchase price	$1,520,183	$770,498	$180,160	$2,470,841
Acquisition related expenses	1,755	2,040	—	3,795
Total purchase price	$1,521,938	$772,538	$180,160	$2,474,636
Allocation of purchase price:				
Proved oil and natural gas properties	$1,417,823	$586,407	$159,502	$2,163,732
Unproved oil and natural gas properties	58,192	4,725	20,658	83,575
Gulf Coast Sale	—	241,948	—	241,948
Gas gathering and related facilities	119,409	—	—	119,409
Fair value (liability) of assumed derivative financial instruments	(60,015)	(42,204)	—	(102,219)
Asset retirement obligations	(10,726)	(12,567)	—	(23,293)
Other liabilities, net	(2,745)	(5,771)	—	(8,516)
Total purchase price allocation	$1,521,938	$772,538	$180,160	$2,474,636

(1) Reflects the final purchase price allocation for the Southern Gas Acquisition. The preliminary purchase price as of December 31, 2007 was $761.1 million.

On March 30, 2007, EXCO Operating completed the purchase of substantially all of the oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009 from entities affiliated with Anadarko Petroleum Corporation, or Anadarko, in the Vernon and Ansley fields located in Jackson Parish, Louisiana for approximately $1.5 billion in cash, net of final purchase price adjustments. The Vernon Acquisition was funded by a $1.75 billion capital contribution from EXCO to EXCO Operating. The capital contribution consisted of $1.67 billion in cash and application of an $80.0 million deposit paid by EXCO to Anadarko in December 2006.

On May 2, 2007, we completed the purchase of oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009, from entities affiliated with Anadarko in multiple fields primarily located in Oklahoma, Texas and Louisiana for approximately $761.1 million in cash, including net purchase price adjustments, or the Southern Gas Acquisition. The Southern Gas Acquisition was funded with cash on hand of $145.2 million, including $133.0 million from escrow accounts from prior sales, borrowings under the EXCO Resources credit agreement of $572.9 million and the application of a $43.0 million deposit paid by EXCO to Anadarko in February 2007.

On October 9, 2007, we closed the acquisition of an additional 45% interest in 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand field in West Texas for $155.0 million from private sellers.

In addition to the acquisitions detailed above, the following sales transactions occurred during 2007:

On January 5, 2007, we completed the sale of oil and natural gas properties and undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, or the Wattenberg Field, for approximately $130.9 million in cash, net of contractual adjustments. The transaction included substantially all of the assets EXCO held in the area. Proceeds from the sale were deposited with a third party intermediary pending closing of the Southern Gas Acquisition to facilitate a like-kind exchange for federal income tax purposes.

On May 8, 2007, we completed the Gulf Coast Sale, which included oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson for an aggregate sale price of $241.9 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock. In connection with the closing of the Gulf Coast Sale, the borrowing base on the EXCO Resources credit agreement was reduced from $1.0 billion to $900.0 million. On August 15, 2007, we sold the 750,000 shares of unregistered restricted common stock of Crimson for an aggregate sales price of approximately $5.2 million. We recorded a gain of $0.7 million on the sale, which is included in other income for the year ended December 31, 2007.

On July 13, 2007, we completed the sale of substantially all of our interest in the Cement Field, located in Caddo and Grady Counties Oklahoma, in our Mid-Continent area for approximately $99.7 million, after contractual purchase price adjustments. Proceeds from this sale were deposited with a third party intermediary pending closing of assets purchased in West Texas in October 2007.

No gain or loss was recognized from these sales since we use the full cost method of accounting and the sales did not represent a significant divestiture resulting in a significant alteration to our depletion rate or Proved Reserves.

5. Derivative financial instruments

Our objective in entering into derivative financial instruments is to manage exposure to commodity price and interest rate fluctuations, protect our returns on investments, and achieve a more predictable cash flow in connection with our acquisition activities and borrowings related to these activities. These transactions limit exposure to declines in prices or increases in interest rates, but also limit the benefits we would realize if prices increase or interest rates decrease. When prices for oil and natural gas or interest rates are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense due to changes in the fair value of our derivative financial instrument contracts. Cash charges or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration.

We account for our derivative financial instruments in accordance with FASB ASC Topic 815. ASC 815 requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. ASC 815 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes, and, as a result, we recognize the change in the respective instruments' fair value currently in earnings. In accordance with FASB ASC Section 815-10-65, the table below outlines the location of our derivative financial instruments on our condensed consolidated balance sheets and their financial impact in our condensed consolidated statement of operations.

Fair Value of Derivative Financial Instruments

(in thousands)	Balance Sheet location	December 31, 2009	December 31, 2008
Commodity contracts	Derivative financial instruments—Current assets	$138,120	$247,614
Commodity contracts	Derivative financial instruments—Long-term assets	34,677	173,003
Commodity contracts	Derivative financial instruments—Current liabilities	(1,246)	(2,734)
Commodity contracts	Derivative financial instruments—Long-term liabilities	(11,688)	(11,585)
Interest rate contracts	Derivative financial instruments—Current liabilities	(2,018)	(8,873)
Interest rate contracts	Derivative financial instruments—Long-term liabilities	—	(1,005)
Net derivatives		$157,845	$396,420

The Effect of Derivative Financial Instruments

(in thousands)	Statement of Operations location	Year ended December 31, 2009	2008	2007
Commodity contracts(1)	Gain on derivative financial instruments	$232,025	$384,389	$26,807
Interest rate contracts(2)	Interest expense	(4,319)	(9,290)	—
Net gain		$227,706	$375,099	$26,807

(1) Included in these amounts are cash settlements, including net cash receipts of $478.5 million and $108.4 million for the year ended December 31, 2009 and 2007, respectively and net cash payments of $109.3 million for the year ended December 31, 2008.

(2) Included in these amounts are cash settlements, including net cash payments of $12.2 million for the year ended December 31, 2009, and net cash receipts of $0.6 million for the year ended December 31, 2008.

Settlements in the normal course of maturities of our derivative financial instrument contracts result in cash receipts from or cash disbursement to our derivative contract counterparties. Changes in the fair value of our derivative financial instrument contracts are included in income currently with a corresponding increase or decrease in the balance sheet fair value amounts. Unrealized fair value adjustments included in Gain (loss) on derivative financial instruments on the Consolidated Statements of Operations, which do not impact cash flows, were losses of $246.5 million and $81.6 million for the years ended December 31, 2009 and December 31, 2007, respectively, and a gain of $493.7 million for the year ended December 31, 2008. Unrealized fair value adjustments included in Interest expense on the Consolidated Statements of Operations, which do not impact cash flows, were a gain of $7.9 million for the year ended December 31, 2009 and a loss of $9.9 million for the year ended December 31, 2008.

We place our derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with our counterparties on our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty. As of December 31, 2009 and December 31, 2008, we had a net asset position of $157.8 million and $396.4 million, respectively.

Fair value measurements

We value our derivatives according to FASB ASC Topic 820 for Fair Value Measurements and Disclosures, which defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. This fair value may be different from the settlement value based on company-specific inputs, such as credit rating, futures markets and forward curves, and readily available buyers or sellers for such assets or liabilities.

We prioritize the inputs used in measuring fair value into a three-tier fair value hierarchy. These tiers include:

Level 1—Observable inputs, such as quoted market prices in active markets, for substantially identical assets and liabilities.

Level 2—Observable inputs other than quoted prices within *Level 1* for similar assets and liabilities. These include quoted prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. If the asset or liability has a specified or contractual term, the input must be observable for substantially the full term of the asset or liability.

Level 3—Unobservable inputs that are supported by little or no market activity, generally requiring development of fair value assumptions by management.

The following presents a summary of the estimated fair value of our derivative financial instruments for the years ended December 31, 2009 and 2008:

(in thousands)	For the year ended December 31, 2009			
	Level 1	Level 2	Level 3	Total
Oil and natural gas derivative financial instruments	$—	$159,863	$—	$159,863
Interest rate swaps	—	(2,018)	—	(2,018)
	$—	$157,845	$—	$157,845

(in thousands)	For the year ended December 31, 2008			
	Level 1	Level 2	Level 3	Total
Oil and natural gas derivative financial instruments	$—	$406,298	$—	$406,298
Interest rate swaps	—	(9,878)	—	(9,878)
	$—	$396,420	$—	$396,420

In accordance with FASB ASC Section 815-10-45 for the Scope Section of Subtopic 815-10 for Derivatives and Hedging, we value derivative assets and liabilities considering the effects of master netting agreements with the derivative counterparties, but report them gross on the Condensed Consolidated Balance Sheets. Net derivative asset values are determined, in part by utilization of the derivative counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined, in part, by utilization of our credit-adjusted risk-free rate curve. The credit-adjusted risk-free rates of our counterparties are based on an independent market-quoted credit default swap rate curve for the counterparties' debt plus the London Interbank Offered Rate, or LIBOR, curve as of the end of the reporting period. Our credit-adjusted risk-free rate is based on the blended rate of independent market-quoted credit default swap rate curves for companies that have the same credit rating as us plus the LIBOR curve as of the end of the reporting period.

Oil and natural gas derivatives

Our commodity price derivatives represent oil and natural gas swap, natural gas basis swap and natural gas collar contracts. We have classified our oil and natural gas swaps and their related fair value tier as Level 2.

Oil derivatives. Our oil derivatives are swap contracts for notional Bbls of oil at fixed NYMEX West Texas Intermediate (WTI) oil prices. The asset and liability values attributable to our oil derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil, (iii) the applicable estimated credit-adjusted risk-free rate curve, as described above.

Natural gas derivatives. Our natural gas derivatives are swap contracts for notional Mmbtus of gas at posted price indexes, including NYMEX Henry Hub (HH) swap contracts. The asset and liability values attributable to our natural gas derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH for natural gas swaps and PEPL index quotes for our existing basis swaps and (iii) the applicable credit-adjusted risk-free rate curve, as described above.

The following table presents our financial assets and liabilities for oil and natural gas derivative financial instruments measured at fair value as of December 31, 2009:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2009
Natural gas:			
Swaps:			
2010	64,473	$ 7.71	$122,432
2011	12,775	7.48	14,305
2012	5,490	5.91	(3,153)
2013	5,475	5.99	(3,350)
2014	—		—
Total natural gas	88,213		130,234
Oil:			
Swaps:			
2010	447	114.96	14,442
2011	456	116.00	13,337
2012	92	109.30	1,850
2013	—	—	—
2014	—	—	—
Total oil	995		29,629
Total oil and natural gas derivatives			$159,863

At December 31, 2008, we had outstanding derivative contracts covering 168,658 Mmcf of natural gas and 4,335 Mbbls of oil. At December 31, 2009, the average forward NYMEX natural gas price per Mmbtu for calendar 2010 and 2011 was $5.79 and $6.34, respectively, and the average forward NYMEX oil prices per Bbl for calendar 2010 and 2011 was $82.32 and $86.10, respectively.

Our derivative financial instruments covered approximately 83.0% and 79.7% of our total equivalent Mcfe production for the years ended December 31, 2009 and December 31, 2008, respectively.

Interest rate swaps

In January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal of our credit agreements through February 14, 2010 at LIBOR ranging from 2.45% to 2.8%. The net derivative liability value attributable to our interest rate derivative contracts as of the end of the reporting period are based on (i) the contracted notional amounts, (ii) forward active market-quoted LIBOR yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. We have classified our interest rate swaps and their related fair value tier as Level 2.

During the twelve months ended December 31, 2009 and 2008, we recognized increases of $4.3 million and $9.3 million in interest expense related to our interest rate swaps. As of December 31, 2009 and December 31, 2008, the fair value of our interest rate swaps was a liability of $2.0 million and $9.9 million, respectively.

Fair value of other financial instruments

Our financial instruments include cash and cash equivalents, accounts receivable and payable, current portion of debt and accrued liabilities. The carrying amount of these instruments approximates fair value because of their short-term nature.

The estimated fair value of our 7 1/4% senior notes due January 15, 2011, or Senior Notes, is $445.8 million with a carrying amount of $448.7 million as of December 31, 2009. The estimated fair value was $344.7 million with a carrying amount of $452.3 million as of December 31, 2008. The estimated fair value has been calculated based on market quotes.

6. Long-term debt

(in thousands)	December 31, 2009	December 31, 2008
EXCO Resources Credit Agreement	$ 81,486	$1,048,951
EXCO Operating Credit Agreement	666,078	1,218,485
Term Credit Agreement	—	300,000
7 1/4% senior notes due 2011	444,720	444,720
Unamortized premium on 7 1/4% senior notes due 2011	3,993	7,582
Total debt	$1,196,277	$3,019,738

Credit agreements

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement, pursuant to the fifth amendment effective on October 2, 2009, has a borrowing base of $450.0 million with commitments spread among a consortium of banks, none of which have commitments exceeding 10% of the aggregate commitment amount. The borrowing base is redetermined semi-annually, with EXCO and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are made on or about April 1 and October 1 of each year. Borrowings under the EXCO Resources Credit Agreement are collateralized by a first lien mortgage providing a security interest in our oil and natural gas properties. EXCO may have in place derivative financial instruments covering no more than 80% of its forecasted production from total Proved Reserves (as defined) for each of the first two years of the five year period commencing on the date of incurrence on each new derivative financial instrument and 70% of the forecasted production from total Proved Reserves for each of the third through fifth years of the five year period thereafter. EXCO is required to have mortgages in place covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The EXCO Resources Credit Agreement matures on March 30, 2012.

The fifth amendment to the EXCO Resources Credit Agreement, among other things, modified the terms and conditions under which EXCO is permitted to pay a cash dividend on its common stock. Pursuant to the fifth amendment, EXCO may declare and pay cash dividends on its common stock in an amount not to exceed $50.0 million in any four consecutive fiscal quarters, provided that as of each payment date and after giving effect to the dividend payment date, (i) no default has occurred and is continuing, (ii) EXCO has at least 10% of its borrowing base available under the EXCO Resources Credit Agreement, and (iii) payment of such dividend is permitted under EXCO's 7 1/4% Senior Notes Indenture.

The EXCO Resources Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The interest rate ranges from LIBOR plus 175 basis points, or bps, to LIBOR plus 250 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 75 bps to ABR plus 150 bps depending upon borrowing base usage.

On December 31, 2009, we had $81.5 million of outstanding indebtedness and $353.3 million of available borrowing capacity under the EXCO Resources Credit Agreement. On December 31, 2009, the one month LIBOR was 0.23%, which would result in an interest rate of approximately 1.98% on any new indebtedness we may incur under the EXCO Resources Credit Agreement.

As of December 31, 2009, EXCO was in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a consolidated current ratio (as defined) of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- not permit our ratio of consolidated funded indebtedness (as defined) to consolidated EBITDAX (as defined) to be greater than (i) 4.0 to 1.0 at the end of any fiscal quarter ending on or after December 31, 2008 up to and including December 31, 2009, (ii) 3.75 to 1.0 at the end of the fiscal quarter ending on March 31, 2010 and (iii) 3.50 to 1.0 beginning with the quarter ending June 30, 2010 and each quarter end thereafter; and

- maintain a consolidated EBITDAX to consolidated interest expense (as defined) ratio of at least 2.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Resources Credit Agreement.

EXCO Operating Credit Agreement

The EXCO Operating Credit Agreement, as amended, currently has a borrowing base of $850.0 million with commitments spread among a consortium of banks, none of which have commitments exceeding 10% of the aggregate commitment amount. The borrowing base is redetermined semi-annually, with EXCO Operating and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are made on or about April 1 and October 1 of each year. The EXCO Operating Credit Agreement is secured by a first priority lien on the assets of EXCO Operating, including 100% of the equity of EXCO Operating's subsidiaries, and is guaranteed by all existing and future subsidiaries of EXCO Operating. EXCO Operating may have in place derivative financial instruments covering no more than 80% of the forecasted production from total Proved Reserves (as defined) for each of the first two years of the five year period commencing on the date of incurrence on each new derivative financial instrument and 70% of the forecasted production from total Proved Reserves for each of the third through fifth years of the five year period thereafter. EXCO Operating is required to have mortgages in place covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The EXCO Operating Credit Agreement matures on March 30, 2012.

On October 16, 2009, the lenders agreed to consents which (i) confirmed the borrowing base under the EXCO Operating Credit Agreement at $850.0 million until the next borrowing base redetermination date, (ii) provided for EXCO Operating to grant to lenders a first priority lien and security interest in all of its equity interest in TGGT, representing EXCO Operating's retained 50% interest in the midstream assets contributed in connection with the BG Midstream Transaction, and (iii) by November 30, 2009, consummate transactions to unwind oil and natural gas derivatives with respect to notional volumes of oil and natural gas with respect to sold production volumes which had been waived by a July 29, 2009 consent, and with regard to items (ii) and (iii) have been completed as required.

The EXCO Operating Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The interest rate under the EXCO Operating Credit Agreement ranges from LIBOR plus 175 bps to LIBOR plus 250 bps depending upon borrowing base usage. The facility also includes an ABR pricing alternative ranging from ABR plus 75 bps to ABR plus 150 bps depending upon borrowing base usage.

On December 31, 2009, we had $666.1 million of outstanding indebtedness and $183.9 million available borrowing capacity under the EXCO Operating Credit Agreement. At December 31, 2009, the one month LIBO rate was 0.23%, which would result in an interest rate of approximately 2.48% on any new indebtedness we may incur under the EXCO Operating Credit Agreement.

As of December 31, 2009, EXCO Operating was in compliance with the financial covenants contained in the EXCO Operating Credit Agreement, which require that EXCO Operating:

- maintain a consolidated current ratio (as defined) of at least 1.0 to 1.0 at the end of any fiscal quarter, beginning with the quarter ended September 30, 2007;

- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined) to be greater than 3.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended September 30, 2007; and

- not permit our interest coverage ratio (as defined) to be less than 2.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended September 30, 2007.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Operating Credit Agreement.

Term Credit Agreement.

On December 8, 2008, EXCO Operating entered into the Term Credit Agreement with an aggregate balance of $300.0 million. Net proceeds from the loan of $274.4 million, after bank fees and expenses, were used to repay and terminate an original $300.0 million senior unsecured term credit agreement that was scheduled to mature on December 15, 2008. In addition to the fees incurred upon the closing of the Term Credit Agreement, EXCO Operating provided for additional fees on unpaid principal amounts, or duration fees, as defined in the agreement. These included a 5% fee on the unpaid principal on June 15, 2009 and an additional 3% fee on any unpaid outstanding balance as of September 15, 2009. On June 15, 2009 we remitted the first duration fee payment of $15.0 million.

In connection with the closings of the BG Upstream Transaction, the BG Midstream Transaction and the East Texas Transaction, EXCO Operating repaid the outstanding $300.0 million under the Term Credit Agreement. As a consequence of the early payment of the Term Credit Agreement, EXCO Operating avoided payment of a $9.0 million duration fee that would have been due on September 15, 2009.

The unamortized balance of deferred financing costs attributable to the Term Credit Agreement of approximately $9.9 million was written off and is included in interest expense in the year ended December 31, 2009.

7¼% senior notes due January 15, 2011

As of December 31, 2009, $444.7 million in principal was outstanding on our Senior Notes. The unamortized premium on the Senior Notes at December 31, 2009 was $4.0 million. The estimated fair value of the Senior Notes, based on quoted market prices for the Senior Notes, was $445.8 million on December 31, 2009.

Interest is payable on the Senior Notes semi-annually in arrears on January 15 and July 15 of each year. Effective January 15, 2007, we may redeem some or all of the Senior Notes for the redemption price set forth in the Senior Notes. On January 15, 2010, we paid $16.1 million of interest on the Senior Notes. Another interest payment of $16.1 million will be due on July 15, 2010.

The indenture governing the Senior Notes contains covenants, which limit our ability and the ability of our guarantor subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred stock;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated debt;
- make investments;
- create liens on our assets;
- enter into sale/leaseback transactions;
- create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- engage in transactions with our affiliates;
- transfer or issue shares of stock of subsidiaries;
- transfer or sell assets; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

7. Preferred stock

On March 30, 2007, we issued Series A-1, Series B and Series C 7.0% Cumulative Convertible Perpetual Preferred Stock, or the 7.0% Preferred Stock and Series A-1 Hybrid Preferred Stock, or the Hybrid Preferred Stock, and together with the 7.0% Preferred Stock, the Preferred Stock, in several series at a purchase price of $10,000 per share. On July 18, 2008, we converted all outstanding shares of our Preferred Stock into a total of approximately 105.2 million shares of our common stock. The conversion of the Preferred Stock had the effect of increasing the book value of shareholders' equity by approximately $2.0 billion. We paid all accrued but unpaid dividends in cash totaling approximately $12.8 million to the holders of the converted shares of Preferred Stock as of July 18, 2008. After July 18, 2008, dividends ceased to accrue on the Preferred Stock and all rights of the holders with respect to the Preferred Stock terminated, except for the right to receive the whole shares of common stock issuable upon conversion, accrued dividends through July 18, 2008 and cash in lieu of any fractional shares.

We paid cash dividends totaling $82.8 million to the holders of our Preferred Stock from January 1, 2008 through July 18, 2008, the date upon which the preferred stock was converted into our common stock.

8. Environmental regulation

Various federal, state and local laws and regulations covering discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our operations and the costs of our oil and natural gas exploitation, development and production operations. We do not anticipate that we will be required in the foreseeable future to expend amounts material in relation to the financial statements taken as a whole by reason of environmental laws and regulations. Because these laws and regulations are constantly being changed, we are unable to predict the conditions and other factors over which we do not exercise control that may give rise to environmental liabilities affecting us.

9. Commitments and contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $28.1 million, $21.3 million and $8.8 million for the years ended December 31, 2009, 2008, and 2007, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2009, are as follows:

(in thousands)	Firm Transportation and other	Operating Leases	Drilling Contracts	Total
2010	$ 40,570	$ 7,357	$51,438	$ 99,365
2011	35,300	6,173	27,830	69,303
2012	34,248	5,288	9,825	49,361
2013	36,075	5,041	—	41,116
2014	35,591	5,022	—	40,613
Thereafter	199,515	4,329	—	203,844
Total	$381,299	$33,210	$89,093	$503,602

We entered into firm transportation agreements in August 2009 with an independent pipeline company which commits us to ship 237,500 Mmbtu's per day for a period of ten years in the East Texas/North Louisiana area. The commitment becomes effective upon completion of the construction of the shipper's pipeline.

In the ordinary course of business, we are periodically a party to lawsuits. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition.

10. Employee benefit plans

At December 31, 2009, we sponsored a 401(k) plan for our employees and matched 100% of employee contributions. Our matching contributions were $7.0 million, $6.1 million and $2.6 million for the years ended December 31, 2009, 2008 and 2007. Prior to 2008, we sponsored two 401(k) plans with different matching terms. Our separate plans were combined effective January 1, 2008.

11. Earnings per share

We account for earnings per share in accordance with FASB ASC Subtopic 260-10 for Earnings Per Share. ASC 260-10 requires companies to present two calculations of earnings per share; basic and diluted. Basic loss per share for the years ended December 31, 2009, 2008 and 2007 equals the net loss available to common shareholders divided by the weighted average common shares outstanding during the period. Common shares resulting from the conversion of our Preferred Stock on July 18, 2008 are included in the weighted average common shares for the years ended December 31, 2009 and 2008. Diluted loss per common share for the year ended December 31, 2009, 2008 and 2007 is computed in the same manner as basic earnings per share after assuming issuance of common stock for all potentially dilutive common stock equivalents, including our Preferred Stock for the years ended 2008 and 2007, whether exercisable or not. Since we incurred net losses for the years ended 2009, 2008 and 2007, we have excluded the potential common stock equivalents from the assumed conversion of stock options of 14,729,424, 12,578,968, and 9,206,970 respectively. We have also excluded 57,097,494 and 105,263,158 shares of common stock equivalents from the assumed conversion of the Preferred Stock from the computation of earnings per share for the years ended December 31, 2008 and 2007, respectively, as they were antidilutive.

The following table presents basic and diluted earnings (loss) per share for the years ended December 31, 2009, 2008 and 2007 (in thousands, except per share amounts):

	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Basic and diluted loss per share:			
Net loss available to common shareholders	$(496,804)	$(1,810,468)	$(83,312)
Shares:			
Weighted average number of common shares outstanding	211,266	153,346	104,364
Basic and diluted loss per share:			
Total basic earnings per share	$ (2.35)	$ (11.81)	$ (0.80)

12. Stock options

We account for stock options in accordance with FASB ASC Topic 718 for Compensation—Stock Compensation. As required by ASC 718, the granting of options to our employees under our 2005 Incentive Plan are share-based payment transactions and are treated as compensation expense by us with a corresponding increase to additional paid-in capital.

The 2005 Incentive Plan, as amended, provides for the granting of options to purchase up to 23,000,000 shares of EXCO's common stock. The options expire ten years following the date of grant and have a weighted average remaining life of 7.6 years. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of the grant. We generally grant incentive stock options.

On June 4, 2009, our shareholders approved an amendment to the 2005 Incentive Plan to increase the number of shares authorized for issuance by an additional 3,000,000 shares. As of December 31, 2009 and 2008, there were 3,920,100 and 3,342,450 shares available to be granted under the 2005 Incentive Plan, respectively.

The following table summarizes stock option activity related to our employees under the 2005 Incentive Plan:

	Stock options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
Options outstanding at December 31, 2006	8,267,373	$10.32		
Granted	4,951,700	14.94		
Forfeitures	399,600	13.83		
Exercised	416,700	9.99		
Options outstanding at December 31, 2007	12,402,773	12.06		
Granted	4,079,000	13.21		
Forfeitures	399,075	15.57		
Exercised	1,119,383	13.20		
Options outstanding at December 31, 2008	14,963,315	12.20		
Granted	3,072,650	17.05		
Forfeitures	650,300	15.32		
Exercised	931,371	11.12		
Options outstanding at December 31, 2009	16,454,294	$13.04	7.63	$139,077,030
Options exercisable at December 31, 2009	11,521,563	$12.14	7.01	$107,116,729

The weighted average grant date fair value of stock options granted during the years 2009, 2008 and 2007 were $9.67, $6.02 and $5.43, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2009, 2008 and 2007 was $5.3 million, $11.4 million and $2.9 million, respectively.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. Options are granted at the fair market value of the common stock on the date of grant. The following assumptions were used for the options included in the table below:

	2009	2008	2007
Expected life	7.5–8.5 years	5–8.5 years	4–6 years
Risk-free rate of return	2.33%–3.57%	1.71%–3.33%	3.28%–4.97%
Volatility	53.87%–55.61%	34.17%–55.26%	35.67%–37.72%
Dividend yield	0.568%–0.652%	0%	0%

In connection with certain divestures, we accelerated the vesting of a number of employee stock options on the date of the employee's termination and extended their exercise terms to one year from date of termination. We recognized $1.5 million in additional compensation expense related to the modification of options terms, $1.2 million of which would have been recognized over the remaining life of the options had they not be accelerated. The underlying stock price on the dates of modification ranged from $16.35 to $17.13 and the exercise prices of the options accelerated ranged from $6.33 to $38.01.

Expected life was determined based on EXCO's exercise history, as well as comparable public companies. Risk-free rate of return is a rate of a similar term U.S. Treasury zero coupon bond. Volatility was determined based on the weighted average of historical volatility of our common stock and the daily closing prices from comparable public companies.

The following is a reconciliation of our stock option expense for the years ended December 31, 2009, 2008 and 2007:

(in thousands)	Year ended December 31, 2009	2008	2007
General and administrative expense	$16,156	$11,804	$ 9,041
Lease operating expense	2,831	4,174	3,591
Total share-based compensation expense	18,987	15,978	12,632
Share-based compensation capitalized	5,066	4,060	2,410
Total share-based compensation	$24,053	$20,038	$15,042

The total tax benefit for the years ended December 31, 2009, 2008 and 2007 was $1.1 million, $1.7 million and $1.1 million, respectively. Total share-based compensation to be recognized on unvested awards is $30.5 million over a weighted average period of 1.45 years as of December 31, 2009.

13. Income taxes

The income tax provision attributable to our income (loss) before income taxes consists of the following:

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Current:			
U.S.			
Federal	$ —	$ —	$ (6,075)
State	(130)	252	—
Total current income tax (benefit)	(130)	252	(6,075)
Deferred:			
U.S.			
Federal	(130,740)	(693,391)	61,748
State	(20,606)	(88,266)	4,423
Valuation allowance	141,975	526,372	—
Total deferred income tax (benefit)	(9,371)	(255,285)	66,171
Total income tax (benefit)	$ (9,501)	$(255,033)	$60,096

We have net operating loss carryforwards, or NOLs, for United States income tax purposes that have either been generated from our operations or were purchased in our acquisitions. Our NOLs are scheduled to expire if not utilized between 2010 and 2029. Our ability to use the purchased NOLs has been restricted by Section 382 of the Internal Revenue Code due to ownership changes which occurred on various dates between December 19, 1997 and October 3, 2005. In addition, we experienced a change in control on August 30, 2007 based upon the transformation of the Hybrid Preferred Stock to the same terms as the 7.0% Preferred Stock, but the result was no limitation on 2007 NOLs. We estimate that approximately $9.7 million of the NOLs limited by Section 382 and $9.3 million of foreign tax credit carryforwards will expire prior to their utilization. Our total NOL available for utilization at December 31, 2009 is approximately $808.9 million.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax liabilities and assets are as follows:

(in thousands)	December 31, 2009	December 31, 2008
Current deferred tax assets (liabilities):		
Basis difference in fair value of derivative financial instruments	$ —	$ —
Total current deferred tax assets (liabilities)	—	—
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards—U.S	316,867	161,574
Purchase accounting adjustment to bond premium	3,206	6,314
Share-based compensation	6,592	4,150
Foreign tax credit carryforwards	9,336	9,336
Tax basis of oil and natural gas properties in excess of book basis	770,598	706,166
Tax basis of deductible tax goodwill in excess of book basis	11,783	—
Other	84	103
Total long-term deferred tax assets	1,118,466	887,643
Valuation allowance	(677,683)	(535,708)
Net total non-current deferred tax assets	440,783	351,935
Non-current deferred tax liabilities:		
Book basis of gathering and other properties in excess of tax basis	(331,000)	(216,591)
Book basis of investment in partnership in excess of tax basis	(60,557)	—
Basis difference in fair value of derivative financial instruments	(49,226)	(135,344)
Basis of temporary goodwill	—	(9,371)
Total non-current deferred liabilities	(440,783)	(361,306)
Net total non-current deferred tax assets (liabilities)	$ —	$ (9,371)

A reconciliation of our income tax provision (benefit) computed by applying the statutory United States federal income tax rate to our income (loss) before income taxes for the years ended December 31, 2009, 2008 and 2007 is presented in the following table:

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008	Year ended December 31, 2007
United States federal income taxes (benefit) at statutory rate of 35%	$(177,207)	$(695,977)	$38,413
Increases (reductions) resulting from:			
Goodwill	43,455	—	—
Adjustments to the valuation allowance	141,975	526,372	9,336
Non-deductible compensation	2,808	2,321	3,144
State tax rate change	—	—	3,078
State taxes net of federal benefit	(20,606)	(88,266)	4,423
Other	74	517	1,702
Total income tax provision (benefit)	$ (9,501)	$(255,033)	$60,096

During 2009, our income tax rate was impacted by the recognition of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets and divestitures of properties.

During 2008, our income tax rate was impacted by the establishment of a valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets. Our deferred tax assets were offset by valuation allowances after testing to determine if the asset would meet a more likely than not criteria for realization pursuant to FASB ASC Topic 740- Income Taxes.

During 2007, our income tax rate was impacted by the substitution of a current federal net operating loss carryback for previously claimed foreign tax credits resulting from the 2005 sale of our Canadian subsidiary. The impact, net of a federal refund of $6.1 million, was an $11.0 million non-cash expense, principally related to foreign tax credits which are required since we no longer have any foreign operations.

Also, as a result of our 2007 acquisitions, our state effective rate increased which required us to change the rate in which we record our deferred tax assets and liabilities. This amount was recognized in our 2007 income tax expense as a current period expense and is presented as part of the Other line item in the above table.

The Company adopted the provisions of FASB ASC Subtopic 740-10 for Income Taxes on January 1, 2007. As a result of the implementation of ASC Subtopic 740-10, the Company recognized zero liabilities for unrecognized tax benefits. As of December 31, 2009, 2008 and 2007, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the current financials.

EXCO files income tax returns in the U.S. federal jurisdictions and various state jurisdictions. With few exceptions, EXCO is no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2004. The Internal Revenue Service, or IRS, completed its examination of EXCO's 2004 U.S. federal income tax return in January 2008. The result of the audit was an adjustment between U.S. and our Canadian subsidiary for a hedge recorded to the wrong entity. There was no material change to EXCO's financial position.

14. Related party transactions

Corporate use of personal aircraft

We periodically charter, for company business, two jet aircraft from DHM Aviation, LLC, a company owned by Douglas H. Miller, our chairman and chief executive officer. The Board of Directors has adopted a written policy covering the use of these aircraft. The Company believes that prudent use of a chartered private airplane by our senior management while on company business can promote efficient use of management time. Such usage can allow for unfettered, confidential communications among management during the course of the flight and minimize airport commuting and waiting time, thereby promoting maximum use of management time for company business. However, we restrict the use of the aircraft to priority company business being conducted by senior management in a manner that is cost effective for us and our shareholders. As a result, EXCO's reimbursed use of the aircraft is restricted to travel that is integrally and directly related to performing senior management's jobs. Such use must be approved in advance by our President and Chief Financial Officer. We maintain a detailed written log of such usage specifying the company personnel (and others, if any) that fly on the aircraft, the travel dates and destination(s), and the company business being conducted. In addition, the log contains a detail of all charges paid or reimbursed by us with supporting written documentation.

In the event the aircraft is chartered for a mixture of company business and personal use, all charges will be reasonably allocated between company-reimbursed charges and charges to the person using the aircraft for personal use.

At least annually, and more frequently if requested by the Audit Committee, our Director of Internal Audit surveys fixed base operators and other charter operators located at Dallas Love Field, Dallas, Texas to ascertain hourly flight rates for aircraft of comparable size and equipment in relation to the aircraft. This survey also ascertains other charges (including fuel surcharges) invoiced by such charter operators as well as out-of-pocket reimbursement policies. Such survey is supplied to the Audit Committee in order for the Audit Committee to establish an hourly rate and other charges EXCO shall pay for the upcoming calendar year for the use of the aircraft. In addition, DHM Aviation, LLC is reimbursed for customary out-of-pocket catering expenses invoiced for a flight and any reimbursement of out-of-pocket expenses incurred by the pilots.

During 2007, DHM Aviation, LLC purchased an additional, larger used jet aircraft. Based upon a national survey of corporate aircraft charter rates, in August 2007, the Board of Directors approved a rate of $5,700 per flight hour plus $600 per flight hour fuel surcharge for the larger aircraft, which was utilized in 2008 and 2007. In August 2009, the Audit Committee approved a rate of $5,400 per flight hour plus a $400 per flight hour surcharge. The Audit Committee also approved an hourly rate on the smaller aircraft of $3,700 per flight hour plus a $400 per flight hour surcharge. The rate for the smaller aircraft was $3,600 per hour, including fuel surcharges, in 2008 and 2007.

Payments to DHM Aviation, LLC for the year ended December 31, 2009, 2008 and 2007 aggregated $1.1 million, $0.8 million and $0.5 million, respectively, for use of these aircraft.

Private Placement of Preferred Stock

As discussed in Note 7. Preferred stock, on March 30, 2007, we completed the Private Placement of an aggregate of $390.0 million of 7.0% Preferred Stock and $1.61 billion of Hybrid Preferred Stock to accredited investors pursuant to the terms and conditions of a Preferred Stock Purchase Agreement dated March 28, 2007. The following related persons participated in the transaction:

- Entities affiliated with Ares Management LLC, or Ares, purchased 2,925 shares of Series C 7.0% Preferred Stock and 12,075 shares of Series A-1 Hybrid Preferred Stock for $150.0 million. Prior to the Private Placement, Ares beneficially owned approximately 6.3% of our outstanding common stock. Jeffrey S. Serota, one of our directors, is a Managing Director of Ares. Mr. Serota was designated to our Board of Directors by Ares pursuant to the terms of the Series C 7.0% Preferred Stock.
- Entities affiliated with Oaktree Capital Management, L.P., or Oaktree, purchased 11,700 shares of Series B 7.0% Preferred Stock and 48,300 shares of Series A-1 Hybrid Preferred Stock for $600.0 million. Prior to the Private Placement, Oaktree beneficially owned approximately 3.1% of our outstanding common stock. Vincent J. Cebula, one of our directors, was a Managing Director of Oaktree until October 31, 2007. Mr. Cebula was originally designated to our Board of Directors by Oaktree pursuant to the terms of the Series B 7.0% Preferred Stock. On October 31, 2007, Mr. Cebula resigned from Oaktree and subsequently joined Jefferies Capital Partners. Since Mr. Cebula resigned from Oaktree, he also resigned as the Series B Preferred Stock director effective December 1, 2007 and was replaced by B. James Ford, a Managing Director of Oaktree. Mr. Cebula remains on our Board of Directors and served in one of the four board seats reserved for the Preferred Stock.
- Entities affiliated with Greenhill Capital Partners, LLC purchased 1,463 shares of Series A-1 7.0% Preferred Stock and 6,037 shares of Series A-1 Hybrid Preferred Stock for $75.0 million. Prior to the Private Placement, Greenhill beneficially owned approximately 2.2% of our outstanding common stock. Robert H. Niehaus, one of our directors at the time, is a Senior Member of GCP 2000, LLC and Managing Director of Greenhill Capital Partners, LLC, which control the general partners of Greenhill Capital Partners, L.P. and its affiliated investment funds.
- Entities affiliated with FMR Corp. purchased 1,952 shares of Series A-1 7.0% Preferred Stock and 8,048 shares of Series A-1 Hybrid Preferred Stock for $100.0 million. Prior to the Private Placement, FMR Corp. beneficially owned approximately 7.0% of our outstanding common stock.

In connection with the Private Placement, we entered into a letter agreement, dated March 28, 2007, with Oaktree pursuant to which we agreed to cause an individual designated by Oaktree to be nominated to serve on our Board of Directors following such time as (i) Oaktree ceases to have the right to elect a director to serve on our Board of Directors pursuant to the Statement of Designation for the Series B 7.0% Preferred Stock and

(ii) less than 25% of the shares of 7.0% Preferred Stock and Hybrid Preferred Stock originally issued on March 30, 2007 remain outstanding, and for so long as Oaktree owns at least 10,000,000 shares of our common stock (including, for this purpose, shares of common stock into which any Preferred Stock then held by Oaktree is convertible).

In connection with the Private Placement, we also entered into a letter agreement, dated March 28, 2007, with certain investors affiliated with Ares pursuant to which we agreed to cause an individual designated by Ares to be nominated to serve on our Board of Directors following such time as (i) Ares ceases to have the right to elect a director to serve on our Board of Directors pursuant to the Statement of Designation for the Series C 7.0% Preferred Stock and (ii) less than 25% of the shares of 7.0% Preferred Stock and Hybrid Preferred Stock originally issued on March 30, 2007 remain outstanding, for so long as Ares owns at least 10,000,000 shares of our common stock (including, for this purpose, shares of common stock into which any Preferred Stock then held by Ares is convertible).

For more information about the Private Placement, see "Note 7. Preferred stock."

Gulf Coast Sale

On May 8, 2007, we completed the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson, for an aggregate sale price of $241.9 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock, or the Gulf Coast Sale. The purchase price was negotiated on an arm's-length basis based upon customary industry metrics for acquisitions of oil and natural gas reserves. The purchase agreement for the Gulf Coast Sale contained customary representations, warranties and covenants. Crimson is a publicly-held company that is controlled by investment funds managed by Oaktree. At the time of the Gulf Coast Sale, one of our directors, Vincent J. Cebula was a managing director of Oaktree. B. James Ford, a managing director of Oaktree and a member of Crimson's board of directors, began serving on our Board of Directors on December 1, 2007.

On August 15, 2007, we entered into an agreement with funds managed by Oaktree to sell our 750,000 shares of Crimson's unregistered restricted common stock for an aggregate sales price of approximately $5.2 million.

Other

Penny Wilson, the spouse of Mark E. Wilson, our Vice President, Chief Accounting Officer and Controller, was retained by us from February 2007 to January 2008 as a consultant, through an independent consulting firm to perform accounting work related to our 2007 acquisitions. In addition to Ms. Wilson's base salary, she also received approximately $19,000 in bonus and commissions from the consulting firm, which were directly tied to her engagement at EXCO. During 2007, fees paid to the consulting firm for Ms. Wilson and other consultants totaled approximately $0.6 million.

Jeff Smith, the son of Stephen F. Smith, our Vice Chairman, President, Chief Financial Officer and one of our directors, owns a 50% interest in S&S Directional Drilling, LLC ("S&S"). One of EXCO's vendors, Select Energy Services, LLC ("Select"), and/or its affiliates subcontracts with S&S to provide equipment for use in connection with services provided by Select and/or its affiliates to EXCO. During 2009, S&S was paid approximately $0.8 million by Select and/or its affiliates for the use of equipment in connection with services provided to EXCO.

15. Segment information

We follow FASB ASC Topic 280 for Segment Reporting when reporting operating segments. Prior to the August 14, 2009 sale of a 50% interest in our midstream investment, as discussed below and in "Note 4. Divestures and Acquisitions," our reportable segments consisted of exploration and production and midstream. Our exploration and production operational segment and midstream segment were managed separately because of the nature of their products and services. The exploration and production segment is responsible for acquisition, development and production of oil and natural gas. The midstream segment was responsible for purchasing, gathering, transporting, processing and treating natural gas. We evaluated the performance of our operating segments based on segment profits, which included segment revenues, excluding the gain (loss) on derivative financial instruments, from external and internal customers and segment costs and expenses. Segment profit generally excluded income taxes, interest income, interest expense, unallocated corporate expenses, depreciation and depletion, asset retirement obligations, and gains and losses associated with ceiling test write-downs and asset sales, other income and expense, and income from equity investments.

As discussed in "Note 4. Divestures and Acquisitions," on August 14, 2009 we closed the BG Midstream Transaction and contributed TGG and Talco to TGGT. We received net sales proceeds of $269.2 million at closing, including preliminary closing adjustments. We own 50% of TGGT and now account for our interest using the equity method (see "Note 16. Equity investment").

As a result of this sale, we reviewed the criteria outlined in ASC 280-10, and determined that the midstream assets we retained, made up exclusively of the Vernon Field midstream assets, were not material and therefore, would no longer meet thresholds to be defined as a reportable segment. We also reviewed our equity investment in TGGT and concluded that it also would not be considered a reportable segment.

Summarized financial information concerning our reportable segments is shown in the following table. The reportable midstream segment for 2009 is effective from January 1, 2009 through August 13, 2009. The Vernon Field midstream assets operations are included in the Exploration and production segment effective August 14, 2009.

Summarized financial information concerning our reportable segments is shown in the following table:

(in thousands)	Exploration and production	Midstream	Intersegment eliminations	Consolidated total
For the year ended December 31, 2009:				
Third Party revenues	$ 550,505	$ 35,330	$ —	$ 585,835
Intersegment revenues	(20,356)	41,148	(20,792)	—
Total revenues	$ 530,149	$ 76,478	$(20,792)	$ 585,835
Segment profit	$ 333,560	$ 20,106	$ —	$ 353,666
For the year ended December 31, 2008:				
Third Party revenues	$1,404,826	$ 85,432	$ —	$1,490,258
Intersegment revenues	(32,296)	62,204	(29,908)	—
Total revenues	$1,372,530	$147,636	$(29,908)	$1,490,258
Segment profit	$1,120,253	$ 34,931	$ —	$1,155,184
For the year ended December 31, 2007:				
Third Party revenues	$ 875,787	$ 18,817	$ —	$ 894,604
Intersegment revenues	(20,959)	26,946	(5,987)	—
Total revenues	$ 854,828	$ 45,763	$ (5,987)	$ 894,604
Segment profit	$ 675,619	$ 23,487	$ —	$ 699,106
As of December 31, 2009:				
Capital Expenditures	$ 458,410	$ 53,122	$ —	$ 511,532
Goodwill	$ 269,656	$ —	$ —	$ 269,656
Total assets	$2,358,894	$ —	$ —	$2,358,894
As of December 31, 2008:				
Capital Expenditures	$ 934,141	$ 54,993	$ —	$ 989,134
Goodwill	$ 441,872	$ 28,205	$ —	$ 470,077
Total assets	$4,392,218	$430,134	$ —	$4,822,352

The following table reconciles the segment profits reported above to income (loss) before income taxes:

(in thousands)	Year ended December 31, 2009	2008	2007
Segment profits	$ 353,666	$ 1,155,184	$ 699,106
Depreciation, depletion and amortization	(221,438)	(460,314)	(375,420)
Write-down of oil and natural gas properties	(1,293,579)	(2,815,835)	—
Gain on divestures and other operating items	676,434	2,692	3,997
Accretion of discount on asset retirement obligations	(7,132)	(6,703)	(4,878)
General and administrative	(99,177)	(87,568)	(64,670)
Interest expense	(147,161)	(161,638)	(181,350)
Gain on derivative financial instruments	232,025	384,389	26,807
Other income	126	1,289	6,160
Equity method loss on TGGT Holdings, LLC	(69)	—	—
Income (loss) before income taxes	$ (506,305)	$(1,988,504)	$ 109,752

16. Equity investment

In connection with the sale of 50% of our interest in our midstream assets to BG Group, as discussed in Note 4. Divestitures and acquisitions and Note 15. Operating segments, TGGT now holds substantially all of our East Texas/North Louisiana midstream assets. Our 50% ownership interest in TGGT is accounted for under the equity method. As of December 31, 2009, our proportionate 50% interest in the $521.0 million of TGGT's equity, or $260.5 million, consists of our contribution of $158.2 million of net assets, representing 50% of the historical cost basis of net assets, plus $47.5 million of working capital contributions, a $55.5 million basis adjustment discussed below and our proportionate 50% share of TGGT's inception to date loss of $0.7 million. Our equity investment in TGGT exceeds our book value of assets by $44.1 million represented by a $55.5 million difference in the historical basis of our contribution and the fair value of BG Group's contribution offset by $11.4 million of goodwill included in our investment. The $55.5 million basis difference is being amortized over the estimated life of TGGT's assets.

The following table presents summarized financial information of TGGT:

(in thousands)	As of December 31, 2009
Assets	
Total current assets	$ 54,818
Property and equipment, net	509,501
Total assets	$564,319
Liabilities and members' equity	
Total current liabilities	$ 40,915
Total long term liabilities	2,393
Members' equity:	
Total members' equity	521,011
Total liabilities and members' equity	$564,319

	For the period of August 14, 2009 to December 31, 2009
Revenues	
Gas sales	$ 19,059
Condensate, shrinkage and loss revenues	3,762
Gathering, compression and other services	15,083
Total revenues	37,904
Costs and expenses:	
Gas purchases	18,556
Operating expenses	12,506
Depreciation expense	5,350
Other expenses	2,753
Total costs and expenses	39,165
Loss before taxes	(1,261)
Income tax expense	110
Net loss	$ (1,371)
EXCO's equity in TGGT loss before amortization	$ (686)
Amortization of the difference in the historical basis of our contribution	$ 617
EXCO's equity in TGGT loss after amortization	$ (69)

17. Dividends

On October 1, 2009 our Board of Directors approved the commencement of a dividend program with an initial quarterly cash dividend rate of $0.025 per share of EXCO's common stock. The first quarterly dividend of $0.025 per share was paid on October 26, 2009 to holders of record on October 12, 2009. The second quarterly dividend of $0.025 per share was paid on December 15, 2009 to holders of record on November 30, 2009. Any future declaration of dividends, as well as the establishment of record and payment dates, is subject to the approval of EXCO's Board of Directors.

18. Subsequent events

We have evaluated our activity after December 31, 2009 until the date of issuance, February 24, 2010, for recognized and unrecognized subsequent events not discussed elsewhere in these footnotes.

Pursuant to our joint development agreement with BG Group pursuant to the BG Upstream Transaction, we received $53.8 million in January 2010 representing reimbursements from BG Group for their 50% proportionate share of acreage and acquisitions within the BG AMI.

19. Consolidating financial statements

Set forth below are condensed consolidating financial statements of EXCO, the guarantor subsidiaries and the non-guarantor subsidiaries. The Senior Notes, which were issued by EXCO Resources, Inc., are jointly and severally guaranteed by some of our subsidiaries in the U.S. (referred to as Guarantor Subsidiaries). Each of the Guarantor Subsidiaries are wholly-owned subsidiaries of Resources, and the guarantees are unconditional as it relates to the assets of the Guarantor Subsidiaries. For purposes of this footnote, EXCO Resources, Inc. is referred to as Resources to distinguish us from the Guarantor Subsidiaries. The Non-Guarantor Subsidiaries, as defined in this footnote represent the consolidated financials of EXCO Operating. In 2007, certain subsidiaries, previously guarantor subsidiaries, were merged into and with Resources. We have presented the 2007 consolidating financial statements to reflect these changes as if they were in place at the beginning of the year.

The following financial information presents consolidating financial statements, which include:

- Resources;
- the Guarantor Subsidiaries on a combined basis;
- the Non-Guarantor Subsidiaries;
- elimination entries necessary to consolidate Resources, the guarantor subsidiaries and the non-guarantor subsidiaries; and
- EXCO on a consolidated basis.

Investments in subsidiaries are accounted for using the equity method of accounting. The financial information for the guarantor and non-guarantor subsidiaries is presented on a combined basis. The elimination entries primarily eliminate investments in subsidiaries and intercompany balances and transactions.

EXCO Resources, Inc.

Consolidating balance sheet

December 31, 2009

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 47,412	$ (4,154)	$ 25,149	$ —	$ 68,407
Restricted cash	—	—	58,909	—	58,909
Other current assets	69,449	20,922	184,401		274,772
Total current assets	116,861	16,768	268,459	—	402,088
Equity investment in TGGT Holdings, LLC	—	—	216,987	—	216,987
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	54,570	99,812	338,500	—	492,882
Proved developed and undeveloped oil and natural gas properties	328,135	302,323	1,245,291	—	1,875,749
Accumulated depletion	(274,275)	(174,268)	(684,061)	—	(1,132,604)
Oil and natural gas properties, net	108,430	227,867	899,730	—	1,236,027
Gas gathering, office and field equipment, net	8,175	46,558	134,703	—	189,436
Investments in and advances to affiliates	198,661	—	—	(198,661)	—
Deferred financing costs, net	3,166	—	4,436	—	7,602
Derivative financial instruments	31,312	—	3,365	—	34,677
Goodwill	38,100	164,469	67,087	—	269,656
Other assets	3	818	1,600	—	2,421
Total assets	$ 504,708	$ 456,480	$1,596,367	$(198,661)	$ 2,358,894
Liabilities and shareholders' equity					
Current liabilities	$ 39,917	$ 16,376	$ 156,621	$ —	$ 212,914
Long-term debt	530,199	—	666,078	—	1,196,277
Deferred income taxes	—	—	—	—	—
Other liabilities	5,998	46,963	37,154	—	90,115
Payable to parent	(930,994)	862,536	68,458	—	—
Total shareholders' equity	859,588	(469,395)	668,056	(198,661)	859,588
Total liabilities and shareholders' equity	$ 504,708	$ 456,480	$1,596,367	$(198,661)	$ 2,358,894

EXCO Resources, Inc.

Consolidating balance sheet

December 31, 2008

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 8,618	$ 12,360	$ 36,161	$ —	$ 57,139
Other current assets	162,607	29,935	263,359	—	455,901
Total current assets	171,225	42,295	299,520	—	513,040
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	85,061	119,940	276,595	—	481,596
Proved developed and undeveloped oil and natural gas properties	940,529	673,814	1,964,001	—	3,578,344
Accumulated depletion	(232,261)	(145,103)	(558,724)	—	(936,088)
Oil and natural gas properties, net	793,329	648,651	1,681,872	—	3,123,852
Gas gathering, office and field equipment, net	8,582	55,404	414,630	—	478,616
Investments in and advances to affiliates	802,902	—	—	(802,902)	—
Derivative financial instruments	120,097	—	52,906	—	173,003
Deferred financing costs, net	6,414	—	56,470	—	62,884
Other assets	2	678	200	—	880
Goodwill	110,800	164,469	194,808	—	470,077
Total assets	$2,013,351	$ 911,497	$2,700,406	$(802,902)	$4,822,352
Liabilities and shareholders' equity					
Current liabilities	$ 66,871	$ 50,256	$ 205,746	$ —	$ 322,873
Long-term debt	1,501,253	—	1,518,485	—	3,019,738
Deferred income taxes	9,371	—	—	—	9,371
Other liabilities	27,065	78,316	32,488	—	137,869
Payable to parent	(923,710)	948,463	(24,753)	—	—
Commitments and contingencies	—	—	—	—	—
Total shareholders' equity	1,332,501	(165,538)	968,440	(802,902)	1,332,501
Total liabilities and shareholders' equity	$2,013,351	$ 911,497	$2,700,406	$(802,902)	$4,822,352

EXCO Resources, Inc.
Consolidating statement of operations
For the year ended December 31, 2009

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 142,963	$ 91,832	$ 315,710	$ —	$ 550,505
Midstream	—	—	35,330	—	35,330
Total revenues	142,963	91,832	351,040	—	585,835
Costs and expenses:					
Oil and natural gas production	44,158	33,263	100,208	—	177,629
Midstream operating expenses	—	—	35,580	—	35,580
Gathering and transportation	86	3,451	15,423	—	18,960
Depreciation, depletion and amortization	45,555	34,476	141,407	—	221,438
Write-down of oil and natural gas properties	279,632	282,073	731,874	—	1,293,579
Accretion of discount on asset retirement obligations	1,628	3,328	2,176	—	7,132
General and administrative	26,319	20,158	52,700	—	99,177
Gain on divestitures and other operating items	(332,327)	5,075	(349,182)	—	(676,434)
Total costs and expenses	65,051	381,824	730,186	—	1,177,061
Operating income (loss)	77,912	(289,992)	(379,146)	—	(591,226)
Other income (expense):					
Interest expense	(58,927)	—	(88,234)	—	(147,161)
Gain on derivative financial instruments	54,286	10,726	167,013	—	232,025
Other income (expense)	24,845	(24,771)	52	—	126
Equity method loss in TGGT Holdings, LLC	—	—	(69)	—	(69)
Equity in earnings of subsidiaries	(604,241)	—	—	604,241	—
Total other income (expense)	(584,037)	(14,045)	78,762	604,241	84,921
Income (loss) before income taxes	(506,125)	(304,037)	(300,384)	604,241	(506,305)
Income tax expense	(9,321)	(180)	—	—	(9,501)
Net income (loss)	(496,804)	(303,857)	(300,384)	604,241	(496,804)
Preferred stock dividends	—	—	—	—	—
Net income (loss) available to common shareholders	$(496,804)	$(303,857)	$(300,384)	$604,241	$ (496,804)

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2008

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 393,026	$ 209,221	$ 802,579	$ —	$ 1,404,826
Midstream	—	—	85,432	—	85,432
Total revenues	393,026	209,221	888,011	—	1,490,258
Costs and expenses:					
Oil and natural gas production	74,025	37,149	126,897	—	238,071
Midstream operating expenses	—	—	82,797	—	82,797
Gathering and transportation	233	3,238	10,735	—	14,206
Depreciation, depletion and amortization	122,328	65,461	272,525	—	460,314
Write-down of oil and natural gas properties	485,468	717,628	1,612,739	—	2,815,835
Accretion of discount on asset retirement obligations	1,853	2,921	1,929	—	6,703
General and administrative	15,266	18,302	54,000	—	87,568
Other operating items	(2,176)	(1,465)	949	—	(2,692)
Total costs and expenses	696,997	843,234	2,162,571	—	3,702,802
Operating income (loss)	(303,971)	(634,013)	(1,274,560)	—	(2,212,544)
Other income (expense):					
Interest expense	(77,563)	—	(84,075)	—	(161,638)
Gain on derivative financial instruments	254,756	(3,028)	132,661	—	384,389
Other income	26,829	(26,090)	550	—	1,289
Equity in earnings of subsidiaries	(1,722,584)	—	—	1,722,584	—
Total other income (expense)	(1,518,562)	(29,118)	49,136	1,722,584	224,040
Income (loss) before income taxes	(1,822,533)	(663,131)	(1,225,424)	1,722,584	(1,988,504)
Income tax benefit	(89,062)	(165,971)	—	—	(255,033)
Net income (loss)	(1,733,471)	(497,160)	(1,225,424)	1,722,584	(1,733,471)
Preferred stock dividends	(76,997)	—	—	—	(76,997)
Net income (loss) available to common shareholders	$(1,810,468)	$(497,160)	$(1,225,424)	$1,722,584	$(1,810,468)

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2007

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 224,846	$121,994	$ 528,947	$ —	$ 875,787
Midstream	—	—	18,817	—	18,817
Total revenues	224,846	121,994	547,764	—	894,604
Costs and expenses:					
Oil and natural gas production	50,755	24,838	93,406	—	168,999
Midstream operating expenses	—	—	16,289	—	16,289
Gathering and transportation	610	1,441	8,159	—	10,210
Depreciation, depletion and amortization	70,767	44,427	260,226	—	375,420
Accretion of discount on asset retirement obligations	1,512	1,946	1,420	—	4,878
General and administrative	36,040	10,962	17,668	—	64,670
Other operating items	(1,263)	(2,216)	(518)	—	(3,997)
Total costs and expenses	158,421	81,398	396,650	—	636,469
Operating income	66,425	40,596	151,114	—	258,135
Other income (expense):					
Interest expense	(62,540)	—	(118,810)	—	(181,350)
Gain (loss) on derivative financial instruments	(25,788)	(8,612)	61,207	—	26,807
Other income (loss)	34,311	(29,393)	1,242	—	6,160
Equity in earnings of subsidiaries	89,823	—	—	(89,823)	—
Total other income (expense)	35,806	(38,005)	(56,361)	(89,823)	(148,383)
Income before income taxes	102,231	2,591	94,753	(89,823)	109,752
Income tax expense	52,575	7,521	—	—	60,096
Net income (loss)	49,656	(4,930)	94,753	(89,823)	49,656
Preferred stock dividends	(132,968)	—	—	—	(132,968)
Net income (loss) available to common shareholders	$ (83,312)	$ (4,930)	$ 94,753	$(89,823)	$ (83,312)

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2009

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 226,012	$ 6,283	$ 201,310	$—	$ 433,605
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(44,434)	(61,313)	(626,949)	—	(732,696)
Restricted cash	—	—	(58,909)	—	(58,909)
Equity investment in TGGT Holdings, LLC	—	—	(47,500)	—	(47,500)
Deposit on pending property divestitures	—	—	—	—	—
Proceeds from dispositions	910,891	13,064	1,150,425	—	2,074,380
Advances/investments with affiliates	(137,305)	25,452	111,853	—	—
Net cash provided by (used in) investing activities	729,152	(22,797)	528,920	—	1,235,275
Financing Activities:					
Borrowings under credit agreements	14,979	—	232,820	—	247,799
Repayments under credit agreements	(982,444)	—	(1,085,227)	—	(2,067,671)
Proceeds from issuance of common stock, net	10,361	—	—	—	10,361
Payment of common stock dividends	(10,582)	—	—	—	(10,582)
Settlement of derivative financial instruments with a financing element	56,701	—	126,251	—	182,952
Deferred financing costs and other	(5,385)	—	(15,086)	—	(20,471)
Net cash used in financing activities	(916,370)	—	(741,242)	—	(1,657,612)
Net increase (decrease) in cash	38,794	(16,514)	(11,012)	—	11,268
Cash at the beginning of the period	8,618	12,360	36,161	—	57,139
Cash at end of period	$ 47,412	$ (4,154)	$ 25,149	$—	$ 68,407

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2008

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 286,804	$ 116,991	$ 571,171	$—	$ 974,966
Investing Activities:					
Property and Midstream acquisitions and additions to oil and natural gas properties, gathering systems and equipment	(604,235)	(212,185)	(907,702)	—	(1,724,122)
Proceeds from dispositions of property and equipment	1,315	13,425	803	—	15,543
Advances/investments with affiliates	(67,897)	86,879	(18,982)	—	—
Net cash used in investing activities	(670,817)	(111,881)	(925,881)	—	(1,708,579)
Financing Activities:					
Borrowings under credit agreements	784,951	—	915,185	—	1,700,136
Repayments under credit agreements	(296,500)	—	(479,700)	—	(776,200)
Settlement of derivative financial instruments with a financing element	(50,135)	—	(33,468)	—	(83,603)
Proceeds from issuance of common stock, net	14,777	—	—	—	14,777
Dividends on preferred stock	(82,827)	—	—	—	(82,827)
Deferred financing costs and other	(704)	—	(36,337)	—	(37,041)
Net cash provided by financing activities	369,562	—	365,680	—	735,242
Net increase (decrease) in cash	(14,451)	5,110	10,970	—	1,629
Cash at the beginning of the period	23,069	7,250	25,191	—	55,510
Cash at end of period	$ 8,618	$ 12,360	$ 36,161	$—	$ 57,139

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2007

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 141,403	$ 69,223	$ 367,203	$—	$ 577,829
Investing Activities:					
Property and Midstream acquisitions and additions to oil and natural gas properties, gathering systems and equipment	(999,434)	(68,154)	(1,779,381)	—	(2,846,969)
Proceeds from dispositions of property and equipment	485,714	354	4,294	—	490,362
Advance payment on pending acquisition	(39,500)	—	—	—	(39,500)
Proceeds from sales of marketable securities	5,228	—	—	—	5,228
Other investing activities	—	—	(5,558)	—	(5,558)
Advances/investments with affiliates	(1,648,245)	(406)	1,648,651	—	—
Net cash used in investing activities	(2,196,237)	(68,206)	(131,994)	—	(2,396,437)
Financing Activities:					
Borrowings under credit agreements	972,500	—	1,263,000	—	2,235,500
Repayments under credit agreements	(751,000)	—	(1,470,532)	—	(2,221,532)
Settlement of derivative financial instruments with a financing element	(11,578)	—	(2,636)	—	(14,214)
Proceeds from issuance of common stock, net	4,162	—	—	—	4,162
Proceeds from issuance of preferred stock, net	1,992,273	—	—	—	1,992,273
Payment of preferred stock dividend	(127,134)	—	—	—	(127,134)
Deferred financing costs and other	(7,842)	—	(9,917)	—	(17,759)
Net cash provided by (used in) financing activities	2,071,381	—	(220,085)	—	1,851,296
Net increase in cash	16,547	1,017	15,124	—	32,688
Cash at the beginning of the period	6,522	6,233	10,067	—	22,822
Cash at end of period	$ 23,069	$ 7,250	$ 25,191	$—	$ 55,510

20. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2009 and 2008:

(in thousands)	Quarter 1st	2nd	3rd	4th
2009				
Total revenues	$ 189,221	$ 159,194	$ 130,868	$ 106,552
Operating income (loss)	(1,283,830)	6,958	464,022	221,624
Net income (loss) available to common shareholders	$(1,099,611)	$ (71,992)	$ 433,330	$ 241,469
Basic earnings (loss) per share:				
Net income (loss)	$ (5.21)	$ (0.34)	$ 2.05	$ 1.14
Weighted average shares	210,995	211,089	211,266	211,707
Diluted earnings (loss) per share:				
Net income (loss)	$ (5.21)	$ (0.34)	$ 2.03	$ 1.13
Weighted average shares	210,995	211,089	213,235	214,553
2008				
Total revenues	$ 332,735	$ 455,692	$ 429,411	$ 272,420
Operating income (loss)	136,943	236,546	(1,006,470)	(1,579,563)
Net loss available to common shareholders	$ (197,839)	$(297,914)	$ (153,326)	$(1,161,389)
Basic earnings (loss) per share:				
Net loss	$ (1.89)	$ (2.83)	$ (0.80)	$ (5.51)
Weighted average shares	104,683	105,253	191,452	210,944
Diluted earnings (loss) per share:				
Net loss	$ (1.89)	$ (2.83)	$ (0.80)	$ (5.51)
Weighted average shares	104,683	105,253	191,452	210,944

21. Supplemental information relating to oil and natural gas producing activities (unaudited)

For the year ended December 31, 2009, the SEC issued Release No. 33-8995, which amended oil and natural gas reporting requirements. The FASB also issued Topic 932, to align oil and natural gas reserve estimation and disclosures with the SEC's release. The following information has been prepared in accord with these revised rules for 2009.

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

(in thousands, except per unit amounts)	Amount
2009:	
Proved property acquisition costs	$ 6,473
Unproved property acquisition costs(1)	227,161
Total property acquisition costs	233,634
Development	262,786
Exploration costs(2)	37,051
Lease acquisitions and other(3)	106,040
Capitalized asset retirement costs	879
Depreciation, depletion and amortization per Boe	$ 10.37
Depreciation, depletion and amortization per Mcfe	$ 1.72
2008:	
Proved property acquisition costs(4)	$ 604,723
Unproved property acquisition costs(5)	87,170
Total property acquisition costs	691,893
Development	581,747
Exploration costs(6)	111,426
Lease acquisitions and other(7)	187,134
Capitalized asset retirement costs	19,182
Depreciation, depletion and amortization per Boe	$ 19.10
Depreciation, depletion and amortization per Mcfe	$ 3.18
2007:	
Proved property acquisition costs(8)	$2,356,354
Unproved property acquisition costs(9)	117,893
Total property acquisition costs	2,474,247
Development and exploration costs(6)	446,675
Lease acquisitions and other	21,415
Capitalized asset retirement costs	5,127
Depreciation, depletion and amortization per Boe	$ 18.57
Depreciation, depletion and amortization per Mcfe	$ 3.10

(1) Reflects fourth quarter acquisitions, consisting primarily of undeveloped acreage in the Haynesville shale play in DeSoto Parish, Louisiana and Caddo Parish, Louisiana.

(2) Exploration costs incurred in 2009 included approximately $27.5 million incurred in the Haynesville shale play in Caddo Parish, Louisiana and Gregg County, Texas, approximately $5.5 million in Appalachia and approximately $1.7 million in Permian.

(3) Lease acquisitions in 2009 include approximately $98.7 million and $6.6 million in the Haynesville/Bossier and Marcellus shale plays, respectively.

(4) Includes $334.3 million and $199.2 million allocated to proved oil and natural gas properties in connection with the Appalachian Acquisition and the Danville Acquisition, respectively.

(5) Includes $44.8 million and $42.4 million allocated to unproved oil and natural gas properties in connection with the Appalachian Acquisition and the Danville Acquisition, respectively.

(6) Exploration costs incurred in 2008 included approximately $52.2 million in Appalachia (Marcellus shale resource play) and approximately $51.2 million in the Haynesville shale resource play in East Texas/North Louisiana. Exploration costs in 2007 were not material.

(7) Lease acquisitions in 2008 include approximately $84.0 million and $55.8 million to lease in the Marcellus and Haynesville shale resource plays, respectively.

(8) Includes $1,417.8 million and $577.9 million allocated to proved oil and natural gas properties in connection with the Vernon and Southern Gas acquisitions, respectively. In addition, $201.2 million of proved property acquisitions have been included to reflect the purchase of the Southern Gas properties on May 2, 2007 which were sold to Crimson on May 8, 2007.

(9) Includes $58.2 million and $4.7 million allocated to unproved oil and natural gas properties in connection with the Vernon and Southern Gas acquisitions, respectively. In addition, $34.3 million of unproved property acquisitions resulting from the purchase of Southern Gas properties on May 2, 2007 which were sold to Crimson on May 8, 2007.

We retain independent engineering firms to provide annual year-end estimates of our future net recoverable oil and natural gas reserves. The estimated proved net recoverable reserves we show below include only those quantities that we expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves that we may recover through existing wells. Proved Undeveloped Reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations. All of our reserves are located onshore in the continental United States of America.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise.

Estimated Quantities of Proved Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	Mcfe(1)
December 31, 2006	16,155	1,126,602	1,223,532
Purchase of reserves in place	10,500	770,567	833,567
New discoveries and extensions(2)	2,469	178,248	193,062
Revisions of previous estimates(3):			
Due to changes in price	139	58,716	59,550
Due to other factors	(327)	(137,363)	(139,325)
Production	(1,645)	(111,419)	(121,289)
Sales of reserves in place	(6,361)	(145,801)	(183,967)
December 31, 2007	20,930	1,739,550	1,865,130
Purchase of reserves in place	635	175,679	179,489
New discoveries and extensions(4)	5,040	259,801	290,041
Revisions of previous estimates(5):			
Due to changes in price	(2,407)	(93,015)	(107,457)
Due to other factors	(1,060)	(130,605)	(136,965)
Production	(2,236)	(131,159)	(144,575)
Sales of reserves in place	(101)	(5,113)	(5,719)
December 31, 2008	20,801	1,815,138	1,939,944
Purchase of reserves in place	—	8,065	8,065
New discoveries and extensions(6)	202	240,844	242,056
Revisions of previous estimates(7):			
Due to changes in price	(1,482)	(249,948)	(258,840)
Due to other factors	124	(54,613)	(53,869)
Production	(1,571)	(118,735)	(128,161)
Sales of reserves in place(8)	(12,556)	(715,023)	(790,359)
December 31, 2009	5,518	925,728	958,836

Estimated Quantities of Proved Developed Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	Mcfe(1)
December 31, 2009	3,505	622,160	643,190
December 31, 2008	14,815	1,354,729	1,443,619
December 31, 2007	15,180	1,228,736	1,319,816

(1) Mcfe—one thousand cubic feet equivalent calculated by converting on Bbl of oil to six Mcf of natural gas.

(2) New discoveries and extensions between December 31, 2006 and December 31, 2007 include 114,980 Mmcfe in East Texas/North Louisiana, 43,271 Mmcfe in Appalachia, 28,608 Mmcfe in Permian and 6,203 Mmcfe in our other areas.

(3) Total revisions between December 31, 2006 and December 31, 2007 include a positive revision of 59,550 Mmcfe due to price changes and negative revisions totaling 139,325 Mmcfe due primarily to performance issues in Appalachia and East Texas/North Louisiana and cost increases, particularly in Appalachia.

(4) New discoveries and extension between December 31, 2007 and December 31, 2008 include 167,381 Mmcfe in East Texas/North Louisiana, 67,161 Mmcfe in Appalachia, 34,833 Mmcfe in Permian and 20,666 Mmcfe in other areas.

(5) Total revisions between December 31, 2007 and December 31, 2008 include negative revisions of 107,457 Mmcfe due to price changes and negative revisions of 136,965 Mmcfe due to changes other than price, particularly in our Appalachia and Permian regions.

(6) New discoveries and extensions between December 31, 2008 and December 31, 2009 include 238,475 Mmcfe in East Texas/North Louisiana (primarily in the Haynesville shale play), 2,303 Mmcfe in Appalachia and 1,279 Mmcfe in Permian.

(7) Total revisions of 312,709 Mmcfe reflect negative revisions attributable to price of 258,840 Mmcfe and 65,008 Mmcfe of downward performance revisions, which occurred primarily in our Appalachia region. The other than price downward revisions were offset by positive performance revisions of 11,139 Mmcfe, which occurred primarily in our East Texas/North Louisiana region.

(8) Sales of reserves in place in 2009 reflect 346,283 Mmcfe in East Texas/North Louisiana (including the BG Upstream Transaction), 292,158 Mmcfe in the Mid-Continent area, 121,578 Mmcfe in Appalachia and 30,340 Mmcfe in Permian.

Standardized measure of discounted future net cash flows

We have summarized the Standardized Measure related to our proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on prices as prescribed by the SEC, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place, and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

(in thousands)	Amount
Year ended December 31, 2009:	
Future cash inflows	$ 3,509,227
Future production costs	1,337,898
Future development costs	695,174
Future income taxes(1)	—
Future net cash flows	1,476,155
Discount of future net cash flows at 10% per annum	728,452
Standardized measure of discounted future net cash flows	$ 747,703
Year ended December 31, 2008:	
Future cash inflows	$11,045,544
Future production costs	3,650,402
Future development costs	1,732,321
Future income taxes	649,807
Future net cash flows	5,013,014
Discount of future net cash flows at 10% per annum	2,776,720
Standardized measure of discounted future net cash flows	$ 2,236,294
Year ended December 31, 2007:	
Future cash inflows	$13,562,925
Future production costs	3,624,057
Future development costs	1,491,801
Future income taxes	1,857,530
Future net cash flows	6,589,537
Discount of future net cash flows at 10% per annum	3,470,650
Standardized measure of discounted future net cash flows	$ 3,118,887

(1) Due to a 32.2% reduction in price for natural gas in 2009 from 2008, estimated future net cash flows, combined with available net operating loss carry-forwards resulted in no estimated future taxable income as of December 31, 2009.

During recent years, prices paid for oil and natural gas have fluctuated significantly. The prices at December 31, 2009, 2008 and 2007 used in the above table, were $61.18, $44.60 and $95.92 per Bbl of oil, respectively, and $3.87, $5.71 and $6.80 per Mmbtu of natural gas, respectively, in each case adjusted for historical differentials. The prices for 2008 and 2007 were based on the spot price as of December 31 of each year for oil and natural gas. The price for oil and natural gas used at December 31, 2009 reflects the new SEC rules effective December 31, 2009 requiring the use of simple average of the first day of the month price for the previous twelve month period. The principle change in our 2009 reserve estimates arising from the revised rules were in our Haynesville shale properties, where we had 25 operated proved developed wells and 12 proved developed outside operated wells as of December 31, 2009. We added an average of 2.5 offsetting proved undeveloped locations with average gross reserves of 6.6 Bcfe for each producing well drilled. The most significant impacts to the changes in the value of Standardized Measure during 2009 are attributable to lower prices and significant sales of reserves in place.

The following are the principal sources of change in the Standardized Measure:

(in thousands)	
Year ended December 31, 2009:	
Sales and transfers of oil and natural gas produced	$ (356,746)
Net changes in prices and production costs	(915,030)
Extensions and discoveries, net of future development and production costs	275,622
Development costs during the period	80,218
Changes in estimated future development costs	373,336
Revisions of previous quantity estimates	(329,573)
Sales of reserves in place	(1,028,622)
Purchase of reserves in place	472
Accretion of discount before income taxes	240,507
Changes in timing and other	(66,011)
Net change in income taxes	237,236
Net change	$(1,488,591)
Year ended December 31, 2008:	
Sales and transfers of oil and natural gas produced, net of production costs	$(1,156,723)
Net changes in prices and production costs	(857,254)
Extensions and discoveries, net of future development and production costs	243,912
Development costs during the period	287,975
Changes in estimated future development costs	(191,993)
Revisions of previous quantity estimates	(393,359)
Sales of reserves in place	(8,490)
Purchase of reserves in place	203,707
Accretion of discount before income taxes	388,395
Changes in timing and other	11,460
Net change in income taxes	589,777
Net change	$ (882,593)
Year ended December 31, 2007:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (679,211)
Net changes in prices and production costs	513,856
Extensions and discoveries, net of future development and production costs	461,961
Development costs during the period	446,675
Changes in estimated future development costs	(125,395)
Revisions of previous quantity estimates	(175,857)
Sales of reserves in place	(298,328)
Purchase of reserves in place	1,923,731
Accretion of discount before income taxes	156,736
Changes in timing and other	126,192
Net change in income taxes	(543,248)
Net change	$ 1,807,112

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures. Pursuant to Rule 13a-15(b) under the Exchange Act, management has evaluated, under the supervision and with the participation of our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act), as of the end of the period covered by this report. Based on this evaluation, our principal executive officer and principal financial officer have concluded that EXCO's disclosure controls and procedures were effective as of December 31, 2009 to ensure that information that is required to be disclosed by EXCO in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to EXCO's management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's report on internal control over financial reporting. EXCO's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) of the Exchange Act). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions. Management's annual report of internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm, KPMG LLP, are included in Item 8 of this annual report on Form 10-K and are incorporated by reference herein.

Changes in internal control over financial reporting. EXCO's management assessed the effectiveness of EXCO's internal control over financial reporting as there were no changes in EXCO's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, EXCO's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) See Part II—Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(a)(2) None.

(a)(3) See "Index to Exhibits" for a description of our exhibits.

(b) See "Index to Exhibits" for a description of our exhibits.

(c) None.

SIGNATURE PAGE

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

Date: February 24, 2010

EXCO RESOURCES, INC.
(Registrant)

By: /s/ DOUGLAS H. MILLER

Douglas H. Miller
Chairman and Chief Executive Officer

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

Date: February 24, 2010

/s/ DOUGLAS H. MILLER

Douglas H. Miller
Director, Chairman and Chief Executive Officer

/s/ STEPHEN F. SMITH

Stephen F. Smith
Director, Vice Chairman, President and
Chief Financial Officer

/s/ MARK E. WILSON

Mark E. Wilson
Vice President, Chief Accounting Officer and
Controller

/s/ JEFFREY D. BENJAMIN

Jeffrey D. Benjamin
Director

/s/ VINCENT J. CEBULA

Vincent J. Cebula
Director

/s/ EARL E. ELLIS

Earl E. Ellis
Director

/s/ B. JAMES FORD

B. James Ford
Director

/s/ BOONE PICKENS

Boone Pickens
Director

/s/ JEFFREY S. SEROTA

Jeffrey S. Serota
Director

/s/ ROBERT L. STILLWELL

Robert L. Stillwell
Director

* Mr. Mark Mulhern was not a director during 2009. He joined the Board of Directors on February 1, 2010.

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

Not applicable.

INDEX TO EXHIBITS

Exhibit Number	Description of Exhibits
2.1	Asset Purchase Agreement, dated December 7, 2007, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC and Energy Search, Incorporated, as sellers, filed as an Exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
2.2	First Amendment to Asset Purchase Agreement, dated February 20, 2008, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC, and Energy Search, incorporated, as sellers, filed as an exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
2.3	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.4	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.5	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.6	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
2.7	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.8	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
2.9	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO—North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
2.10	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
3.1	Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 8, 2006 and filed on February 14, 2006 and incorporated by reference herein.
3.2	Articles of Amendment to the Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 30, 2007 and filed on September 5, 2007 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
3.3	Second Amended and Restated Bylaws of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 4, 2009 and filed on March 6, 2009 and incorporated by reference herein.
3.4	Statement of Designation of Series A-1 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.5	Statement of Designation of Series A-2 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.6	Statement of Designation of Series B 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.7	Statement of Designation of Series C 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.8	Statement of Designation of Series A-1 Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.9	Statement of Designation of Series A-2 Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.1	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
4.2	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004, filed as an Exhibit to EXCO's Registration Statement on Form S-4 filed March 25, 2004 and incorporated by reference herein.
4.3	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
4.4	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K filed on February 21, 2006 and incorporated by reference herein.
4.5	Form of 7 ¼% Global Note Due 2011, filed as an Exhibit to EXCO's Quarterly Report on From 10-Q, filed on May 6, 2009 and incorporated by reference herein.
4.6	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Amendment No. 2 to the Form S-1 (File No. 333-129935) filed on January 27, 2006 and incorporated by reference herein.
4.7	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
4.8	Fifth Supplemental Indenture, dated as of May 2, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
4.9	Sixth Supplemental Indenture, dated as of February 12, 2008, by and among EXCO Resources, Inc., EXCO Services, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.
4.10	First Amended and Restated Registration Rights Agreement, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), effective January 5, 2006, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed on January 6, 2006 and incorporated by reference herein.
4.11	Seventh Supplemental Indenture, dated as of June 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2008 and incorporated by reference herein.
4.12	Eighth Supplemental Indenture, dated as of December 31, 2008, by and among EXCO Resources, Inc., EXCO Mid-Continent MLP, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated herein by reference.
10.1	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
10.2	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004, filed as an Exhibit to EXCO's Registration Statement on Form S- 4 filed March 25, 2004 and incorporated by reference herein.
10.3	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, dated as of December 21, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
10.4	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.5	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.
10.6	Form of 7 ¼% Global Note Due 2011, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed May 6, 2009 and incorporated by reference herein.
10.7	Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*

Exhibit Number	Description of Exhibits
10.8	Form of Incentive Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.9	Form of Nonqualified Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.10	Form of Restricted Stock Award Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Registration Statement on Form S-8 (File No. 333-132551) filed on March 17, 2006 and incorporated by reference herein.*
10.11	Third Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.12	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.
10.13	Amendment Number One to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed herewith.
10.14	Letter Agreement, dated March 28, 2007, with OCM Principal Opportunities Fund IV, L.P. and OCM EXCO Holdings, LLC, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.*
10.15	Letter Agreement, dated March 28, 2007, with Ares Corporate Opportunities Fund, ACOF EXCO, L.P., ACOF EXCO 892 Investors, L.P., Ares Corporate Opportunities Fund II, L.P., Ares EXCO, L.P. and Ares EXCO 892 Investors, L.P, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.16	Amended and Restated Credit Agreement, dated as of March 30, 2007, among EXCO Partners Operating Partnership, LP, as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Book runner and Lead Arranger, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.17	Second Amended and Restated Credit Agreement, dated as of May 2, 2007, among EXCO Resources, Inc. as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined therein, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Book runner and Lead Arranger, filed as an Exhibit to EXCO's Form 8-K dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
10.18	Fifth Supplemental Indenture, dated as of May 2, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
10.19	Asset Purchase Agreement, dated December 7, 2007, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC and Energy Search, Incorporated, as sellers, filed as an Exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.20	Sixth Supplemental Indenture, dated as of February 12, 2008, by and among EXCO Resources, Inc., EXCO Services, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.21	Counterpart Agreement, dated February 4, 2008, to that Certain Second Amended and Restated Credit Agreement, dated May 2, 2007, among EXCO Resources, Inc., as Borrower, and certain subsidiaries of Borrower and the lender parties thereto, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.
10.22	First Amendment to Second Amended and Restated Credit Agreement, dated as of February 20, 2008, by and among EXCO Resources, Inc., as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined herein, and JP Morgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.23	First Amendment to Amended and Restated Credit Agreement, dated as of February 20, 2008, by and among EXCO Partners Operating Partnership, LP, as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined therein and JP Morgan Chase Bank, N.A., as Administrative Agent, filed as an exhibit to EXCO's Current Report on Form 8-K, dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.24	First Amendment to Asset Purchase Agreement, dated February 20, 2008, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC, and Energy Search, Incorporated, as sellers, filed as an exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.25	Seventh Supplemental Indenture, dated as of September 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q filed on August 6, 2008 and incorporated by reference herein.
10.26	Second Amendment to Amended and Restated Credit Agreement, dated as of July 14, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries as guarantors, and JP Morgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K dated July 14, 2008 and filed on July 16, 2008 and incorporated by reference herein.
10.27	Second Amendment to Second Amended and Restated Credit Agreement, dated as of July 14, 2008 and effective as of June 30, 2008, among EXCO Resources, Inc., as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated July 14, 2008 and filed on July 16, 2008 and incorporated by reference herein.
10.28	Seventh Supplemental Indenture, dated as of June 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2008 and incorporated by reference herein.
10.29	Third Amendment to Amended and Restated Credit Agreement, dated as of December 1, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated December 1, 2008 and filed on December 5, 2008 and incorporated by reference herein.
10.30	Senior Unsecured Term Credit Agreement, dated as of December 8, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A. as administrative agent, J.P. Morgan Securities Inc., as sole book runner and lead arranger, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated December 8, 2008 and filed on December 8, 2008 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.31	Third Amendment to Second Amended and Restated Credit Agreement, dated as of February 4, 2009, among EXCO Resources, Inc., as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated February 4, 2009 and filed on February 5, 2009 and incorporated by reference herein.
10.32	Eighth Supplemental Indenture, dated as of December 31, 2008, by and among EXCO Resources, Inc., EXCO Mid-Continent MLP, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
10.33	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of April 17, 2009, among EXCO Resources, Inc., as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated April 17, 2009 and filed on April 20, 2009 and incorporated by reference herein.
10.34	Fourth Amendment to Amended and Restated Credit Agreement, dated as of April 17, 2009, among EXCO Operating Company, LP, as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated April 17, 2009 and filed on April 20, 2009 and incorporated by reference herein.
10.35	Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 1, 2009, among EXCO Resources, Inc., as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated September 29, 2009 and filed on October 5, 2009 and incorporated by reference herein.
10.36	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.37	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.38	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.39	Amendment Number One to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an exhibit to EXCO's Current Report on Form 8-K, dated June 4, 2009 and filed on June 10, 2009 and incorporated by reference herein.
10.40	Joint Development Agreement, dated August 14, 2009, by and among BG US Production Company, LLC, EXCO Operating Company, LP and EXCO Production Company, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.41	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.42	Amended and Restated Limited Liability Company Agreement of TGGT Holdings, LLC, dated August 14, 2009, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.43	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.44	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
10.45	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO – North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
10.46	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
14.1	Code of Ethics for the Chief Executive Officer and Senior Financial Officers, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.2	Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.3	Amendment No. 1 to EXCO Resources, Inc. Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
21.1	Subsidiaries of the registrant, filed herewith.
23.1	Consent of KPMG LLP, filed herewith
23.2	Consent of Lee Keeling and Associates, Inc., filed herewith.
23.3	Consent of Haas Petroleum Engineering Services, Inc., filed herewith.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Financial Officer of EXCO Resources, Inc., filed herewith.
31.3	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Accounting Officer of EXCO Resources, Inc., filed herewith.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer and Chief Financial Officer of EXCO Resources, Inc., filed herewith.

* These exhibits are management contracts.

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

FORM 10-K/A
Amendment No. 1

(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, 2009

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 0-9204

EXCO RESOURCES, INC.
(Exact name of Registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**74-1492779** (I.R.S. Employer Identification No.)
12377 Merit Drive, Suite 1700, LB 82 **Dallas, Texas** (Address of principal executive offices)	**75251** (Zip Code)

Registrant's telephone number, including area code: **(214) 368-2084**

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	New York Stock Exchange

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

None
(Title of class)

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 ☒

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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant is required to submit and post such files). YES ☐ NO ☐

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 ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of February 12, 2010, the registrant had 212,054,805 outstanding shares of common stock, par value $.001 per share, which is its only class of common stock. As of the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates was $1,803,590,000.

For purposes of this calculation only, affiliates include all shares held by all officers, directors and 10% or greater shareholders.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to shareholders in connection with its 2010 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

EXPLANATORY NOTE

EXCO Resources, Inc. is filing this Amendment No. 1 on Form 10-K/A (this "Amendment") to its Annual Report on Form 10-K for the fiscal year ended December 31, 2009, originally filed on February 24, 2010, for the purpose of filing Exhibits 99.1 and 99.2 to be included as part of the exhibits under Item 15 of Part IV of the Annual Report on Form 10-K. In addition, we are including as exhibits to this Amendment the certifications required under Section 302 of the Sarbanes-Oxley Act of 2002. Because no financial statements are contained within this Amendment, we are not including certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Except as set forth herein, no other changes are made to our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) See Part II—Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(a)(2) None.

(a)(3) See "Index to Exhibits" for a description of our exhibits.

(b) See "Index to Exhibits" for a description of our exhibits.

(c) None.

SIGNATURE PAGE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Amendment No. 1 to its annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 3, 2010

EXCO RESOURCES, INC.
(Registrant)

By: /s/ DOUGLAS H. MILLER

Douglas H. Miller
Chairman and Chief Executive Officer

INDEX TO EXHIBITS

Exhibit Number	Description of Exhibits
2.1	Asset Purchase Agreement, dated December 7, 2007, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC and Energy Search, Incorporated, as sellers, filed as an Exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
2.2	First Amendment to Asset Purchase Agreement, dated February 20, 2008, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC, and Energy Search, incorporated, as sellers, filed as an exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
2.3	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.4	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.5	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.6	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
2.7	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.8	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
2.9	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO—North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
2.10	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
3.1	Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 8, 2006 and filed on February 14, 2006 and incorporated by reference herein.
3.2	Articles of Amendment to the Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 30, 2007 and filed on September 5, 2007 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
3.3	Second Amended and Restated Bylaws of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 4, 2009 and filed on March 6, 2009 and incorporated by reference herein.
3.4	Statement of Designation of Series A-1 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.5	Statement of Designation of Series A-2 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.6	Statement of Designation of Series B 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.7	Statement of Designation of Series C 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.8	Statement of Designation of Series A-1 Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.9	Statement of Designation of Series A-2 Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.1	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
4.2	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004, filed as an Exhibit to EXCO's Registration Statement on Form S-4 filed March 25, 2004 and incorporated by reference herein.
4.3	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
4.4	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K filed on February 21, 2006 and incorporated by reference herein.
4.5	Form of 7 ¼% Global Note Due 2011, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed on May 6, 2009 and incorporated by reference herein.
4.6	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Amendment No. 2 to the Form S-1 (File No. 333-129935) filed on January 27, 2006 and incorporated by reference herein.
4.7	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
4.8	Fifth Supplemental Indenture, dated as of May 2, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
4.9	Sixth Supplemental Indenture, dated as of February 12, 2008, by and among EXCO Resources, Inc., EXCO Services, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.
4.10	First Amended and Restated Registration Rights Agreement, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), effective January 5, 2006, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed on January 6, 2006 and incorporated by reference herein.
4.11	Seventh Supplemental Indenture, dated as of June 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2008 and incorporated by reference herein.
4.12	Eighth Supplemental Indenture, dated as of December 31, 2008, by and among EXCO Resources, Inc., EXCO Mid-Continent MLP, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated herein by reference.
10.1	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
10.2	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004, filed as an Exhibit to EXCO's Registration Statement on Form S- 4 filed March 25, 2004 and incorporated by reference herein.
10.3	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, dated as of December 21, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
10.4	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.5	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.
10.6	Form of 7 ¼% Global Note Due 2011, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed May 6, 2009 and incorporated by reference herein.
10.7	Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*

Exhibit Number	Description of Exhibits
10.8	Form of Incentive Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.9	Form of Nonqualified Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.10	Form of Restricted Stock Award Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Registration Statement on Form S-8 (File No. 333-132551) filed on March 17, 2006 and incorporated by reference herein.*
10.11	Third Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.12	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.
10.13	Amendment Number One to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
10.14	Letter Agreement, dated March 28, 2007, with OCM Principal Opportunities Fund IV, L.P. and OCM EXCO Holdings, LLC, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.*
10.15	Letter Agreement, dated March 28, 2007, with Ares Corporate Opportunities Fund, ACOF EXCO, L.P., ACOF EXCO 892 Investors, L.P., Ares Corporate Opportunities Fund II, L.P., Ares EXCO, L.P. and Ares EXCO 892 Investors, L.P, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.16	Amended and Restated Credit Agreement, dated as of March 30, 2007, among EXCO Partners Operating Partnership, LP, as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Book runner and Lead Arranger, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.17	Second Amended and Restated Credit Agreement, dated as of May 2, 2007, among EXCO Resources, Inc. as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined therein, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Book runner and Lead Arranger, filed as an Exhibit to EXCO's Form 8-K dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
10.18	Fifth Supplemental Indenture, dated as of May 2, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 2, 2007 and filed on May 8, 2007 and incorporated by reference herein.
10.19	Asset Purchase Agreement, dated December 7, 2007, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC and Energy Search, Incorporated, as sellers, filed as an Exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.20	Sixth Supplemental Indenture, dated as of February 12, 2008, by and among EXCO Resources, Inc., EXCO Services, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.
10.21	Counterpart Agreement, dated February 4, 2008, to that Certain Second Amended and Restated Credit Agreement, dated May 2, 2007, among EXCO Resources, Inc., as Borrower, and certain subsidiaries of Borrower and the lender parties thereto, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2007 filed February 29, 2008 and incorporated by reference herein.
10.22	First Amendment to Second Amended and Restated Credit Agreement, dated as of February 20, 2008, by and among EXCO Resources, Inc., as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined herein, and JP Morgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.23	First Amendment to Amended and Restated Credit Agreement, dated as of February 20, 2008, by and among EXCO Partners Operating Partnership, LP, as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined therein and JP Morgan Chase Bank, N.A., as Administrative Agent, filed as an exhibit to EXCO's Current Report on Form 8-K, dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.24	First Amendment to Asset Purchase Agreement, dated February 20, 2008, between EXCO Appalachia, Inc., as purchaser, and EOG Resources, Inc., EOG Resources Appalachian LLC, and Energy Search, Incorporated, as sellers, filed as an exhibit to EXCO's Current Report on Form 8-K dated February 20, 2008 and filed on February 26, 2008 and incorporated by reference herein.
10.25	Seventh Supplemental Indenture, dated as of September 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q filed on August 6, 2008 and incorporated by reference herein.
10.26	Second Amendment to Amended and Restated Credit Agreement, dated as of July 14, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries as guarantors, and JP Morgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K dated July 14, 2008 and filed on July 16, 2008 and incorporated by reference herein.
10.27	Second Amendment to Second Amended and Restated Credit Agreement, dated as of July 14, 2008 and effective as of June 30, 2008, among EXCO Resources, Inc., as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated July 14, 2008 and filed on July 16, 2008 and incorporated by reference herein.
10.28	Seventh Supplemental Indenture, dated as of June 30, 2008, by and among EXCO Resources, Inc., EXCO-North Coast Energy, Inc. and Wilmington Trust Company, as Trustee, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2008 and incorporated by reference herein.
10.29	Third Amendment to Amended and Restated Credit Agreement, dated as of December 1, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated December 1, 2008 and filed on December 5, 2008 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.30	Senior Unsecured Term Credit Agreement, dated as of December 8, 2008, among EXCO Operating Company, LP, as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A. as administrative agent, J.P. Morgan Securities Inc., as sole book runner and lead arranger, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated December 8, 2008 and filed on December 8, 2008 and incorporated by reference herein.
10.31	Third Amendment to Second Amended and Restated Credit Agreement, dated as of February 4, 2009, among EXCO Resources, Inc., as borrower, and certain of its subsidiaries, as guarantors, and JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated February 4, 2009 and filed on February 5, 2009 and incorporated by reference herein.
10.32	Eighth Supplemental Indenture, dated as of December 31, 2008, by and among EXCO Resources, Inc., EXCO Mid-Continent MLP, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2008 filed February 26, 2009 and incorporated by reference herein.
10.33	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of April 17, 2009, among EXCO Resources, Inc., as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated April 17, 2009 and filed on April 20, 2009 and incorporated by reference herein.
10.34	Fourth Amendment to Amended and Restated Credit Agreement, dated as of April 17, 2009, among EXCO Operating Company, LP, as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated April 17, 2009 and filed on April 20, 2009 and incorporated by reference herein.
10.35	Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 1, 2009, among EXCO Resources, Inc., as borrower, certain of its subsidiaries, as guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders signatories thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated September 29, 2009 and filed on October 5, 2009 and incorporated by reference herein.
10.36	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.37	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.38	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.39	Amendment Number One to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an exhibit to EXCO's Current Report on Form 8-K, dated June 4, 2009 and filed on June 10, 2009 and incorporated by reference herein.
10.40	Joint Development Agreement, dated August 14, 2009, by and among BG US Production Company, LLC, EXCO Operating Company, LP and EXCO Production Company, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.41	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
10.42	Amended and Restated Limited Liability Company Agreement of TGGT Holdings, LLC, dated August 14, 2009, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.43	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.44	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
10.45	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO – North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
10.46	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
14.1	Code of Ethics for the Chief Executive Officer and Senior Financial Officers, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.2	Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.3	Amendment No. 1 to EXCO Resources, Inc. Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
21.1	Subsidiaries of the registrant, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
23.1	Consent of KPMG LLP, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
23.2	Consent of Lee Keeling and Associates, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
23.3	Consent of Haas Petroleum Engineering Services, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Financial Officer of EXCO Resources, Inc., filed herewith.

Exhibit Number	Description of Exhibits
31.3	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Accounting Officer of EXCO Resources, Inc., filed herewith.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer and Chief Financial Officer of EXCO Resources, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated by reference herein.
99.1	2009 Reports of Lee Keeling and Associates, Inc., filed herewith.
99.2	2009 Report of Haas Petroleum Engineering Services, Inc., filed herewith.

* These exhibits are management contracts.

DIRECTORS

Douglas H. Miller
Chairman of the Board and Chief Executive Officer
EXCO Resources, Inc.

Stephen F. Smith
Vice Chairman of the Board, President and Chief Financial Officer
EXCO Resources, Inc.

Jeffrey D. Benjamin [1,2,3]
Senior Advisor
Cyrus Capital Partners, LP

Vincent J. Cebula [2,3]
Managing Director
Jeffries Capital Partners

Earl E. Ellis [2]
Chairman and Chief Executive Officer
Whole Harvest Products

B. James Ford [2,3]
Managing Director
Oaktree Capital Management, L.P.

Mark F. Mulhern [1,2]
Chief Financial Officer
Progress Energy, Inc.

Boone Pickens
Chairman and Chief Executive Officer
BP Capital LP

Jeffrey S. Serota [1,2,3]
Senior Partner
Ares Management, LLC

Robert L. Stillwell [2,3]
General Counsel
BP Capital LP

[1]Audit Committee Member
[2]Compensation Committee Member
[3]Nominating and Corporate Governance Committee Member

OFFICERS

Douglas H. Miller
Chairman of the Board and Chief Executive Officer

Stephen F. Smith
Vice Chairman of the Board, President and Chief Financial Officer

Harold L. Hickey
Vice President and Chief Operating Officer

Mark E. Wilson
Vice President, Controller and Chief Accounting Officer

William L. Boeing
Vice President, General Counsel and Secretary

Michael R. Chambers, Sr.
Vice President of Operations and General Manager-East Texas / North Louisiana Division

W. Justin Clarke
Assistant General Counsel, Chief Compliance Officer and Assistant Secretary

Joe D. Ford
Vice President of Human Resources

Richard L. Hodges
Vice President of Land and Assistant Secretary

John D. Jacobi
Vice President of Business Development and Marketing

Tommy Knowles
Vice President and General Manager-Permian Division

Stephen E. Puckett
Vice President of Reservoir Engineering

J. Douglas Ramsey, Ph.D.
Vice President-Finance and Treasurer

Paul B. Rudnicki
Vice President of Financial Planning and Analysis

Marcia Reeves Simpson
Vice President of Engineering

Andrew C. Springer
Vice President of Tax

Wendy L. Straatmann
Vice President and General Manager-Appalachia Division

Robert L. Thomas
Chief Information Officer

SHAREHOLDER INFORMATION

Shareholder Relations
Donna Sablotny
214-706-3310

NYSE Symbol
XCO – Common Stock

Auditors
KPMG LLP
717 North Harwood Street,
Suite 3100
Dallas, TX 75201

Legal Counsel
Haynes and Boone, LLP
2323 Victory Avenue, Suite 700
Dallas, TX 75219

Vinson & Elkins LLP
Trammell Crow Center
2001 Ross Avenue, Suite 3700
Dallas, TX 75201

Annual Meeting
The 2010 Annual Meeting of Shareholders will be held on Thursday, June 17, 2010 at 9:30 am Dallas time, at the Westin Park Central, Salon ABC, 12720 Merit Drive, Dallas, Texas 75251.

Stock Transfer Agent
Continental Stock Transfer & Trust Company
Communications concerning transfer or exchange requirements, lost certificates, shareholdings or changes of address should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212-509-4000

Number of Common Shareholders
22,019
(As of March 3, 2010)

EXCO Resources, Inc.
12377 Merit Drive, Suite 1700, Dallas, TX 75251
www.excoresources.com