PARKERVISION INC
Form DEF 14A
August 16, 2012

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

SCHEDULE 14A
(Rule 14a-101)

INFORMATION REQUIRED IN PROXY STATEMENT

SCHEDULE 14A INFORMATION

Proxy Statement Pursuant to Section 14(a) of the Securities
Exchange Act of 1934 (Amendment No.)

Filed by the Registrant [X]
Filed by a Party other than the Registrant [ ]

Check the appropriate box:

[ ]	Preliminary Proxy Statement
[ ]	Confidential, For Use of the Commission Only (as permitted by Rule 14a-6(e)(2))
[X]	Definitive Proxy Statement
[ ]	Definitive Additional Materials
[ ]	Soliciting Material Pursuant to §240.14a-12

PARKERVISION, INC.
(Name of Registrant as Specified in Its Charter)

N/A
(Name of Person(s) Filing Proxy Statement, if Other Than the Registrant)

Payment of Filing Fee (Check the appropriate box):

[X] No fee required.

[ ] Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies: ___________________

(2) Aggregate number of securities to which transaction applies: ___________________

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

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(4) Proposed maximum aggregate value of transaction: ___________________

(5) Total fee paid: ___________________

[ ] Fee paid previously with preliminary materials: ___________________

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(1) Amount previously paid: ___________________

(2) Form, Schedule or Registration Statement No.: ___________________

(3) Filing Party: ___________________

(4) Date Filed: ___________________

PARKERVISION, INC.
7915 Baymeadows Way, Suite 400
Jacksonville, Florida 32256

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS
TO BE HELD OCTOBER 2, 2012

Notice is hereby given that the Annual Meeting of Shareholders (the "Annual Meeting") of ParkerVision, Inc. (the "Company") will be held on Tuesday, October 2, 2012 at 9:00 a.m. Eastern Daylight Time, at The Westin Lake Mary Orlando North, 2974 International Parkway, Lake Mary, Florida 32746, for the following purposes:

1. To elect seven members of the Company's board of directors to hold office until the next annual meeting and until their respective successors are duly elected and qualified;

2. To approve an amendment to the articles of incorporation of the Company, as amended, to increase the number of authorized shares of common stock from 100,000,000 shares to 150,000,000 shares;

3. To ratify the selection of PricewaterhouseCoopers LLP as the Company's independent registered certified public accounting firm for the year ending December 31, 2012; and

4. To transact such other business as may properly come before the Annual Meeting or any adjournments or postponements thereof.

The transfer books will not be closed for the Annual Meeting. The board of directors has fixed the close of business on August 6, 2012 as the record date for the determination of shareholders entitled to notice of, and to vote at, the Annual Meeting, and any adjournments thereof.

Pursuant to rules adopted by the Securities and Exchange Commission, the Company has elected to provide access to its proxy materials over the Internet. Accordingly, the Company has sent you a Notice of Internet Availability of Proxy Materials. You are urged to read the attached proxy statement, which contains information relevant to the actions to be taken at the Annual Meeting. In order to assure the presence of a quorum, whether or not you expect to attend the Annual Meeting in person, please vote your shares by proxy by following the procedures and instructions described on the Notice of Internet Availability of Proxy Materials. You may revoke your proxy if you so desire at any time before it is voted. For directions to the Annual Meeting, please contact the Company's Corporate Secretary at (904) 732-6100.

Important Notice Regarding the Availability of Proxy Materials for the Shareholder Meeting to be held on October 2, 2012: The Company's proxy statement and annual report to security holders are available at https://www.proxyvote.com.

By Order of the Board of Directors

Cynthia Poehlman
Chief Financial Officer and Corporate Secretary

Jacksonville, Florida
August 16, 2012

PARKERVISION, INC.

PROXY STATEMENT
FOR THE ANNUAL MEETING OF SHAREHOLDERS
TO BE HELD ON OCTOBER 2, 2012

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PARKERVISION, INC.

PROXY STATEMENT
FOR THE ANNUAL MEETING OF SHAREHOLDERS
TO BE HELD ON OCTOBER 2, 2012

INFORMATION CONCERNING SOLICITATION AND VOTING

General

This proxy statement and the accompanying proxy materials are being furnished to our shareholders in connection with the solicitation of proxies by our board of directors (our “Board”) for use at our annual meeting of shareholders (the “Annual Meeting”) to be held at 9:00 a.m. Eastern Daylight Time on Tuesday, October 2, 2012 and any adjournments or postponements thereof. The Annual Meeting is being held for the following purposes:

1. To elect seven members of our Board to hold office until the next annual meeting and until their respective successors are duly elected and qualified;

2. To approve an amendment to the articles of incorporation of the company, as amended (the “Articles”), to increase the number of authorized shares of common stock from 100,000,000 shares to 150,000,000 shares;

3. To ratify the selection of PricewaterhouseCoopers LLP as our independent registered certified public accounting firm for the year ending December 31, 2012; and

4. To transact such other business as may properly come before the Annual Meeting or any adjournment or postponement thereof.

The Annual Meeting will be held at The Westin Lake Mary Orlando North, 2974 International Parkway, Lake Mary, Florida 32746. This proxy statement and the accompanying proxy materials will be sent or made available to shareholders on or about August 16, 2012.

Internet Availability of Proxy Materials

The Securities and Exchange Commission (“SEC”) has adopted rules that allow us to mail a notice to our shareholders that our proxy statement, annual report to shareholders, and related materials are available for viewing free of charge, on the Internet. Shareholders may access these materials and vote over the Internet or request delivery of a full set of material by mail or email. We have elected to utilize this process for many of our shareholders for the Annual Meeting. We intend to begin mailing the required notice, called Notice of Internet Availability of Proxy Materials (the “Notice”), to such shareholders on or about August 16, 2012. The proxy materials will be posted on the Internet at https://www.proxyvote.com, no later than the day we begin mailing the Notice. If you receive a Notice, you will not receive a paper or email copy of the proxy materials unless you request one in the manner set forth in the Notice.

The Notice contains important information, including:

- The date, time and location of the Annual Meeting;

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- A brief description of the matters to be voted on at the Annual Meeting
- A list of the proxy materials available for viewing on https://www.proxyvote.com and the control number you will use to access the site; and
- Instructions on how to access and review the proxy materials online, how to vote your shares over the Internet, and how to get a paper or email copy of the proxy materials, if that is your preference.

These rules give us the opportunity to serve you more efficiently by making the proxy materials available quickly online and reducing costs associated with printing and postage. Shareholders who do not receive a Notice will instead receive a full set of the proxy materials, including our proxy statement, annual report to shareholders, and proxy card. Such shareholders may vote by mail or by Internet by following the instructions set forth on the proxy card.

Record Date and Voting Securities

Our Board has fixed the close of business on August 6, 2012 as the record date for determination of shareholders entitled to notice of, and to vote at, the Annual Meeting. As of August 6, 2012, we had issued and outstanding 78,305,174 shares of common stock, par value $.01 per share, our only class of voting securities outstanding. Each of our shareholders is entitled to one vote for each share of common stock registered in his or her name on the record date.

Voting

If you hold your shares of record, you may vote by proxy via the Internet by following the instructions provided in the Notice. If you requested printed copies of the proxy materials by mail, you also may vote by proxy via the telephone by calling the toll free number found on the proxy card, or via the mail by filling out the proxy card and sending it back in the envelope provided. You also may vote in person at the Annual Meeting by submitting the ballot that will be provided to you.

If you hold your shares in street name, please refer to the materials provided to you by your bank, broker or other holder of record for information on communicating your voting instructions. If you hold your shares in street name and you want to vote in person, you must obtain an additional proxy from your bank, broker or other holder of record authorizing you to vote. You must bring this proxy to the Annual Meeting, present it to the inspector of election and produce valid identification. If you hold your shares in street name, your bank, broker or other holder of record will not be permitted to vote on your behalf for the election of our directors unless it receives voting instructions from you. To ensure that your vote is counted, please communicate your voting instructions to your broker, bank, or other financial institution before the Annual Meeting, or arrange to attend the Annual Meeting in person.

Proxies and Revocation of Proxies

Your proxy is being solicited by our Board. By giving your proxy, you are appointing as your proxies the persons that have been designated by our Board. Any proxy given pursuant to this solicitation and received in time for the Annual Meeting will be voted in accordance with your instructions. If no instructions are given, proxies given by shareholders will be voted “FOR” the election of each of the director nominees, “FOR” the amendment to the Articles to increase the number of authorized shares of common stock, and “FOR” ratification of the selection of PriceWaterhouseCoopers LLC as our independent registered certified public accounting firm. With respect to any other proposal that properly comes before the Annual Meeting, the persons appointed as proxies will vote as recommended by our Board or, if no recommendation is given, in their own discretion, to the extent permitted by applicable laws and regulations.

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Any proxy may be revoked by (i) submitting a written notice of revocation that is received by our Corporate Secretary at any time prior to the voting at the Annual Meeting, (ii) submitting a subsequent proxy prior to the voting at the Annual Meeting or (iii) attending the Annual Meeting and voting in person. Attendance by a shareholder at the Annual Meeting does not alone serve to revoke his or her proxy. Shareholders may send written notice of revocation to the Corporate Secretary, ParkerVision, Inc., 7915 Baymeadows Way, Suite 400, Jacksonville, Florida 32256.

Quorum and Required Vote

The presence, in person or by proxy, of a majority of the votes entitled to be cast at the Annual Meeting will constitute a quorum at the meeting. A proxy submitted by a shareholder may indicate that all or a portion of the shares represented by his or her proxy are not being voted ("shareholder withholding") with respect to a particular matter. Similarly, a broker may not be permitted to vote stock held in street name on a particular matter in the absence of instructions from the beneficial owner of the stock ("broker non-vote"). The shares subject to a proxy which are not being voted on a particular matter because of either shareholder withholding or a broker non-vote will not be considered shares present and entitled to vote on the matter. These shares, however, may be considered present and entitled to vote on other matters and will count for purposes of determining the presence of a quorum, unless the proxy indicates that the shares are not being voted on any matter at the Annual Meeting, in which case the shares will not be counted for purposes of determining the presence of a quorum.

The directors will be elected by a plurality of the votes cast at the Annual Meeting. "Plurality" means that the nominees who receive the highest number of votes in their favor will be elected as our directors. Consequently, any shares not voted "FOR" a particular nominee, because of either shareholder withholding or broker non-vote, will not be counted in the nominee's favor. Shareholders do not have cumulative voting rights for directors.

The ratification of the selection of PricewaterhouseCoopers LLC as our independent registered certified public accounting firm and the approval of the amendment to the Articles to increase the number of authorized shares of common stock must be approved by the affirmative vote of a majority of the votes cast at the Annual Meeting. Abstentions from voting are counted as "votes cast" with respect to the proposals and, therefore have the same effect as a vote against the proposals. Shares deemed present at the Annual Meeting but not entitled to vote because of either shareholder withholding or broker non-vote are not deemed "votes cast" with respect to the proposals, and therefore will have no effect on the vote.

All other matters that may be brought before the shareholders must be approved by the affirmative vote of a majority of the votes cast at the Annual Meeting, unless the governing corporate law, the Articles or our bylaws require otherwise. Abstentions from voting are counted as "votes cast" with respect to the proposal and, therefore have the same effect as a vote against the proposal. Shares deemed present at the Annual Meeting but not entitled to vote because of either shareholder withholding or broker non-vote are not deemed "votes cast" with respect to the proposal, and therefore will have no effect on the vote.

No appraisal rights are available under Florida law, the Articles or our bylaws if you dissent from or vote against any of the proposals to be presented at the Annual Meeting.

Solicitation of Proxies

Your proxy is being solicited by our Board. In addition to the use of the mail and the Internet, solicitations may be made personally or by email or telephone, as well as by public announcement. We have engaged Morrow & Co., LLC to assist with the solicitation of proxies at an estimated cost of $7,500 plus disbursements. Our officers and other employees, without additional remuneration, may also assist in the solicitation of proxies in the ordinary course of their employment. We will bear the cost of this proxy solicitation. We may also request brokers, dealers, banks and their nominees to solicit proxies from their clients where appropriate, and may reimburse them for reasonable expenses related thereto.

Our Annual Report on Form 10-K for the fiscal year ended December 31, 2011 (“Annual Report”), which contains our audited financial statements, is being sent or made available to our shareholders along with this proxy statement. We will provide to you exhibits to the Annual Report upon payment of a fee of $.25 per page, plus $5.00 postage and handling charge, if a request is sent in writing to the Corporate Secretary, ParkerVision, Inc., 7915 Baymeadows Way, Suite 400, Jacksonville, Florida 32256.

PROPOSAL 1: ELECTION OF DIRECTORS

All of the members of our Board are elected annually. Our Board currently consists of seven members. Our Board has nominated Jeffrey Parker, William Hightower, John Metcalf, David Sorrells, Robert Sterne, Nam Suh, and Papken der Torossian for re-election as directors, to serve until the next annual meeting of shareholders and until their respective successors have been elected and qualified. Unless otherwise specified by you when you give your proxy, the shares subject to your proxy will be voted “FOR” the election of these nominees. In case any of these nominees become unavailable for election to the Board, an event which is not anticipated, the persons appointed as proxies, or their substitutes, shall have full discretion and authority to vote or refrain from voting your shares for any other person in accordance with their judgment.

THE BOARD RECOMMENDS THAT YOU VOTE “FOR” EACH OF THE NOMINEES.

Directors and Executive Officers

Name	Age	Position with the Company
Jeffrey Parker	55	Chairman of the Board and Chief Executive Officer
William Hightower	69	Director
John Metcalf	61	Director
David Sorrells	53	Chief Technical Officer and Director
Robert Sterne	60	Director
Nam Suh	76	Director
Papken der Torossian	73	Director
Cynthia Poehlman	45	Chief Financial Officer and Corporate Secretary

John Stuckey	41	Executive Vice President of Corporate Strategy and Business Development

Jeffrey Parker has been the chairman of our Board and our chief executive officer since our inception in August 1989 and was our president from April 1993 to June 1998. From March 1983 to August 1989, Mr. Parker served as executive vice president for Parker Electronics, Inc., a joint venture partner with Carrier Corporation performing research development, manufacturing and sales and marketing for the heating, ventilation and air conditioning industry. Mr. Parker holds 31 United States patents. As Chief Executive Officer, Mr. Parker has relevant insight into our operations, our industry, and related risks as well as experience bringing disruptive technologies to market.

William Hightower has been a director of ours since March 1999. Mr. Hightower has extensive experience as an executive officer and operating officer for both public and private companies in a number of industries, including telecommunications. From September 2003 to his retirement in November 2004, Mr. Hightower served as our president. Mr. Hightower was the president and chief operating officer and a director of Silicon Valley Group, Inc. ("SVGI"), from August 1997 until his retirement in May 2001. SVGI is a publicly held company which designs and builds semiconductor capital equipment tools for chip manufacturers. From January 1996 to August 1997, Mr. Hightower served as chairman and chief executive officer of CADNET Corporation, a developer of network software solutions for the architectural industry. From August 1989 to January 1996, Mr. Hightower was the president and chief executive officer of Telematics International, Inc. Mr. Hightower's longevity on our board provides him with a historical perspective and a relevant understanding of both our target markets and our industry as a whole.

John Metcalf has been a director of ours since June 2004. From November 2002 until his retirement in July 2010, Mr. Metcalf was a chief financial officer ("CFO") partner with Tatum LLC, the largest executive services and consulting firm in the United States. Mr. Metcalf has 18 years experience as a CFO. Since August 2011, Mr. Metcalf has served on the board of directors and has been chairman of the audit, compensation, and nominating committees of Trellis Earth Products, Inc. From July 2006 to September 2007, Mr. Metcalf served as CFO for Electro Scientific Industries, Inc. ("ESI"), a provider of high-technology manufacturing equipment to the global electronics market. From June 2004 to July 2006, Mr. Metcalf served as CFO for Siltronic AG. From June 2007 until July 2011, Mr. Metcalf served on the board of directors and was chairman of the audit committee of EnergyConnect Group, Inc. (formerly Microfield Group, Inc.), a publicly traded company that was acquired by Johnson Controls, Inc. in July 2011. Mr. Metcalf has extensive experience in the semiconductor industry, an in-depth understanding of generally accepted accounting principles, financial statements and SEC reporting requirements, and satisfies the audit committee requirement for financial expertise.

David Sorrells has been our chief technical officer since September 1996 and has been a director of ours since January 1997. Mr. Sorrells is one of the leading inventors of our core technologies. From June 1990 to September 1996, Mr. Sorrells served as our engineering manager. Mr. Sorrells has an in-depth understanding of our technologies and their relevance to target markets. He holds 201 United States patents.

Robert Sterne has been a director of ours since September 2006 and also served as a director from February 2000 to June 2003. Since 1978, Mr. Sterne has been a partner of the law firm of Sterne, Kessler, Goldstein & Fox PLLC, specializing in patent and other intellectual property law. Mr. Sterne provides legal services to us as one of our patent and intellectual property attorneys. As such, Mr. Sterne has an in-depth knowledge of our intellectual property portfolio and patent strategies. Furthermore, Mr. Sterne is considered a leader in best practices and board responsibilities concerning intellectual property.

Nam Suh has been a director of ours since December 2003. Mr. Suh has served as the president of Korea Advanced Institute of Science and Technology since July 2006. In 2008, he retired from the Massachusetts Institute of Technology ("MIT") where he had been a member of the faculty since 1970. At MIT, Mr. Suh held many positions including director of the MIT Laboratory for Manufacturing and Productivity, head of the department of Mechanical Engineering, director of the MIT Manufacturing Institute, and director of the Park Center for Complex Systems. In 1984, Mr. Suh was appointed the assistant director for Engineering of the National Science Foundation by President Ronald Reagan and confirmed by the U.S. Senate. From 2005 to 2009, Mr. Suh served on the board of directors of Integrated Device Technology, Inc., a NASDAQ-listed company that develops mixed signal semiconductor solutions, and, from 2004 to 2007, he served on the board of directors of Therma-Wave, Inc., a NASDAQ-listed company that manufactures process control metrology systems for use in semiconductor manufacturing. Mr. Suh has significant experience with technology innovation and the process of new product introduction, including an invention selected as one of the 50 most promising new inventions of 2010 by TIME magazine. Mr. Suh is a widely published author of approximately 300 articles and seven books on topics related to tribology, manufacturing, plastics and design. Mr.

Suh has approximately 60 United States patents and many foreign patents, some of which relate to plastics, polymers and design and is the recipient of eight honorary doctorates from various universities on four continents. Mr. Suh has a relevant professional network in the Korean community as well as relevant experience with Korean culture and commerce.

Papken der Torossian has been a director of ours since June 2003. Mr. der Torossian has extensive experience as chairman and chief executive of a number of semiconductor and technology-based companies. Mr. der Torossian was chief executive officer of SVGI from 1986 until 2001. Prior to his joining SVGI, he was president and chief executive officer of ECS Microsystems, a communications and PC company that was acquired by Ampex Corporation where he stayed on as a manager for a year. From 1976 to 1981, Mr. der Torossian was president of the Santa Cruz Division of Plantronics where he also served as vice president of the Telephone Products Group. Previous to that he spent four years at Spectra-Physics, Inc. and twelve years with Hewlett-Packard in a variety of management positions. Mr. der Torossian has served as director on a number of private company boards including executive chairman of Vistec Semiconductor Systems Group, one of the portfolio companies of Golden Gate Capital, a private equity firm where Mr. der Torossian serves as advisor for semiconductor related activities. Since August 2007, Mr. der Torossian has served as a director and a member of the compensation committee and nominating and governance committees of Atmel Corporation, a publicly traded company. From March 2003 until May 2007, Mr. der Torossian served as chairman of the board of directors of Therma-Wave, Inc., a NASDAQ-listed company. Mr. der Torossian has a relevant network in the technology community as well as relevant operating experience with small, high growth companies.

Cynthia Poehlman has been our chief financial officer since June 2004 and our corporate secretary since August 2007. From March 1994 to June 2004, Ms. Poehlman was our controller and our chief accounting officer. Ms. Poehlman has been a certified public accountant in the state of Florida since 1989.

John Stuckey joined the company in July 2004 as the vice-president of corporate strategy and business development and was promoted to executive vice-president of corporate strategy and business development in June 2008. Prior to July 2004, Mr. Stuckey spent five years at Thomson, Inc. where he most recently served as director of business development.

CORPORATE GOVERNANCE

We maintain corporate governance policies and practices that reflect what the Board believes are "best practices." A copy of our Corporate Governance Guidelines is available upon request to our Secretary, or may be viewed or downloaded from our website at http://www.parkervision.com.

Leadership Structure

Our Board is led by Jeffrey Parker, our Chairman of the Board and Chief Executive Officer. The decision as to who should serve as Chairman of the Board, who should serve as Chief Executive Officer, and whether those offices should be combined or separate, is the responsibility of our Board. The members of our Board possess considerable experiences and unique knowledge of the challenges and opportunities we face, and are in the best position to evaluate our needs and how best to organize the capabilities of the directors and senior officers to meet those needs. Our Board does not believe that our size or the complexity of our operations warrants a separation of the Chairman of the Board and Chief Executive Officer functions. Furthermore, our Board believes that combining the roles of Chief Executive Officer and Chairman of the Board promotes leadership and direction for the Board and for executive management, as well as allowing for a single, clear focus for the chain of command.

The Board believes that the most effective leadership structure for us at this time is for Mr. Parker to serve as both Chairman of the Board and Chief Executive Officer. Mr. Parker is one of our founders and has been our Chairman of the Board and our Chief Executive Officer since our inception in August 1989. The Board believes that he is uniquely qualified through his experience and expertise to be the person who generally sets the agenda for, and leads discussions of, issues relating to the implementation of our strategic plan. Mr. Parker's leadership, in both his Chairman of the Board and Chief Executive Officer roles, continues to ensure that we remain dedicated to and focused on both our short and long-term objectives. While the Board does not have a lead independent director, the independent directors meet in executive session regularly without the presence of management.

Independence of Directors

Our common stock is listed on the NASDAQ Capital Market of The NASDAQ Stock Market, LLC ("NASDAQ"), and we follow the rules of NASDAQ in determining if a director is independent. The Board consults with our counsel to ensure that the Board's determinations are consistent with the rules of NASDAQ and all relevant securities and other laws and regulations regarding the independence of directors. Consistent with these considerations, the Board affirmatively has determined that William Hightower, John Metcalf, Robert Sterne, Nam Suh, and Papken der Torossian are our independent directors. The other directors are not considered independent due to their current employment by us.

Risk Management and Board Oversight

The Board as a whole works with our management team to promote and cultivate a corporate environment that incorporates enterprise-wide risk management into strategy and operations. Management periodically reports to the Board about the identification, assessment and management of critical risks and management's risk mitigation strategies. Each committee of the Board is responsible for the evaluation of elements of risk management based on the committee's expertise and applicable regulatory requirements. In evaluating risk, the Board and its committees consider whether our programs adequately identify material risks in a timely manner and implement appropriately responsive risk management strategies throughout the organization. The audit committee focuses on assessing and mitigating financial risk, including internal controls, and receives at least quarterly reports from management on identified risk areas. In setting compensation, the compensation committee strives to create incentives that encourage behavior consistent with our business strategy, without encouraging undue risk-taking. The nominating and corporate governance committee considers areas of potential risk within corporate governance and compliance, such as management succession. Each of the committees reports regularly to the Board as a whole as to their findings with respect to the risks they are charged with assessing.

Board Meetings and Committees

Members of our Board are elected annually by our shareholders and may be removed as provided for in the Florida Business Corporation Act, the Articles and our bylaws. The Board has three separately standing committees: the audit committee, the compensation committee and the nominating and corporate governance committee. Each committee is composed entirely of independent directors as determined in accordance with current NASDAQ listing standards. In addition, each committee has a written charter, a copy of which is available free of charge on our website at http://www.parkervision.com.

During the fiscal year ended December 31, 2011, our Board met eleven times and acted by unanimous consent three times. All of our directors attended 75% or more of the aggregate number of meetings of the Board and committees on which they served, except for Mr. Robert Sterne who attended 64% of the Board meetings. The directors are strongly encouraged to attend meetings of shareholders. All of our directors attended our 2011 annual meeting of shareholders, except Mr. Robert Sterne and Dr. Nam Suh who were unable to attend due to international travel conflicts.

Audit Committee

John Metcalf (Chair), William Hightower and Papken der Torossian are the current members of our audit committee. The audit committee met six times in 2011 and acted by unanimous consent two times. The functions of the audit committee include oversight of the integrity of our financial statements, compliance with legal and regulatory requirements, and the performance, qualifications and independence of our independent auditors. The audit committee also reviews and recommends to the board of directors whether or not to approve transactions between the company and an officer or director outside the ordinary course of business. The purpose and responsibilities of our audit committee are set forth in full in the Audit Committee Charter. The Report of the Audit Committee is included on page 10 of this proxy statement.

Audit Committee Financial Expert

The Board has determined that John Metcalf is an audit committee financial expert within the meaning of the rules and regulations of the SEC and is independent as determined in accordance with current NASDAQ listing standards for audit committee members. In addition, we must certify to NASDAQ that the audit committee has, and will continue to have, at least one member who has past employment experience in finance or accounting, requisite professional certification in accounting, or other comparable experience or background that results in the individual's "financial sophistication." Our board has determined that Mr. Metcalf's qualifications also satisfy NASDAQ's definition of financial sophistication.

Compensation Committee

Papken der Torossian (Chair), William Hightower and Nam Suh are the current members of our compensation committee. The compensation committee met nine times in 2011 and acted by unanimous consent two times. The functions of the compensation committee include oversight of the development, implementation and effectiveness of our compensation philosophy, policies and strategies and oversight of the regulatory compliance and reporting requirements with respect to compensation and related matters. Our compensation committee has overall responsibility for evaluating and approving our executive officer incentive compensation, benefit, severance, equity-based and other compensation plans, policies and programs. The compensation committee is responsible for discussing and reviewing with management any compensation discussion and analysis that we include in our filings with the SEC. The purpose and responsibilities of our compensation committee are set forth in full in the Compensation Committee Charter. The Compensation Committee Report is included on page 11 of this proxy statement.

The compensation committee sets the chief executive officer's compensation and the compensation for other executive officers after review of the recommendations of the chief executive officer, and makes recommendations to the Board with respect to the non-employee directors' compensation. The compensation committee also administers our 2011 Long-Term Incentive Equity Plan, our 2008 Equity Incentive Plan (Non-Named Executive), our 2000 Performance Equity Plan and, to the extent of outstanding awards, our 1993 Stock Option Plan. According to its charter, the compensation committee may delegate the authority to grant equity awards, within parameters defined by the compensation committee and subject to the rules of NASDAQ. The compensation committee has retained, from time to time, a third-party compensation consultant to assist in the review of executive and board compensation programs. During 2011, however, the committee did not retain a compensation consultant.

Nominating and Corporate Governance Committee

John Metcalf (Chair), Robert Sterne and Nam Suh are the current members of our nominating and corporate governance committee. The nominating and corporate governance committee met one time in 2011 and acted one time by unanimous consent. The functions of the nominating and corporate governance committee include identification and recommendation of director nominees qualified to serve on the Board and recommendation to the Board of corporate governance guidelines for our company. The purpose and responsibilities of our nominating and corporate governance committee are set forth in full in the Nominating and Corporate Governance Committee Charter.

Director Nomination Process

The nominating and corporate governance committee considers persons identified by its members, management, shareholders, potential investors, investment bankers and others with the objective of having a Board with diverse perspectives and skills. The committee does not distinguish among nominees recommended by shareholders and other persons. Each individual is evaluated in the context of the Board as a whole, with the objective of recommending a group of persons that can best implement our business plan, perpetuate our business and represent shareholder interests.

The nominating and corporate governance committee is responsible for assessing the appropriate balance of skills and characteristics required of Board members. Though the committee does not have specific guidelines on diversity, it is one of many criteria considered by the Board when evaluating candidates. Nominees for director are selected on the basis of, among other things, experience, integrity, ability to make independent analytical inquiries, understanding of our business environment and willingness and ability to devote adequate time to Board duties. Nominees for director shall be assessed based on the needs of the Board at that point in time and with an objective of ensuring diversity in background, experience and viewpoints of Board members.

Shareholders and others wishing to suggest candidates to the nominating committee for consideration as directors must submit written notice to the Corporate Secretary, ParkerVision, Inc., 7915 Baymeadows Way, Suite 400, Jacksonville, Florida 32256, who will provide it to the nominating committee. We also have a method by which shareholders may nominate persons as directors, which is described in the section “Shareholder Proposals and Nominations” on page 31 of this proxy statement. We did not receive any recommendations from shareholders for this Annual Meeting.

Code of Ethics and Shareholder Contact

The Board has adopted a code of ethics that is designed to deter wrongdoing and to promote ethical conduct and full, fair, accurate, timely and understandable reports that we file or submit to the SEC and others. A copy of the code of ethics may be found on our website at www.parkervision.com.

Shareholders may contact the Board or individual members of the Board by writing to them in care of the Corporate Secretary, ParkerVision, Inc., 7915 Baymeadows Way, Suite 400, Jacksonville, Florida 32256. The Corporate Secretary will forward all correspondence received to the Board or the applicable director from time to time. This procedure was approved by the independent directors.

AUDIT COMMITTEE REPORT

Pursuant to the charter of the audit committee originally adopted on April 25, 2003, as amended on July 31, 2006 and March 5, 2012, the audit committee's responsibilities include, among other things:

- annually reviewing and reassessing the adequacy of the audit committee's formal charter;
- reviewing and discussing our annual audited financial statements, our interim financial statements, and the adequacy of our internal controls and procedures with our management and our independent auditors;
- reviewing the quality of our accounting principles, including significant financial reporting issues and judgments made in connection with the preparation of our financial statements;
- appointing the independent auditor, which firm will report directly to the audit committee;
- reviewing the independence of the independent auditors; and
- reviewing and approving all related party transactions on an ongoing basis.

The audit committee also pre-approves the services to be provided by the Company's independent auditors. During the period April 1, 2011 through March 31, 2012, the committee reviewed in advance the scope of the annual audit and non-audit services to be performed by the independent auditors and the independent auditors' audit and non-audit fees and approved them.

The audit committee reviewed and discussed the audited financial statements with management, as well as with our independent auditors. During 2011 and thereafter, the audit committee met privately at regularly scheduled meetings and held discussions with management, including the chief financial officer and our independent auditors. Management represented to the audit committee that our consolidated financial statements were prepared in accordance with generally accepted accounting principles. The audit committee also discussed and reviewed with management and the independent auditors the internal controls and procedures of the audit functions and the objectivity of the process of reporting on the financial statements. The committee discussed with management financial risk exposures relating to the company and the processes in place to monitor and control the resulting exposure, if any.

The audit committee discussed with the independent auditors the matters required to be discussed by the statement on Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board ("PCAOB") in Rule 3200T, as well as various accounting issues relating to presentation of certain items in our financial statements and compliance with Section 10A of the Securities Exchange Act of 1934. The committee received the written disclosures and letter from the independent auditors required by the applicable requirements of the PCAOB regarding the independent auditors' communications with the committee concerning independence, and the committee discussed with the independent auditors the independent auditors' independence.

Based upon the review and discussions referred to above, the audit committee recommended to the board of directors that our audited consolidated financial statements be included in the company's Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC. The committee evaluated the performance of PricewaterhouseCoopers LLP and recommended to the board of directors their re-appointment as the independent auditors for the fiscal year ending December 31, 2012.

Submitted by the Audit Committee:
John Metcalf (Chair)
William Hightower
Papken der Torossian

EXECUTIVE OFFICER AND DIRECTOR COMPENSATION

Compensation Committee Interlocks and Insider Participation

The members of our compensation committee are all independent directors as determined in accordance with the rules of NASDAQ. As of December 31, 2011, the members of our compensation committee were Messrs. Papken der Torossian, William Hightower, and Nam Suh. No member of our compensation committee is or has been an executive officer of our company or had any relationship with us requiring disclosure as a related party transaction under the rules and regulations of the SEC, except that Mr. Hightower served as our President from September 2003 to November 2004. None of our executive officers served as a director or member of a compensation committee (or other committee serving an equivalent function) of any other entity, an executive officer of which served as one of our directors or a member of our compensation committee.

Compensation Committee Report

We, the Compensation Committee of the Board of Directors, have reviewed and discussed the Compensation Discussion and Analysis ("CD&A") required by Item 402(b) of Regulation S-K with management of the company. Based on such review and discussion, we have recommended to the Board of Directors that the CD&A be included as part of this proxy statement.

Submitted by the Compensation Committee:
Papken der Torossian (Chair)
William Hightower
Nam Suh

Compensation Discussion and Analysis

Overview of Compensation Program

Our compensation program is designed to support our business objectives by structuring compensation packages to retain, reward, motivate, and attract employees who possess the required technical and entrepreneurial skills and talent. The overall objectives of the business are to continue innovative technological advances of our wireless technologies, achieve technical and commercial acceptance of our wireless technologies, and, in doing so, to create significant shareholder value. The compensation of our executives is designed to reward the achievement of both quantitative and qualitative performance goals, which specifically relate to the objectives of the business both short- and long-term.

Based on a consideration of our financial performance and other relevant corporate factors, the Committee limited its review of executive compensation programs in 2011 to long-term equity incentive award programs.

Comparative Benchmarking

In establishing our executive compensation policies, programs and awards, the Committee periodically reviews a comparative peer group ("Peer Group") for compensation benchmarking data. The Peer Group is selected based on (i) companies generally in wireless communications or communications equipment industries with an emphasis on semiconductor providers in particular, (ii) companies that are similarly sized in terms of market capitalization values, (iii) companies with similar growth and performance potential, and/or (iv) companies that are considered competitors of ours in either the labor or capital markets. The current Peer Group was established by the Committee in 2009 and updated in 2011 to eliminate companies that were no longer relevant based on their business or financial metrics. The Peer Group utilized for 2011 comparative benchmarking includes the following twelve companies: Anadigics, Inc., Anaren, Inc., DSP Group, Inc., Emcore Corporation, GlobalStar, Inc., KVH Industries, Inc., MoSys, Inc., Oplink Communications, Inc., Powerwave Technologies, Inc., Superconductor Technologies, Inc., TranSwitch Corporation, and Volterra Semiconductor Corporation.

The Committee utilized data from this Peer Group to analyze executive long-term incentive compensation in 2011, as more fully discussed below.

Compensation Components

There are three primary components of our compensation plan: (1) base salaries, (2) annual performance incentives, and (3) long-term incentives. These components are the same for all of our employees. The amount of each component is scaled according to the level of business responsibilities of each individual. We do not target a specific weighting of these three components or use a prescribed formula to establish pay levels. Rather the Committee considers changes in the business, external market factors, and our financial position each year when determining pay levels and allocating between long-term and current compensation for our named executive officers as defined in Item 402(a) of Regulation S-K (each an "NEO").

Each component of the compensation program and the manner in which the Committee determines each component is discussed in detail below. In addition to these components, we provide standard employee benefits that include health benefits, life insurance, and tax-qualified savings plans to all of our employees. We did not provide any special employee benefits or perquisites in 2011 for executives other than supplemental life insurance policies for the benefit of the executives and an automotive allowance for Mr. Jeffrey Parker. We do not have pension or other retirement benefits or any type of nonqualified deferred compensation programs for our executives or other employees.

Base Pay – Base salaries and related benefits are designed to provide basic economic security for our employees. Our base salaries are established at a level consistent with competitive practices in a technological, innovative and fast-moving industry in order to help retain and recruit our highly skilled workforce without placing undue emphasis on fixed compensation. The current base salaries for our executives were established in connection with executive employment agreements in 2008 and have remained unchanged since that time due to our financial position and other relevant corporate factors.

Annual Performance Incentives – Annual performance incentives are generally established for the purpose of linking a meaningful portion of the executive's pay to accomplishment of short-term objectives that are necessary for successful execution of our longer-term business plan. Due to our financial performance and overall general economic conditions, the Committee did not implement a formal annual performance incentive plan for 2009, 2010 or 2011. Rather, the Committee determined that it would discretionarily consider short-term equity-based or cash incentives at the end of the year based on individual contributions. For 2011, the Committee approved cash bonuses to three of its NEOs for an aggregate of $26,000. These discretionary cash bonuses were in recognition of significant efforts in preparation for and support of our patent infringement litigation. The Committee did not make any short-term equity performance incentive awards to its executives in 2011.

The Committee has not approved any short-term incentive award programs for executives or other employees for 2012. The Committee may continue to utilize discretionary cash and/or equity-based awards for short-term incentives although no such awards are currently being contemplated.

Long-Term Incentives – Long term incentives are specifically designed to align employee and shareholder interests by rewarding performance that enhances shareholder value. Equity-based awards are used for long-term incentives in order to link employee's compensation to the value of our common stock. Long-term equity-based incentive awards have been in the form of both stock options and restricted stock units ("RSUs"). The Committee believes both equity instruments are strong motivators for enhancing shareholder value through corporate achievements.

In 2008, the Committee awarded RSUs as long-term incentive awards in connection with the execution of executive employment agreements. These awards provided for long-term incentives for 2008 and 2009. No long-term incentives were awarded by the Committee to executives in 2010.

In 2011, the Committee approved long-term equity incentive awards for its NEOs and one senior management employee in the form of stock options. The Committee awarded an aggregate of 2,250,000 stock options which vest in twelve equal quarterly increments beginning January 15, 2012. The long-term incentive awards were based on the Committee's analysis of the 2011 Peer Group, individual achievements, and consideration that no long-term equity incentive awards had been granted to the executives since 2008. The Peer Group data analyzed by the Committee included executives' aggregate equity holdings and annual long-term equity incentive awards as a percentage of total company shares outstanding. The Peer Group data revealed that our executives' equity ownership, on average, was significantly below that of the Peer Group.

The Committee believes that long-term equity incentives are a critical element in the overall compensation plan for all employees and anticipates continuing to use both stock options and RSU awards in the future to align executive and employee interests with longer term goals of the company.

Equity Grant Practices

Employee and director grants are made on the 15th day of the month following the date on which all terms of the grant are approved by the Committee or its delegate. In the case of grants made in connection with new hires, grants are made on the 15th of the month following the new employee's hire date. Stock options are granted with an exercise price equal to the closing market value of our common stock on the grant date. Options are never granted with exercise prices below market value on the grant date.

Role of Executive Officers in Determining Executive Pay

The Committee makes all compensation decisions for all elements of compensation for the chief executive officer and other NEOs and approves recommendations regarding equity awards for all employees. Our chief executive officer, chief financial officer and human resource management personnel make recommendations to the Committee with regard to overall pay strategy including program designs, annual incentive plan design, and long-term incentive plan design for management employees. Our chief executive officer evaluates the performance of the other executive officers and makes recommendations regarding their compensation to the Committee for its consideration and determination. Human resource management provides the Committee with market information regarding executive officers' base pay and annual performance incentives as requested. Executives do not determine any element or component of their own pay package or total compensation amount.

Executive and Director Stock Ownership Requirements

We currently do not have a policy with regard to minimum stock ownership for our executives or non-employee directors.

Federal Income Tax Consequences

Although we consider the potential tax impact of our compensation programs in our compensation planning, these impacts are not heavily weighted with regard to our compensation decisions. The material federal income tax consequences of our compensation programs, based on the current provisions of the Internal Revenue Code (Code) include the following:

Section 162(m) of the Code limits the deductibility from U.S. taxable income of certain types of compensation in excess of $1,000,000 paid by us to certain of our NEOs. This limitation may apply to the realized value of awards made under our equity award plans. Compensation that is determined to be “performance-based” under the Code is not subject to this deduction limit. For 2011, we did not pay compensation in excess of $1,000,000 to any executive and therefore we did not incur a deduction limitation under Section 162(m).

Code Section 409A generally governs the form and timing of nonqualified deferred compensation payments and imposes sanctions on participants in nonqualified deferred compensation plans that fail to comply with Section 409A rules. Our compensation arrangements with our NEOs, as discussed more fully below, are intended to be compliant with Section 409A.

In the event of a change-in-control, our NEOs are entitled to certain severance payments as more fully discussed under “Potential Payments upon Termination or Change-in-Control” below. To the extent those payments exceed three times the executive’s five-year average W-2 income, they may be deemed “excess parachute payments,” subject to a 20 percent excise tax, and nondeductible. Certain payments, such as reasonable compensation for non-compete agreements, may be excluded from the excess parachute payment calculation.

Employment and Other Agreements

In June 2008, we entered into Executive Employment Agreements (“Prior Agreements”) with each of our NEOs including Jeffrey Parker, our chief executive officer, Cynthia Poehlman, our chief financial officer, David Sorrells, our chief technology officer, and John Stuckey, our executive vice-president of corporate strategy and business development. The Agreements had an initial three-year term, which ended on May 31, 2011, with a provision for automatic annual renewal thereafter. The Committee allowed the Agreements to renew for a one-year term which ended May 31, 2012. In 2012, the Committee provided notice to the executives that the Prior Agreements would not automatically renew upon their expiration. Instead, on June 6, 2012, we entered into new three-year Executive Employment Agreements (“Agreements”) with each of our NEOs.

The Agreements provide each executive with a base salary commensurate with his or her position in the organization, a potential annual achievement bonus based on performance as determined by the Committee, and long-term equity incentive awards at the discretion of the Committee. In connection with the execution of the Prior Agreements in 2008, the Committee awarded each executive RSUs that vested in twelve equal quarterly increments from August 31, 2008 through May 31, 2011 (the “time-based RSUs”) as well as RSUs that vested on the earlier of June 4, 2011 or such date that certain market conditions were met, as measured by the price of our common stock (the “market-based RSUs”). The time-based RSUs and market-based RSUs collectively represented the 2008 and 2009 long-term equity incentive awards for our NEOs. In addition, in October 2011, the Committee granted stock option awards to each of the executives as more fully described in “Grants of Plan-Based Awards” and “Outstanding Equity Awards at Fiscal Year

End" below.

The Agreements contain provisions for the protection of our intellectual property and for severance benefits and non-compete restrictions in the event of termination of the executive's employment. Severance benefits are payable to the executives under the terms of the Agreements in the event the executive's employment is terminated without cause, due to a change in control event, or for "Good Reason" as defined in the Agreements. The severance package to be paid under the Agreements includes continuation of base salary for a one year period following the termination date, continuation of group health benefits and payment of any annual achievement bonus on a prorated basis. In the case of termination due to a change in control, or within two years following a change in control, the executive is entitled to 150% to 300% of his or her base salary plus an amount equal to the greater of the prior year's annual bonus or the average of the three prior year's annual bonus amount. Amounts to be paid to each executive for various termination events are included in the tables under "Potential Payments upon Termination or Change-in-Control" below.

The non-compete provisions of the Agreements impose restrictions on (i) employment or consultation with competing companies or customers, (ii) recruiting or hiring employees for a competing company and (iii) soliciting or accepting business from our customers. We also have non-compete arrangements in place with all of our other employees that are similar to the non-compete restrictions for our NEOs. The non-compete provision of the Agreements remain in effect for up to three years following the executive's termination, provided that we compensate the executive the equivalent of his or her base salary on a monthly basis over the restriction period ("Non-Compete Compensation"). In the event of termination due to a change in control, the executive's severance pay in excess of twelve months' base salary is applied as a credit toward the Non-Compete Compensation. Furthermore, in the event the executive is terminated for cause or resigns without "Good Reason" as defined in the Agreements, all gains realized by the executive from the sale of equity awards during the twelve months preceding termination, as well as the value at the date of termination of all outstanding equity awards, will be credited towards the Non-Compete Compensation.

The Agreements specifically comply with the applicable requirements of Section 409A of Code.

Under the specific terms of the Agreements, Mr. Parker, our chief executive officer, will receive an annual base salary of no less than $325,000. In the event of termination due to a change in control, Mr. Parker's severance multiplier is 300% of his base salary, or $975,000. Mr. Parker's agreement also provides for an automobile allowance of $24,000 annually and reimbursement of up to $150,000 annually for premium payments on personal life insurance policies. The Committee intends to use the cash value of our whole life policy on Mr. Parker to fund the annual life insurance premium payments to Mr. Parker. Ms. Poehlman, our chief financial officer, will receive an annual base salary of no less than $225,000. In the event of termination due to a change in control, Ms. Poehlman's severance multiplier is 200% of her base salary, or $450,000. Mr. Sorrells, our chief technology officer, will receive an annual base salary of no less than $275,625. In the event of termination due to a change in control, Mr. Sorrells' severance multiplier is 300% of his base salary, or $826,875. Mr. Stuckey, our executive vice president of corporate strategy and business development, will receive an annual base salary of no less than $250,000. In the event of termination due to a change in control, Mr. Stuckey's severance multiplier is 150% of his base salary, or $375,000.

Summary Compensation Table

The following table summarizes the total compensation of each of our NEOs for the fiscal years ended December 31, 2011, 2010, and 2009. Given the complexity of disclosure requirements concerning executive compensation, and in particular with respect to the standards of financial accounting and reporting related to equity compensation, there is a difference between the compensation that is reported in this table versus that which is actually paid to and received by the NEOs. The amounts in the Summary Compensation Table that reflect the full grant date fair value of an equity award, do not necessarily correspond to the actual value that has been realized or will be realized in the future with respect to these awards.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)
		Salary	Bonus	Stock Awards	Option Awards 1	Non-equity Incentive Plan Com-pensation	All Other		Total
Name and Principal Position	Year	($)	($)	($)	($)	($)	($)		($)
Jeffrey Parker, Chief	2011	$325,000	$0	$0	$671,756	$0	$27,690	3	$1,024,446
Executive Officer and	2010	337,5002	0	0	0	0	28,613		366,116
Chairman of the Board	2009	325,000	0	0	0	0	29,690		354,690
Cynthia Poehlman,	2011	225,000	8,500	0	167,939	0	750	4	402,189
Chief Financial Officer	2010	233,6542	0	0	0	0	750		234,404
and Corporate Secretary	2009	225,000	0	0	0	0	2,750		227,750
David Sorrells, Chief	2011	275,625	10,000	0	335,878	0	2,100	4	623,603
Technology Officer	2010	286,2262	0	0	0	0	2,100		288,326
	2009	275,625	5,000	0	0	0	2,100		282,725
John Stuckey,	2011	250,000	7,500	0	167,939	0	1,263	4	426,702
Executive Vice	2010	259,6152	0	0	0	0	1,263		260,878
President, Corporate Strategy	2009	250,000	0	0	0	0	2,895		252,895
and Business Development									

1 The amounts reported in column (f) represent the full grant date fair value of stock awards in accordance with ASC 718, net of estimated forfeitures. Refer to Note 8 of the financial statements included in Item 8 of our Annual Report for the assumptions made in the valuation of stock awards. See Grants of Plan-Based Awards table below.

2 All salaried employees are paid on a biweekly basis. The biweekly salary is determined by dividing annual base salary by 26 biweekly pay periods. In 2010, our pay schedule included 27 biweekly pay periods resulting in a higher annual salary in 2010 for all salaried employees, including our NEOs.

3 This amount includes (i) the dollar value of premiums paid by us in 2011 for life insurance for the benefit of Mr. Parker in the amount of $3,690 and (ii) the gross value of Mr. Parker's automobile allowance of $24,000.

4 This amount represents the dollar value of premiums paid by us in 2011 for life insurance for the benefit of the executive.

Grants of Plan-Based Awards

The following table summarizes information concerning each grant of an award made in our fiscal year ending December 31, 2011 to each of our NEOs:

Name	Grant Date	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or base price of option awards per share ($)	Grant Date Fair Value of Stock and Option Awards ($)
Jeffrey Parker	10/17/2011	1,000,000	$ 0.89	$ 671,756
Cynthia Poehlman	10/17/2011	250,000	0.89	167,939
David Sorrells	10/17/2011	500,000	0.89	335,878
John Stuckey	10/17/2011	250,000	0.89	167,939

These awards were each granted from our 2011 Long-Term Incentive Equity Plan, vest in equal quarterly increments beginning January 15, 2012 and expire October 15, 2018.

Outstanding Equity Awards at Fiscal Year End

The following table summarizes information concerning the outstanding equity awards as of December 31, 2011 for each of our NEOs:

	Option Awards			
Name	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Option Exercise price ($)	Option expiration date
(a)	(b)	(c)	(d)	(e)
Jeffrey Parker	15,000		$19.99	2/26/12
	75,000		5.77	8/9/12
	10,908		8.91	12/20/12
	7,583		9.80	5/3/13
	90,000		8.81	10/12/13
	37,500		9.89	2/15/14
	37,500		10.82	5/15/14
	37,500		12.30	8/15/14
	37,500		10.36	11/15/14
		1,000,000 1	0.89	10/15/18
Cynthia Poehlman	25,000		5.77	8/9/12
	4,563		8.91	12/20/12

3,205		9.80	5/6/13
25,000		8.81	10/12/13
8,750		9.89	2/15/14
8,750		10.82	5/15/14
150,000		5.70	6/25/14
8,750		12.30	8/15/14
8,750		10.36	11/15/14
	250,000[1]	0.89	10/15/18

	Option Awards			
Name	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Option Exercise price ($)	Option expiration date
(a)	(b)	(c)	(d)	(e)
David Sorrells	25,000		5.77	8/9/12
	125,000		9.00	11/21/12
	4,988		8.91	12/20/12
	3,898		9.80	5/3/13
	38,000		8.81	10/12/13
		500,0001	0.89	10/15/18
John Stuckey	25,000		5.77	8/9/12
	5,133		8.91	12/20/12
	3,394		9.80	5/3/13
	25,000		8.81	10/12/13
	8,750		9.89	2/15/14
	8,750		10.82	5/15/14
	107,875		4.67	7/8/14
	8,750		12.30	8/15/14
	8,750		10.36	11/15/14
		250,0001	0.89	10/15/18

1 Option vests in twelve equal quarterly increments beginning on January 15, 2012.

Option Exercises and Stock Vested

The following table summarizes information concerning the option exercises and vesting of stock awards for the fiscal year ended December 31, 2011 on an aggregate basis for each of our NEOs:

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting 1 (#)	Value Realized on Vesting ($)
Jeffrey Parker	0	$ 0	87,500	$67,750
	0	0	26,250	20,325

Cynthia Poehlman				
David Sorrells	0	0	52,090	40,397
John Stuckey	0	0	26,250	20,325

1 These shares represent vesting of RSUs awarded in connection with executive employment agreements in June 2008.

Potential Payments upon Termination or Change-in-Control

The Agreement with each of our NEOs provide for payments upon termination for various events including, with or without cause termination by us, termination due to death or disability of the executive, termination due to a change-in-control event and termination by the executive for “Good Reason” as defined in the Agreements. Upon the termination of a NEO, we may enforce non-compete provisions over a restriction period not to exceed three years provided that we compensate the NEO at their ending base salary for the designated restriction period. Certain severance payments and other amounts may be applied as credits toward our Non-Compete Compensation obligation as more fully described below.

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Payments Made Upon Termination – When a NEO's employment is terminated for any reason, other than for cause, he or she is entitled to receive his or her base salary through the date of termination and any earned but unused vacation pay. When a NEO's employment is terminated for cause, he or she is only entitled to his or her base salary through the date of termination. Furthermore, in the event a NEO's employment is terminated for cause or a NEO resigns without "Good Reason", all gains realized from the NEO's sale of our common shares from vested RSUs or stock options during the twelve months immediately preceding the termination date shall be credited towards Non-Compete Compensation. In addition, the total value of equity instruments provided to the NEO during the entire term of his or her employment with us that are vested and outstanding at the termination date shall be credited towards the Non-Compete Compensation. The value of outstanding equity awards shall be determined using the closing market price of our common stock on the termination date.

Payments Made Upon Termination Due to a Change in Control – In the event a NEO's employment is terminated without cause or a NEO resigns with "Good Reason" within two years of a change-in-control event, in addition to the benefits listed under "Payments Made Upon Termination" above, he or she is entitled to receive a multiple of his or her base salary, an amount in lieu of annual bonus or incentive compensation, continuation of group health benefits and acceleration of certain unvested and outstanding equity awards. The base salary multiple varies by individual and ranges from 150% to 300%. The amount in lieu of annual bonus or incentive compensation is determined based on the greater of the bonus or annual incentive compensation earned in the year prior to the change in control, the average of the prior three year's bonus or annual incentive compensation, or a prorated amount of the current year's bonus or annual incentive compensation. The severance pay in excess of twelve months' base salary is applied as a credit toward the Non-Compete Compensation.

In accordance with the terms of the executive's individual equity agreements, the NEO would also be eligible for accelerated vesting of certain equity awards in the event of a change-in-control. Any unvested stock options or unvested time-based RSUs will automatically vest upon a change-in-control. If the change-in-control occurrence is approved by our board of directors, the board may, at its option, accelerate the vesting of any unvested time-based RSUs and repurchase them for a cash value as defined in the equity plan.

Payments Made Upon Termination Without Cause – In the event a NEO's employment is terminated without cause and the executive executes a release agreement with us, he or she is entitled to a severance package. The severance package includes continuation of base salary for a one year period following the termination date, continuation of group health benefits and payment of any annual achievement bonus on a prorated basis. In the event a NEO resigns for "Good Reason" as defined in the Agreement and executes a release agreement with us, he or she is entitled to the same severance benefits as if he or she was terminated without cause. Good Reason is defined in the Agreement as a material diminution in the executive's authority, duties or responsibilities, a material diminution in the executive's base compensation and benefits, except for reductions applicable to all executives, a material relocation of the executive's primary office or a material breach of the Agreement by us.

Payments Made Upon Termination Due to Disability – In the event a NEO's employment is terminated within six months of becoming disabled, as defined in the Agreement, he or she will be entitled to the benefits listed under "Payments Made upon Termination" and the severance package listed under "Payments Made upon Termination without Cause" above. If, however, the NEO's employment is terminated after six months of becoming disabled, he or she becomes eligible for payments under a company-paid long-term disability plan with a third-party carrier in which case, the severance package is limited to the continuation of health benefits. In addition, if a NEO's employment is terminated due to disability, he or she receives an automatic acceleration of fifty percent of any unvested options or RSUs in accordance with the terms of the individual equity agreements.

Payments Made Upon Death – Upon the death of a NEO, the executive's beneficiaries shall receive the proceeds from company-paid life insurance policies purchased for the benefit of the executive. In addition, the NEO's beneficiaries shall receive an acceleration of fifty percent of any unvested options or RSUs in accordance with the terms of the individual equity agreements.

The following tables reflect the estimated amount of compensation due to each of our NEOs in the event of termination of their employment. Actual amounts to be paid out could only be determined at the time of an executive's actual separation. For purposes of this disclosure, we assume the triggering event for termination occurred on December 31, 2011, but that the current Agreements were in effect as of such date. The intrinsic value of equity awards upon termination is calculated based on the December 31, 2011 closing price of our common stock of $0.86.

Jeffrey Parker, Chairman and Chief Executive Officer

Benefit and Payments Upon Separation	Change in Control (Not Board Approved)		Change in Control (Board Approved)		Without Cause or for "Good Reason"		Disability		Death	
Salary	$975,000	1	$975,000	1	$325,000		$325,000	2	$0	
Short-term Incentive Compensation	0	3	0	3	0	4	0	2,4	0	
Long-term Equity Compensation:										
Stock Options	0		0		0		0		0	
Benefits & Perquisites										
Health Benefits	28,689		28,689		28,689		28,689		28,689	
Life Insurance Proceeds	0		-		-		-		2,000,000	5
Accrued Vacation Pay	12,500		12,500		12,500		12,500		12,500	
Total	$1,016,189		$1,016,189		$366,189		$366,189		$2,041,189	

1 Under the Agreement, Mr. Parker is entitled to three times his regular annual base salary.

2 Assumes termination occurs within first six months of executive becoming disabled. Following a six month period, executive is not entitled to salary continuation or short-term incentive compensation payments.

3 Under the Agreement, executive is entitled the greater of (i) an amount equal to his bonus or annual incentive compensation earned in the year prior to the change in control, (ii) the average of bonus and annual incentive compensation for the three full fiscal years prior to the change in control, or (iii) a prorated amount of the current year's bonus or annual incentive compensation.

4 Short-term incentive compensation is based on the established incentive target for the year of termination. As no targets were established for 2011, executive is not entitled to short-term incentive payment under this scenario.

5 Represents proceeds payable by a third-party insurance carrier on a company-paid life insurance policy for the benefit of the executive.

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Cynthia Poehlman, Chief Financial Officer and Corporate Secretary

Benefit and Payments Upon Separation	Change in Control (Not Board Approved)	Change in Control (Board Approved)	Without Cause or for "Good Reason"	Disability	Death
Salary	$ 450,000 [1]	$ 450,000 [1]	$225,000	$225,000 [2]	$0
Short-term Incentive Compensation	8,500 [3]	8,500 [3]	0 [4]	0 [2,4]	0
Long-term Equity Compensation:					
Stock Options	0	0	0	0	0
Benefits & Perquisites					
Health Benefits	28,689	28,689	28,689	28,689	28,689
Life Insurance Proceeds	0	0	0	0	1,000,000 [5]
Accrued Vacation Pay	0	0	0	0	0
Total	$ 487,189	$ 487,189	$253,689	$253,689	$1,028,689

1 Under the Agreement, Ms. Poehlman is entitled to two times her regular annual base salary.

2 Assumes termination occurs within first six months of executive becoming disabled. Following a six month period, executive is not entitled to salary continuation or short-term incentive compensation payments.

3 Under the Agreement, executive is entitled the greater of (i) an amount equal to her bonus or annual incentive compensation earned in the year prior to the change in control, (ii) the average of bonus and annual incentive compensation for the three full fiscal years prior to the change in control, or (iii) a prorated amount of the current year's bonus or annual incentive compensation.

4 Short-term incentive compensation is based on the established incentive target for the year of termination. As no targets were established for 2011, executive is not entitled to short-term incentive payment under this scenario.

5 Represents proceeds payable by a third-party insurance carrier on a company-paid life insurance policy for the benefit of the executive.

David Sorrells, Chief Technology Officer

Benefit and Payments Upon Separation	Change in Control (Not Board Approved)	Change in Control (Board Approved)	Without Cause or for "Good Reason"	Disability	Death				
Salary	$826,875	22	22	592	592				
Permian Basin	37.4/49.05	82	40			15,888	7,124	20,089	7,598
Niobrara Formation (7)	36.4/44.04	4	2	1	0.4	2,240	628	41,480	18,817
Williston Basin (8)	3.2/3.9	5	0.2			2,560	127	3,920	779

Overrides/Royalty Non-operated	Various	76	0.2	1		2							
Total		287	162.4	4	3	260	257.4	18	18	30,239	17,430	67,068	28,773

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(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes nine gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 36% of our acreage is developed acreage and has been perpetuated by production.
(4) E. Hackberry acreage does not include 2,868 net acres subject to a two-year exploration agreement.
(5) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(6) NRI shown is for producing wells.
(7) The leases relating to our Niobrara Formation acreage will expire at the end of their respective primary terms unless the applicable leases are renewed or extended, we have commenced the necessary operations required by the terms of the applicable leases or we have obtained actual production from acreage subject to the applicable leases, in which event they will remain in effect until the cessation of production. Leases representing 35%, 20%, 22%, 4% and 19% of our total Niobrara acreage are currently scheduled to expire in 2011, 2012, 2013, 2014 and thereafter, respectively.
(8) NRI/WI is from wells that have been drilled or in which we have elected to participate.

Completed and Present Drilling and Recompletion Activities

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2010		**2009**		**2008**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Recompletions:						
Productive	87	84	64	62.5	58	56.5
Dry						
Total	87	84	64	62.5	58	56.5
Development:						
Productive	57	42	25	18	69	27
Dry			1	1		
Total	57	42	26	19	69	27
Exploratory:						
Productive			1	1		
Dry					1	1
Total			1	1	1	1

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management s opinion, will in the aggregate materially restrict our operations.

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ITEM 3. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The case is in the early stages of discovery.

More recently, in December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we have denied all liability and will vigorously defend the lawsuit. The cases are in the very early stages, and we have not yet filed a response to the recent lawsuits.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us, Great White Pressure Control LLC, or Great White, and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that we conspired with the other defendants to misappropriate, and misappropriated Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, our motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. On February 15, 2011, Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6.0 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name us as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and

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mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses; and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. Our motion is currently set to be heard on March 23, 2011.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations.

In addition to the above, we have been named as a defendant in various other lawsuits related to our business. The ultimate resolution of such other matters is not expected to have a material adverse effect on our financial condition or results of operations.

ITEM 4. RESERVED

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PART II

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

Since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market under the symbol GPOR. The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2009		
First Quarter	$ 5.20	$ 1.50
Second Quarter	7.65	2.23
Third Quarter	8.99	5.23
Fourth Quarter	11.89	7.25
2010		
First Quarter	$ 12.68	$ 8.89
Second Quarter	15.25	10.60
Third Quarter	14.71	10.37
Fourth Quarter	22.92	13.59
2011		
First Quarter (through March 10, 2011)	$ 30.99	$ 20.00

On March 10, 2011, the last reported sale price of our common stock on The NASDAQ Global Select Market was $24.69.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 3, 2011, there were 340 stockholders of record holding 44,549,037 shares of our outstanding common stock. There were approximately 14,970 beneficial owners of our common stock as of March 3, 2011.

Dividend Policy

We have never paid dividends on our common stock. We currently intend to retain all earnings to fund our operations. Therefore, we do not intend to pay any cash dividends on the common stock in the foreseeable future. In addition, the terms of our credit facility prohibit the payment of any dividends to the holders of our common stock.

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ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2010, December 31, 2009 and December 31, 2008 and the selected consolidated balance sheet data at December 31, 2010 and December 31, 2009 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2007 and December 31, 2006 and the selected consolidated balance sheet data at December 31, 2008, December 31, 2007 and December 31, 2006 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Selected Consolidated Statements of Operations Data:					
Revenues	$ 126,944,000	$ 85,262,000	$ 141,217,000	$ 105,838,000	$ 60,390,000
Costs and expenses:					
Lease operating expenses	17,614,000	16,316,000	22,856,000	16,670,000	10,670,000
Production taxes	13,966,000	9,797,000	15,813,000	12,667,000	7,366,000
Depreciation, depletion and amortization	38,907,000	29,225,000	42,472,000	29,681,000	12,652,000
Impairment of oil and natural gas properties			272,722,000		
General and administrative	6,063,000	4,992,000	6,843,000	5,802,000	3,251,000
Accretion expense	617,000	582,000	560,000	554,000	596,000
	77,167,000	60,912,000	361,266,000	65,374,000	34,535,000
Income (Loss) from Operations	49,777,000	24,350,000	(220,049,000)	40,464,000	25,855,000
Other (Income) Expense:					
Interest expense	2,761,000	2,309,000	4,762,000	3,091,000	1,956,000
Insurance recoveries		(1,050,000)	(769,000)		(3,601,000)
Settlement of fixed price contracts			(39,000,000)		
Interest income	(387,000)	(564,000)	(540,000)	(523,000)	(308,000)
	2,374,000	695,000	(35,547,000)	2,568,000	(1,953,000)
Income (Loss) before Income Taxes	47,403,000	23,655,000	(184,502,000)	37,896,000	27,808,000
Income Tax Expense	40,000	28,000		121,000	
Net Income (Loss)	47,363,000	23,627,000	(184,502,000)	37,775,000	27,808,000
Net Income (Loss) Available to Common Stockholders	47,363,000	$ 23,627,000	$ (184,502,000)	$ 37,775,000	$ 27,808,000
Net Income (Loss) Per Common Share Basic:	$ 1.08	$ 0.55	$ (4.33)	$ 1.03	$ 0.85
Net Income (Loss) Per Common Share Diluted:	$ 1.07	$ 0.55	$ (4.33)	$ 1.01	$ 0.82

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	At December 31,				
	2010	2009	2008	2007	2006
Selected Consolidated Balance Sheet Data:					
Total assets	$ 319,693,000	$ 227,344,000	$ 221,873,000	$ 419,137,000	$ 195,151,000
Total debt, including current maturity	$ 51,917,000	$ 52,428,000	$ 70,731,000	$ 66,533,000	$ 37,691,000
Total liabilities	$ 108,637,000	$ 102,293,000	$ 107,772,000	$ 115,015,000	$ 71,342,000
Stockholders equity	$ 211,056,000	$ 125,051,000	$ 114,101,000	$ 304,122,000	$ 123,809,000

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled Risk Factors and Cautionary Note Regarding Forward-Looking Statements appearing elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. In 2010, we acquired an acreage position in Western Colorado in the Niobrara Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2010 Highlights

Oil and natural gas revenues increased 49% to $127.6 million for the year ended December 31, 2010 from $85.6 million for the year ended December 31, 2009.

Net income increased 100% to $47.4 million for the year ended December 31, 2010 from $23.6 million for the year ended December 31, 2009.

Production increased 18% to approximately 1,976,000 barrels of oil equivalent, or BOE, for the year ended December 31, 2010 from approximately 1,677,000 BOE for the year ended December 31, 2009.

During 2010, we drilled 57 gross (42 net) wells, which includes 26 gross (11 net) wells drilled by our operators in the Permian Basin and Bakken, and recompleted 87 gross (84 net) wells. Of our 57 new wells drilled, 56 were completed as producing wells and one was waiting on completion.

During 2010, we acquired approximately 6,500 additional net acres in the Permian Basin, which brought our total net acreage position in the Permian Basin to approximately 14,700 net acres.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Colorado and held leases for 19,172 net acres as of March 1, 2011.

In May 2010, we completed an underwritten public offering of 1,668,503 shares of our common stock and received approximately $21.4 million in net proceeds, which we used to fund the acquisition of our interests in the Niobrara Formation, pay the purchase price for a portion of the additional acreage acquired by us in the Permian Basin in 2010 and for general corporate purposes.

On September 30, 2010, we entered into a new $100.0 million senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association, and repaid and terminated our existing revolving credit facility and term loan, each with Bank of America, N.A., as administrative agent, with borrowings under our new revolving credit facility. Our borrowing base under this facility was increased from $50.0 million to $65.0 million in December

2010.

Recent Developments

In February 2011, we entered into an agreement to acquire certain leasehold interests located in the Utica Shale in Ohio. The agreement also grants us an exclusive right of first refusal for a period of six months on

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certain additional tracts leased by the seller. Windsor, an affiliate of ours, has agreed to participate with us on a 50/50 basis in the acquisition of all of the leases described above. We will be the operator on this acreage in the Utica Shale. The purchase price for our 50% interest in the initial acreage is approximately $31.6 million, subject to certain closing adjustments. This transaction is expected to close in mid-May 2011.

Critical Accounting Policies and Estimates

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

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period 2010 and 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $16.8 million at December 31, 2010 and $17.5 million at December 31, 2009. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period January December of the applicable year beginning with 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives,

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if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the year ended December 31, 2010.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Pinnacle Energy Services, LLC and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2010 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

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Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2010, a valuation allowance of $54.4 million had been provided for deferred tax assets based on the uncertainty of future taxable income.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, *Derivatives and Hedging*, as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

To mitigate the effects of commodity price fluctuations, for the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB

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production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our estimated 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

RESULTS OF OPERATIONS

Results of Operations

The markets for oil and natural gas have historically been, and will continue to be, volatile. Prices for oil and natural gas may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of factors beyond our control.

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2010	2009	2008
Production Volumes:			
Oil (MBbls)	1,777	1,531	1,584
Gas (MMcf)	788	491	712
Natural gas liquids (MGal)	2,821	2,719	2,583
Oil equivalents (Mboe)	1,976	1,677	1,764
Average Prices:			
Oil (per Bbl)	$ 68.29(1)	$ 53.29(1)	$ 83.23(1)
Gas (per Mcf)	$ 4.40	$ 4.06	$ 9.23
Natural gas liquids (per Gal)	$ 1.00	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$ 64.61	$ 51.01	$ 80.30
Production Costs:			
Average production costs (per Boe)	$ 8.92(2)	$ 9.73(2)	$ 12.96(2)
Average production taxes (per Boe)	$ 7.07	$ 5.84	$ 8.96
Total production costs (per Boe)	$ 15.99	$ 15.57	$ 21.92

(1) Includes fixed contract prices at a weighted average price of:

January	December 2008	$ 78.56
January	December 2009	$ 55.01
January	December 2010	$ 57.55

Excluding the net effect of the fixed price contracts, the average oil price for 2010 would have been $78.12 per barrel and $73.45 per barrel of oil equivalent. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2009 would have been $57.98 per barrel and $55.29 per barrel of oil equivalent. The total volume hedged for 2009 represented approximately 49% of our total sales volumes for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $97.36 per barrel and $92.98 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total sales volumes for the year.

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(2) Does not include production taxes.

From 2009 to 2010, our net equivalent oil production increased 18% from 1,677,000 barrels to 1,976,000 barrels due to increased drilling activity, the success of our drilling activities and our acquisitions of additional properties in the Permian Basin and the Niobrara Formation. From 2008 to 2009, our net equivalent oil production decreased 5% from 1,764,000 barrels to 1,677,000 barrels due to our reduced drilling activity and normal production declines. We currently estimate that our 2011 production will be between 2,200,000 and 2,400,000 BOE. However, such estimate may change based on a change in our expected drilling and recompletion activities or the changing economic climate and unforeseen events, such as hurricanes.

Comparison of the Years Ended December 31, 2010 and December 31, 2009

We reported net income of $47,363,000 for the year ended December 31, 2010, as compared to net income of $23,627,000 for the year ended December 31, 2009. This 100% increase in 2010 was due primarily to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,976,000 BOE, partially offset by an 8% increase in lease operating expenses, a 21% increase in general and administrative expenses and a 43% increase in production taxes.

Oil and Gas Revenues. For the year ended December 31, 2010, we reported oil and natural gas revenues of $127,636,000 as compared to oil and natural gas revenues of $85,576,000 during 2009. This $42,060,000, or 49%, increase in revenues is primarily attributable to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,975,576 BOE for the year ended December 31, 2010 from 1,677,474 BOE for the year ended December 31, 2009.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2010 and December 31, 2009:

	Year Ended December 31, 2010	2009
Oil production volumes (MBbls)	1,777	1,531
Gas production volumes (MMcf)	788	491
Natural gas liquids production volumes (MGal)	2,821	2,719
Oil equivalents (Mboe)	1,976	1,677
Average oil price (per Bbl)	$ 68.29	$ 53.29
Average gas price (per Mcf)	$ 4.40	$ 4.06
Average natural gas liquids (per Gal)	$ 1.00	$ 0.73
Oil equivalents (per Boe)	$ 64.61	$ 51.01

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $17,614,000 for 2010 from $16,316,000 for 2009. This increase is mainly a result of an increase in ad valorem taxes and expenses related to well workovers.

Production Taxes. Production taxes increased to $13,966,000 for 2010 from $9,797,000 for 2009. This increase was primarily related to a 49% increase in oil and gas revenues as a result of a 27% increase in average realized BOE price received and an 18% increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $38,907,000 for 2010, and consisted of $38,600,000 in depletion on oil and natural gas properties and $307,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $29,225,000 for 2009. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

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General and Administrative Expenses. Net general and administrative expenses increased to $6,063,000 for 2010 from $4,992,000 for 2009. This $1,071,000 increase was primarily due to a $450,000 increase in franchise taxes, a $200,000 increase in legal expenses and increases related to salaries, benefits expenses partially offset by an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $617,000 for 2010 from $582,000 for 2009.

Interest Expense. Interest expense increased to $2,761,000 for 2010 from $2,309,000 for 2009. This increase was due to an increase in the interest rate paid as well as the recognition of approximately $225,000 in unamortized loan fees associated with the termination of the Bank of America revolving credit facility. Effective September 30, 2010, this facility, along with the term loan with Bank of America, were repaid with borrowings under our new senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, entered into on September 30, 2010. This increase in interest expense was partially offset by a decrease in average debt outstanding for the year ended December 31, 2010, as compared to the year ended December 31, 2009. Total debt outstanding under our new revolving credit facility was $49.5 million as of December 31, 2010, as compared to $49.9 million outstanding under our prior facilities with Bank of America as of the same date in 2009. Total weighted debt outstanding under our facilities was $46.9 million for 2010 and $59.9 million for 2009. Until September 30, 2010, amounts borrowed under our term loan and revolving credit facility with Bank of America bore interest of 3.76% and 3.25%, respectively. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%.

Income Taxes. As of December 31, 2010, we had a net operating loss carry forward of approximately $52.4 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2010, a valuation allowance of $54.4 million had been provided for deferred tax assets, with the exception of $628,000 for alternative minimum taxes. We paid $40,000 of state income tax for the year ended December 31, 2010.

Comparison of the Years Ended December 31, 2009 and December 31, 2008

We reported net income of $23,627,000 for the year ended December 31, 2009, as compared to a net loss of $184,502,000 for the year ended December 31, 2008. This net income is primarily attributable to a 29% decrease in lease operating expenses, a 27% decrease in general and administrative expenses and a 38% decrease in production taxes, partially offset by a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE. In addition, the net loss for 2008 was primarily attributable to an impairment charge of $272,722,000 related to the drastic decline in oil and gas prices. Further, we had $1,050,000 of insurance proceeds received during the year ended December 31, 2009 compared to insurance proceeds of $769,000 received during 2008.

Oil and Gas Revenues. For the year ended December 31, 2009, we reported oil and natural gas revenues of $85,576,000 as compared to oil and natural gas revenues of $141,650,000 during 2008. This $56,074,000, or 40%, decrease in revenues is primarily attributable to a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE for the year ended December 31, 2009 from 1,764,053 BOE for the year ended December 31, 2008.

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The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2009 and December 31, 2008:

	Year Ended December 31, 2009	2008
Oil production volumes (MBbls)	1,531	1,584
Gas production volumes (MMcf)	491	712
Natural gas liquids production volumes (MGal)	2,719	2,583
Oil equivalents (Mboe)	1,677	1,764
Average oil price (per Bbl)	$ 53.29	$ 83.23
Average gas price (per Mcf)	$ 4.06	$ 9.23
Average natural gas liquids (per Gal)	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$ 51.01	$ 80.30

Lease Operating Expenses. Lease operating expenses not including production taxes decreased to $16,316,000 for 2009 from $22,856,000 for 2008. This decrease is mainly a result of a decrease in contract labor expenses, a decrease in workovers, compressor and other equipment rentals and repairs, a decrease in the cost of chemicals and supplies and a decrease in personal property taxes. In addition, the lease operating expenses for 2008 included $3,408,000 of unreimbursed expenses related to hurricane repairs as compared to approximately $23,000 of unreimbursed expenses related to hurricane repairs in 2009.

Production Taxes. Production taxes decreased to $9,797,000 for 2009 from $15,813,000 for 2008. This decrease was primarily related to a 40% decrease in oil and gas revenues mainly as a result of the decrease in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $29,225,000 for 2009, and consisted of $28,939,000 in depletion on oil and natural gas properties and $286,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $42,472,000 for 2008. This decrease was due primarily to the reduction in the book value of our oil and gas properties used to calculate depreciation, depletion and amortization expense. This reduction resulted from the drop in commodity prices reflected as of December 31, 2008 and the resulting reduction in our proved reserves which caused us to recognize a ceiling test impairment to our full cost pool of $272,722,000 for the year ended December 31, 2008.

Impairment of Oil and Gas Properties. We use the full cost method of accounting for oil and gas properties and are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of our oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period of January through December 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on our balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash write-down is required. There was no impairment charge for the year ended December 31, 2009. As a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008.

General and Administrative Expenses. Net general and administrative expenses decreased to $4,992,000 for 2009 from $6,843,000 for 2008. This $1,851,000 decrease was due primarily to reductions in franchise taxes as a result of the impairment mentioned in the depreciation, depletion and amortization section above which reduced our net assets used to calculate franchise taxes, a reduction in stock based compensation expenses, reductions in payroll costs including payroll taxes and related benefits mainly due to decreases in the total number of employees partially offset by a decrease in general and administrative reimbursements from our affiliates and a decrease in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $582,000 for 2009 from $560,000 for 2008.

Interest Expense. Interest expense decreased to $2,309,000 for 2009 from $4,762,000 for 2008 due to a decrease in average debt outstanding and lower interest rates on amounts borrowed under our facilities with Bank of America. Total debt outstanding under our facilities with Bank of America was $49.9 million as of December 31, 2009 and $68.1 million as of the same date in 2008. Total weighted debt outstanding under our facilities with Bank of America was $59.9 million for 2009 and $84.2 million for 2008. As of December 31, 2009, amounts borrowed under our revolving credit facility and our two term loans with Bank of America bore interest of 3.73%, 4.23% and 3.25%, respectively.

Income Taxes. As of December 31, 2009, we had a net operating loss carry forward of approximately $55.7 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2009, a valuation allowance of $73.2 million had been provided for deferred tax assets, as the Company has historically had non-taxable income and has future projections of no taxable income during the carryforward period, with the exception of $533,000 related to alternative minimum taxes. We had $28,000 of state income tax expense for the year ended December 31, 2009.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our bank and other credit facilities and the issuance of equity securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or our oil and gas production. During 2009, we also received proceeds from the sale of certain of our Bakken assets and, in 2010, we received net proceeds (before offering expenses) of approximately $21.6 million from the sale of our common stock in an underwritten public offering.

Net cash flow provided by operating activities was $85,835,000 for 2010, as compared to $53,299,000 for 2009. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 27% increase in net realized prices and an 18% increase in our net BOE production.

Net cash flow provided by operating activities was $53,299,000 for 2009, as compared to $135,323,000 for 2008. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 36% decrease in net realized prices and a 5% decrease in our net BOE production.

Net cash used in investing activities for 2010 was $105,315,000, as compared to $39,246,000 for 2009. During 2010, we spent $101,644,000 in additions to oil and natural gas properties, of which $51,356,000 was spent on our 2010 drilling and recompletion programs, $16,735,000 was spent on acquisitions in our Niobrara and Permian fields, $11,697,000 was spent on expenses attributable to the wells drilled during 2009, $3,093,000 was spent on our 2009 recompletions, $6,838,000 was spent on compressors and other facility enhancements, $1,425,000 was spent on plugging costs, $771,000 was spent on lease related costs and $3,449,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, we paid $3,719,000 in cash calls to Grizzly during 2010. During 2010, we used cash from operations, borrowings under our credit facilities and proceeds from our equity offering to fund our investing activities.

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Net cash used in investing activities for 2009 was $39,246,000, as compared to $136,823,000 for 2008. During the year ended December 31, 2009, we spent (a) $49,533,000 in additions to oil and natural gas properties, of which $20,296,000 was spent on our 2009 drilling and recompletion programs, $14,255,000 was spent on costs attributable to the wells drilled during 2008, $3,719,000 was spent on our 2008 recompletions, $1,191,000 was spent on barges and other facility enhancements, $866,000 was spent on plugging and abandonment activities, $2,853,000 was spent on lease related costs and $1,744,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses, and (b) $3,813,000 on our investment in Tatex III and we loaned $4,377,000 to Grizzly. In May, September and December 2009, we received aggregate net proceeds of approximately $18,286,000 from our sale of properties in the Bakken. During the year ended December 31, 2009, we used cash from operations and proceeds from the sale of Bakken properties to fund our investing activities.

Net cash provided by financing activities for 2010 was $20,224,000 as compared to net cash used by financing activities of $18,273,000 for 2009. The 2010 amount provided by financing activities is primarily attributable to the net proceeds of $21,358,000 from our equity offering and borrowings of $52,200,000 under our new credit facility, partially offset by principal payments of $49,903,000 on borrowings under our prior credit facilities with Bank of America. We used the net proceeds of our 2010 equity offering to fund the acquisition of our interests in the Niobrara Formation, pay the purchase price for a portion of the additional acreage acquired by us in the Permian Basin in 2010 and for general corporate purposes.

The 2009 amount used by financing activities is primarily attributable to principal payments on borrowings of $18,206,000 under our credit facility with Bank of America, partially offset by $30,000 received from the exercise of stock options.

Net cash provided by financing activities for 2008 was $4,680,000. The 2008 amount was primarily attributable to $30,000,000 of borrowings under our line of credit, mostly offset by repayments on the line.

Credit Facility. In March 2005, we entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated from time to time and, among other things, the maturity date was extended to April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of our borrowing base giving consideration to our year-end 2008 and mid-year 2009 reserve information and the lender s then current pricing decks, among other factors. As a result of this redetermination, our available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. Our outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and we agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010. We paid the outstanding balance of the term loan in full in February 2010. On September 30, 2010, we repaid all borrowings under the credit facility.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at our option, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, we also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, we agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for

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Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on our utilization percentage. In addition, we agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

Our obligations under the credit facility were collateralized by a lien on substantially all of our Louisiana and West Texas assets and were guaranteed by our subsidiaries. The restated credit agreement contained certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. We made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at Bank of America Prime. We made quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, we repaid this loan in full with borrowings under the new revolving credit agreement discussed below.

On September 30, 2010, we entered into a new $100.0 million senior secured revolving credit facility with The Bank of Nova Scotia, or Scotia Capital, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association, which facility matures on September 30, 2013. The new revolving credit agreement provided for an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010.

As of December 31, 2010, we had an outstanding balance of $49.5 million drawn under our new revolving credit agreement, which is included in long-term debt, net of current maturities, on our accompanying consolidated balance sheet at December 31, 2010. The amounts borrowed under our new revolving credit agreement were used to repay our outstanding indebtedness under our prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and for general corporate purposes. The new revolving credit agreement is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our obligations under the new revolving credit agreement.

Advances under the new revolving credit agreement may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the Eurodollar rate for an interest period of one month plus 1.00%. The interest rate for Eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%.

The credit agreement contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at December 31, 2010.

In connection with our scheduled spring 2011 borrowing base redetermination completed in March 2011, Scotia Capital has advised us that it has approved an increase to our borrowing base from the current level of $65.0 million to $85.0 million. In addition, Scotia has given us a commitment letter providing for an amendment to our credit facility which would, among other things, increase the maximum commitment to $350.0 million, provide for an $85.0 million current borrowing base, extend the maturity date to April 2015 and reduce our average credit spread by 75 basis points per annum from current levels. Both the increase in the borrowing base to $85.0 million and the other proposed amendments to our existing credit facility will require the approval of our other current lender and the addition of one or more additional lenders to our bank group. As a result, we cannot assure you that we will be able to amend our existing credit facility on the terms described above.

During 2010, in conjunction with the repayment of the Bank of America revolving credit facility on September 30, 2010, we expensed approximately $225,000 in unamortized loan fees associated with this facility, which is included in interest expense in our consolidated statements of operations for the year ended December 31, 2010.

We used the proceeds of our borrowings under the credit facilities for the development of our oil and natural gas properties and other capital expenditures, acquisition opportunities and for other general corporate purposes.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is secured by the Oklahoma City office building and associated land. As of December 31, 2010, approximately $2.4 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, to fund Grizzly s delineation drilling program and for acquisitions, primarily in the Permian Basin and the Niobrara Formation. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the reprocessing of 3-D seismic data in one of our principal properties, WCBB and shot 3-D seismic for the first time

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in our Hackberry field. The new and reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the fields, thus creating a portfolio of new drilling opportunities. In addition, with our acquisition of strategic assets in the Permian Basin in West Texas, we are required to pay 50% of all drilling costs for drilling activity on such properties. To combat significant declines in the commodity prices during the second half of 2008, management undertook a series of actions aimed at reducing capital spending and operating costs. As a result, we reduced our drilling and other capital activities to a minimum in the fourth quarter of 2008, releasing all rigs in Southern Louisiana and the Permian and only selectively participating in wells in the Bakken. During 2009, we were not bound by lease obligations and long term capital commitments relating to the exploration or development of our oil and gas properties. As a result of the then current economic conditions, we initially reduced our estimated capital activities and aggressively sought price concessions from our service providers until such time costs were reduced to more appropriate levels. In June 2009, we restarted our drilling programs. We commenced our 2010 drilling programs during March 2010.

In our December 31, 2010 reserve reports, 63% of our net reserves were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

Our inventory of prospects includes approximately 29 proved undeveloped drilling locations at WCBB. The drilling schedule used in our December 31, 2010 reserve report anticipates that all of those wells will be drilled by 2013. During 2010, we recompleted 72 wells and drilled 23 wells, all of which were completed as producers, at WCBB for an aggregate cost of $40.9 million. From January 1, 2011 through March 11, 2011, we recompleted twelve existing wells and drilled two wells at our WCBB field. We currently intend to spend a total of approximately $36.0 to $38.0 million to drill 20 to 24 wells and recomplete 60 wells in our WCBB field during 2011.

In our East Hackberry field, in 2010, we recompleted ten existing wells and drilled eight wells, all of which were completed as producers, for an aggregate cost of $20.0 million. From January 1, 2011 through March 11, 2011, we recompleted three existing wells and drilled three wells, two of which are currently drilling, at our East Hackberry field. We currently intend to drill seven to ten wells and recomplete five wells in our East Hackberry field in 2011. Total capital expenditures for our East Hackberry field during 2011 are estimated at $24.0 to $26.0 million.

In the Permian Basin, our booked inventory of prospects includes 226 gross (113 net) future development drilling locations. During 2010, 25 gross (11 net) wells were drilled on this acreage, of which 24 gross (10.7 net) were completed as producers and one gross (0.5 net) well was waiting on completion. Our aggregate capital expenditures in the Permian Basin were $29.0 million in 2010, which includes acreage acquisitions. From January 1, 2011 through March 11, 2011, four gross (two net) wells were recompleted and five gross (2.5 net) wells were drilled on this acreage, three of which are waiting on completion and two of which are currently drilling. We currently anticipate that our capital requirements to drill a total of 40 to 42 gross (19 to 20 net) wells and recomplete ten gross (five net) wells in the Permian Basin in West Texas will be approximately $37.0 to $39.0 million.

In the Niobrara Formation in Western Colorado, effective April 1, 2010, we acquired leasehold interests for a total of approximately $7.6 million. In addition, we recompleted one existing well and acquired additional acreage for an aggregate cost, including acquisition costs, of approximately $8.1 million in 2010. We are in the process of permitting a 60 square mile 3-D seismic survey and expect to begin shooting in mid-2011. We currently anticipate that our total capital expenditures in the Niobrara Formation will be approximately $4.0 million in 2011 relating to the seismic survey and drilling of four to five gross wells.

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During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. During 2010, we paid Grizzly $3.7 million in cash calls. As of December 31, 2010, our net investment in Grizzly was approximately $26.5 million. In addition, we have loaned Grizzly $20.0 million including interest and net of foreign currency adjustments as of December 31, 2010. Our capital requirements in 2011 for this project are currently estimated to be approximately $25.6 million, primarily for the expenses associated with the initial preparations of the Algar Lake SAGD facility and planned drilling activity.

Capital expenditures in 2010 relating to our interest in Thailand were approximately $400,000. Capital expenditures in 2011 relating to our interest in Thailand are expected to be approximately $1.0 million, which we believe will be mostly funded from our share of production from the Phu Horm field.

Our total capital expenditures for 2011 are currently estimated to be $127.0 million to $133.0 million, excluding our anticipated acquisition in the Utica Shale. This is an increase from the $85.8 million spent in 2010 due to improved commodity pricing and cost environment. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand and cash flow from operations will be sufficient to meet our normal recurring operating needs and our WCBB, Hackberry, Permian Basin, Niobrara and Grizzly capital requirements for the next twelve months. Although we currently anticipate significant free cash flow during 2011, in the event we elect to further expand or accelerate our drilling programs, complete acquisitions (including our anticipated acquisition in the Utica Shale) or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On March 7, 2011, the West Texas Intermediate posted price for crude oil was $105.44 per barrel and the Henry Hub spot market price of natural gas was $3.93 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations, for the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contacts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

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Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2010, the plugging and abandonment trust totaled approximately $3,129,000. At December 31, 2010, we have plugged 311 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2010.

		Payment due by period (1)			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Short-term and long-term debt	$ 51,917,000	$ 2,417,000	$ 49,500,000	$	$
Asset retirement obligations	10,845,000	635,000	1,334,000	816,000	8,060,000
Total	$ 62,762,000	$ 3,052,000	$ 50,834,000	$ 816,000	$ 8,060,000

(1) Does not include estimated interest of $1,970,000 less than one year and $3,312,000 1-3 years and short-term derivative instruments of $4,720,000 less than one year.

New Accounting Pronouncements

In December 2008, the SEC published a final rule, Modernization of Oil and Gas Reporting. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than year end prices. The new requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. We adopted this final rule as of December 31, 2009. The adoption of the rule resulted in a lower price used in reserve calculations and a decrease in 2009 reserves. Updated disclosures are included in Item 2. Properties Proved Oil and Natural Gas Reserves and Note 21 to our consolidated financial statements included in this report.

In January 2010, the FASB issued Accounting Standards Update 2010-03, Oil and Gas Reserve Estimation and Disclosures (currently codified in FASB ASC Topic 932, Extractive Activities Oil & Gas), or FASB ASC 932. The purpose of the amendments in this Update is to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the SEC s final rule, Modernization of Oil and Gas Reporting. The amendments to FASB ASC 932 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted FASB ASC 932 effective December 31, 2009, the impact of which is noted above.

In January 2010, the FASB issued Accounting Standards Update 2010-06, Improving Disclosures about Fair Value Measurements, which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosure, (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. We adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on our consolidated financial statements.

In December 2010, the FASB issued Accounting Standards Update 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (currently codified in FASB ASC Topic 805, Business Combinations), or FASB ASC 805. The purpose of the amendments in this update is to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this update also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments to FASB ASC 805 are effective prospectively for 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, 2010. The adoption did not have an immediate impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and 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, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On March 7, 2011, the West Texas Intermediate posted price for crude oil was $105.44 per barrel and the Henry Hub spot market price of natural gas was $3.93 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

For the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel, before transportation costs and differentials, for the period January 2011 through December 2011. Under the 2010 contracts, we

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delivered approximately 45% of our 2010 production. Under the 2011 contracts, we have committed to deliver approximately 30% to 33% of our estimated 2011 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At December 31, 2010, we had a net liability derivative position of $4.7 million related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $6.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by $6.8 million. However, any realized derivative gain or loss would be substantially offset by a decrease of increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our new revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or Eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the Eurodollar rates are elected, the Eurodollar rates. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%. Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $495,000 per year, based on $49.5 million outstanding under our credit facility as of December 31, 2010. As of December 31, 2010, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2010, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2010, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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Management s Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in *Internal Control Integrated Framework*, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2010.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2010 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2010, as stated in their accompanying report.

/s/ James D. Palm
Name: James D. Palm
Title: Chief Executive Officer

/s/ Michael G. Moore
Name: Michael G. Moore
Title: Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

Because of 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, Gulfport Energy Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010 and our report dated March 14, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 14, 2011

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10 Directors, Executive Officers and Corporate Governance, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11 Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

For information concerning Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For information concerning Item 13 Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14 Principal Accounting Fees and Services, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List the following documents filed as part of this report:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

Exhibit Number	Description
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5+	Summary of Oral Employment Agreement with James D. Palm (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 7, 2010).
10.5	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.6	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Pinnacle Energy Services, LLC
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Pinnacle Energy Services, LLC.

* Filed herewith
\+ Management contract, compensatory plan or arrangement.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 14, 2011

GULFPORT ENERGY CORPORATION

By: /s/ JAMES D. PALM
James D. Palm

Chief Executive Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: March 14, 2011	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 14, 2011	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 14, 2011	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 14, 2011	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: March 14, 2011	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Director**
Date: March 14, 2011	By:	/s/ SCOTT E. STRELLER **Scott E. Streller** **Director**

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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 Gulfport Energy Corporation and Subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Gulfport Energy Corporation and Subsidiaries internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 14, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 14, 2011

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Amounts rounded to nearest thousand)

	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,468,000	$ 1,724,000
Accounts receivable oil and gas	14,952,000	9,492,000
Accounts receivable related parties	573,000	136,000
Prepaid expenses and other current assets	1,732,000	2,047,000
Total current assets	19,725,000	13,399,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $16,778,000 and $17,521,000 excluded from amortization in 2010 and 2009, respectively	747,344,000	628,849,000
Other property and equipment	7,609,000	7,182,000
Accumulated depletion, depreciation, amortization and impairment	(512,822,000)	(473,915,000)
Property and equipment, net	242,131,000	162,116,000
Other assets:		
Equity investments	33,021,000	32,006,000
Note receivable related party	20,006,000	15,920,000
Other assets	4,182,000	3,370,000
Total other assets	57,209,000	51,296,000
Deferred tax asset	628,000	533,000
Total assets	$ 319,693,000	$ 227,344,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 41,155,000	$ 20,977,000
Asset retirement obligation current	635,000	635,000
Short-term derivative instruments	4,720,000	18,735,000
Current maturities of long-term debt	2,417,000	2,842,000
Total current liabilities	48,927,000	43,189,000
Asset retirement obligation long-term	10,210,000	9,518,000
Long-term debt, net of current maturities	49,500,000	49,586,000
Total liabilities	108,637,000	102,293,000
Commitments and contingencies (Notes 18 and 19)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding		

Stockholders' equity:		
Common stock $.01 par value, 100,000,000 authorized, 44,645,435 issued and outstanding in 2010 and 42,696,409 in 2009	446,000	427,000
Paid-in capital	296,253,000	273,901,000
Accumulated other comprehensive income (loss)	(1,768,000)	(18,039,000)
Retained earnings (accumulated deficit)	(83,875,000)	(131,238,000)
Total stockholders' equity	211,056,000	125,051,000
Total liabilities and stockholders' equity	$ 319,693,000	$ 227,344,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Amounts rounded to nearest thousand)

	Year Ended December 31, 2010	2009	2008
Revenues:			
Oil and condensate sales	$ 121,350,000	$ 81,587,000	$ 131,825,000
Gas sales	3,468,000	1,992,000	6,570,000
Natural gas liquid sales	2,818,000	1,997,000	3,255,000
Other income (expense)	(692,000)	(314,000)	(433,000)
	126,944,000	85,262,000	141,217,000
Costs and expenses:			
Lease operating expenses	17,614,000	16,316,000	22,856,000
Production taxes	13,966,000	9,797,000	15,813,000
Depreciation, depletion, and amortization	38,907,000	29,225,000	42,472,000
Impairment of oil and gas properties			272,722,000
General and administrative	6,063,000	4,992,000	6,843,000
Accretion expense	617,000	582,000	560,000
	77,167,000	60,912,000	361,266,000
INCOME (LOSS) FROM OPERATIONS	49,777,000	24,350,000	(220,049,000)
OTHER (INCOME) EXPENSE:			
Interest expense	2,761,000	2,309,000	4,762,000
Settlement of fixed price contracts			(39,000,000)
Insurance proceeds		(1,050,000)	(769,000)
Interest income	(387,000)	(564,000)	(540,000)
	2,374,000	695,000	(35,547,000)
INCOME (LOSS) BEFORE INCOME TAXES	47,403,000	23,655,000	(184,502,000)
INCOME TAX EXPENSE	40,000	28,000	
NET INCOME (LOSS)	$ 47,363,000	$ 23,627,000	$ (184,502,000)
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 1.08	$ 0.55	$ (4.33)
Diluted	$ 1.07	$ 0.55	$ (4.33)

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(Amounts rounded to nearest thousand)

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount				
Balance at January 1, 2008	42,453,587	$ 424,000	$ 271,807,000	$ 2,254,000	$ 29,637,000	$ 304,122,000
Net loss					(184,502,000)	(184,502,000)
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				(7,057,000)		(7,057,000)
Total Comprehensive Income (Loss)						(191,559,000)
Stock Compensation			1,056,000			1,056,000
Issuance of Restricted Stock	41,493					
Issuance of Common Stock through exercise of options	144,121	2,000	480,000			482,000
Balance at December 31, 2008	42,639,201	426,000	273,343,000	(4,803,000)	(154,865,000)	114,101,000
Net income					23,627,000	23,627,000
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				5,499,000		5,499,000
Change in fair value of derivative instruments				(13,422,000)		(13,422,000)
Reclassification of derivative contracts				(5,313,000)		(5,313,000)
Total Comprehensive Income (Loss)						10,391,000
Stock Compensation			529,000			529,000
Issuance of Restricted Stock	43,458					
Issuance of Common Stock through exercise of options	13,750	1,000	29,000			30,000
Balance at December 31, 2009	42,696,409	427,000	273,901,000	(18,039,000)	(131,238,000)	125,051,000
Net income					47,363,000	47,363,000
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment				2,255,000		2,255,000
Change in fair value of derivative instruments				(4,720,000)		(4,720,000)
Reclassification of derivative contracts				18,736,000		18,736,000
Total Comprehensive Income (Loss)						63,634,000
Stock Compensation			492,000			492,000
Issuance of Common Stock in public offering, net of related expenses of $210,000	1,668,503	17,000	21,341,000			21,358,000
Issuance of Common Stock through exercise of warrants	173,109	2,000	204,000			206,000
Issuance of Restricted Stock	58,525					
Issuance of Common Stock through exercise of options	48,889		315,000			315,000

Balance at December 31, 2010	44,645,435	$ 446,000	$ 296,253,000	$ (1,768,000)	$ (83,875,000)	$ 211,056,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOW

(Amounts rounded to nearest thousand)

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 47,363,000	$ 23,627,000	$ (184,502,000)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Accretion of discount Asset Retirement Obligation	617,000	582,000	560,000
Depletion, depreciation and amortization	38,907,000	29,225,000	42,472,000
Impairment of oil and gas properties			272,722,000
Stock-based compensation expense	295,000	317,000	634,000
Loss from equity investments	977,000	706,000	656,000
Interest income note receivable	(267,000)	(547,000)	(410,000)
Deferred income tax benefit	(95,000)	120,000	(653,000)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(5,460,000)	3,051,000	(2,033,000)
(Increase) decrease in accounts receivable related party	(437,000)	965,000	1,107,000
Decrease (increase) in prepaid expenses	315,000	(1,002,000)	301,000
Increase in other asset	(75,000)		
Increase (decrease) in accounts payable and accrued liabilities	4,948,000	(3,686,000)	5,328,000
Settlement of asset retirement obligation	(1,253,000)	(59,000)	(859,000)
Net cash provided by operating activities	85,835,000	53,299,000	135,323,000
Cash flows from investing activities:			
Deductions (additions) to cash held in escrow	8,000	8,000	(40,000)
Additions to other property, plant and equipment	(427,000)	(14,000)	(60,000)
Additions to oil and gas properties	(101,644,000)	(49,533,000)	(126,030,000)
Proceeds from sale of oil and gas properties	304,000	18,286,000	
Advances on note receivable to related party	(2,877,000)	(4,377,000)	(10,519,000)
Contributions to investment in Grizzly Oil Sands ULC	(842,000)		(151,000)
Distributions from investment in Tatex Thailand II, LLC	565,000	197,000	862,000
Contributions to investment in Tatex Thailand III, LLC	(402,000)	(3,813,000)	(885,000)
Net cash used in investing activities	(105,315,000)	(39,246,000)	(136,823,000)
Cash flows from financing activities:			
Principal payments on borrowings	(52,711,000)	(18,303,000)	(25,802,000)
Borrowings on line of credit	52,200,000		30,000,000
Loan commitment fees	(1,144,000)		
Proceeds from issuance of common stock, net of offering costs of $210,000 for 2010, and exercise of stock options	21,879,000	30,000	482,000
Net cash provided by (used in) financing activities	20,224,000	(18,273,000)	4,680,000
Net (decrease) increase in cash and cash equivalents	744,000	(4,220,000)	3,180,000
Cash and cash equivalents at beginning of period	1,724,000	5,944,000	2,764,000
Cash and cash equivalents at end of period	$ 2,468,000	$ 1,724,000	$ 5,944,000
Supplemental disclosure of cash flow information:			
Interest payments	$ 1,949,000	$ 2,300,000	$ 4,898,000
Income tax payments	$ 40,000	$ 543,000	$ 135,000

Supplemental disclosure of non-cash transactions:						
Capitalized stock based compensation	$	197,000	$	212,000	$	422,000
Asset retirement obligation capitalized	$	1,328,000	$	361,000	$	934,000
Dissolution of interest in Windsor Bakken, LLC	$		$		$	2,468,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$	1,313,000	$	3,656,000	$	(5,281,000)
Foreign currency translation gain (loss) on note receivable related party	$	942,000	$	1,843,000	$	(1,776,000)

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation (Gulfport or the Company) is an independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast, in West Texas in the Permian Basin and in Western Colorado in the Niobrara Formation and has investments in companies operating in Canada and Thailand.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc. and Puma Resources, Inc. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company s accounts receivable oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from two purchasers of the Company s oil and gas and one operator of certain of the Company s properties. Credit is extended based on evaluation of a customer s payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company s previous loss history, the customer s current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2010 and December 31, 2009.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for 2010 and 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company s oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled $16,778,000 and $17,521,000 at December 31, 2010 and December 31, 2009, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport s consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders equity. The following table presents the balances of the Company s cumulative translation adjustments included in accumulated other comprehensive income.

December 31, 2007	$ 2,254,000
December 31, 2008	$ (4,803,000)
December 31, 2009	$ 696,000
December 31, 2010	$ 2,952,000

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 13.

Income Taxes

Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The company adopted the provisions of FASB ASC Topic 740 as of January 1, 2007. The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company s 1996 2009 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2010, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2010, there is no interest or penalties associated with uncertain tax positions in the Company s consolidated financial statements.

Revenue Recognition

Gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company s ownership percentage in the property are recorded as a liability. If less than Gulfport s entitlement is received, the underproduction is recorded as a receivable. There is no such liability or asset recorded at December 31, 2010 and 2009 because the Company has no imbalances. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments Equity Method

Investments in entities greater than 20% and less than 50% are accounted for under the equity method. Under the equity method, the Company s share of investees earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2010 or 2009.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC Topic 718, *Compensation Stock Compensation* (FASB ASC 718). FASB ASC 718 requires share-based payments to employees, including grants of employee stock options, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period.

Accounting for Derivative Instruments and Hedging Activities

The Company may seek to reduce its exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. The Company follows the provisions of FASB ASC 815, *Derivatives and Hedging* (FASB ASC 815) as amended. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value.

The Company estimates the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and the Company s realized prices, time to maturity and credit risk. The values reported in the consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Recent Accounting Pronouncements

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12 month period rather than year end prices. The new requirements were effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company adopted the Final Rule as of December 31, 2009. The adoption of the rule resulted in a lower price used in reserve calculations and a decrease in 2009 reserves. See Item 2. Properties and Note 21 for further discussion of the impact of implementation.

In January 2010, the FASB issued Accounting Standards Update 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (currently codified in FASB ASC Topic 932, *Extractive Activities Oil & Gas*) (FASB ASC 932). The purpose of the amendments in this Update is to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the Security and Exchange Commission s Final Rule, *Modernization of Oil and Gas Reporting.* The amendments to FASB ASC 932 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The impact of the adoption of FASB ASC 932 is noted above.

In January 2010, the FASB issued Accounting Standards Update 2010-06, *Improving Disclosures about Fair Value Measurements,* which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosure* (FASB ASC 820). FASB ASC 820 requires additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) significant transfers between Levels 1, 2 and 3. The updated guidance is effective for annual and interim periods beginning after December 15, 2009. The Company adopted FASB ASC 820 effective January 1, 2010. The adoption did not have a material impact on the Company s consolidated financial statements.

In December 2010, the FASB issued Accounting Standards Update 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (currently codified in FASB ASC Topic 805, *Business Combinations*) (FASB ASC 805). The purpose of the amendments in this update is to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments in this update also expand the supplemental pro forma disclosures under FASB ASC 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments to FASB ASC 805 are effective prospectively for 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, 2010. The adoption did not have an immediate impact on the Company s consolidated financial statements.

2. ACQUISITIONS

On June 15, 2010, Gulfport acquired an ownership interest in certain oil and gas properties located in the Niobrara Formation of Colorado, including three gross producing wells for a cash price of approximately $7.75 million. The effective date of the acquisition was April 1, 2010. The total purchase price for the acquired assets, as adjusted at closing on June 15, 2010, was $7.7 million, which was recorded as oil and natural gas properties on the accompanying December 31, 2010 consolidated balance sheet. This amount includes an adjustment for the results of operations of the assets between the April 1, 2010 effective date and the June 15, 2010 closing date. The Company may adjust the purchase price for any post closing adjustments. The results of operations from

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(Amounts rounded to nearest thousand)

these properties were included in the December 31, 2010 consolidated statement of operations for the period from June 16, 2010 through December 31, 2010. No pro forma financials for this acquisition are disclosed as the acquisition was not deemed significant to the Company.

During May 2010, Gulfport acquired a 50% interest in 4,979 gross (2,489 net) undeveloped acres in the Permian Basin for approximately $7.6 million.

Gulfport funded these transactions predominately through a 1.7 million common share offering completed in May of 2010. The Company received net proceeds (before offering expenses) of approximately $21.6 million from the equity offering, as discussed below in Note 8.

3. ACCOUNTS RECEIVABLE RELATED PARTIES

Included in the accompanying December 31, 2010 and December 31, 2009 consolidated balance sheets are amounts receivable from related parties of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport s personnel on behalf of these related parties. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At December 31, 2010 and December 31, 2009, these receivables totaled $573,000 and $136,000, respectively. The Company recorded $593,000 and $1,363,000 for the years ended December 31, 2009 and 2008, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below. No amounts were reimbursed for general and administrative functions for the year ended December 31, 2010.

The Company is or has been a party to administrative service agreements with Caliber Development Company, LLC, Great White Energy Services LLC, and Diamondback Energy Services LLC. Under these agreements, the Company s services include accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a three-year term, and upon expiration of that term the agreements will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

The Company is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under these agreements, the Company s services include professional and technical support and office space. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a two-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

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The Company was reimbursed the following amounts by the specified entities in consideration for its administrative services for the years ended December 31, 2010, 2009 and 2008. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Wexford Capital LP (Wexford) controls and/or owns a greater than 10% interest in each of these entities. Affiliates of Wexford own approximately 25% of Gulfport s outstanding stock.

Agreement		December 31,		
Effective Date	**Entity**	**2010**	**2009**	**2008**
2/9/2005	Caliber Development Company, LLC*	$	$	$ 60,000
7/22/2006	Great White Energy Services LLC		61,000	83,000
9/26/2006	Diamondback Energy Services LLC*			10,000
3/1/2008	Stampede Farms LLC			159,000
3/1/2008	Grizzly Oil Sands ULC **		20,000	368,000
3/1/2008	Everest Operations Management LLC		508,000	154,000
3/1/2008	Tatex Thailand III, LLC			

* Agreement was terminated effective December 10, 2008.

** Agreement was terminated effective December 31, 2010.

For the year ended December 31, 2009, the Company was also reimbursed approximately $2,000 and $1,000 by Stampede Farms LLC and Everest Operations Management LLC, respectively, and approximately $20,000 and $26,000, respectively, for the year ended December 31, 2008, for office space under the administrative service agreements, which is included in other income (expense) in the consolidated statements of operations. For the year ended December 31, 2010, the Company was reimbursed approximately $20,000 by Orange Leaf Holdings, LLC, an affiliate of Gulfport, for office space which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest Operations Management LLC (Everest) to identify and evaluate potential oil and gas properties in which the Company and Everest may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party s proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice.

Effective April 1, 2010, the Company entered into an area of mutual interest agreement with Windsor Niobrara LLC (Windsor Niobrara), an entity controlled by Wexford, to jointly acquire oil and gas leases on certain lands located in Northwest Colorado for the purpose of exploring, exploiting and producing oil and gas from the Niobrara Formation. The agreement provides that each party must offer the other party the right to participate in such acquisitions on a 50%/50% basis. The parties also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to their respective participating interests and pay certain other fees as provided in the agreement. In connection with this agreement, Gulfport and Windsor Niobrara also entered into a development agreement, effective as of April 1, 2010, pursuant to which the Company and Windsor Niobrara agreed to jointly develop the contract area, and Gulfport agreed to act as the operator under the terms of a joint operating agreement.

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4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2010 and 2009 are as follows:

	December 31, 2010	December 31, 2009
Oil and natural gas properties	$ 747,344,000	$ 628,849,000
Office furniture and fixtures	3,277,000	2,996,000
Building	4,049,000	3,926,000
Land	283,000	260,000
Total property and equipment	754,953,000	636,031,000
Accumulated depletion, depreciation, amortization and impairment	(512,822,000)	(473,915,000)
Property and equipment, net	$ 242,131,000	$ 162,116,000

At December 31, 2008, the net book value of the Company s oil and natural gas properties, less related deferred income taxes, was above the calculated ceiling as a result of reduced commodity prices at December 31, 2008. As a result, the Company was required to record an impairment of its oil and natural gas properties under the full cost method of accounting in the amount of $272.7 million for the year ended December 31, 2008. No impairment of oil and natural gas properties was required for the years ended December 31, 2010 and December 31, 2009.

Included in oil and natural gas properties at December 31, 2010 and December 31, 2009 is the cumulative capitalization of $18,126,000 and $14,009,000, respectively, in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $4,117,000, $3,395,000 and $4,645,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

The following is a summary of Gulfport s oil and gas properties not subject to amortization as of December 31, 2010:

	Costs Incurred in 2010	2009	2008	Prior to 2008	Total
Acquisition costs	$ 9,950,000	$ 1,163,000	$ 5,000	$ 638,000	$ 11,756,000
Exploration costs	2,692,000	155,000	1,069,000	1,106,000	5,022,000
Development costs					

Total oil and gas properties not subject to amortization	$ 12,642,000	$ 1,318,000	$ 1,074,000	$ 1,744,000	$ 16,778,000

At December 31, 2010, approximately $5,022,000 of oil and gas properties related to the Company s Belize properties is excluded from amortization as it relates to non-producing properties. In addition, approximately

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$8,595,000 of non-producing leasehold costs resulting from the Company s acquisition of West Texas Permian properties, $301,000 of non-producing leasehold costs related to the Company s Bakken properties and $1,727,000 of non-producing leasehold costs related to the Company s Colorado properties are excluded from amortization at December 31, 2010. Approximately $1,089,000 of non-producing leasehold costs related to the Company s Southern Louisiana assets and $44,000 of non-producing leasehold costs related to other projects are also excluded from amortization. At December 31, 2009, approximately $17,521,000 of non-producing leasehold costs was not subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company s activities, the inclusion of most of the above referenced costs into the Company s amortization calculation is expected to occur within three to five years.

A reconciliation of the asset retirement obligation for the years ended December 31, 2010 and 2009 is as follows:

	December 31, 2010	December 31, 2009
Asset retirement obligation, beginning of period	$ 10,153,000	$ 9,269,000
Liabilities incurred	1,328,000	361,000
Liabilities settled	(1,253,000)	(59,000)
Accretion expense	617,000	582,000
Asset retirement obligation as of end of period	10,845,000	10,153,000
Less current portion	635,000	635,000
Asset retirement obligation, long-term	$ 10,210,000	$ 9,518,000

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
Investment in Tatex Thailand II, LLC	$ 1,907,000	$ 2,485,000
Investment in Tatex Thailand III, LLC	4,660,000	4,482,000
Investment in Grizzly Oil Sands ULC	26,454,000	25,039,000
	$ 33,021,000	$ 32,006,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC (Tatex) at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (APICO), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field. During 2010, Gulfport received $565,000 in distributions, reducing its total investment in Tatex (including previous investments) to $1,907,000. The loss on equity investment related to Tatex was immaterial for the years ended December 31, 2010, 2009 and 2008.

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Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC (Tatex III) at a cost of $850,000. In December 2009, the Company purchased an additional approximately 12.9% ownership interest at a cost of approximately $3,385,000 bringing its total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the year ended December 31, 2010, Gulfport paid $402,000 in cash calls, bringing its total investment in Tatex III to $4,660,000. The Company recognized a loss on equity investment of $224,000, $207,000 and $9,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC (Grizzly), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has drilled core holes and water supply test wells in nine separate lease blocks for feasibility of oil production and conducted a seismic program, but has not commenced development of operations. As of December 31, 2010 and 2009, Gulfport s net investment in Grizzly was $26,454,000 and $25,039,000, respectively. Grizzly s functional currency is the Canadian dollar. The Company s investment in Grizzly was increased by $1,313,000 and $3,656,000 as a result of a currency translation gain for the years ended December 31, 2010 and 2009. The Company recognized a loss on equity investment of $740,000, $498,000 and $639,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds initially bore interest at LIBOR plus 400 basis points and had an original maturity date of December 31, 2012. Effective April 1, 2010, the loan agreement was amended to modify the interest rate to 0.69% and change the maturity date to December 31, 2011. Effective October 15, 2010, the loan agreement was further amended to change the maturity date to the original maturity date of December 31, 2012. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company loaned Grizzly approximately $2,877,000 during the year ended December 31, 2010. The Company recognized interest income of approximately $267,000, $547,000 and $410,000 for the years ended December 31, 2010, 2009 and 2008, respectively, which is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $942,000 and $1,843,000 as a result of a currency translation gain for the years ended December 31, 2010 and 2009, respectively. The total $20,006,000 due from Grizzly is included in note receivable related party on the accompanying consolidated balance sheets.

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The table below summarizes financial information for Grizzly as of December 31, 2010, 2009 and 2008:

	December 31,		
	2010	2009	2008
Current assets	$ 3,277,000	$ 2,064,000	$ 1,481,000
Noncurrent assets	$ 188,786,000	$ 164,043,000	$ 125,024,000
Current liabilities	$ 3,708,000	$ 1,585,000	$ 2,663,000
Noncurrent liabilities	$ 81,089,000	$ 64,365,000	$ 36,397,000
Gross revenue	$	$	$
Loss from continuing operations	$ 3,234,000	$ 1,992,000	$ 2,595,000
Net loss	$ 3,234,000	$ 1,991,000	$ 2,557,000

6. OTHER ASSETS

Other assets consist of the following as of December 31, 2010 and 2009:

	December 31,	
	2010	2009
Plugging and abandonment escrow account on the WCBB properties (Note 18)	$ 3,129,000	$ 3,136,000
Certificates of Deposit securing letter of credit	275,000	200,000
Prepaid drilling costs	7,000	30,000
Loan commitment fees	767,000	
Deposits	4,000	4,000
	$ 4,182,000	$ 3,370,000

7. LONG-TERM DEBT

A break-down of long-term debt as of December 31, 2010 and 2009 is as follows:

	December 31,	
	2010	2009
Revolving credit agreement (1)	$ 49,500,000	$ 45,000,000
Term loans (1)		4,903,000
Building loans (2)	2,417,000	2,525,000
Less: current maturities of long term debt	(2,417,000)	(2,842,000)

Debt reflected as long term	$ 49,500,000	$ 49,586,000

Maturities of long-term debt as of December 31, 2010 are as follows:

2011	$ 2,417,000
2012	
2013	49,500,000
2014	
2015	
Thereafter	
Total	$ 51,917,000

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(1) In March 2005, Gulfport entered into a three-year secured credit agreement with Bank of America, N.A. providing for a revolving credit facility. The credit agreement was subsequently amended and restated from time to time and, among other things, the maturity date was extended to April 1, 2011. Borrowings under the revolving credit facility were subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. Effective July 19, 2007, the credit facility was increased to $150.0 million and effective December 20, 2007, the amount available under the borrowing base limitation was increased to $90.0 million.

On August 31, 2009, the lender completed its periodic redetermination of the Company s borrowing base giving consideration to the Company s year-end 2008 and mid-year 2009 reserve information and the lender s then current pricing decks, among other factors. As a result of this redetermination, the Company s available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. The Company s outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and the Company agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010. The Company paid the outstanding balance of the term loan in full in February 2010.

Outstanding borrowings under the term loan accrued interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% or, at the option of the Company, at the base rate (which was the highest of the lender s prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, the Company also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, the Company agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on the Company s utilization percentage. In addition, the Company agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

The Company s obligations under the credit facility were collateralized by a lien on substantially all of the Company s Louisiana and West Texas assets and were guaranteed by its subsidiaries. The restated credit agreement contained certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period could not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period could not be less than 3.00 to 1.00.

On September 30, 2010, the Company entered into a $100 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association. The new revolving credit facility matures on September 30, 2013 and has an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. As of December 31, 2010, the Company had an outstanding balance of $49.5 million drawn under the credit agreement, which is included in long-term debt, net of current maturities, on the accompanying consolidated balance sheets. The amounts borrowed under the credit agreement were used to repay all of the Company s

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outstanding indebtedness under its prior revolving credit facility ($42.0 million) and term loan ($2.5 million), each with Bank of America, N.A., as administrative agent, and for general corporate purposes. The new credit agreement is secured by substantially all of the Company s assets. The Company s wholly-owned subsidiaries guaranteed the obligations of the Company under the credit agreement.

Advances under the credit agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.75% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. At December 31, 2010, amounts borrowed under the credit agreement bore interest at the Eurodollar rate (3.77%).

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company s and its subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with all covenants at December 31, 2010.

In conjunction with the repayment of the Bank of America credit facilities on September 30, 2010, the Company expensed approximately $225,000 in unamortized loan fees associated with the Bank of America revolving credit facility, which is included in interest expense in the accompanying consolidated statements of operations.

On July 10, 2006, Gulfport entered into a $5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company made quarterly principal payments of approximately $176,000. Amounts borrowed bore interest at

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Bank of America Prime. The Company made quarterly interest payments on amounts borrowed under the agreement. The Company s obligations under the agreement were collateralized by a lien on the compressor units. On September 30, 2010, the Company repaid this loan in full with borrowings under the new credit agreement discussed above.

(2) In June 2004, the Company purchased the office building it occupies in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is secured by the Oklahoma City office building and associated land.

8. COMMON STOCK OPTIONS, RESTRICTED STOCK, WARRANTS AND CHANGES IN CAPITALIZATION

Options

The Company sponsors the 1999 Stock Option Plan (the Plan), which is administered by the Compensation Committee (the Committee) of the Board of Directors of the Company. Under the terms of the Plan, the Committee could determine: to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting period of such options and the exercisable period of such options. Eligible participants are defined as all directors of the Company, all officers of the Company and all key employees of the Company with a customary work week of at least 40 hours in the employ of the Company. The maximum number of shares for which options could be granted under the Plan, as adjusted for changes in capitalization which have taken place since the Plan s adoption, was 883,000. The Company has granted 627,337 options for the purchase of shares of the Company s common stock under the Plan as of December 31, 2010. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

The Company replaced the Plan in January 2005 with the 2005 Stock Incentive Plan (2005 Plan), which is administered by the Committee. Under the terms of the 2005 Plan, the Committee may determine when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) Incentive Stock Options, (b) Nonstatutory Stock Options, (c) Restricted Awards (Restricted Stock and Restricted Stock Units), (d) Performance Awards and (e) Stock Appreciation Rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2010, the Company has granted 997,269 options for the purchase of shares of the Company s common stock under the 2005 Plan.

Restricted Stock

On March 13, 2008, the Company granted 6,666 shares of restricted common stock of the Company, of which 740 shares vested on April 1, 2008 with the remaining shares vesting over 36 equal monthly installments

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beginning on May 1, 2008. On August 6, 2008, the Company granted 2,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On September 15, 2008, the Company granted 10,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On December 5, 2008, the Company granted 66,667 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2008.

On November 3, 2009, the Company granted 13,332 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2009.

On March 8, 2010, the Company granted 66,667 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $662,000. The shares vest over twelve substantially equal quarterly installments beginning on March 18, 2010. On November 3, 2010, the Company granted 45,000 shares of restricted common stock of the Company to employees of the Company at a fair value of approximately $783,000. The shares vest annually over five years, with 3,000 vesting the first year, 6,000 vesting the second year, 9,000 vesting the third year, 12,000 vesting the fourth year, and 15,000 vesting the fifth year. All shares of restricted common stock of the Company were granted under the amended and restated 2005 Plan.

Sale of Common Stock

On May 19, 2010, the Company sold 1,481,481 shares of its common stock in an underwritten public offering at a public offering price of $13.50 per share less the underwriting discount. On May 25, 2010, the Company sold an additional 187,022 shares of common stock at the public offering price less the underwriting discount in connection with the underwriters partial exercise of the over-allotment option granted to them by the Company. The Company received the aggregate net proceeds of approximately $21.6 million from the sale of these shares after deducting the underwriting discount and before offering expenses. A portion of the net proceeds from the offering was used to fund the Company s Niobrara Formation and Permian Basin acquisitions as discussed in Note 2. The remaining net proceeds from this offering were used for general corporate purposes, including expenditures associated with the Company s 2010 drilling programs.

Private Placement Offering

In March 2002, the Company completed a private placement offering of 10,000 units. Each unit consisted of (i) one share of Cumulative Preferred Stock, Series A, of the Company (the Preferred) and (ii) a warrant to purchase up to 250 shares of common stock, par value $0.01 per share, of the Company (the Warrants). Holders of the Preferred were entitled to receive dividends at the rate of 12% of the liquidation preference per annum payable quarterly in cash or, at the option of the Company for all quarters ending on or prior to March 31, 2004, payable in whole or in part in additional shares of Preferred at the rate of 15% of the liquidation preference per annum. All Preferred shares were redeemed in 2005.

The 2,322,962 Warrants issued have a term of ten years and a current exercise price of $1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the Warrants. The Company considered the valuation of the Warrants and did not consider them materially significant. The Company had 9,050 Warrants outstanding at December 31, 2010 which can be converted into 30,420 shares of common stock.

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9. STOCK-BASED COMPENSATION

During the years ended December 31, 2010, 2009 and 2008, the Company s stock-based compensation cost was $492,000, $529,000 and $1,056,000, respectively, of which the Company capitalized $197,000, $212,000 and $422,000, respectively, relating to its exploration and development efforts, which reduced basic and diluted earnings per share by $0.01 and $0.01 for the years ended December 31, 2010 and December 31, 2009, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport s common stock over a period of time ending on the grant date. Based upon historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2005 Plan provides that all options must have an exercise price not less than the fair value of the Company s common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2010, 2009 and 2008.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

A summary of the status of stock options and related activity for the years ended December 31, 2010, 2009 and 2008 are presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2007	674,390	$ 6.22	6.97	$ 8,098,000
Granted				
Exercised	(144,121)	3.34		1,694,000
Forfeited/expired	(7,889)	6.17		
Options outstanding at December 31, 2008	522,380	7.01	6.24	$ (1,599,000)
Granted				
Exercised	(13,750)	2.20		71,000
Forfeited/expired				
Options outstanding at December 31, 2009	508,630	7.14	5.38	$ 2,192,000
Granted				
Exercised	(48,889)	6.46		545,000
Forfeited/expired	(1,500)	2.00		

Options outstanding at December 31, 2010	458,241	$	7.23	4.48	$ 6,621,000
Options exercisable at December 31, 2010	458,241	$	7.23	4.48	$ 6,621,000

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Unrecognized compensation expense as of December 31, 2010 related to outstanding stock options and restricted shares was $1,329,000. The expense is expected to be recognized over a weighted average period of 2.21 years. The following table summarizes information about the stock options outstanding at December 31, 2010:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$2.00		0.00	
$3.36	222,241	4.06	222,241
$9.07	36,000	4.69	36,000
$11.20	200,000	4.92	200,000
	458,241		458,241

The following table summarizes restricted stock activity for the twelve months ended December 31, 2010, 2009 and 2008:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2007	59,033	$ 13.94
Granted	85,333	5.64
Vested	(41,493)	11.97
Forfeited	(9,417)	15.84
Unvested shares as of December 31, 2008	93,456	$ 7.04
Granted	13,332	$ 8.08
Vested	(43,458)	8.16
Forfeited	(3,086)	15.77
Unvested shares as of December 31, 2009	60,244	$ 6.01
Granted	111,667	$ 12.94
Vested	(58,525)	8.17
Forfeited		
Unvested shares as of December 31, 2010	113,386	$ 11.72

10. INSURANCE PROCEEDS

In May 2008, the Company received insurance proceeds of approximately $769,000 related to damages incurred resulting from a 2006 barge accident in its WCBB field. The costs associated with repairing the field were expensed to lease operating expenses as incurred in 2006 and 2007. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations.

In March 2009, the Company received insurance proceeds of approximately $1,050,000 related to damages incurred in its WCBB field as a result of Hurricane Ike in 2008. The costs associated with repairing the field were

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expensed to lease operating expenses as incurred in 2008 and 2009. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations. In September and October 2009, the Company received additional insurance proceeds of approximately $994,000 related to damages incurred in the WCBB field as a result of Hurricane Ike and related debris removal. As the costs related to these repairs and debris removal were incurred in 2009 and expensed to lease operating expense, the Company recognized the insurance proceeds in lease operating expenses in the accompanying consolidated statements of operations.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current and long-term debt are carried at cost, which approximates market value.

The fair value of the derivative instruments is computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials. Forward market prices for oil are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

12. INCOME TAXES

The income tax provision consists of the following:

	2010	2009	2008
Current:			
State	$ 40,000	$ 28,000	$
Federal	95,000	32,000	653,000
Deferred:			
State			
Federal	(95,000)	(32,000)	(653,000)
Total income tax expense provision	$ 40,000	$ 28,000	$

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2010	2009	2008
Income (loss) before income taxes	$ 47,403,000	$ 23,655,000	$ (184,502,000)
Expected income tax at statutory rate	16,591,000	8,279,000	(64,576,000)
State income taxes	2,378,000	1,370,000	(7,033,000)
Other differences	(111,000)	(891,000)	(527,000)
Changes in valuation allowance	(18,818,000)	(8,730,000)	72,136,000

Income tax expense recorded	$	40,000	$	28,000	$

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The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2010, 2009 and 2008 are estimated as follows:

	2010	2009	2008
Deferred tax assets:			
Net operating loss carryforward	$ 20,967,000	$ 22,268,000	$ 23,810,000
Oil and gas property basis difference	32,054,000	49,638,000	57,789,000
FASB ASC 718 compensation expense	347,000	341,000	238,000
Investment in pass through entities	722,000	528,000	
AMT credit	693,000	598,000	718,000
Non-oil and gas property basis difference	279,000	316,000	118,000
Total deferred tax assets	55,062,000	73,689,000	82,673,000
Deferred tax liabilities:			
Oil and gas property basis difference			
Investment in pass through entities			134,000
Unrealized gain on hedging activities			
Total deferred tax liabilities			134,000
Total deferred tax asset	55,062,000	73,689,000	82,539,000
Valuation allowance	(54,434,000)	(73,156,000)	(81,886,000)
Net deferred tax asset	$ 628,000	$ 533,000	$ 653,000

The Company has an available tax net operating loss carryforward estimated at approximately $52,417,000 as of December 31, 2010. This carryforward will begin to expire in the year 2018. A valuation allowance has been provided at December 31, 2010, 2009 and 2008 because it is management s belief, based upon the Company s past history of no taxable income and future projections of no taxable income during the carryforward period, it is more likely than not the net deferred tax assets will not be realized.

The Company had income tax expense of $40,000 and $28,000 related to state income tax for the years ended December 31, 2010 and 2009, respectively.

13. EARNINGS PER SHARE

A reconciliation of the components of basic and diluted net income per common share is presented in the table below:

2010		2009		2008	
Income	Shares	Income	Shares	Income	Shares

			Per Share			Per Share			Per Share
Basic:									
Net income (loss)	$ 47,363,000	43,863,190	$ 1.08	$ 23,627,000	42,667,581	$ 0.55	$ (184,502,000)	42,599,611	$ (4.33)
Effect of dilutive securities:									
Stock options and awards		392,902			350,067				
Diluted:									
Net income	$ 47,363,000	44,256,092	$ 1.07	$ 23,627,000	43,017,648	$ 0.55	$ (184,502,000)	42,599,611	$ (4.33)

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For the year ended December 31, 2009, options to purchase 64,889 shares at $9.07 per share and 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share because they were anti-dilutive. For the year ended December 31, 2008, all options were excluded from the calculation of dilutive earnings per share because the Company had a net loss and, therefore, the effect would have been anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2010.

14. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by entering into forward sales contracts or fixed price swaps. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

At December 31, 2010, the fair value of derivative liabilities related to the fixed price swaps is as follows:

Short-term derivative instruments liability	$ 4,720,000

At December 31, 2009, the fair value of derivative liabilities related to the forward sales contracts is as follows:

Short-term derivative instruments liability	$ 18,735,000

All forward sales contracts and fixed price swaps have been executed in connection with the Company s oil price hedging program. For forward sales contracts and fixed price swaps qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil sales in the period for which the underlying production was hedged.

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income into earnings as a component of oil and condensate sales for the years ended December 31, 2010 and 2009 are presented below.

	Year ended December 31,	
	2010	**2009**
(Reduction) addition to oil and condensate sales	($ 18,736,000)	$ 5,313,000

The Company expects to reclassify $4,720,000 out of accumulated other comprehensive income into earnings as a component of oil and condensate sales during the year ended December 31, 2011 related to fixed price swaps.

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Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company did not recognize into earnings any amount related to hedge effectiveness for the year ended December 31, 2010 related to the 2010 hedges as these hedges were deemed to be perfectly effective. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the year ended December 31, 2010 related to the 2011 hedges, however, these hedges could be considered ineffective in future periods.

During the fourth quarter of 2010, the Company entered into fixed price swap contracts for 2011 with the purchaser of the Company s WCBB oil and another financial institution. The Company will pay the counterparty the excess of the oil market price over the fixed price and will receive the excess of the fixed price over the market prices as defined in each contract. The Company s fixed price swap contracts are tied to the commodity prices on the New York Mercantile Exchange (NYMEX). The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price for oil as listed on the NYMEX West Texas Index (WTI). However, due to the geographic location of the Company s assets and the cost of transporting oil to another market, the amount that the Company receives when it actually sells its oil differs from the index price. At December 31, 2010, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day	Weighted Average Price
January December 2011	2,000	$ 86.96

In 2009, the Company was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs and differentials, for the period April 2009 to August 2009. The Company also was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period September 2009 to December 2009. For the period January 2010 through February 2010, the Company was party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, the Company was party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel, before transportation costs and differentials.

In the first quarter of 2009, the Company terminated forward sales contracts for 3,000 barrels per day of March 2009 production for approximately $1.5 million and terminated forward sales contracts for 3,000 barrels per day in the second quarter of 2009 for $476,000. For the year ended December 31, 2009, approximately $2.0 million related to such terminations is included in oil and condensate sales on the accompanying consolidated statements of operations. There were no contracts in place which were accounted for as hedges at December 31, 2008.

The Company delivered approximately 45% of its 2010 production under forward sales contracts.

15. FAIR VALUE MEASUREMENTS

The Company adopted FASB ASC 820 for all financial assets and liabilities measured at fair value on a recurring basis. The Company adopted FASB ASC 820 effective January 1, 2009 for all non-financial assets and liabilities. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer

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a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 Quoted prices in active markets for identical assets and liabilities.

Level 2 Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following tables summarizes the Company s financial and nonfinancial liabilities by FASB ASC 820 valuation level as of December 31, 2010 and 2009:

	As of December 31, 2010		
	Level 1	**Level 2**	**Level 3**
Assets:			
Fixed price swaps	$	$	$
Liabilities:			
Fixed price swaps	$	$ 4,720,000	$

	As of December 31, 2009		
	Level 1	**Level 2**	**Level 3**
Assets:			
Forward sales contracts	$	$	$
Liabilities:			
Forward sales contracts	$	$ 18,735,000	$

The estimated fair value of the Company s fixed price swap contracts was based upon forward commodity prices based on quoted market prices, adjusted for differentials.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred during the twelve months ended December 31, 2010 were approximately $1,328,000.

16. OPERATING LEASES

In October 2006, the Company began leasing the Louisiana building that it owns to an unrelated party. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately

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$97,000 as of December 31, 2010. The lease commenced on October 15, 2006 and was extended to expire on October 14, 2011, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31, 2011	$ 100,000

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company conducts business activities with certain entities affiliated with its largest stockholder.

Windsor Energy Group, LLC (WEG), an entity controlled by Wexford, operates the Permian Basin wells in West Texas. At December 31, 2010 and 2009, the Company owed WEG approximately $5,871,000 and $1,631,000, respectively, related to reimbursement for services provided. Approximately $2,386,000 and $2,368,000 of services provided by WEG are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively. Approximately $21,666,000 and $8,063,000 related to services performed by WEG are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Athena Construction LLC (Athena), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2010 and December 31, 2009, the Company owed Athena approximately $791,000 and $836,000, respectively, related to these services. Approximately $438,000 and $709,000 of services provided by Athena are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively. Approximately $2,554,000 and $1,286,000 related to services performed by Athena are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Great White Directional Services LLC (Directional), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2010 and December 31, 2009, the Company owed Directional approximately $952,000 and $699,000, respectively, related to these services. Approximately $3,008,000 and $1,064,000 relating to services performed by Directional are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010 and 2009, respectively.

Great White Pressure Control (Pressure Control), an entity controlled by Wexford, performs services for the Company at its WCBB field. At December 31, 2010, the Company owed Pressure Control approximately $80,000, related to these services. No amounts were owed to Pressure Control at December 31, 2009. Approximately $80,000 of services performed by Pressure Control is included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010. No services were performed by Pressure Control in 2009.

Black Fin P&A, LLC (Black Fin), an entity controlled by Wexford, performs services for the Company at its WCBB field. No amounts were owed to Black Fin at December 31, 2010. Approximately $826,000 of services performed by Black Fin is included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2010. No services were performed by Black Fin in 2009.

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18. COMMITMENTS

Plugging and Abandonment Funds

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2010, the plugging and abandonment trust totaled approximately $3,129,000. At December 31, 2010, the Company has plugged 311 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Texaco Global Settlement

Pursuant to the terms of a global settlement between Texaco and the State of Louisiana which includes the State Lease No. 50 portion of Gulfport s East Hackberry field, Gulfport was obligated to commence drilling a well or other qualifying development operation on certain non-producing acreage in the field prior to March 1998. Because of prevailing market conditions during 1998, the Company believed it was commercially impractical to shoot seismic or commence drilling operations on the subject property. As a result, Gulfport agreed to surrender approximately 440 non-producing acres in this field to the State of Louisiana. At December 31, 2010, Gulfport was in the process of releasing these properties to the State of Louisiana.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 15% of their total compensation through salary deferrals. Also under these plans, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee s participation in salary deferrals. During the years ended December 31, 2010, 2009 and 2008, Gulfport incurred $316,000, $279,000 and $651,000, respectively, in contributions expense related to this plan.

Employment Agreement

In May 1999, Gulfport entered into an employment agreement with its Chairman of the Board. The original term of the agreement expired on May 31, 2004, but automatically renews for successive terms of one year unless Gulfport or the Chairman elects otherwise. The employment agreement calls for an annual salary of $200,000, subject to adjustment for cost of living increases.

The Company is party to an oral agreement with the Company s Chief Executive Officer, with respect to his compensation and benefits, pursuant to which he is entitled to an annual salary of $200,000 and, at the discretion of the Company s board of directors, an annual cash incentive bonus. The compensation committee of the Board of Directors may make upward adjustments to this salary.

19. CONTINGENCIES

The Louisiana Department of Revenue (LDR) is disputing Gulfport s severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains

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that Gulfport paid approximately $1,800,000 less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2,275,729 in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit.

In December 2010, the LDR filed two identical lawsuits against Gulfport in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by LDR in 2009, Gulfport denies all liability and will vigorously defend the lawsuit. The cases are in the early stages, and Gulfport has not yet filed a response to the recent lawsuits.

Other Litigation

In November 2006, Cudd Pressure Control, Inc. (Cudd) filed a lawsuit against Gulfport, Great White Pressure Control LLC (Great White) and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Gulfport filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including Gulfport, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that Gulfport conspired with the other defendants to misappropriate, and misappropriated, Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, Gulfport s motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled *Reeds et al. v. BP American Production Company et al.,* 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name Gulfport as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants, which in addition to BP America Production Company include ExxonMobil Corporation, Shell Oil Company, ConocoPhillips Company, Sun Oil Company and Schlumberger Technology Corporation, conducted, directed and participated in various oil and gas

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exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, Gulfport was served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including Gulfport, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. Gulfport s motion is currently set to be heard on March 23, 2011.

Due to the current stages of the LDR, Cudd and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on the Company s financial condition or results of operations.

The Company has been named as a defendant on various other litigation matters. The ultimate resolution of these matters is not expected to have a material adverse effect on the Company s financial condition or results of operations for the periods presented in the consolidated financial statements.

Concentration of Credit Risk

Gulfport operates in the oil and gas industry principally in the state of Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company s results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. At December 31, 2010, Gulfport held cash in excess of insured limits in these banks totaling $1,986,000.

During the year ended December 31, 2010, Gulfport sold approximately 75% and 19% of its oil production to Shell Trading Company (Shell) and WEG, respectively, and 50%, 32% and 10% of its natural gas production to WEG, Chevron, and Hilcorp Energy Company (Hilcorp), respectively. During the year ended December 31, 2009, Gulfport sold approximately 92% and 7% of its oil production to Shell and WEG, respectively, 100% of its natural gas liquids production to WEG, and 45%, 38%, and 16% of its natural gas production to WEG, Chevron, and Hilcorp, respectively. During the year ended December 31, 2008, Gulfport sold approximately 87% and 11% of its oil production to Shell and WEG, respectively, 100% of its natural gas liquids production to WEG, and 60%, 22%, and 16% of its natural gas production to Chevron, WEG, and Hilcorp, respectively.

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Forward Sales Contracts

The Company was party to forward sales contracts for the sale of 3,500 barrels of production per day for the months of January 2008 through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For June 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the month of July 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $85.89 per barrel before transportation costs. For August 2008, Gulfport had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $86.81 per barrel before transportation costs. For the periods September 2008 through December 2008, the Company entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $86.60 per barrel before transportation costs. For the period of January 2009 through December 2009, the Company entered into agreements to sell 3,000 barrels of production per day at a weighted average daily price of $89.06 per barrel before transportation costs. These contracts were originally designated as normal sales of production under FASB ASC 815, based on the Company s intent to physically deliver the production quantities under the contract terms, and exempted from the provisions of FASB ASC 815.

In December 2008, the Company terminated the 2009 forward sales contracts in exchange for $39.0 million cash, which is included in other (income) expense on the accompanying consolidated statements of operations. As a result of this cash settlement, beginning in 2009, the Company is required to account for similar contracts under the provisions of FASB ASC 815 until a reasonable period passes and the Company redevelops a past history of physical delivery under fixed price contracts without net cash settlement. See Note 14 for further discussion of the Company s 2009 and 2010 forward sales contracts.

20. LITIGATION TRUST ENTITY

Pursuant to the Company s 1997 plan of reorganization, all of Gulfport s possible causes of action against third parties (with the exception of certain litigation related to recovery of marine and rig equipment assets and claims against Tri-Deck), existing as of the effective date of that plan, were transferred into a Litigation Trust controlled by an independent party for the benefit of most of the Company s existing unsecured creditors. The litigation related to recovery of marine and rig equipment and the Tri-Deck claims were subsequently transferred to the Litigation Trust as described below.

The Litigation Trust was funded by a $3,000,000 cash payment from the Company, which was made on the effective date of reorganization. Gulfport owns a 12% interest in the Litigation Trust with the other 88% being owned by the former general unsecured creditors of Gulfport. For financial statement reporting purposes, Gulfport has not recognized the potential value of recoveries which may ultimately be obtained, if any, as a result of the actions of the Litigation Trust, treating the entire $3,000,000 payment as a reorganization cost at the time of Gulfport s reorganization.

On January 20, 1998, Gulfport and the Litigation Trust entered into a Clarification Agreement whereby the rights to pursue various claims reserved by Gulfport under the plan of reorganization were assigned to the Litigation Trust. In connection with this agreement, the Litigation Trust agreed to reimburse the Company $100,000 for legal fees Gulfport had incurred in connection with these claims. As additional consideration for the contribution of this claim to the Litigation Trust, Gulfport is entitled to 20% to 80% of the net proceeds from these claims.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(Amounts rounded to nearest thousand)

In December 2009, the Company received a final distribution from the Litigation Trust of approximately $234,000. No proceeds were received from the Litigation Trust for the years ended December 31, 2010 or 2008.

21. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The following is historical revenue and cost information relating to the Company s oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2010	2009
Proven properties	$ 730,566,000	$ 610,778,000
Unproven properties	11,756,000	15,192,000
	742,322,000	625,970,000
Accumulated depreciation, depletion, amortization and impairment reserve	(509,248,000)	(470,649,000)
Net capitalized costs	$ 233,074,000	$ 155,321,000

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2010	2009	2008
Acquisition	$ 17,627,000	$ 1,885,000	$ 2,468,000
Development of proved undeveloped properties	64,652,000	28,652,000	64,643,000
Exploratory		502,000	9,764,000
Recompletions	16,917,000	8,980,000	16,877,000
Capitalized asset retirement obligation	1,328,000	361,000	934,000
Total	$ 100,524,000	$ 40,380,000	$ 94,686,000

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(Amounts rounded to nearest thousand)

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2010	2009	2008
Revenues	$ 127,636,000	$ 85,576,000	$ 141,650,000
Production costs	(31,580,000)	(26,113,000)	(38,669,000)
Impairment of oil and gas assets			(272,722,000)
Depletion	(38,600,000)	(28,939,000)	(42,194,000)
	57,456,000	30,524,000	(211,935,000)
Income tax expense			
Current	40,000	28,000	
Deferred			
	40,000	28,000	
Results of operations from producing activities	$ 57,416,000	$ 30,496,000	$ (211,935,000)
Depletion per barrel of oil equivalent (BOE)	$ 19.54	$ 17.25	$ 23.92

Oil and Gas Reserves (Unaudited)

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2010, 2009 and 2008 and changes in proved reserves during the last three years. The 2010 and 2009 reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2010 and 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31, 2008. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for the 2010 reserve report are $76.16 per barrel and $4.38 per MMbtu, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2009 and 2008 for reserve report purposes are $57.90 per barrel and $3.87 per MMbtu and $41.00 per barrel and $5.71 per MMbtu, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(Amounts rounded to nearest thousand)

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	2010		2009		2008	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Reserves						
Beginning of the period	17,488	14,332	21,771	22,235	25,115	24,259
Purchases in oil and gas reserves in place	3,913	3,482	1,728	1,135	77	26
Extensions and discoveries	5,574	5,303	2,614	2,874	1,315	1,965
Sales of oil and gas reserves in place			(736)	(282)		
Revisions of prior reserve estimates	(5,426)	(6,171)	(6,294)	(11,139)	(3,091)	(3,303)
Current production	(1,845)	(788)	(1,595)	(491)	(1,645)	(712)
End of period	19,704	16,158	17,488	14,332	21,771	22,235
Proved developed reserves	7,230	6,068	6,165	4,325	7,072	7,187

The Company experienced downward reserve revisions in estimated proved reserves in 2010. These downward revisions were primarily the result of the application of the five-year schedule for the development of proved undeveloped reserves required by the SEC s Modernization of Oil and Gas Reporting Final Rule, which resulted in the elimination of proved undeveloped reserves that remained undeveloped beyond such five-year schedule. The Company experienced downward reserve revisions in estimated proved reserves in 2009. These downward revisions were primarily the result of application of the five-year schedule for the development of proved undeveloped reserves required by the SEC s Modernization of Oil and Gas Reporting Final Rule. The Company experienced downward reserve revisions in estimated proved reserves in 2008. These downward revisions were primarily a result of year end commodity prices utilized for the reserve estimate decreasing from $92.50 per barrel and $6.80 per MMbtu at December 31, 2007 to $41.00 per barrel and $5.71 per MMbtu at December 31, 2008.

Discounted Future Net Cash Flows (Unaudited)

The following tables present the estimated future cash flows, and changes therein, from Gulfport s proven oil and gas reserves as of December 31, 2010, 2009 and 2008 using an unweighted average first-of-the-month price for the period January through December for 2010 and 2009 and the applicable year end price for 2008.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

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

	Year ended December 31,		
	2010	**2009**	**2008**
Future cash flows	$ 1,479,295,000	$ 1,005,029,000	$ 1,023,056,000
Future development and abandonment costs	(301,651,000)	(209,975,000)	(299,362,000)
Future production costs	(305,814,000)	(236,003,000)	(376,176,000)
Future production taxes	(136,323,000)	(97,841,000)	(109,478,000)
Future income taxes	(159,171,000)	(50,229,000)	
Future net cash flows	576,336,000	410,981,000	238,040,000
10% discount to reflect timing of cash flows	(260,849,000)	(170,207,000)	(111,800,000)
Standardized measure of discounted future net cash flows	$ 315,487,000	$ 240,774,000	$ 126,240,000

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport s reserve report, the Company will need to spend $71,320,000, $63,100,000 and $52,038,000 during years 2011, 2012 and 2013, respectively.

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

	Year ended December 31,		
	2010	**2009**	**2008**
Sales and transfers of oil and gas produced, net of production costs	$ (96,056,000)	$ (59,463,000)	$ (102,981,000)
Net changes in prices, production costs, and development costs	122,147,000	183,426,000	(662,004,000)
Acquisition of oil and gas reserves in place	63,043,000	20,981,000	376,000
Extensions and discoveries	88,227,000	32,638,000	7,801,000
Revisions of previous quantity estimates, less related production costs	(89,155,000)	(77,531,000)	(13,480,000)
Sales of reserves in place		(13,185,000)	
Accretion of discount	24,077,000	12,624,000	66,830,000
Net changes in income taxes	(54,879,000)	(22,238,000)	152,949,000
Change in production rates and other	17,309,000	37,282,000	8,454,000
Total change in standardized measure of discounted future net cash flows	$ 74,713,000	$ 114,534,000	$ (542,055,000)

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2010, 2009 AND 2008

(Amounts rounded to nearest thousand)

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2010 and 2009:

	2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 27,355,000	$ 28,875,000	$ 33,181,000	$ 37,533,000
Income from operations	10,526,000	11,004,000	13,468,000	14,779,000
Income tax expense		40,000		
Net income	9,981,000	10,389,000	12,678,000	14,315,000
Income per share:				
Basic	$ 0.23	$ 0.24	$ 0.28	$ 0.32
Diluted	$ 0.23	$ 0.24	$ 0.28	$ 0.32

	2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 17,784,000	$ 20,514,000	$ 22,071,000	$ 24,893,000
Income from operations	2,214,000	5,410,000	7,130,000	9,596,000
Income tax expense		28,000		
Net income	2,733,000	5,078,000	6,674,000	9,142,000
Income per share:				
Basic	$ 0.06	$ 0.12	$ 0.16	$ 0.21
Diluted	$ 0.06	$ 0.12	$ 0.16	$ 0.21

23. SUBSEQUENT EVENTS (Unaudited)

In February 2011, the Company entered into an agreement to acquire certain leasehold interests located in the Utica Shale in Ohio. The agreement also grants the Company an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Windsor, an affiliate of the Company, has agreed to participate with the Company on a 50/50 basis in the acquisition of all leases described above. Gulfport will be the operator on this acreage in the Utica Shale. The purchase price for the Company s 50% interest in the initial acreage is approximately $31,625,000, subject to certain closing adjustments. This transaction is expected to close in mid-May 2011.

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EXHIBIT INDEX

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

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Exhibit Number	Description
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5+	Summary of Oral Employment Agreement with James D. Palm (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 7, 2010).
10.5	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.6	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Pinnacle Energy Services, LLC
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Pinnacle Energy Services, LLC.

* Filed herewith
\+ Management contract, compensatory plan or arrangement.