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Ute Indian Tribe of the Uintah and Ouray Reservation

Comments on the Department of the Interior's Proposal to Update the "Licensed Indian Traders" Regulations

August 23, 2017

I. INTRODUCTION

The Business Committee of the Ute Indian Tribe (the "Tribe") of the Uintah and Ouray Indian Reservation appreciates the opportunity to provide the following comments on the Department of the Interior's proposal to update the "Licensed Indian Traders" regulations, at 25 C.F.R. Part 140. The Tribe believes that 25 C.F.R. Part 140 should be updated in order to support and promote tribal sovereignty, jurisdiction, and self-determination. By updating and streamlining the regulations, and protecting tribal sovereignty, the Tribe believes that updated regulations will benefit the Tribe through an improved ability to regulate our resources and trade and commerce on our Reservation.

The Ute Indian Tribe is a major oil and gas producer. Production of oil and gas began on the Reservation in the 1940's and has continued with significant periods of expansion. The Tribe leases about 400,000 acres for oil and gas development. We have about 7,000 wells that produce 45,000 barrels of oil per day. We also produce about 900 million cubic feet of gas per day. These amounts are likely to increase. The Tribe relies on its oil and gas development as the primary source of funding for its tribal government and the services it provides.

Any update to the regulations must affirm tribal sovereignty and preserve tribal jurisdiction over our lands. The clarification of a tribe's sovereign power to exercise civil jurisdiction and its authority to enforce tribal law will help the Ute Indian Tribe better manage the development of trust resources on our Uintah and Ouray Indian Reservation. The Tribe supports updating the regulations and we have also provided comments on additional recommendations on what the proposed rule should contain. These regulations should aim to shift power back into the hands of Indian tribal governments. We hope that our concerns are taken into account and incorporated into the proposed and final rule.

II. GENERAL COMMENTS

The Department must keep two overarching themes in mind when revising the Part 140 Regulations. First, the regulations should support tribal authority to control and regulate tribal land and resources while promoting business development and economic growth on reservations by Indians and non-Indian entrepreneurs. Second, updates to these regulations will only be successful if the federal government improves its processes for approving permits, leases, licenses, and other business agreements. The federal government must provide more funding to better staff local Bureau of Indian Affairs (BIA) Agency Offices so that development of tribal projects can proceed in a timely manner.

Revising the Part 140 regulations provides the Department with an opportunity to make simple changes that will result in increased investment and development opportunities in Indian Country. Updates to the regulations should address the following areas: (1) remove barriers to investment capital and financing in Indian Country; (2) clarify tribal jurisdiction and regulatory authority over all (Indian and non-Indian) business activities on Indian lands and empower tribes to authorize any person to engage in trade within Indian reservations pursuant to the laws of the tribal government; and (3) clarify taxing authority over commerce in Indian Country.

1. Access to External Funding

The revisions to the Part 140 regulations should remove barriers to investment capital and financing for tribal enterprises. Tribes need better access to capital for both public sector finance investments and to develop and grow tribal government-owned enterprises. Tribal government-owned enterprises are a boon for community development as sources of jobs and income for local residents and for generating revenue for tribal governmental services. Tribal access to investors and financing tools is critical to supporting tribal business and sustained economic growth; however, due to the unique issues associated with doing business in Indian Country, numerous barriers prevent tribal access to capital and discourage external investment in tribally-owned enterprises.

An example of this problem is demonstrated by the Tribe's experience in creating and growing Ute Energy into a company valued at $1 billion, but due to a lack of access to investment capital the Tribe was forced to sell the company. Specifically, the Tribe owned 51% of Ute Energy and sought to obtain the remaining ownership interest of our existing partner in the company, when that partner took action to wind up the company and sell its assets so that it could get a return on its original investment in the company. The Tribe explored various types of financing options to raise the necessary capital, including the use of Tribal Economic Development (TED) Bond financing, but this was not an option as a previous TED Bond application for the company was denied because the company was not 100% tribally owned. As a result, the Tribe had to sell its interest and its exploration and production assets to a non-Indian company—actually a Canadian non-Indian company, which means that all of the revenue is not only leaving the Reservation, but also the United States. Restrictions on the ability of tribes to raise capital and invest in our reservation infrastructure must be addressed.

Another important source of capital for reservation economic development are the Federal government's loan guarantee programs for Indian Country. For many years, Interior has provided loan guarantees through a small but successful program in its Office of Indian Energy and Economic Development. While this program has been successful, the funding is too small for energy projects and major economic development projects. Meanwhile the Department of

Energy's Indian Energy Loan Guarantee Program was only recently funded more than 10 years after Congress authorized the program. In addition, the Department of Energy's program has only been provided $9 million in funding, less than the funding typically provided for Interior's program. These are both good programs and could be important parts of revitalizing reservation economies, but without a serious commitment from the Federal government, Indian economic development will continue to suffer as tribes are left without financing or access to capital to pursue true economic sovereignty and self-determination.

2. Tribal Jurisdiction over all Business Activities on Indian Lands

The Ute Indian Tribe believes that the Part 140 regulations should be updated to provide for tribal jurisdiction and regulatory authority to regulate all business activities, individuals, and entities engaging in commerce subject to tribal jurisdiction, and to specifically recognize tribal authority to regulate and tax non-Indian economic activity on tribal lands. The regulations should defer to tribal laws and authority to the maximum extent. The Secretary of the Interior has broad authority under the Indian Trader statutes to do this. The statute at 25 U.S.C. § 262 covers "any person desiring to trade with the Indians" and authorizes any regulations Interior "may prescribe for the protection of said Indians."

Our Tribe manages our Reservation through 60 tribal departments and agencies including land, fish and wildlife management, housing, education, emergency medical services, public safety, and energy and minerals management. The Tribe has developed its own policies and regulations that better identify and resolve issues related to development activities on the Tribe's lands.

One example of a federal agency whose regulatory authority regularly results in inexplicable delays to a project's approval is the Fish and Wildlife Service (FWS). The FWS regularly delays approving and completing its required consultation on energy projects that are crucial to the Tribe's economy and ability to provide essential governmental services to our members. Further, the Tribe has developed its own species-specific management plans to protect endangered or threatened species on our Reservation, yet the FWS failed to recognize and give effect to the Tribe's conservation and mitigation plans despite a Secretarial Order requiring them to do so.

Despite the progress we have made, our ability to fully benefit from our resources is limited by the federal agencies overseeing oil and gas development on the Reservation that lack staff and expertise and impose bureaucratic laws and regulations that serve as barriers to our energy development. The United States must maintain its treaty and trust responsibilities to Indian tribes while also supporting Indian self-determination and preventing state and local interference on Indian lands.

As it stands, federal staff limitations and restrictions on various aspects of oil and gas production are causing energy companies to limit their activities on the Reservation. The restrictions currently in place already hamper development and the economic incentive for producers to operate on the Reservation. As a result, the Tribe is not able to fully develop its resources and revenues available for tribal operations are limited.

The Ute Indian Tribe is in the best position to understand the needs of our community, the sensitivities of our land, the effects of competition off-Reservation, and the market conditions needed to attract and grow businesses on our Reservation. The federal government should foster our trade relationship by recognizing and deferring to tribal authority.

3. Clarification of Taxing Authority in Indian Country

The Ute Indian Tribe and the State of Utah have entered into an agreement to share collected tax revenue to limit the impacts of dual taxation of mineral development on the Tribe's lands. In the early 1990's the Tribe and the State of Utah entered into a tax agreement that has been codified in the Utah Code as the "Uintah Basin Revitalization Fund." The Revitalization fund was created to support government and economic development in the Tribe's region in return for the Tribe's agreement not to impose its own taxes. In general, oil and gas companies operating on the Tribe's land pay into the Revitalization Fund based on the removal and production of oil and gas from mineral interests held in trust by the United States for the Tribe and its members. In Fiscal Year 2015, out of the $4,150,300 in project funding awarded under the Revitalization Fund, projects within the Tribe's Reservation received $1,265,300 or 30.4% of the total amount. Two counties surrounding the Tribe's Reservation were awarded the remaining $2,885,000.

The agreement provides that either 33% or 80% (depending on the land status where the well is located) of severance taxes collected will be deposited into the Fund, although the maximum annual deposit cannot exceed a statutory cap of $6,000,000. The State keeps either 66% or 20% of the collected taxes (again, dependent on the land status where the well is located). The State also keeps all of the severance taxes collected that are in excess of the $6,000,000 maximum annual deposit. The Revitalization Fund is then used to provide financial resources or grants for county agencies, the Tribe, and non-Indian and Indian citizens of the Uintah Basin.

The Revitalization Fund has been advantageous to both the Tribe and the State, and we believe that other tribes and states could use it as model for their own agreements. However, as beneficial as our agreement has been for the Tribe, there would be no need for the Tribe to share these tax revenues if the Tribe had clear and exclusive authority to tax natural resource development, commercial activities, and personal property within its Reservation.

III. CONCLUSION

The Ute Indian Tribe appreciates the opportunity to comment on Interior's proposal to update the Licensed Indian Traders Regulations. Again, we commend Interior and BIA for undertaking this very important endeavor with the overall goals of strengthening and supporting tribal self-determination, tribal sovereignty and tribal governance. We hope that our comments and concerns prove informative and beneficial to Interior and BIA.

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Ute Indian Tribe of the Uintah and Ouray Reservation

Supplemental Comments on the Department of the Interior's Proposal to Update the "Licensed Indian Traders" Regulations

August 30, 2017

On August 23, 2017, the Ute Indian Tribe of the Uintah and Ouray Reservation submitted comments on the Department of the Interior's proposal to update the "Licensed Indian Traders" regulations, at 25 C.F.R. Part 140. As the Tribe stated at that time, 25 C.F.R. Part 140 should be updated in order to support and promote tribal sovereignty, jurisdiction, and self-determination. By updating and streamlining the regulations, and protecting tribal sovereignty, the Tribe believes that updated regulations will benefit the Tribe through an improved ability to regulate our resources and trade and commerce on our Reservation.

Following the submission of those comments and consultation with Interior officials, the Ute Indian Tribe collected supplemental materials in support of its comments to further document the amount of revenue allocated from state taxation of Tribal and Indian lands as part of the Ute Indian Tribe's Revitalization Fund Agreement with the State of Utah as well as information relating to the Ute Indian Tribe's initial public offering (IPO) of stock in the Tribe's energy company, Ute Energy LLC. As the Ute Indian Tribe outlined at the recent consultation session in Portland, Oregon on August 22, 2017, this IPO was later withdrawn after financial institutions seeking to underwrite the IPO devalued Ute Energy's assets by $100 million dollars simply because the assets were located on Tribal lands. These supplemental materials are enclosed. Please find enclosed:

- News article summary of the Ute Energy IPO offering
- Ute Energy's S-1 filing with the Security and Exchange Commission submitted in relation to the IPO
- Summary of Uintah Basin Revitalization Fund Revenue Approved Project FY-2014-2016
- Uintah Basin Revitalization Fund Agreement
- Uintah Basin Revitalization Fund Statute in Utah Code

UTE Exchange

A new tribal IPO will finance oil and gas exploration in Utah, debt reduction

BY MARK FOGARTY

Denver-based Ute Energy Corp. plans to use the proceeds of an initial public offering (IPO) of up to $250 million in stock to repay some of its parent company Ute Energy LLC's debts and for oil and natural gas exploration and development programs in the Uinta Basin of northeast Utah.

The parent firm, founded in 2005 by the Ute Indian Tribe of the Uintah and Ouray Reservation, currently has two revolving credit facilities, one for $500 million and a second lien credit facility of $50 million. (Revolving credit means that any amount that is repaid is eligible to be borrowed again.)

"We have a multiyear inventory of development drilling and exploration projects in the Uinta Basin," the company said of its exploration and development efforts in an S-1 registration statement filed with the Securities and Exchange Commission (SEC) on January 5. Ute Energy said it had "identified 5,791 gross (2,680.1 net) potential drilling locations (609 gross (340.1 net) of which are proved undeveloped), targeting multiple zones in the Green River and Wasatch formations."

Ute Energy will apply to list on the New York Stock Exchange with the stock symbol UTE. Credit Suisse Securities (USA) and Goldman, Sachs & Co. are underwriting the stock offering. Because the SEC mandates a company "quiet period" around the time of stock offerings, telephone messages and e-mails to Joseph N. Jaggers, Ute Energy president and chief executive officer, were not returned.

The company noted that 60 percent of its net acreage and 62 percent of its net identified potential drilling sites are on tribal land or leased from the tribe: "We have accumulated approximately 162,695 net leasehold acres in the established and highly prospective Uinta Basin, approximately 94 percent of which are undeveloped.... As of September 30, 2011, our estimated net proved reserves were 35.1 MMBoe (million barrels of oil equivalent), approximately 23 percent of which were classified as proved developed and approximately 88 percent of which were comprised of oil."

UTE's IPO proceeds will fund oil–natural gas exploration.

Prior to this planned IPO, the company said it had changed its focus: "During 2010, we shifted our focus from participating primarily in nonoperated positions to establishing a significant portfolio of operated acreage and growing our asset base primarily through operated drilling activities." As part of this change, the firm, which employs 44 people—including at its second location in Fort Duchesne, Utah—hired Jaggers, who had been president of Bill Barrett Corp., another oil and natural gas company.

The firm stated that it began drilling "our first operated well in our Randlett project area in April 2011. We had drilled 22 gross (22 net) operated wells as of September 30, 2011 with a 100 percent success rate."

It also said it had deployed "a second operated drilling rig to the basin in November 2011, and we expect to deploy a third drilling rig by mid-year 2012.... Our 2012 drilling program contemplates the drilling of approximately 123 gross (109.7 net) operated wells utilizing two operated drilling rigs for the full year."

Ute Energy plans to develop its identified potential drilling locations "primarily through vertical drilling and utilization of multistage fracture stimulation techniques. We continue to evaluate the potential for horizontal drilling to target zones such as the Uteland Butte, the Mahogany Oil Shale and the Black Shale/G-1 Lime as well as the potential for enhanced recovery techniques, such as waterfloods, to improve results and increase oil and gas recoveries."

As of December 21, 2010, the company had total assets of $99.7 million. "Our total 2012 capital expenditure budget is expected to be approximately $315 million, consisting of approximately $297 million for drilling and completion costs, of which 74 percent is for operated wells," officials said, according to the S-1 registration statement.

On November 30, Ute Energy "acquired approximately 29,281 net fee, state and federal acres with 751 identified potential drilling locations in Horseshoe Bend and approximately 6,062 net fee and allotted acres in Randlett with 221 identified potential drilling locations, for approximately $100 million in cash.... We operate all of the approximately 6,062 net acres acquired in Randlett and substantially all of the approximately 29,281 net acres acquired in Horseshoe Bend."

The firm had net earnings of $11.7 million in 2010 and $50.8 million for the nine months ending September 30, 2011. It does not expect to declare to pay cash dividends on their common stock. Indeed, "We anticipate that our new credit facility will restrict the payment of dividends on our common stock."

THINKSTOCK

As filed with the Securities and Exchange Commission on December [●], 2011

Registration No. 333-[●]

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Ute Energy Upstream Holdings LLC
to be converted as described herein to
a corporation to be renamed

Ute Energy Corporation

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**26-2508194**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

1875 Lawrence Street, Suite 200
Denver, Colorado 80202
(720) 420-3200
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Joseph N. Jaggers
President and Chief Executive Officer
1875 Lawrence Street, Suite 200
Denver, Colorado 80202
(720) 420-3200
(Name, address, including zip code, and telephone number, including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this registration statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933 check the following box: ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer þ Smaller reporting company ¨
(Do not check if a smaller reporting company)

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee
Common Stock, par value $[●] per share	$ [●]	$ [●]

(1) Includes shares of common stock issuable upon exercise of the underwriters' option to purchase additional shares of common stock.
(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Commission acting pursuant to said Section 8(a), may determine.

SUBJECT TO COMPLETION, DATED DECEMBER [●], 2011

The information in this prospectus is not complete and may be changed. We and the selling stockholders may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and we and the selling stockholders are not soliciting offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

Shares

Ute Energy Corporation

Common Stock

We are offering shares of common stock and the selling stockholders are offering shares of common stock. We will not receive any of the proceeds from the shares of common stock sold by the selling stockholders.

Prior to this offering, there has been no public market for our common stock. The initial public offering price of our common stock is expected to be between $ and $ per share. We will apply to list our common stock on the New York Stock Exchange under the symbol “UTE.”

The underwriters have an option to purchase a maximum of additional shares of our common stock from the selling stockholders.

Investing in our common stock involves risks. Please read “Risk Factors” beginning on page [●].

	Price to Public	Underwriting Discounts and Commissions	Proceeds to Ute Energy	Proceeds to Selling Stockholders
Per Share	$	$	$	$
Total	$	$	$	$

Delivery of the shares of common stock will be made on or about , 2012.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Credit Suisse **Goldman, Sachs & Co.**

The date of this prospectus is , 2012.

[Inside Cover Art]

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You should rely only on the information contained in this document or to which we have referred you. We have not authorized anyone to provide you with information that is different. This document may only be used where it is legal to sell these securities. The information in this document may only be accurate as of the date of this document.

Dealer Prospectus Delivery Obligation

Until , all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

Industry and Market Data

The industry and market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. Because it is abbreviated, this summary does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully before making an investment decision, including the information presented under the headings "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical financial statements and unaudited condensed pro forma financial information and related notes thereto included elsewhere in this prospectus. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters' option to purchase additional shares of common stock from the selling stockholders is not exercised.

Unless otherwise indicated, our estimated net proved reserves, average net daily production and related operational data presented in this prospectus as of and for the three and nine months ended September 30, 2011 give pro forma effect to the properties acquired in the Horseshoe Bend acquisition as if such properties were acquired on January 1, 2011, and information related to our operated acreage position in Horseshoe Bend includes certain acreage in Ouray Valley that is subject to a vote of the working interest owners to determine the operator. Please read "— Horseshoe Bend Acquisition" beginning on page [●] of this prospectus. For a detailed explanation of the basis for our estimated net proved reserves and average net daily production, please read "— Summary Historical and Pro Forma Operating and Reserve Data."

Prior to completion of this offering, Ute Energy Upstream Holdings LLC will convert from a Delaware limited liability company to a Delaware corporation and change its name to Ute Energy Corporation. Unless the context otherwise requires, references to "we," "us," "our," the "company" and "Ute Energy" refer to Ute Energy Upstream Holdings LLC before the completion of our corporate reorganization and Ute Energy Corporation as of the completion of our corporate reorganization and thereafter. References to "our parent" refer to our parent company, Ute Energy LLC, before the completion of our corporate reorganization. We have included a glossary of certain oil and natural gas terms used in this prospectus in Appendix A.

UTE ENERGY CORPORATION

Overview

We are an independent oil and natural gas company engaged in the exploration, development, production and acquisition of oil and natural gas reserves with a primary focus on acquiring and developing oil reserves. We have accumulated approximately 162,695 net leasehold acres in the established and highly prospective Uinta Basin, approximately 94% of which are undeveloped. We are currently focused on exploration and development in the Green River and Wasatch formations, which we believe have significant resource potential and are characterized by multiple oil producing horizons with long-life reserves. As of September 30, 2011, our estimated net proved reserves were 35.1 MMBoe, approximately 23% of which were classified as proved developed and approximately 88% of which were comprised of oil. For the three and nine months ended September 30, 2011, our average net daily production from our properties was 4,172 Boe/d and 3,408 Boe/d, respectively. For the month ended October 31, 2011, our average net daily production from our properties was 4,711 Boe/d.

The Ute Indian Tribe of the Uintah and Ouray Reservation (the "Tribe") formed our parent company, Ute Energy LLC, in 2005 to participate in the exploration and development of the Tribe's mineral estate in the Uinta Basin. The Tribe partnered with leading oil and gas operators in the Uinta Basin to develop its oil and natural gas properties. In 2007, Quantum Energy Partners and Quantum Resources Management made their initial investment in our parent company, which provided our parent with the capital to accelerate operations and fund the cost of developing its properties. We were formed by our parent in 2008 to manage the oil and natural gas operations distinctly from our parent's midstream activities.

During 2010, we shifted our focus from participating primarily in non-operated positions to establishing a significant portfolio of operated acreage and growing our asset base primarily through operated drilling activities. As a part of this strategy, we hired a management team and technical personnel with significant industry and operational experience. Since our strategic shift, we have increased our operated acreage position in the Uinta Basin through an active leasing and acquisition program and we have balanced our portfolio of tribal acreage with the addition of significant interests in fee, state, federal and allotted lands. As of September 30, 2011, we have 75,420 net operated acres, which represents 46% of our total net acreage position, and we have 64,827 net acres on fee, state, federal and allotted lands, which represents 40% of our total net acreage position. Additionally, we commenced drilling of our first operated well in our Randlett project area in April 2011. We had drilled 22 gross (22 net) operated wells as of September 30, 2011 with a 100% success rate, and we operated 32% of our average net daily production for the month ended September 30, 2011.

In addition to expanding our operated acreage position, we continue to derive substantial benefits from our non-operated properties throughout the Uinta Basin. As of September 30, 2011, we have participated in 326 gross (96.9 net) non-operated wells. These wells are operated by other leading operators in the basin, including Berry Petroleum Corporation ("Berry Petroleum"), Bill Barrett Corporation ("Bill Barrett") and Newfield Exploration Company ("Newfield"). Our participation in non-operated project areas offers attractive return opportunities and enables us to gain additional exposure to emerging resource plays without committing all of the capital required to drill the wells during the early-stage testing and refinement of drilling and completion techniques in emerging areas. For example, our operating partners are leading the development of an emerging horizontal play targeting the Uteland Butte producing zone of the lower Green River formation. Through November 2011, we have participated in eight gross (2.25 net) horizontal Uteland Butte wells drilled by our operating partners.

Our oil and natural gas properties are divided among multiple project areas within the Uinta Basin. These project areas are described in more detail under the heading "— Our Core Project Areas" beginning on page [●] of this prospectus. The following table presents a summary of acreage, reserves, production and identified potential drilling locations for each of our project areas as of the dates, and for the periods, indicated.

	Net Acreage as of September 30, 2011	Estimated Net Proved Reserves as of September 30, 211			Average Net Daily Production (Boe/d) for the Three Months Ended September 30, 2011	Identified Potential Drilling Locations as of September 30, 2011(2)	
		MMBoe(1)	% of Total Proved Reserves	% Oil		Gross	Net
Randlett	39,351	12.9	37%	93%	925	935	844.0
Horseshoe Bend	29,281	8.4	24%	100%	301	751	523.7
Rocky Point	10,789	-	-	-	-	472	205.0
Blacktail Ridge	28,569	7.6	22%	77%	1,451	594	290.6
North Monument Butte	11,724	5.3	15%	79%	816	1,027	256.8
Bridgeland	9,883	0.5	1%	58%	458	530	185.5
Lake Canyon	30,371	0.3	1%	69%	133	1,465	366.3
Other	2,727	0.1	0%	0%	88	17	8.2
Total	162,695	35.1	100%	88%	4,172	5,791	2,680.1

(1) One Boe is equal to one Bbl of oil or six Mcf of natural gas based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(2) To identify our potential drilling locations, we analyze both our own proprietary information as well as industry data available in the public domain. Specifically, petrophysical data derived from open hole logs and cores and production data from operated and non-operated wells provide the technical basis from which we identified the potential locations. We also adjust locations for topographical issues as well as environmental and cultural concerns. Our identified potential drilling locations are scheduled out over many years, and there is no guarantee that all or even a substantial portion of these potential drilling locations will be drilled. Based on our currently projected capital expenditure budget, we estimate that we will have drilled approximately 234 gross wells on these potential locations by the end of 2012 and approximately 2,209 by the end of 2016. In addition, we are not the operator of 68% of our gross (45% net) identified potential drilling locations, and because we are not the operator of these properties we have limited control over the timing of drilling of the wells, or whether wells will be drilled at all, on these properties.

We have a multi-year inventory of development drilling and exploration projects in the Uinta Basin. We believe that the size and concentration of our acreage will allow us to efficiently grow our reserves, production and cash flow over time. As of September 30, 2011, we have identified 5,791 gross (2,680.1 net) potential drilling locations (609 gross (340.1 net) of which are proved undeveloped), targeting multiple zones in the Green River and Wasatch formations. To accelerate our drilling program, we deployed a second operated drilling rig to the basin in November 2011, and we expect to deploy a third drilling rig by mid-year 2012. We may deploy additional operated drilling rigs to the basin should drilling results, market conditions and drilling permit availability allow us to further accelerate our drilling program in the near term. As of September 30, 2011, our partners were operating four drilling rigs in our non-operated project areas.

We plan to develop our identified potential drilling locations primarily through vertical drilling and utilization of multi-stage fracture stimulation techniques. We continue to evaluate the potential for horizontal drilling to target zones such as the Uteland Butte, the Mahogany Oil Shale and the Black Shale/G-1 Lime as well as the potential for enhanced recovery techniques, such as waterfloods, to improve results and increase oil and gas recoveries.

Our total 2012 capital expenditure budget is expected to be $[●] million, consisting of:

- $[●] million for drilling and completing operated wells;
- $[●] million for drilling and completing non-operated wells;
- $[●] million for maintaining our leasehold position;
- $[●] million for constructing strategic infrastructure to support production in our core project areas; and
- $[●] million in unallocated funds for general corporate purposes.

The amount and allocation of capital we spend may fluctuate materially based on drilling results, market conditions and drilling permit availability. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our Competitive Strengths

We believe the following competitive strengths will allow us to successfully execute our business strategies:

- *Large, regionally focused acreage position in an established and highly prospective oil resource area.* We have a substantial and concentrated acreage position of approximately 162,695 net acres in the Uinta Basin, approximately 94% of which is undeveloped. We believe our acreage position is highly prospective, primarily for crude oil within multiple target zones of the Green River and Wasatch formations, including the Uteland Butte. The Uinta Basin has a long history of exploration and development activity with substantial remaining resource potential. According to IHS, Inc., the Uinta Basin has produced 1.3 billion Boe of crude oil and natural gas since commercial production began in the 1940s, and, according to Wood Mackenzie, the Uinta Basin has remaining recoverable reserves, defined as proved plus probable reserves, of 3.1 billion Boe.

- *Multi-year inventory of identified potential drilling locations targeting crude oil zones.* We have an inventory of 5,791gross (2,680.1 net) identified potential drilling locations in the Uinta Basin. Our drilling activity focuses on producing crude oil, with all of our identified potential drilling locations targeting crude oil zones. For the nine months ended September 30, 2011, we drilled or participated in 100 gross (45.4 net) wells with a 100% success rate. We currently plan to drill 234 gross (160.5 net) wells within our existing project areas by the end of 2012.

- *Management and technical team with extensive public company experience in resource play development.* Our senior management and technical team has a successful record of identifying, acquiring and developing resource plays and has an average of over 25 years of oil and gas industry experience, with extensive operating experience in the Rocky Mountain region and particular experience in the Uinta Basin. Our technical team includes engineers, geoscientists, landmen and regulatory specialists. Our team has enabled us to expand our asset base and successfully execute our strategic shift to growing our operated production and acreage position. In addition, our team has significant public company experience as a result of prior work for companies such as Barrett Resources Corporation, The Williams Companies, Inc., Bill Barrett and Rosetta Resources Inc.

- *Significant liquidity and financial flexibility to fund our drilling program.* Following this offering, we expect to have no debt outstanding under our new $ million revolving credit facility, with approximately $ million available for borrowing and $ million of cash on hand. We expect that the cash proceeds from this offering and funds available under our new credit facility, together with the cash flows from our operations, will be sufficient to fund our anticipated capital expenditures. Moreover, as the operator of a significant portion of our acreage position, we expect to have control over the level and pace of a significant portion of our capital expenditures as we develop our properties. To allow for more predictable cash flows in the near term, we maintain an active hedging program with an average of 3,808 bbl/d of crude oil production hedged in 2012 at a weighted average minimum price of $94.16 per bbl as of November 30, 2011.

- *Strong relationship with the Tribe.* Approximately 60% of our acreage and 62% of our net identified potential drilling locations are located on Ute tribal lands or are leased from the Tribe. Our relationship with the Tribe has been instrumental in building an asset base that includes both high growth development properties and properties with exposure to emerging Uinta Basin resource plays. Following this offering, the Tribe will own approximately % of our outstanding common stock, which we believe may give us a competitive advantage in acquiring additional mineral interests on Ute tribal lands. Moreover, we believe that our relationship with the Tribe provides us with a significant competitive advantage in securing drilling and operating permits on Ute tribal lands and otherwise working with government entities with oversight authority for oil and natural gas exploration and production on Ute tribal lands.

Our Business Strategy

Our goal is to increase stockholder value by growing our reserves and increasing our production and cash flows by executing the following strategies:

- *Focus on aggressive expansion of operated drilling activities.* We intend to aggressively drill our current operated acreage to maximize the value of our resource potential. We have 75,420 net operated acres, which are 97% undeveloped with approximately 1,844 identified potential drilling locations. We believe that the concentration and growth of our operated properties will enable us to achieve economies of scale on drilling service costs and leasehold operating expenses. Our 2012 drilling program contemplates the drilling of approximately 133 gross (116.3 net) operated wells utilizing two operated drilling rigs for the full year. We expect to deploy a third drilling rig by the middle of 2012 to support the development of our Rocky Point and Horseshoe Bend properties. We may deploy additional drilling rigs to the basin should drilling results, market conditions and drilling permit availability allow us to accelerate our drilling program in the near term.

- *Apply operating experience to enhance returns*. We are focused on the continuous improvement of our operating practices and have significant experience in converting resource opportunities into cost-effective development projects. We intend to draw on our technical team's significant experience in utilizing modern drilling and completion techniques to optimize our resource recovery in a cost efficient manner. In the near term, our primary focus will be the use of vertical drilling and multi-stage fracturing techniques to potentially enhance resource recovery, and we will continue to evaluate the effectiveness of horizontal drilling, down-spacing and waterflooding as a means to further increase resource recovery.

- *Continue to participate in drilling on non-operated leasehold acreage*. Our participation in non-operated project areas offers attractive return opportunities and enables us to gain additional exposure to emerging resource plays without committing all of the capital required to drill the wells during the early-stage testing and refinement of drilling and completion techniques. For example, our operating partners are leading the development of an emerging horizontal play targeting the Uteland Butte producing zone of the lower Green River formation. Through November 2011, we have participated in eight gross (2.25 net) horizontal Uteland Butte wells drilled by our operating partners. We plan to apply the knowledge and expertise gained from participating in the drilling and completion of these wells to target prospective horizontal Uteland Butte or other prospective horizontal zones in our operated portfolio of oil and natural gas properties. In addition, we believe that the knowledge and expertise gained through our non-operated positions will enhance our ability to continue the efficient growth of our operated acreage positions throughout the Uinta Basin.

- *Allocate capital to strategic infrastructure to support our upstream operations.* We will continue to identify and fund strategic infrastructure projects to reduce risks, increase marketing flexibility and enhance the value of our business. For example, we are installing a high pressure gas gathering system within our Randlett project area, which will connect to a pipeline system that flows to the Chipeta natural gas processing plant. We have contracted capacity on this pipeline system and have secured 25,000 Mcf/d of processing capacity at the Chipeta plant. Our Randlett gathering system will provide an outlet for associated natural gas from our oil wells, which will minimize the risk of a curtailment of oil production due to lack of takeaway capacity for produced natural gas. In addition, the gathering system will enable us to realize additional value on our future natural gas production, as this production will be gathered and transported to the Chipeta plant where it will be processed to recover marketable natural gas liquids.

- *Pursue acquisitions in areas that leverage our operating strengths.* In the near term, we intend to identify and acquire additional acreage and producing properties in the Uinta Basin, with an emphasis on increasing our operated asset base. Over time, we may selectively target additional basins in the Rocky Mountain region or other resource opportunities with characteristics similar to our existing areas of operations to leverage our operating strengths in areas outside the Uinta Basin.

Our Core Project Areas

Randlett

We operate all of our properties in our Randlett project area and have approximately 39,351 net leasehold acres with an average 86% working interest. We acquired our initial acreage in Randlett in December 2010 and commenced drilling activities in April 2011. As of September 30, 2011, we had drilled a total of 22 wells, with 18 wells completed and producing and four wells awaiting completion. All of our wells drilled in Randlett have been vertically drilled wells targeting the Green River formation, and we expect to have commenced drilling three wells targeting the Wasatch formation by the end of 2011.

We have completed all of our Randlett wells in the Uteland Butte zone of the Green River formation, which is one of several zones we currently complete in our vertical drilling program. We believe this area may also be prospective for a horizontal drilling program targeting the Uteland Butte zone. In addition, we anticipate implementing a pilot waterflood program as part of our 2012 capital expenditure budget. Other operators are currently utilizing this secondary recovery technique in nearby fields.

Horseshoe Bend

We acquired our Horseshoe Bend properties in November 2011. We operate substantially all of our Horseshoe Bend properties, and have approximately 29,281 net leasehold acres with an average working interest of 66% and 50 gross (33.9 net) producing wells. Operatorship with respect to approximately 3,993 net leasehold acres in Ouray Valley remains subject to a vote of the working interest owners. The Horseshoe Bend project area abuts the northwest corner of Randlett and represents a substantial expansion of our operated leasehold and drilling inventory. We plan to commence operated drilling activities in this area during the second half of 2012, primarily targeting the Green River and Wasatch formations with vertically drilled wells. We believe this area may also be prospective for a horizontal drilling program targeting the Black Shale/G-1 Lime and Uteland Butte zones of the Green River formation and provide additional opportunities for future waterflooding.

Rocky Point

We operate 50% of our approximately 10,789 net leasehold acres in the Rocky Point project area, and Newfield operates the remaining 50%. Our operated leasehold acres are adjacent to the western boundary of Randlett. We hold a 75% working interest in our operated position and a 30% working interest in our non-operated position. We expect to commence drilling in Rocky Point by mid-year 2012 with our initial drilling program primarily targeting the lower Green River and Wasatch formations.

Blacktail Ridge

We have a non-operated interest in approximately 28,569 net leasehold acres in our Blacktail Ridge project area. Our working interests in our Blacktail Ridge wells are typically either 25% or 50%, depending on participation in prior wells. Bill Barrett operates our Blacktail Ridge acreage position and has historically drilled vertical wells primarily targeting the Wasatch formation. We believe this area may also be prospective for a horizontal drilling program targeting the Uteland Butte and Black Shale zones. We participated in Bill Barrett's first horizontal well in Blacktail Ridge targeting the Uteland Butte zone, which was completed in November 2011.

North Monument Butte

We hold a 25% working interest covering approximately 11,724 net leasehold acres in the North Monument Butte project area. Newfield operates North Monument Butte, and the wells in this project area primarily target the Green River formation. Newfield recently began testing the deeper Wasatch formation. We believe North Monument Butte provides additional opportunities for both horizontal drilling of multiple zones and waterflooding of the Green River formation to increase recovery of reserves.

Bridgeland

We hold a 35% working interest covering approximately 9,883 net leasehold acres in the Bridgeland project area. Newfield operates Bridgeland, and the wells in this project area primarily target the Green River formation. Newfield is currently testing the Wasatch formation.

Lake Canyon

We hold a 25% working interest covering approximately 30,371 net leasehold acres in the Lake Canyon project area. Bill Barrett and Berry Petroleum operate Lake Canyon, and the wells in this project area primarily target the Green River and Wasatch formations. The operators are evaluating the emerging horizontal Uteland Butte play in Lake Canyon. To date, we have participated in five gross (1.25 net) horizontal Uteland Butte wells drilled by Bill Barrett and two gross (0.50 net) horizontal Uteland Butte wells drilled by Berry Petroleum.

Horseshoe Bend Acquisition

On November 30, 2011, we acquired approximately 29,281 net fee, state and federal acres with 751 identified potential drilling locations in Horseshoe Bend and approximately 6,062 net fee and allotted acres in Randlett with 221 identified potential drilling locations, for approximately $100 million in cash, subject to customary post-closing purchase price adjustments. This acquisition significantly increased our operated leasehold acreage position from 32% to 46%, increased our identified potential drilling locations by 20%, and increased our net fee, state, federal and allotted acres by 120%. We operate all of the approximately 6,062 net acres acquired in Randlett and substantially all of the approximately 29,281 net acres acquired in Horseshoe Bend. However, operatorship with respect to approximately 3,993 net acres in Ouray Valley remains subject to a vote of the working interest owners.

In addition to significantly increasing our operated acreage position and our inventory of undeveloped acreage, the acquisition included 50 producing wells in our Horseshoe Bend project area with 8.4 MMBoe of proved reserves as of September 30, 2011. The average net daily production from these wells was 301 Boe/d for the three months ended September 30, 2011 and 415 Boe/d for the month ended September 30, 2011.

Our Relationship with Quantum Energy Partners

Quantum Energy Partners is a leading private equity firm founded in 1998 to make investments in the energy sector. Quantum Energy Partners currently has more than $6.5 billion in assets under management. The employees of Quantum Energy Partners are experienced energy professionals with expertise in finance and operations and broad technical skills in the oil and natural gas business. In connection with the business of Quantum Energy Partners, these employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which Quantum Energy Partners owns interests.

In 2007, Quantum Energy Partners and one of its affiliates, Quantum Resources Management (together with Quantum Energy Partners, "Quantum"), made an initial investment in our parent to provide a portion of the capital necessary for our parent to enhance its operations and fund the development of its oil and gas properties. Since then, Quantum has continued to provide support and resources to us, which has allowed us to further enhance our operations and increase our capabilities. Following this offering, Quantum Energy Partners and Quantum Resources Management will continue to be two of our largest stockholders.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

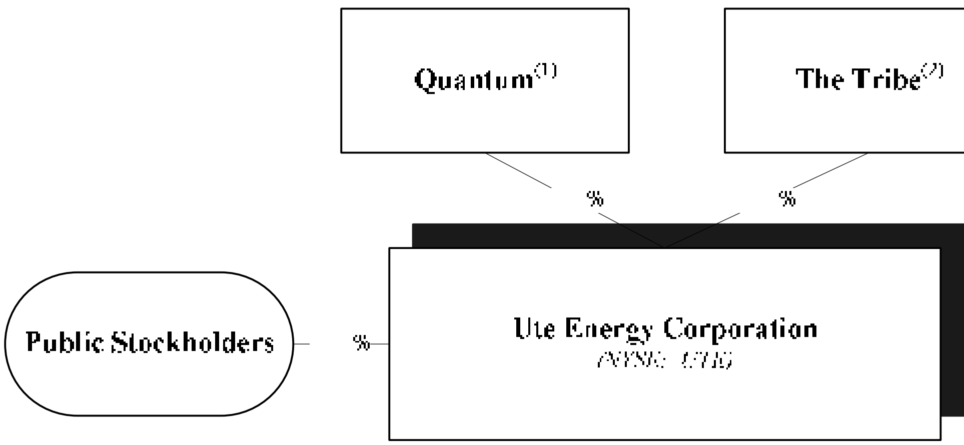
- A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.
- Our exploration, development and production projects require substantial capital expenditures. We may be unable to obtain sufficient capital or financing on satisfactory terms to fund our operations or drilling program, which could lead to expiration of our leases or a decline in our oil and natural gas reserves.
- Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- The identified potential drilling locations that we decide to drill may not yield oil or natural gas in commercial quantities.
- Our identified potential drilling location inventories are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- If we fail to drill wells or establish production sufficient to maintain our acreage, we may lose future rights to drill our current acreage.
- There is limited transportation and refining capacity for our yellow and black wax crude oil, which may limit our ability to sell our current production or to increase our production.
- Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Currently, a majority of our oil producing properties are located on the Uintah and Ouray Reservation, making us vulnerable to risks associated with tribal sovereignty laws and regulations pertaining to the operation of oil and gas properties on Native American tribal lands.
- All of our producing properties and operations are located in the Uinta Basin region, making us vulnerable to risks associated with a lack of geographic diversification.
- We have a limited history of operating our drilling locations and may be unable to realize our target returns on the drilling locations that we operate.
- The concentration of our capital stock ownership among our largest stockholders and their affiliates will limit your ability to influence corporate matters.

For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, please read “Risk Factors” beginning on page [●] and “Cautionary Note Regarding Forward-Looking Statements.”

Corporate Reorganization

In connection with this offering, Ute Energy Upstream Holdings LLC will convert to a Delaware corporation, change its name to Ute Energy Corporation and our membership interests will be converted into shares of common stock in our corporation. As a result of the conversion, Ute Energy LLC will own the then outstanding shares of our common stock. Immediately prior to the closing of this offering, Ute Energy LLC will distribute all of its shares of our common stock to its members in accordance with their respective membership interests, and we and the selling stockholders will issue shares of our common stock to the public.

The following diagram illustrates our ownership structure based on total shares of common stock outstanding after giving effect to this offering and our related corporate reorganization and assuming no exercise of the underwriters' option to purchase additional shares of common stock from the selling stockholders.



(1) Includes shares of common stock held by an affiliate of Quantum Energy Partners and shares of common stock held by an affiliate of Quantum Resources Management.

(2) Includes shares of common stock held by Ute Energy Holdings LLC, an entity wholly-owned and controlled by the Tribe.

Corporate Information

Our principal executive offices are located at 1875 Lawrence Street, Suite 200, Denver, Colorado 80202, and our telephone number at that address is (720) 420-3200. We maintain a website at www.uteenergy.com. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

The Offering

Common stock offered by Ute Energy	shares
Common stock offered by the selling stockholders	shares (shares if the underwriters' option to purchase additional shares is exercised in full)
Total common stock offered	shares (shares if the underwriters' option to purchase additional shares is exercised in full)
Common stock to be outstanding after the offering	shares
Common stock owned by the selling stockholders after the offering	shares (shares if the underwriters' option to purchase additional shares is exercised in full)
Option to purchase additional shares	The selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of additional shares of our common stock.
Use of proceeds	We expect to receive approximately $ million of net proceeds from the sale of the common stock offered by us, based upon the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), after deducting underwriting discounts and estimated offering expenses. We will use approximately $ million of the net proceeds from this offering to repay in full debt that we intend to assume in connection with this offering. The remaining net proceeds of approximately $ million will be used to fund our exploration and development program and for general corporate purposes. We will not receive any proceeds from the sale of shares by the selling stockholders. Affiliates of certain of the underwriters are lenders under our parent's credit facilities and therefore will indirectly receive a portion of the proceeds of this offering in connection with the repayment of the debt assumed by us. Please read "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources—Parent credit facilities" and "Underwriting."
Dividend policy	We do not anticipate paying any cash dividends on our common stock. In addition, we anticipate that our new credit facility will restrict the payment of dividends on our common stock. Please read "Dividend Policy."
New York Stock Exchange symbol	We intend to apply to list our common stock on the New York Stock Exchange (the "NYSE") under the symbol "UTE."
Risk factors	You should carefully read and consider the information beginning on page [●] of this prospectus set forth under the heading "Risk Factors" and all other information set forth in this prospectus before deciding to invest in our common stock.

Summary Historical and Unaudited Pro Forma Financial Data

You should read the following summary financial data in conjunction with "Selected Historical and Unaudited Pro Forma Financial Data," "Summary—Corporate Reorganization," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical financial statements and unaudited pro forma financial information and related notes thereto included elsewhere in this prospectus. The financial data included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Set forth below is our summary historical financial data for the years ended December 31, 2008, 2009 and 2010 and the nine months ended September 30, 2010 and 2011 and balance sheet data as of December 31, 2009 and 2010 and September 30, 2011. Historical financial data for the years ended December 31, 2008, 2009 and 2010 and balance sheet data as of December 31, 2009 and 2010 are derived from the audited financial statements of Ute Energy Upstream Holdings LLC. The financial statements as of and for the year ended December 31, 2010 have been audited by KPMG LLP, an independent registered public accounting firm, and are included elsewhere in this prospectus. The financial statements as of December 31, 2009 and for the years ended December 31, 2008 and 2009 have been audited by Erhardt Keefe Steiner & Hottman PC, an independent registered public accounting, and are included elsewhere in this prospectus.

Our historical financial data as of September 30, 2011 and for the nine months ended September 30, 2010 and 2011 are derived from the unaudited financial statements of Ute Energy Upstream Holdings LLC, which are included elsewhere in this prospectus. The pro forma financial data as of and for the nine months ended September 30, 2011 give effect to the Horseshoe Bend acquisition described in "Summary—Horseshoe Bend Acquisition" and our corporate reorganization as described in "Summary—Corporate Reorganization" and are derived from our unaudited pro forma financial information included elsewhere in this prospectus. All unaudited financial information has been prepared on a basis consistent with our audited financial statements and the notes thereto and includes all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of such information.

	Historical					Pro Forma for the Nine Months Ended September 30,
	Year Ended December 31,			Nine Months Ended September 30,		
	2008	2009	2010	2010	2011	2011
				(Unaudited)		(Unaudited)
	(In thousands)					
Statement of operations data:						
Oil and gas revenues	$ 14,123	$ 10,119	$ 39,087	$ 26,048	$ 56,871	$ 62,914
Expenses:						
Lease operating expenses	2,046	1,658	4,466	2,539	7,503	8,576
Production taxes	996	1,998	2,860	2,437	2,741	3,004
Gathering and transportation expenses	800	1,113	2,274	1,546	3,586	3,620
Depletion, depreciation and amortization	7,792	5,594	13,852	9,313	20,508	22,093
Exploration expenses	-	40	60	59	68	68
Impairment of oil and gas properties and dry hole expense	1,354	-	-	-	-	-
General and administrative expenses	1,653	1,067	3,237	1,635	5,235	5,235
Total operating costs	$ 14,641	$ 11,470	$ 26,750	$ 17,530	$ 39,642	$ 42,597
Operating income (loss)	(517)	(1,351)	12,337	8,518	17,229	20,314
Other income (expense):						
Unrealized gain (loss) on derivative instruments	-	(936)	(1,616)	2,271	36,175	36,175
Realized gain (loss) on derivative instruments	-	(896)	1,082	1,112	(518)	(518)
Interest expense	(339)	(274)	(439)	(283)	(945)	(3,095)
Write-off of deferred debt issue costs	-	-	-	-	(814)	(814)
Other income (expense)	76	38	35	(16)	-	-
Total other income (expense)	(263)	(2,067)	(938)	3,084	33,898	31,748
Net income (loss) before income taxes	(780)	(3,418)	11,399	11,602	51,127	52,065
Income tax expense(1)	-	-	-	-	-	(19,066)
Net income (loss)	$ (780)	$ (3,418)	$ 11,399	$ 11,602	$ 51,127	$ 32,999

	As of December 31, 2009	As of December 31, 2010	As of September 30, 2011	Pro Forma as of September 30, 2011
			(Unaudited)	(Unaudited)
	(In thousands)			
Balance sheet data:				
Cash and cash equivalents	$ 162	$ 67	$ 217	$ 217
Net property, plant and equipment	34,296	88,846	190,838	291,363
Total assets	37,407	99,662	241,823	342,348
Long-term debt	-	10,000	36,847	85,797
Total owner's equity	31,334	66,551	167,704	150,270

	Year Ended December 31, 2008	Year Ended December 31, 2009	Year Ended December 31, 2010	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011
				(Unaudited)	
	(In thousands)				
Cash flow data:					
Net cash provided by (used in) operating activities	$ 9,659	$ (1,310)	$ 23,118	$ 15,027	$ 33,558
Net cash used in investing activities	(27,298)	(10,491)	(56,417)	(30,352)	(107,785)
Net cash provided by (used in) financing activities	17,649	11,955	33,205	18,615	74,377

	Year Ended December 31, 2008	Year Ended December 31, 2009	Year Ended December 31, 2010	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Pro Forma for the Nine Months Ended September 30, 2011
				(Unaudited)		(Unaudited)
	(In thousands)					
Other financial data:						
Adjusted EBITDAX(2)	$ 8,628	$ 3,387	$ 27,078	$ 19,389	$ 37,287	$ 41,960

(1) As a disregarded entity for federal income tax purposes, we are taxed at the member unitholder level rather than at the company level. Following the corporate reorganization described in this prospectus, we will be taxed at the company level. As a result, for periods following the corporate reorganization, our financial statements will include a tax provision on our income. On a pro forma basis after giving effect to the corporate reorganization, we would have recorded a tax provision (benefit) of approximately $3.8 million, ($1.4) million and ($0.4) million for the years ended December 31, 2010, 2009 and 2008 and approximately $18.8 million and $4.3 million for the nine months ended September 30, 2011 and 2010. On a pro forma basis after giving effect to the corporate reorganization and the Horseshoe Bend acquisition, we would have recorded a tax provision of approximately $19.1 million for the nine months ended September 30, 2011.

(2) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss) and net cash provided by operating activities, please read "— Non-GAAP Financial Measure" below.

Non-GAAP Financial Measure

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation accretion, property impairments, exploration expenses, unrealized derivative gains and losses, non-cash compensation expense and other non-recurring items. Adjusted EBITDAX is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted

EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measures of net loss and net cash provided by operating activities, respectively.

	Year Ended December 31,			Nine Months Ended September 30,		Pro Forma for the Nine Months Ended September 30,
	2008	2009	2010	2010	2011	2011
				(Unaudited)		(Unaudited)
	(In thousands)					
Reconciliation of Adjusted EBITDAX to net income (loss):						
Net income (loss)	$ (780)	$ (3,418)	$ 11,146	$ 11,988	$ 51,127	$ 32,999
Change in unrealized (gain) loss on derivative instruments	-	936	1,616	(2,271)	(36,175)	(36,175)
Interest expense	339	274	439	283	945	3,095
Depletion, depreciation and amortization	7,792	5,594	13,852	9,313	20,508	22,093
Impairment of oil and gas properties and dry hole expense	1,354	-	-	-	-	-
Write-off of deferred debt issue costs	-	-	-	-	814	814
Exploration expenses	-	40	60	59	68	68
Income taxes	-	-	-	-	-	19,066
Other	(76)	(38)	(35)	16	-	-
Adjusted EBITDAX	$ 8,628	$ 3,387	$ 27,078	$ 19,389	$ 37,287	$ 41,960

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
	(In thousands)				
Reconciliation of Adjusted EBITDAX to net cash flows provided by (used in) operating activities:					
Net cash provided by (used in) operating activities	$ 9,659	$ (1,310)	$ 23,118	$ 15,027	$ 33,558
Interest expense	339	274	439	283	945
Exploration expenses	-	40	60	59	68
Amortization in interest expense	-	-	(193)	(154)	(111)
Changes in working capital	(1,294)	4,423	3,430	4,159	2,858
Other	(76)	(38)	225	16	(31)
Adjusted EBITDAX	$ 8,628	$ 3,387	$ 27,078	$ 19,389	$ 37,287

Summary Historical and Pro Forma Operating and Reserve Data

The following table presents summary historical and pro forma data with respect to our estimated net proved oil and natural gas reserves as of the dates indicated. The estimated reserve and related data presented as of and for the nine and three months ended September 30, 2011 give effect to the properties acquired in the Horseshoe Bend acquisition as if such properties were acquired on January 1, 2011. Please read "Summary — Horseshoe Bend Acquisition" beginning on page [●] of this prospectus. The estimated reserve data presented as of December 31, 2008 and 2009 are based on reports prepared by Cawley, Gillespie & Associates, Inc., independent reserve engineers ("Cawley Gillespie"), and the estimated reserve data presented as of December 31, 2010 is based on a report prepared by Ryder Scott Company, L.P., independent reserve engineers ("Ryder Scott"). The reserve estimates presented as of September 30, 2011 are based on evaluations prepared by our internal reservoir engineers. The reserve estimates presented as of December 31, 2008 were prepared consistent with the former rules and regulations of the Securities and Exchange Commission, or the SEC, regarding oil and natural gas reserve reporting in effect for such period. The reserve estimates as of December 31, 2009 and 2010 and as of September 30, 2011 were prepared consistent with the SEC's rules regarding oil and natural gas reserve reporting that are currently in effect. For additional information regarding our estimated net proved oil and natural gas reserves, as well as the impact of the SEC's rules governing the presentation of reserve information, please read "Business — Our Operations — Estimated proved reserves."

	As of December 31,			As of September 30,
	2008	**2009**	**2010**	**2011**
Reserve Data(1):				
Estimated proved reserves:				
Oil (MMBbls)	0.9	3.5	7.1	30.9
Natural gas (Bcf)	3.6	8.4	17.3	22.5
Natural Gas Liquids (MMBbls)	0.0	0.1	0.2	0.5
Total estimated proved reserves (MMBoe)	1.5	5.0	10.2	35.1
Estimated proved developed (MMBoe)	1.4	1.4	3.8	8.2
Percent developed	96%	27%	37%	23%
Estimated proved undeveloped (MMBoe)	0.1	3.6	6.4	26.9
PV-10 (in millions)(2)	$ 14.1	$ 25.8	$ 112.6	$ 496.4
Standardized Measure (in millions)(3)	$ 14.1	$ 25.8	$ 112.6	$ 496.4

The following table sets forth the benchmark prices used to determine our estimated proved reserves from proved oil and natural gas reserves on a historical basis for the periods indicated.

	As of December 31,			As of September 30,
	2008	**2009**	**2010**	**2011**
Oil and Natural Gas Prices (1):				
Oil (per Bbl)	$44.60	$61.18	$79.43	$94.50
Natural gas (per MMBtu)	$5.71	$3.87	$4.38	$4.16

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(1) Benchmark prices for oil and natural gas at September 30, 2011 and at December 31, 2010 and 2009 reflect the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months, using NYMEX WTI posted prices for oil and NYMEX Henry Hub prices for natural gas. At December 31, 2008, the year-end benchmark prices for oil and natural gas reflect NYMEX WTI prices for oil and NYMEX Henry Hub prices for natural gas were used. For oil and natural gas liquids volumes, the benchmark WTI posted price is adjusted for quality, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 17%. For gas volumes, the Henry Hub spot price is adjusted for energy content, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 3%.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because as of the period presented, we were a disregarded entity for federal income tax purposes. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our equity holders. However, in connection with the closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. As a result, we will be a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income.

Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(3) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depreciation, depletion and amortization, discounted at 10% per annum to reflect timing of future cash flows. As a disregarded entity for federal income tax purposes, we are not subject to federal income taxes and thus make no provision for federal income taxes in the calculation of our Standardized Measure. In connection with the closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. Future calculations of Standardized Measure will include the effects of income taxes on future net revenues. Standardized Measure does not give effect to derivative transactions. We expect to continue to hedge a substantial portion of our future estimated production from total proved producing reserves. For further discussion of income taxes, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The following table sets forth summary data with respect to our production results, average sales prices and production costs on a historical and pro forma basis for the periods presented. The unaudited pro forma information gives effect to the Horseshoe Bend acquisition as if it had occurred on January 1, 2011.

	Year Ended December 31,			Nine Months Ended September 30,	Nine Months Ended September 30,	Three Months Ended September 30,
	2008	2009	2010	2010	2011	2011
Operating data:						
Net production volumes:						
Oil (MBbls)	148.8	164.9	510.9	342.4	708.3	301.6
Natural gas (MMcf)	636.2	571.3	1,275.6	835.8	1,196.1	437.7
Natural gas liquids (MBbls)	7.6	6.2	8.8	7.0	22.7	9.3
Oil equivalents (MBoe)	262.4	266.3	732.3	488.7	930.3	383.8
Average daily production (Boe/d)	719	730	2,006	1,790	3,408	4.172
Average sales prices:						
Oil, without realized derivatives (per Bbl)	$ 69.90	$ 42.43	$ 67.64	$ 67.36	$ 69.34	$ 75.45
Oil, with realized derivatives(1) (per Bbl)	69.90	47.86	66.66	65.57	70.88	77.23
Natural gas, without realized derivatives (per Mcf)	5.16	3.48	4.11	4.26	4.76	4.56
Natural gas, with realized derivatives (per Mcf)	5.16	3.48	3.55	3.84	4.18	5.06
Natural gas liquids (per Bbl)	61.64	38.93	56.95	55.71	73.88	72.94
Costs and expenses (per Boe of production):						
Lease operating expenses	7.80	6.23	6.10	5.20	8.06	8.04
Production taxes	3.79	7.50	3.91	4.99	2.95	4.28
Gathering and transportation expenses	3.05	4.18	3.11	3.16	3.85	4.91
Depletion, depreciation and amortization	29.69	21.01	18.92	19.06	22.04	21.21

(1) Realized prices include realized gains or losses on cash settlements for our commodity derivatives.

RISK FACTORS

You should carefully consider the risks described below before making an investment decision. Our business, financial condition or results of operations could be materially adversely affected by any of these risks. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and Africa and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- costs associated with exploration and development;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- localized supply and demand fundamentals and transportation availability;
- the availability of refining capacity;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption;
- the impact of energy conservation efforts and the price and availability of alternative fuels; and
- the price and quantity of imports of foreign oil and natural gas.

Substantially all of our production is sold to purchasers at market based prices. Lower oil and, to a lesser extent, natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. For more information, please read "*— Our exploration, development and production projects require substantial capital expenditures. We may be unable to obtain sufficient capital or financing on satisfactory terms to fund our operations or drilling program, which could lead to expiration of our leases or a decline in our oil and natural gas reserves*."

In addition, lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. For more information, please read "— *The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves*." Please also read "—*If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties*."

Our exploration, development and production projects require substantial capital expenditures. We may be unable to obtain sufficient capital or financing on satisfactory terms to fund our operations or drilling program, which could lead to expiration of our leases or a decline in our oil and natural gas reserves.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development and production of our oil and natural gas properties. Our cash flows used in investing activities were $56.4 million and $107.8 million related to capital and exploration expenditures for the year ended December 31, 2010 and the nine months ended September 30, 2011, respectively. Our anticipated capital expenditure budget for 2012 is approximately $[●] million, with approximately $[●] million allocated for drilling and completion operations. To date, our capital expenditures have been financed by contributions from our parent, the source of which was equity contributions by the Tribe and Quantum to our parent, bank borrowings and net cash provided by operating activities. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, changes in commodity prices, actual drilling results, drilling permit availability, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

An increase in product prices could result in a desire to increase our capital expenditures. We expect to finance our future capital expenditures primarily through cash flows provided by operating activities, borrowings under our new credit facility as well as the net proceeds from this offering. Our financing needs, however, may require us to alter or increase our capitalization substantially through the issuance of debt or additional equity securities. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities would have a dilutive effect on the value of your common stock.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of oil and natural gas we are able to produce from our existing wells;
- the price at which our oil and natural gas is sold;
- the costs of developing and producing oil and natural gas from our properties;
- our ability to acquire, locate and produce new reserves;
- our ability to borrow funds; and
- our ability to access the equity and debt capital markets.

If our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or borrowings available under our new credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our identified potential drilling locations, which in turn could lead to the possible expiration of our leases and a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, development and production activities. Our oil and natural gas exploration, development and production activities are subject to numerous risks, including the risk that drilling will not result in commercial oil or natural gas production. Our decisions to purchase, explore or develop drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, please read "*— Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.*" Our cost of drilling, completing and operating wells is often uncertain before drilling is completed. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- unavailability of drilling and/or operating permits;
- facility or equipment malfunctions;
- leaks of oil, natural gas, produced water and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations;
- unexpected adverse drilling conditions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

The identified potential drilling locations that we decide to drill may not yield oil or natural gas in commercial quantities.

We describe some of our identified potential drilling locations and our plans to explore those potential drilling locations in this prospectus. Our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Uinta Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified potential drilling location inventories are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of September 30, 2011, only 609 of our 5,791 specifically identified potential future gross drilling locations were attributed to proved undeveloped reserves. These identified potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these identified potential drilling locations depends on a number of factors, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, the availability of gathering systems, marketing and transportation constraints, refining capacity, regulatory approvals and other factors. Because of the uncertainty inherent in these factors, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations.

If we fail to drill wells or establish production sufficient to maintain our acreage, we may lose future rights to drill on our current acreage.

As of September 30, 2011, we had exclusive rights to drill on tribal acres representing 29,705 net acres expiring in 2012, 3,044 net acres expiring in 2013 and 31,118 net acres expiring in 2014. Unless wells are drilled within the spacing units covering undeveloped or unearned tribal acres, our rights to drill on such acreage will expire. The EDAs with the Tribe require an extension payment equal to the unearned net acres multiplied by the initial bonus payment per acre to extend the exclusive right to drill on the acreage for an additional five years. In addition, the tribal EDAs contain minimum annual drilling commitments to maintain the exclusive right to drill on the acreage during the terms of the EDAs.

As of September 30, 2011, we had leases on fee, state, federal and allotted lands representing 2,799 net acres expiring in 2012, 6,504 net acres expiring in 2013 and 10,097 net acres expiring in 2014. Unless production is established within the spacing units covering the undeveloped acres on these properties, the leases for such acreage will expire. Any renewal of such leases could require us to make significant expenditures, and the cost to renew these leases may increase significantly. We may not be able to renew all such leases on commercially reasonable terms or at all.

If we fail to drill wells or establish production sufficient to maintain our acreage, then our actual drilling activities may materially differ from those presently identified, which could have a material adverse effect on our business, financial condition and results of operations.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our proved undeveloped reserves ultimately may not be developed or produced.

Approximately 77% of our total proved reserves were classified as proved undeveloped as of September 30, 2011. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

There is limited transportation and refining capacity for our yellow and black wax crude oil, which may limit our ability to sell our current production or to increase our production.

Most of the crude oil we produce in the Uinta Basin is known as “yellow wax” or “black wax” because it has a high paraffin content. Due to its high parrafin content, our transportation options are limited, and most of the oil is transported by truck to refiners in the Salt Lake City area. Our inability to obtain transportation or refining services or a failure to obtain such services on acceptable terms could limit our ability to sell our current production or increase our production, which could have a material adverse impact on our financial condition and results of operations.

We currently have agreements in place with two area marketers that provide a reasonable certainty of base load sales to area refiners of substantially all of our expected operated production in the Uinta Basin through November 2012 and our operated production on a portion of our acreage through 2014. However, there is a risk that these marketers may fail to satisfy their obligations to us under those contracts. In addition, we sell our non-operated production through our operating partners under their marketing and transportation arrangements. Any delays in payments from the purchasers of our crude oil will have an immediate impact on our cash flows. Furthermore, an extended loss of any of our purchasers could have a material adverse effect on us because there are limited purchasers of our black and yellow wax crude oil. If we are unable to market our production for any extended period of time, we may be required to shut in wells, and if our production becomes shut-in, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market. We continue to work with marketers and our operating partners to expand the market for our existing yellow and black wax crude oil production and to expand the market to allow for production growth. However, without additional refining capacity, our ability to increase production from the Uinta Basin may be limited.

Unless we replace our oil and natural gas reserves, our reserves and production will decline over time, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be adversely affected.

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

The process of estimating oil and natural gas reserves is complex. It requires analysis of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these analyses or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. Please read “Business — Our Operations” for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of September 30, 2011.

To prepare our estimates, we must project production rates and the timing of development expenditures. We also must analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, operating expenses, capital expenditures, taxes and availability of funds. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production. In addition, this data is based on vertically drilled wells, which may not accurately reflect production, development or operating expenditures that may result from the utilization of horizontal drilling techniques.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant negative variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Due to the limited production history of our developed acreage, the estimates of future production associated with our undeveloped properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our new credit facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our new credit facility and our results of operations for the periods in which such charges are taken.

Our estimates of proved reserves that have not been prepared by an independent reserve engineering firm may not be as reliable or accurate as estimates of proved reserves prepared by an independent reserve engineering firm.

Estimates of proved oil and natural gas reserves are inherently uncertain, and any material inaccuracies in our reserve estimates will materially affect the quantities and values of our reserves. The estimates of the proved reserves as of September 30, 2011 included in this prospectus were prepared by our internal reserve engineers and professionals. Our internal estimates of proved reserves may differ materially from independent proved reserve estimates as a result of the estimation process employed by an independent reserve engineering firm. Our internal proved reserve estimates are based upon various assumptions, including assumptions required by the SEC related to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our internal proved reserve estimates may not be indicative of or may differ materially from the estimates of our proved reserves as of December 31, 2011 that will be prepared by Ryder Scott.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. For the year ended December 31, 2008, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect on the day of the estimate in accordance with previous SEC requirements. In accordance with SEC requirements for the years ended December 31, 2009 and 2010 and the nine months ended September 30, 2011, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this prospectus. If oil prices decline by $1.00 per Bbl, then our PV-10 and Standardized Measure as of December 31, 2010 would decrease approximately $4.2 million, or 4%. If natural gas prices decline by $0.10 per Mcf, then our PV-10 and Standardized Measure as of December 31, 2010 would decrease approximately $1.1 million, or 1%.

Our estimates of proved reserves as of December 31, 2009, December 31, 2010 and September 30, 2011 have been prepared under current SEC rules that went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This prospectus presents estimates of our proved reserves as of December 31, 2008, 2009 and 2010 and September 30, 2011. Estimates of our proved reserves as of December 31, 2009 and 2010 and September 30, 2011 have been prepared and presented under SEC rules that are effective for fiscal years ending on or after December 31, 2009 and require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months. The previous SEC rules required that reserve estimates be calculated using last-day-of-the-year prices, and our reserve estimates as of December 31, 2008 were prepared on this basis. The benchmark price that was used for estimates of our reserves as of September 30, 2011 was $94.50 per barrel for oil and $4.16 per MMBtu for gas without giving any effect to our commodity hedges. These prices are the unweighted arithmetic average of the first day of the month price for the 12 calendar months ending September 30, 2011 and were held constant for the life of each property. Product prices which were actually used for each property reflect all appropriate adjustments including gravity, quality, local conditions, fuel and shrinkage and distance to market. As a result of this change in pricing methodology, comparisons of reserve amounts reported for periods prior to 2009 may be more difficult.

Another impact of the current SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This new requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

Currently, a majority of our oil producing properties are located on the Uintah and Ouray Reservation, making us vulnerable to risks associated with tribal sovereignty laws and regulations pertaining to the operation of oil and gas properties on Native American tribal lands.

A majority of our oil and gas properties are located on the Uintah and Ouray Reservation (the “Reservation”). Operation of oil and gas interests on Native American tribal lands presents unique considerations and complexities that arise from the fact that Native American tribes are “dependent” sovereign nations located within states but are subject only to tribal laws and treaties with, and the laws and Constitution of, the United States. This creates an overlay of three jurisdictional regimes — Native American, federal and state. These considerations and complexities could arise around various aspects of our operations, including real property considerations, permitting, employment practices, environmental matters and taxes.

For example, we are subject to the Ute Tribal Employment Rights Ordinance (the “Employment Act”). The Employment Act requires that we give preference in hiring to members of the Tribe meeting job description requirements, which may sometimes require us to forego offering positions to individuals that are otherwise more qualified. The Employment Act also requires us to give preference to businesses owned by members of the Tribe when we are hiring contractors. These regulatory restrictions can negatively affect our ability to recruit and retain the most highly qualified personnel or to utilize the most experienced and economical contractors for our projects.

Furthermore, because tribal property is considered to be held in trust by the federal government, before we can take actions such as drilling, pipeline installation or similar actions, we are required to obtain approvals from various federal agencies, including the Bureau of Indian Affairs and the Bureau of Land Management. We are also required to obtain approvals from the Tribe for surface use access on certain of our properties. Gaining these approvals could result in delays in implementation of, or otherwise prevent us from implementing, our development program.

In addition, under the Ute tribal laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages.

For additional information about the legal complexities and considerations associated with our operations on the Reservation, please read "Business — Laws and Regulations Pertaining to Oil and Gas Operations on the Uintah and Ouray Reservation."

Our operations are subject to various Native American tribal, federal and state environmental and operational safety laws and regulations that may expose us to significant costs, liabilities and delays.

Our oil and natural gas exploration and production operations occur largely on Tribe Reservation lands and, to a lesser extent, federal, state or private lands located outside those Reservation lands. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management and the Office of Natural Resources Revenue, may promulgate and enforce laws, regulations and/or other approval requirements addressing environmental conditions and pertaining to oil and natural gas operations on Tribe Reservation lands.

In addition, our oil and natural gas exploration and production operations, particularly those located outside the Tribe Reservation lands, may be subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were not in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Part of the regulatory environment in which we operate imposes, under certain circumstances, federal requirements to perform or prepare environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to state regulation of oil and natural gas production and Native American tribe conservation practices and protection of correlative rights. These added requirements may restrict our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and/or Native American tribal authorities. Failures or delays in obtaining regulatory approvals or drilling permits or the receipt of a permit with extensive restrictions or requiring the incurrence of significant costs could have a material adverse effect on our ability to explore on or develop our properties. In addition, if we reasonably believe that we cannot obtain required drilling permits covering locations for which we recorded proved undeveloped reserves in a timely manner, we may be required to write down the level of our proved reserves.

Our ability to enforce our rights against the Tribe is limited by the sovereign immunity of the Tribe.

Although the Tribe has sovereign immunity and generally may not be sued without its consent, a limited waiver of sovereign immunity and consent to suit has been granted in connection with the Tribe's Exploration and Development Agreements with us. These waivers were subject to various United States governmental approvals, which we believe have been obtained. If any waiver of sovereign immunity with us is held to be ineffective, including as a result of failing to obtain appropriate federal governmental approvals, we could be precluded from judicially enforcing our rights and remedies against the Tribe.

Obtaining jurisdiction over a Native American tribe, such as the Tribe, can be difficult. Often, a commercial dispute with a Native American tribe or tribal instrumentality cannot be heard in federal court because the typical requirements for federal jurisdiction are absent. It is possible that neither a federal nor a state court would accept jurisdiction to resolve a matter involving a commercial dispute between us and the Tribe, and no legal recourse to a state or federal court may be available to us. Pursuant to the waivers of sovereign immunity we have obtained from the Tribe, the Tribe has waived its rights to have certain matters resolved in any Ute tribal court or other proceeding of the Tribe. The Tribe has a tribal court system, and a federal or state court may defer to such tribal courts if, contrary to the waivers of sovereign immunity by the Tribe, the Tribe seeks or alleges its right to seek tribal proceedings for resolution of a dispute. The Ute tribal courts may not reach the same conclusions that would be reached in state or federal courts.

Additionally, any state or federal court judgment requiring satisfaction or enforcement within Ute tribal territories may require that an order for such enforcement be issued by Ute tribal courts. Ute tribal courts do not have specific rules related to granting full faith and credit to judgments of courts of the United States or any state, except in limited circumstances.

A significant reduction by the Tribe of their ownership interests in us could adversely affect us.

The Tribe is our largest stockholder. We believe that the Tribe's substantial investment in us provides us with a significant competitive advantage in securing drilling and operating permits on Ute tribal lands and otherwise working with government entities with oversight authority for oil and natural gas exploration and production on Ute tribal lands. Following the 180th day after the closing of this offering, however, the Tribe will not be subject to any obligation to maintain its ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If the Tribe sells all or a substantial portion of its ownership interest in us, the Tribe may have less incentive to assist in our success. A lack of assistance from the Tribe could adversely affect our ability to successfully implement our business strategies which could adversely affect our cash flows or results of operations.

All of our producing properties and operations are located in the Uinta Basin region, making us vulnerable to risks associated with a lack of geographic diversification.

As of September 30, 2011, all of our proved reserves and production were located in the Uinta Basin in northeastern Utah. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the Uinta Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations. For more information, please read "—*There is limited transportation and refining capacity for our yellow and black wax crude oil, which may limit our ability to sell our current production or to increase our production*."

We are not the operator on a significant portion of our identified potential drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We are not the operator on approximately 32% of our identified gross potential drilling locations (approximately 55% of our identified net potential drilling locations). As a result, we may have limited ability to exercise influence over the operation of the drilling locations or subsequent production with respect to wells operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

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

This limited ability to exercise control over the operations of a majority of our identified potential drilling locations may cause a material adverse effect on our results of operations and financial condition.

We have a limited history of operating our drilling locations and may be unable to realize our target returns on the drilling locations that we operate.

Historically, we have not operated our drilling locations. As a result of our limited history as an operator, we may incur higher costs related to the drilling, completion and operation of wells on the drilling locations that we operate as compared to larger, more experienced operators. Our inability to effectively and efficiently operate the drilling locations on which we are the operator could have a material adverse effect on our financial condition, results of operations and reserves.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel. In addition, because we are a relatively small company, we may be disproportionately affected by adverse operational, financial and other events in the ordinary course of our business.

Our ability to acquire additional oil and natural gas properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring oil and natural gas properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. As a relatively small oil and natural gas company, many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, these companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective oil and natural gas properties, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Furthermore, events that would not significantly impact the business of larger companies may have a material adverse effect on our business, financial condition and results of operations. For example, larger companies may be better able to withstand the financial pressures of unsuccessful drilling attempts, operational incidents, customer loss, and sustained periods of volatility in financial markets, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, all of which could adversely affect our business, financial condition and results of operations.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

We utilize third-party services to maximize the efficiency of our operations. The cost of oil field services may increase or decrease depending on the demand for services by other oil and gas companies. While we currently have good working relationships with oil field service companies, we cannot assure you that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and surface water contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Uinta Basin are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. These limitations restrict our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (''GHGs'') present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another which requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new "tailoring" rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. We are currently conducting monitoring of GHG emissions from our operations in accordance with the GHG emissions reporting rule but must evaluate the data from those monitoring activities to determine whether we exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level, we will report the emissions beginning in 2012. Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with operations or could adversely affect demand for our production.

Adoption and/or implementation of new air emissions restrictions in the Uinta Basin could result in increased operating costs and limits on the development of wells in the basin.

On July 1, 2011, the EPA promulgated a final Federal Implementation Plan ("FIP") that implements federal New Source Review ("NSR") pre-construction air pollution control requirements for facilities emitting pollutants in Indian Country. The FIP establishes two rules to protect air quality in Indian lands. The first rule is the Minor NSR rule, which applies to new and modified minor stationary sources and to minor modifications at existing major stationary sources found on Indian lands. The second rule is the Non-Attainment Major NSR rule, which applies to new and modified major stationary sources in areas of Indian lands that do not meet National Ambient Air Quality Standards ("NAAQS") established by the EPA under the federal Clean Air Act. Under the rules, a source owner or operator will need to apply for a permit before building a new facility or expanding an existing one if the facility increases emissions above applicable limits included in the rules. The permitting authority, which may be the EPA or a tribe (should the tribe accept delegation of the federal program or develop and implement an EPA-approved Tribal Implementation Plan), will review the application and grant or deny the air emissions permits. These permits will undergo public notice and comment as part of the review process. With regard to our operations upon the Reservation, promulgation of the FIP and establishment of the two permit programs will require us to acquire air emissions permits prior to well construction, which could result in delays in siting and development of wells and increase the costs of development and production although, at this point, we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities on Indian lands.

In addition, the EPA and several other agencies are pursuing or planning to pursue monitoring studies to assess elevated levels of wintertime ground-level ozone found in the recent past in the Uinta Basin. Ground-level ozone, a gas that is created by a chemical reaction between nitrogen oxides and volatile organic compounds in the presence of sunlight, is one of six criteria pollutants regulated by the EPA under the NAAQS. Ambient concentrations of ground-level ozone were measured in the Uinta Basin between January and March 2010 at levels in excess of the NAAQS of 75 parts per billion for an eight-hour average established by the EPA in 2008. No final determination has been made for the occurrence of elevated concentrations of ozone in the Uinta Basin during the wintertime but a contributing factor could be oil and gas production in the region. The EPA, Utah Department of Environmental Quality, U.S. Fish & Wildlife Service and the federal Bureau of Land Management, among other agencies, are pursuing or are planning to pursue, individually or collectively, long-term wintertime monitoring for ozone and key "precursors" to the chemical formation of ground-level ozone in the Uinta Basin. Any determinations made that emissions from oil and gas development in the Uinta Basin is adversely contributing to air quality in the Uinta Basin, including formation of ground-level ozone at levels in excess of the applicable NAAQS, could result in the adoption and implementation of restrictive federal, state, regional or local requirements relating to current or future oil and gas development in the basin, which restrictions may include increased costs to install added air pollution control equipment and the possibility of partial or total delays or bans in such developmental activities in certain areas of the basin.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We anticipate that most, if not all, of the wells we plan to drill will involve hydraulic fracturing of the producing formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, EPA recently announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. In addition, the U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the U.S. Securities & Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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

On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

We may be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller will not be able to fulfill its contractual obligations. Problems with properties we acquire could have a material adverse effect on our business, financial condition and results of operations.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business; and

- challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

Many of the anticipated benefits of significant acquisitions, such as the Horseshoe Bend acquisition, may not be realized. If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be lower than we expect.

We acquired significant assets in connection with the Horseshoe Bend acquisition with the expectation that the acquisition would result in various benefits, including, among other things, an increase in reserves, producing wells, and operated assets and diversification of our properties. However, the success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with our existing operations. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from a significant acquisition, such as the Horseshoe Bend acquisition, our results of operations may be adversely affected.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring new oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of experienced oil and gas lease field landmen who examine records in the county courthouse or the appropriate governmental office to determine mineral ownership before we acquire an oil and gas lease covering a specific mineral interest.

Prior to the drilling of an oil or gas well, it is the normal practice in our industry for the operator of the well to obtain a drilling title opinion from a qualified title attorney to ensure there are no obvious title defects on the property on which the well is to be located. The title attorney will research all documents that are of record, including liens, taxes and all applicable contracts that burden the property. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to completely cure any title defects may invalidate our title to the property and adversely impact our ability in the future to increase production and reserves. Additionally, because a less strenuous title review is conducted on lands where a well has not yet been scheduled, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we could suffer a financial loss.

We have incurred losses from operations during certain periods since our inception and may do so in the future.

We incurred net losses of $3.4 million and $0.8 million for the years ended December 31, 2008 and 2009, respectively. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this prospectus may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

The loss of senior management or technical personnel could adversely affect our operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Joseph N. Jaggers, our President and Chief

Executive Officer and other members of our senior management team, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We will record substantial compensation expense in the financial quarter in which this offering occurs, and we may incur substantial additional compensation expense related to our future grants of stock compensation, which may have a material negative impact on our operating results for the foreseeable future.

We will report substantial non-cash compensation expense on awards that will have vested at the time of this offering, and we estimate that this expense will be approximately $ million in the quarter in which this offering is consummated. We may withhold shares of our common stock, which would otherwise be distributed to them, to satisfy their withholding tax obligations incurred as a result of such stock vesting upon the consummation of this offering and in the future. If our board elects to exercise this option upon the consummation of this offering, we estimate that up to approximately $ million of the proceeds of this offering will be used to fund such withholding tax payments. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and anticipated employee stock-based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock-related compensation and benefit expenses at this time because applicable accounting practices generally require that they be based on the fair market value of the options or shares of common stock at the date of the grant; however, we expect them to be significant. We will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Actual future production of our properties may be significantly higher or lower than we estimate at the time we enter into derivative contracts for a period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, to the extent we engage in hedging activities, such hedging activities may not be as effective as we intend in reducing the volatility of our cash flows.

Derivative arrangements also expose us to the risk of financial loss in certain other circumstances, including when:

- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements. We cannot assure you that the commodity derivative contracts we have entered into, or will enter into, will adequately protect us from fluctuations in oil prices.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use commodity derivative contracts to reduce the effect of commodity prices, interest rates and other risks associated with our business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In June 2011, this deadline was extended to December 31, 2011. The CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and to establish minimum capital requirements, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the Dodd-Frank Act. The Dodd-Frank Act may also require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain derivative activities, although the application of those provisions is uncertain at this time. The legislation may also require the counterparties to our commodity derivative contracts to spinoff some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with capital requirements, which could result in increased costs to counterparties such as us.

The new legislation and any new regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the new legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the new legislation and regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We expect to enter into a new credit facility upon the completion of this offering, which will contain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

We expect to enter into a new credit facility upon the completion of this offering, which will contain covenants that will, among other things, restrict:

- our investments, loans and advances and the payment of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to our new credit facility and certain permitted liens;

- mergers, consolidations and sales of all or a substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets (other than production sold in the ordinary course of business); and
- our capital expenditures.

Our new credit facility will also require us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our new credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our new credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our new credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our new credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

Our level of indebtedness may increase and reduce our financial flexibility.

In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

The borrowing base under our new credit facility will be subject to periodic redeterminations, and the borrowing base could be reduced in the future if commodity prices decline, which will limit our available funding for exploration and development.

The borrowing base under our new credit facility will be re-determined from time to time by our lenders according to the terms of our new credit facility. The lenders will re-determine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time. In the future, we may not be able to access adequate funding under our new credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. If oil and natural gas commodity prices materially deteriorate or our estimated oil reserves decline, we anticipate that the revised borrowing base under our new credit facility may be reduced. As a result, we may be unable to obtain adequate funding under our new credit facility or even be required to pay down amounts outstanding under our new credit facility to reduce our level of borrowing. If funding is not available when needed, or is available only on unfavorable terms, our exploration and development plans as currently anticipated and our ability to make new acquisitions could be adversely affected, each of which could have a material adverse effect on our production, revenues and results of operations.

Our obligations under our new credit facility will be secured at all times by substantially all of our assets.

Our obligations under our new credit facility will be secured by substantially all of our assets. Therefore, a default by us on any of our obligations under our new credit facility could result in our lenders foreclosing on our assets or otherwise being entitled to revenues generated by and through our assets.

Risks Related to the Offering and our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active liquid trading market for our common stock may not develop, and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between us, the selling stockholders and representatives of the underwriters, based on numerous factors which we discuss in "Underwriting" beginning on page [●], and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

The following factors could affect our stock price:

- our operating and financial performance and identified potential drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, the selling stockholders or other stockholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and

- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value as of September 30, 2011 after giving effect to this offering would be $ per share. Please read "Dilution" for a complete description of the calculation of net tangible book value.

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 ("Section 404") and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

Compliance with these requirements may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

We do not intend to pay, and we anticipate our new credit facility will restrict us from paying, dividends on our common stock and, consequently, your only opportunity to achieve a return on your investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we expect that the new credit facility that we expect to enter into upon the completion of this offering will place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if the market price of our common stock appreciates, which may not occur, and you sell your shares at a profit. There is no guarantee that the price of our common stock that will prevail in the market after this offering will ever exceed the price that you pay.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. After the completion of this offering, we will have outstanding shares of common stock. This number includes shares that we and the selling stockholders are selling in this offering (assuming no exercise of the underwriters' option to purchase additional shares), which may be resold immediately in the public market. Following the completion of this offering, the selling stockholders will own shares, or approximately % of our total outstanding shares, and certain of our affiliates will own shares, or approximately % of our outstanding shares, all of which are restricted from immediate resale under the federal securities laws and are subject to the lock-up agreements between such parties and the underwriters described in "Underwriting," but may be sold into the market in the future. We expect that the selling stockholders will each be a party to a registration rights agreement with us which will require us to effect the registration of its shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering. The holders of the remaining shares and a small portion of shares owned by our affiliates which will be distributed to non-officer employees and other non-affiliates totaling up to approximately shares, or approximately % of our outstanding shares, are not subject to lock-up agreements and, subject to compliance with Rule 144 under the Securities Act, may sell such shares into the public market.

As soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issued or reserved for issuance under our stock incentive plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under this registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- [a classified board of directors, so that only approximately one-third of our directors are elected each year];
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

The concentration of our capital stock ownership among our largest stockholders and their affiliates will limit your ability to influence corporate matters.

Upon completion of this offering (assuming no exercise of the underwriters' option to acquire additional shares of common stock), we anticipate that the Tribe and Quantum will initially own up to approximately % and %, respectively, of our outstanding common stock (based on an assumed initial public offering price of $ per share, the midpoint of the price range set forth on the cover of this prospectus). Consequently, each of the Tribe and Quantum will continue to have significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Quantum and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Quantum is a private equity firm that has invested in, among other things, companies in the energy industry. As a result, the existing and future portfolio companies which Quantum controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

We have also renounced our interest in certain business opportunities. Please read "— *Our certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects.*"

Our certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects.

Our certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to Quantum or its affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer.

As a result, Quantum or its affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Quantum and its affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours. Please read "Description of Capital Stock."

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;

- uncertainty regarding our future operating results;
- estimated future net reserves and present value thereof; and
- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

USE OF PROCEEDS

We will receive net proceeds of approximately $ million from the sale of the common stock offered by us, assuming an initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) and after deducting estimated expenses and underwriting discounts and commissions of approximately $ million. We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholders.

Immediately prior to the closing of this offering, we intend to assume approximately $ million in aggregate principal amount of the outstanding loans under our parent's credit facilities, and we will use a portion of the net proceeds from this offering to repay in full such assumed debt at the closing of this offering. The remaining net proceeds of approximately $ million will be used to fund our exploration and development program and for general corporate purposes.

We intend to apply the net proceeds from this offering in the following manner:

Use of Proceeds	Amount (in millions)
Repayment of allocated portion of our parent's senior secured revolving facility	$
Repayment of allocated portion of our parent's second lien credit facility	
Exploration and development program and general corporate purposes	
Total	$

Our parent's revolving credit facility matures in May 2016 and bears interest at a variable rate of LIBOR + 2.00 – 3.00% per annum. The allocated portion of the debt assumed by us under our parent's revolving credit facility had a weighted average interest rate of approximately 2.26% as of November 30, 2011 and was used for drilling and operating expenses, acquisitions and general corporate purposes. Our parent's second lien credit facility matures in November 2016 and bears interest at a variable rate of LIBOR + 7.00% per annum with a minimum LIBOR floor of 1.50%. The allocated portion of the debt assumed by us under our parent's second lien credit facility had a weighted average interest rate of 8.50% as of November 30, 2011 and was used for drilling and operating expenses, acquisitions and general corporate purposes. For more information regarding our parent's credit facilities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital resources — Parent credit facilities" beginning on page [●] of this prospectus.

Affiliates of certain of the underwriters are lenders under our parent's credit facilities and therefore will indirectly receive a portion of the proceeds of this offering in connection with the repayment of the debt assumed by us.

An increase or decrease in the initial public offering price of $1.00 per share of common stock would cause the net proceeds that we will receive from the offering, after deducting estimated expenses and underwriting discounts and commissions, to increase or decrease by approximately $ million. If our net proceeds are reduced, then we will have fewer proceeds with which to fund our exploration and development program.

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. In addition, we anticipate that our new credit facility will restrict the payment of dividends on our common stock. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities.

CAPITALIZATION

The following table sets forth our capitalization as of September 30, 2011,

- on an actual basis;
- on an as adjusted basis to give effect to the transactions described under "Summary—Corporate Reorganization;" and
- on an as further adjusted basis to give effect to this offering and the application of the net proceeds as set forth under "Use of Proceeds."

You should read the following table in conjunction with "Use of Proceeds," "Selected Historical and Unaudited Pro Forma Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical financial statements and unaudited pro forma financial information and related notes thereto appearing elsewhere in this prospectus.

	As of September 30, 2011		
	Actual	**As Adjusted**	**As Further Adjusted**
		(In thousands)	
Cash and cash equivalents(1)(2)	$	$	$
Long-term debt, including current maturities:			
Our parent's senior secured revolving credit facility	$	$	$
Our parent's second lien credit facility			
Ute Energy Corporation revolving credit facility(3)			
Total long-term debt(3)			
Owner's / stockholders' equity:			
Capital contributions			
Common stock, $ par value; shares authorized, issued and outstanding (actual); shares authorized (pro forma); shares issued and outstanding (pro forma)			
Preferred stock, $ par value; shares authorized (actual); shares authorized (pro forma); shares issued and outstanding (actual; pro forma)			
Additional paid-in capital			
Retained earnings (accumulated loss)(4)			
Total owner's / stockholders' equity			
Total capitalization	$	$	$

(1) As of December [●], 2011, our cash and cash equivalents were $[●] million.

(2) Each $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) would increase (decrease) our as further adjusted cash and cash equivalents by approximately $.

(3) We will enter into a new $ million credit facility, approximately $ million of which will be available for borrowing upon the completion of this offering.

(4) In connection with our corporate reorganization, an estimated net deferred tax liability of approximately $ will be established for differences between the book and tax basis of our assets and liabilities, and a corresponding expense will be recorded to net income for accounting purposes.

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value as of September 30, 2011, after giving pro forma effect to the transactions described under "Summary—Corporate Reorganization," was approximately $ million, or $ per share of common stock. Pro forma net tangible book value per share is determined by dividing our pro forma tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering including giving effect to our corporate reorganization. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting estimated discounts and expenses of this offering), our adjusted pro forma net tangible book value as of September 30, 2011 would have been approximately $ million, or $ per share. This represents an immediate increase in the net tangible book value of $ per share equivalent to our existing owners and an immediate dilution (i.e., the difference between the offering price and the adjusted pro forma net tangible book value after this offering) to investors purchasing shares in this offering of $ per share. The following table illustrates the per share dilution to investors purchasing shares in this offering:

Assumed initial public offering price per share		$
Pro forma net tangible book value per share as of September 30, 2011 (after giving effect to our corporate reorganization)	$	
Increase per share attributable to new investors in this offering		
As adjusted pro forma net tangible book value per share after giving effect to our corporate reorganization and this offering		
Dilution in pro forma net tangible book value per share to investors in this offering		$

The following table summarizes, on an adjusted pro forma basis as of September 30, 2011, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing stockholders and to be paid by investors in this offering at $, the midpoint of the range of the initial public offering prices set forth on the cover page of this prospectus, calculated before deduction of estimated underwriting discounts and commissions:

	Shares Acquired		Total Consideration		Average Price Per Share
	Number	Percent	Amount	Percent	
Existing stockholders(1)			$		$
New investors(2)					
Total			$		$

(1) The number of shares disclosed for the existing stockholders includes shares being sold by the selling stockholders in this offering. The total consideration and average price per share represents the consideration paid in connection with our corporate reorganization. Please read "Summary—Corporate Reorganization."

(2) The number of shares disclosed for the new investors does not include the shares being purchased by the new investors from the selling stockholders in this offering.

SELECTED HISTORICAL AND UNAUDITED PRO FORMA FINANCIAL DATA

You should read the following selected financial data in conjunction with "Summary—Corporate Reorganization," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical financial statements and unaudited pro forma financial information and related notes thereto included elsewhere in this prospectus. We believe that the assumptions underlying the preparation of our historical financial statements and unaudited pro forma financial data are reasonable. The financial data included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Set forth below is our selected historical and pro forma financial data as of and for the years ended December 31, 2006, 2007, 2008, 2009 and 2010 and as of and for the nine months ended September 30, 2010 and 2011. The historical financial data for the years ended December 31, 2008, 2009 and 2010 and the balance sheet data as of December 31, 2009 and 2010 are derived from the audited financial statements of Ute Energy Upstream Holdings LLC. The financial statements as of and for the year ended December 31, 2010 have been audited by KPMG LLP, an independent registered public accounting firm, and are included elsewhere in this prospectus. The financial statements as of December 31, 2009 and for the years ended December 31, 2008 and 2009 have been audited by Erhardt Keefe Steiner & Hottman PC, an independent registered public accounting, and are included elsewhere in this prospectus. The balance sheet data as of December 31, 2008 are derived from the audited balance sheet of Ute Energy Upstream Holdings LLC, which is not included herein. The historical financial data as of and for the year ended December 31, 2007 are derived from the audited financial statements of Ute Energy LLC, our predecessor, which are not included herein. The historical financial data as of and for the year ended December 31, 2006 are derived from the unaudited financial statements of Ute Energy LLC, our predecessor, which are not included herein.

Our historical financial data as of and for the nine months ended September 30, 2010 and 2011 are derived from the unaudited financial statements of Ute Energy Upstream Holdings LLC included elsewhere in this prospectus. The pro forma financial data as of and for the nine months ended September 30, 2011 give effect to the Horseshoe Bend acquisition described in "Summary—Horseshoe Bend Acquisition" and our corporate reorganization as described in "Summary—Corporate Reorganization" are derived from our unaudited pro forma financial statements included elsewhere in this prospectus. All unaudited financial information has been prepared on a basis consistent with our audited financial statements and the notes thereto and includes all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of this information.

	Historical							Pro Forma for the Nine Months Ended September 30, 2011
	Predecessor		Ute Energy Upstream Holdings LLC					
	Year Ended December 31,		Year Ended December 31,			Nine Months Ended September 30,		
	2006	2007	2008	2009	2010	2010	2011	2011
	(Unaudited)					(Unaudited)		(Unaudited)
	(In thousands)							
Statement of operations data:								
Oil and gas revenues	$ 1,148	$ 1,635	$ 14,123	$ 10,119	$ 39,087	$ 26,048	$ 56,871	$ 62,914
Operating costs:								
Lease operating expenses	149	509	2,046	1,654	4,466	2,539	7,503	8,576
Production taxes	53	143	996	1,998	2,860	2,437	2,741	3,004
Gathering and transportation expenses	83	141	800	1,113	2,274	1,546	3,586	3,620
Depletion, depreciation and amortization	388	1,542	7,792	5,594	13,852	9,313	20,508	22,093
Exploration expenses	21	530	-	40	60	59	68	68
Impairment of oil and gas properties and dry hole expense	2,022	1,119	1,354	-	-	-	-	-
General and administrative expenses	860	1,497	1,653	1,067	3,237	1,635	5,235	5,235
Total operating costs	$ 3,576	$ 5,481	$ 14,641	$ 11,470	$ 26,750	$ 17,530	$ 39,642	$ 42,597
Operating income (loss)	(2,428)	(3,846)	(517)	(1,351)	12,337	8,518	17,229	20,314
Other income (expense):								
Change in unrealized gain (loss) on derivative instruments	–	–	-	(936)	(1,616)	2,271	36,175	36,175
Realized gain (loss) on derivative instruments	–	271	-	(896)	1,082	1,112	(518)	(518)
Interest expense	(904)	(1,012)	(339)	(274)	(439)	(283)	(945)	(3,095)
Write-off of deferred debt issue costs	–	(215)	-	-	-	-	(814)	(814)
Other income (expense)	40	59	76	38	35	(16)	-	-
Total other income (expense)	(864)	(897)	(263)	(2,067)	(938)	3,084	33,898	31,748
Net income (loss) before income taxes	(3,292)	(4,743)	(780)	(3,418)	11,399	11,602	51,127	52,065
Income tax expense	–	–	-	-	-	-	-	(19,066)
Net income (loss)	$ (3,292)	$ (4,743)	$ (780)	$ (3,418)	$ 11,399	$ 11,602	$ 51,127	$ 32,999

	Historical							Pro Forma as of September 30, 2011
	Predecessor		Ute Energy Upstream Holdings LLC					
	As of December 31,		As of December 31,			As of September 30,		
	2006	2007	2008	2009	2010	2010	2011	
	(Unaudited)					(Unaudited)		(Unaudited)
	(In thousands)							
Balance sheet data:								
Cash and cash equivalents	$ –	$ –	$ 10	$ 162	$ 67	$ 3,453	$ 217	$ 217
Total property and equipment, net	3,097	8,352	29,155	34,296	88,846	69,930	190,838	291,363
Total assets	3,300	9,198	29,986	37,407	99,662	82,533	241,823	342,348
Long-term debt	–	–	–	–	10,000	–	36,847	85,797
Total owner's equity	3,300	9,198	22,796	31,334	66,551	62,731	167,704	150,270

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
	(In thousands)				
Cash flow data:					
Net cash provided by (used in) operating activities	$ 9,659	$ (1,310)	$ 23,118	$ 15,027	$ 33,558
Net cash used in investing activities	(27,298)	(10,491)	(56,417)	(30,352)	(107,785)
Net cash provided by (used in) financing activities	17,649	11,955	33,205	18,615	74,377

	Year Ended December 31,			Nine Months Ended September 30,		Pro Forma for the Nine Months Ended September 30, 2011
	2008	2009	2010	2010	2011	
				(Unaudited)		(Unaudited)
	(In thousands)					
Other financial data:						
Adjusted EBITDAX(2)	$ 8,628	$ 3,387)	$ 27,078	$ 19,389	$ 37,287	$ 41,960

(1) As a disregarded entity for federal income tax purposes, we are taxed at the member unitholder level rather than at the company level. Following the corporate reorganization described in this prospectus, we will be taxed at the company level. As a result, for periods following the corporate reorganization, our financial statements will include a tax provision on our income. On a pro forma basis after giving effect to the corporate reorganization, we would have recorded a tax provision (benefit) of approximately $3.8 million, ($1.4) million and ($0.4) million for the years ended December 31, 2010, 2009 and 2008 and approximately $18.8 million and $4.3 million for the nine months ended September 30, 2011 and 2010. On a pro forma basis after giving effect to the corporate reorganization and the Horseshoe Bend acquisition, we would have recorded a tax provision of approximately $19.1 million for the nine months ended September 30, 2011.

(2) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net loss and net cash provided by operating activities, please read “Summary Historical and Unaudited Pro Forma Financial Data — Non-GAAP Financial Measure.”

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and related notes appearing elsewhere in this prospectus. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in the prospectus, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the exploration, development, production and acquisition of oil and natural gas reserves with a primary focus on acquiring and developing oil reserves. All of our current acreage positions are concentrated in the Uinta Basin in northeastern Utah where we have accumulated approximately 162,695 net leasehold acres, approximately 94% of which are undeveloped. We are focused on the development of our significant inventory of identified potential drilling locations to grow our reserves, production and cash flow over time. We also seek high quality acquisitions and leasing opportunities with the potential for long-term drilling prospects that generate attractive rates of return.

Our parent company, Ute Energy LLC, was formed in 2005 by the Tribe to participate in the exploration and development of the Tribe's mineral estate in the Uinta Basin. Prior to our formation in 2008, the Tribe contributed to our parent, in exchange for equity, non-operated net acreage positions in the Lake Canyon, Wolf Flat, Blacktail Ridge and Monument Butte project areas. Our parent subsequently entered into an EDA for the Bridgeland project area in October 2008. We were formed by our parent to acquire all of our parent's oil and natural gas participation rights under the Exploration and Development Agreements ("EDAs") relating to these project areas and to manage our oil and gas operations distinctly from our parent's midstream activities. In March 2010, our parent assigned all of its oil and natural gas participation rights under the EDAs to us.

Since the assignment of the EDAs to us by our parent in March 2010, we have accumulated additional asset positions through a combination of acquisitions and leasing activities. In December 2010, we entered into an EDA for our operated Randlett project area for an initial lease bonus of $1.3 million, and in March 2011, we entered into an EDA for our Rocky Point project area, which we jointly operate with Newfield, for an initial net lease bonus of $1.5 million. The following table summarizes our tribal EDAs.

Tribal EDAs	Closing Date	Net Tribal Acres at Closing
Lake Canyon	May 4, 2005	31,198
Blacktail Ridge	February 23, 2007	25,714
Monument Butte	February 23, 2007	11,725
Bridgeland	October 15, 2008	4,561
Randlett	December 27, 2010	17,181
Rocky Point	March 21, 2011	8,374

During 2010, we shifted our focus from participating primarily in non-operated positions to establishing a significant portfolio of operated acreage and growing our asset base primarily through operated drilling activities. Since our strategic shift, we have increased our operated acreage position in the Uinta Basin through an active leasing and acquisition program and we have balanced our portfolio of tribal acreage with the addition of significant interests in fee, state, federal and allotted lands. We currently have operated acreage positions in the Randlett, Rocky Point and Horseshoe Bend project areas. We commenced operated drilling in Randlett in April 2011 and expect to commence operated drilling in Rocky Point and Horseshoe Bend in 2012. We believe that our shift to operated activities will enable us to better control timing, costs and drilling and completion techniques.

Our recent focus on establishing a significant portfolio of operated acreage and growing our asset base primarily through operated drilling activities has significantly impacted our business. As of September 30, 2011, we have 75,420 net operated acres, which represents 46% of our total net acreage position, and we have 64,827 net acres on fee, state and, federal and allotted lands, which represents 40% of our total net acreage position. Our operated net acres increased 127% from December 31, 2010 to September 30, 2011. As of September 30, 2011 approximately 61% of our proved reserves and 73% of our PV-10 are comprised of assets that had no associated proved reserves as of December 31, 2010. For the three months ended September 30, 2011, our operated production contributed 36% of our total net production while we had no operated production prior to 2011.

We continue to derive substantial benefits from our non-operated positions throughout the Uinta Basin and expect to participate in active drilling on our non-operated acreage positions in the future. Our participation in non-operated project areas offers attractive return opportunities and enables us to gain additional exposure to emerging resource plays without committing all of the capital required to drill the wells during the early-stage testing and refinement of drilling and completion techniques. In addition, we believe that the knowledge and expertise gained through our non-operated positions will enhance our ability to continue efficiently growing our operated acreage positions. As of September 30, 2011, we had 87,275 net non-operated acres in five core project areas.

Recent Acquisitions

During 2011, we completed two acquisitions and one election in an area of mutual interest ("AMI") which increased our operated acreage position and diversified our acreage position with additional fee, state, federal and allotted acreage. The following table highlights our 2011 acquisitions as well as our Bridgeland AMI election.

Project Areas	Closing Date	Adjusted Purchase Price(1) ($ in millions)	Net Fee Acres at Closing(2)
Randlett	April 20, 2011	$ 2.5	5,291
Bridgeland (AMI election)	June 15, 2011	$ 12.1	3,964
Horseshoe Bend and Randlett	November 30, 2011	$ 99.9	29,281

(1) The purchase price for the Horseshoe Bend and Randlett acquisition closed on November 30, 2011 remains subject to post-closing adjustments.

(2) Net acres include fee, state, federal and allotted acreage.

Basis of Presentation

We were formed by our parent to acquire all of our parent's oil and natural gas participation rights under the EDAs and to manage our oil and natural gas operations distinctly from our parent's midstream operations. Although we were formed in 2008, we had no assets or operating activities until March 2010 when our parent assigned all of its oil and gas participation rights under these EDAs to us. The transfer of interests in the EDAs from our parent to us in March 2010 was accounted for as a transaction between entities under common control and was retrospectively applied to our financial statements as of January 1, 2008. Prior to 2008, our parent's upstream business was comprised of the EDAs and the related oil and gas activities conducted under them, which is considered to be our accounting predecessor.

The financial statements included elsewhere in this prospectus have been derived from the accounting records of our parent, principally representing our parent's oil and natural gas exploration, development, production and acquisition activities. These allocations were based on what our parent considered to be reasonable reflections of the historical utilization levels of these services required in support of our business.

We believe the assumptions underlying the financial statements are reasonable. However, the financial statements may not necessarily reflect our future results of operations, financial position and cash flows or what our results of operations, financial position and cash flows would have been had we been a stand-alone company during the periods presented.

The statements of operations included elsewhere in this prospectus include allocations of costs for corporate functions historically provided to us by our parent, including:

General corporate expenses. Represents costs related to corporate functions such as accounting, tax, treasury, human resources and legal. Other corporate expenses include cost for leasehold expenses related to our corporate offices and general corporate overhead. These costs have historically been allocated primarily based on estimated use of services as compared to our parent's other businesses. These costs are included in general and administrative expenses in the statement of operations.

Employee compensation and benefits. Represents compensation, payroll taxes and fringe benefit costs such as health insurance and employer matching on retirement plan contributions. These costs have historically been allocated primarily based on estimated time provided to our activities as compared to our parent's other businesses. These costs are included in general and administrative expenses in the statement of operations, except for field personnel whose compensation and benefits generally are included in lease operating expense.

Our parent has provided financing to us through cash flows from its other operations, debt incurred and equity investments. The balance sheets and statements of operations included elsewhere in this prospectus include allocations for funding our operations and associated interest expense as follows:

Debt. Historically, and prior to the closing of this offering, we have guaranteed our parent's obligations under its credit facilities; however, debt has not been allocated to us prior to our balance sheet as of September 30, 2011, as our parent historically has funded our operations through capital contributions instead of debt allocations. Immediately prior to the closing of this offering, we intend to assume the portions of the debt outstanding under our parent's credit facilities that have been used to fund our operations, and we will use a portion of the net proceeds from this offering to repay in full such assumed debt at the closing of this offering. Our balance sheet and pro forma condensed balance sheet as of September 30, 2011 includes an allocation of a portion of the debt outstanding under our parent's credit facilities based on borrowings under those facilities to fund our operations and acquisitions.

Interest expense. Although the debt incurred by our parent has not been allocated to us prior to September 30, 2011, a portion of the interest expense has been allocated to us based on certain borrowings at our parent's average borrowing rates. These expenses are included in other income (expense) in the statement of operations. In the remainder of this Management's Discussion and Analysis of Financial Conditions and Results of Operations, references to "our interest expense" refer to the portion of our parent's interest expense allocated to us.

Sources of our revenue

Oil, natural gas and natural gas liquids revenues. Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives, and may vary significantly from period to period as a result of changes in production volumes or commodity prices.

Commodity prices. Our revenues are heavily influenced by commodity prices. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and gas activities, commodity prices have experienced significant fluctuations. The effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the Uinta Basin. For a description of factors that may impact future commodity prices, please read "Risk Factors — Risks Related to the Oil and Natural Gas Industry and Our Business."

A comparison of our quarterly average net realized oil prices to the NYMEX WTI index prices is shown in the table below.

	2009				Year Ended December 31, 2009	2010				Year Ended December 31, 2010	2011		
	Q1	Q2	Q3	Q4		Q1	Q2	Q3	Q4		Q1	Q2	Q3
NYMEX WTI	$43.08	$59.62	$68.30	$76.19	$61.80	$78.71	$78.03	$76.19	$85.17	$79.53	$94.10	$102.56	$89.72
Average Realized Oil Prices ($/Bbl)(1)	$25.94	$48.71	$56.30	$65.00	$47.87	$67.26	$67.34	$63.56	$69.64	$66.90	$78.48	$86.55	$75.31

Average Price Differential(2)	39.8%	18.3%	17.6%	14.7%	22.5%	14.5%	13.7%	16.6%	18.2%	15.9%	16.6%	15.6%	16.1%

(1) Realized oil prices do not include the effect of realized derivative contract settlements.

(2) Price differential represents the difference between NYMEX West Texas Intermediate crude index price and our actual realized oil prices as a percentage of NYMEX West Texas Intermediate crude index prices.

Crude oil produced and sold in the Uinta Basin has historically sold at a discount to the price quoted by NYMEX for West Texas Intermediate (WTI) crude oil. Most of the crude oil we produce in the Uinta Basin is known as black wax or yellow wax crude because it has higher paraffin content than crude oil found in most other major North American basins. Due to its high paraffin content, it must remain heated during shipping or reheated at its destination, so our transportation options are more limited than in other basins. Currently, our oil production is transported by truck to refiners in the Salt Lake City area. In the past, there have been periods when the discount to the price quoted by NYMEX for WTI crude oil has substantially increased due to the production of oil in the Uinta Basin increasing to a level in excess of the available transportation, regional refining capacity or demand for refined products or due to market shocks. The last such period was late 2008 through early 2009, when oil prices declined significantly compounded by a decrease in regional demand for products refined from black and yellow wax. As a result, refiners had less demand for our type of production yet the differential increased significantly.

Commodity derivatives. To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we generally enter into derivative arrangements for a significant portion of our crude oil and natural gas production. Please read "—Quantitative and Qualitative Disclosures About Market Risk—Commodity price exposure." While these derivative contracts stabilize our cash flows when market prices are below our contract prices, they also prevent us from realizing increases in our cash flow when market prices are higher than our contract prices. We utilize commodity derivatives to reduce our exposure to fluctuations in NYMEX WTI benchmark prices and, to a lesser extent, fluctuations in natural gas prices, including natural gas basis differential. We are unable to effectively hedge our oil differential between black or yellow wax and NYMEX WTI. We will sustain realized and unrealized losses to the extent our derivatives contract prices are lower than market prices and conversely, we will sustain realized and unrealized gains to the extent our derivatives contract prices are higher than market prices. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as other income (expense) in our statements of operations. We view the settlement of such derivatives contracts as adjustments to the price received for natural gas, crude oil and natural gas liquids production to determine realized prices.

Principal components of our cost structure

Lease operating expenses. Lease operating expenses are daily costs incurred to bring oil and natural gas out of the ground, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, utilities, maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (as opposed to hedged prices) or at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. In general, the amount of production taxes we pay is based on oil and natural gas revenues generated from our production. We are also subject to ad valorem taxes in the counties where are production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

Gathering and transportation expense. Our oil and natural gas is sold under two types of agreements, both of which are common in our industry. One is a sale at the wellhead where we receive a price, net of the transportation costs incurred by the purchaser. In this case, we record sales at the price received from the purchaser and no gathering and transportation costs are recognized. Under the other arrangement, our oil or natural gas is sold at a specific delivery point and we are charged transportation costs by the purchaser, which are deducted from our sales proceeds. In this case, we report revenue at the gross amounts we receive before taking into account transportation costs, which are reflected in our statements of operations as gathering and transportation expenses. Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative financial instruments, contain revenues that are reported under two separate bases. Under the first arrangement, we have a lower realized price and under the second arrangement we have higher operating costs, but they have a similar impact on operating income.

Depreciation, depletion and amortization ("DD&A"). Depreciation, depletion and amortization includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop our oil and natural gas properties. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate such costs to each unit of production using the units-of-production method. DD&A expense is separately computed for each project area. The capital expenditures for proved properties in each area compared to the proved reserves corresponding to each project area determine a weighted average DD&A rate for current production. We adjust future DD&A rates to reflect changes in future capital expenditures and proved reserves in specific project areas. We do not include unproved properties in the DD&A calculation. We record depreciation expense on the cost of fixed assets related to our gathering infrastructure and other fixed assets based on their useful lives. DD&A includes accretion expense on our asset retirement obligations, which is recognized in connection with the accretion of the discounted liability over the remaining estimated economic life of the oil and gas property.

Exploration expenses. Exploration expenses consist of exploratory dry hole expenses and costs incurred in evaluating areas that are considered to have prospective oil and natural gas reserves, including costs for topographical, geological and geophysical studies, rights of access to properties and costs of carrying and retaining undeveloped properties, such as delay rentals.

Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We also record impairment charges for proved properties if we determine that the carrying value of the properties exceeds estimated future cash flows from the properties. Please read "— Critical accounting policies and estimates — Impairment of proved properties."

General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our employees, costs of maintaining our corporate office and facilities, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance.

Other income (expense)

Gains (losses) on commodity derivatives, net. Gains and losses on commodity derivatives represent (i) the recognition of unrealized gains and losses associated with our open derivative contracts as commodity prices change and commodity derivative contracts expire or new derivative contracts are entered into, and (ii) our realized gains and losses on the settlement of these commodity derivative contracts. We view the settlement of such derivatives contracts as adjustments to the price received for crude oil, natural gas and natural gas liquids production to determine realized prices. We classify these gains and losses as operating activities in our statements of cash flows.

Interest expense. Historically, we have financed a portion of our working capital requirements, capital expenditures and acquisitions with contributions made from borrowings under our parent's credit facilities and a prior revolving credit facility maintained by us ("our prior revolving credit facility"). In the future, we expect to finance our operations with borrowings under our new credit facility in addition to cash generated from operations and proceeds from this offering. As a result, our interest expense is affected by both fluctuations in interest rates and our financing decisions. We record the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees as interest expense in our statements of operations. We capitalize a portion of our interest costs in unproved properties where significant development plans have commenced. We depreciate capitalized interest over the useful life of the assets in the same manner as the depreciation of the underlying assets.

Income tax expense. As of September 30, 2011, we were a disregarded entity for federal income tax purposes. Accordingly, no provision for federal or state corporate income taxes has been provided for the nine months ended September 30, 2011 or prior fiscal years because taxable income is allocated directly to our equity holders. In connection with the closing of this offering, we will convert into a corporation that will be subject to federal and state entity-level taxation. We will establish a net deferred tax liability for differences between the tax and book basis of our assets and liabilities, and we will record a corresponding "first day" tax expense to net income from continuing operations.

Factors That Significantly Affect Our Results

Our revenue, cash flow from operations, profitability and future growth depend substantially upon the prices and demand for crude oil, natural gas and natural gas liquids, the quantity of our crude oil, natural gas and natural gas liquids production and changes in the fair value of derivative instruments we use to reduce the volatility of the prices we receive for our crude oil, natural gas and natural gas liquids production. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and the amount we can borrow under our new credit facility.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and gas production from a given well will decline over time. Thus, an oil and natural gas exploration company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. We also evaluate secondary recovery techniques, such as waterflooding, to potentially enhance recoverable reserves. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on increasing production from our existing reserves, as well as deploying the capital necessary to add reserves through drilling and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and add reserves through drilling and acquisitions is dependent on our ability to access capital to fund our growth.

Items Impacting Comparability of Our Financial Results

As a result of our separation from our parent and our recent rapid growth through drilling activities, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful. In addition, past results are not indicative of future results.

Results of Operations

The following table summarizes our revenues, expenses and production data for the periods indicated.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	**2009**	**2010**	**2010**	**2011**
				(Unaudited)	
			(In thousands)		
Revenues:					
Oil	$ 10,447	$ 7,892	$ 34,060	$ 22,451	$ 50,200
Natural gas	3,208	1,986	4,525	3,207	4,995
Natural gas liquids	468	241	502	390	1,676
Total oil and gas revenues	14,124	10,119	39,087	26,048	56,871
Operating Expenses:					
Lease operating expenses	2,046	1,654	4,466	2,539	7,503
Production taxes	996	1,998	2,860	2,437	2,741
Gathering and transportation expenses	800	1,113	2,274	1,546	3,586
Depreciation, depletion and amortization	7,792	5,594	13,852	9,313	20,508
Exploration expenses	-	40	60	59	68
Impairment of oil and gas properties and dry hole expense	1,354				
General and administrative expenses	1,653	1,067	3,237	1,635	5,235
Total operating costs	$ 14,641	$ 11,470	$ 26,750	$ 17,530	$ 39,642
Income (loss) from operations	(517	(1,351)	12,337	8,518	17,229
Other Income (Expense):					
Gains (losses) on commodity derivatives, net	-	(1,832)	(534)	3,383	35,657
Interest expense	(339)	(274)	(439)	(283)	(945)
Write-off deferred debt issue costs	-	-	-	-	(814)

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
			(In thousands)		
Other income (expense)	76	38	35	(16)	-
Total other income (expense)	(263)	(2,067)	(938)	3,084	33,898
Net Income (Loss)	(780)	(3,418)	11,399	11,602	51,127
Production Data:					
Oil (Mbbls)	148.8	164.9	510.9	342.4	631.5
Natural gas (Mcf)	636.2	571.3	1,275.6	835.8	1,196.1
Natural gas liquids (Mbbls)	7.6	6.2	8.8	7.0	22.7
Oil equivalents (MBoe)	262.4	266.3	732.3	488.7	853.5
Average daily production (Boe/d)	719	730	2,006	1,790	3,126
Average Sales Prices					
Oil, realized ($/Bbl)	$70.21	$42.43	$67.64	$67.36	$77.78
Oil, unhedged ($/Bbl)	70.21	47.86	66.66	65.57	79.49
Natural gas, realized ($/Mcf)	5.04	3.48	4.11	4.26	4.76
Natural gas, unhedged ($/Mcf)	5.04	3.48	3.55	3.84	4.18
Natural gas, liquids, unhedged ($/Bbl)	61.64	38.93	56.95	55.71	73.88
Cost and Expense (per Boe of Production):					
Lease operating expense	7.80	6.23	6.10	5.20	8.79
Production taxes	3.79	7.50	3.91	4.99	3.21
Gathering and transportation	3.05	4.18	3.11	3.16	4.20
Depreciation, depletion and amortization	29.69	21.01	18.92	19.06	24.03

Nine months ended September 30, 2011 as compared to nine months ended September 30, 2010

Revenues

Oil, natural gas and natural gas liquids revenues. Our oil, natural gas and natural gas liquids revenues increased $30.8 million, or 118%, to $56.9 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. Average daily production increased by 1,336 Boe/d, or 75%, to 3,126 Boe/d for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increase in average daily production was primarily due to the commencement of operated drilling activities in Randlett during 2011 and an active drilling program by our operating partners in our non-operated project areas. Production in Randlett accounted for 345 Boe/d of the increase, and production from our non-operated properties, particularly Blacktail Ridge, North Monument Butte and Bridgeland, accounted for the remaining increase. The higher production amounts contributed to $19.4 million of the revenue increase, and the remaining $11.4 million increase was attributable to an increase in realized commodity prices. Average oil sales prices, without realized derivatives, increased by $13.92 per barrel, or 21%, to an average of $79.49 per barrel for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010.

Operating expenses

Lease operating expenses. Our lease operating expenses increased $5.0 million, or 196%, to $7.5 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. This increase was primarily due to the higher number of producing wells as a result of the commencement of production in Randlett and increased drilling activity in Blacktail Ridge, North Monument Butte and Bridgeland. Although production increased, per unit lease operating costs increased 69% to $8.79 per Boe primarily due to increased water production and the associated water disposal costs. The ratio of water to oil produced increased 33% in total, and 63% in Blacktail Ridge, from the nine months ended September 30, 2010 to the nine months ended September 30, 2011. Water disposal is one of the largest operating costs, and the per barrel cost of disposing water also increased approximately 27% from the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2010. Increased water production also contributes to higher other operating costs, such as chemical expenses and purchased electricity for artificial lift.

Production taxes. Our production taxes increased $0.3 million, or 12%, to $2.7 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. Per unit production taxes, however, declined $1.78 per Boe to $3.21 per Boe for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 primarily due to increased drilling activity. New wells qualify for severance tax exemptions on tribal and state lands of twelve and six months, respectively. As a result, new production is not subject to severance tax and yields a lower effective tax rate in periods of increasing production from new wells.

Gathering and transportation expense. Our gathering and transportation expense increased $2.0 million, or 132%, to $3.6 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, primarily due to increased production volumes. Gathering and transportation expense per unit increased $1.04 per Boe to $4.20 per Boe for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, primarily due to our entry into a new natural gas marketing agreement in Blacktail Ridge in 2011 that charges higher gathering costs but allows us to capture value from natural gas liquids. Our gathering expenses in Blacktail Ridge increased $0.9 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010.

Depreciation, depletion and amortization (DD&A). Our depreciation, depletion and amortization expense increased $11.2 million, or 120%, to $20.5 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increase in DD&A expense for the nine months ended September 30, 2011 was primarily due to both increased production volumes and an increase in the DD&A rate. The DD&A rate increased $4.97 per Boe, or 26%, to $24.03 per Boe for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increase in the DD&A rate was primarily due to an increase in capital expenditures without proportional associated proved developed reserve additions for the period, particularly in our Bridgeland project area.

General and administrative expenses. Our general and administrative expenses increased $3.6 million, or 220%, to $5.2 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. This increase resulted primarily from compensation, benefits and other overhead associated with the additional personnel employed in connection with the expansion of our operations. As of September 30, 2011, we had 44 full-time employees compared to 18 employees as of September 30, 2010.

Other income (expense)

Gains (losses) on commodity derivatives, net. As a result of our derivative activities, we incurred cash settlement losses of $0.5 million for the nine months ended September 30, 2011 and cash settlement gains of $1.1 million for the nine months ended September 30, 2010. In addition, as a result of forward oil price changes, we recognized $36.2 million of unrealized gains for the nine months ended September 30, 2011 and $2.3 million of unrealized losses for the nine months ended September 30, 2010. Unrealized gains during the nine months ended September 30, 2011 occurred as oil prices declined in the third quarter of 2011 relative to the oil hedges in place.

Interest expense. Our interest expense increased $0.7 million to $0.9 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. Interest costs increased in conjunction with higher borrowings to fund our development drilling program and acquisitions during the nine months ended September 30, 2011. Additionally, we expensed $0.8 million of deferred loan costs in the nine months ended September 30, 2011 when we refinanced our credit facility in May 2011.

Year ended December 31, 2010 as compared to year ended December 31, 2009

Revenues

Oil, natural gas and natural gas liquids. Our oil, natural gas and natural gas liquids sales revenues increased $29.0 million, or 286%, to $39.1 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Average daily production increased 1,276 Boe/d, or 175%, to 2,006 Boe/d for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in average daily production was primarily due to increased drilling in response to higher oil prices in our Blacktail Ridge, North Monument Butte and Bridgeland project areas as a result of higher oil prices. The higher production volumes contributed $17.7

million of the revenue increase, and the remaining $11.3 million increase was attributable to an increase in realized commodity prices. Average oil sales prices, without realized derivatives, increased $18.80, or 39%, per barrel to $66.66 per barrel for the year ended December 31, 2010 as compared to the year ended December 31, 2009.

Operating expenses

Lease operating expenses. Our lease operating expenses increased $2.8 million, or 169%, to $4.5 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. This increase was primarily due to the higher number of producing wells as a result of the increased drilling activity in our Blacktail Ridge, North Monument Butte and Bridgeland project areas. Per unit lease operating costs declined $0.10 per Boe, or 2%, to $6.10 per Boe for the year ended December 31, 2010 as compared to the year ended December 31, 2009 due to the 175% increase in production providing greater economies of scale for fixed costs.

Production taxes. Our production taxes increased $0.9 million, or 43%, to $2.9 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Per unit production taxes, however, declined $3.59 per Boe, or 48%, to $3.91 per Boe for the year ended December 31, 2010 as compared to the year ended December 31, 2009 primarily due to increased drilling activity. New wells qualify for severance tax exemptions on tribal and state lands for twelve and six months, respectively. As a result, new production is not subject to severance tax and yields a lower effective tax rate in periods of increasing production from new wells.

Gathering and transportation expense. Our gathering and transportation expenses increased $1.2 million, or 104%, to $2.3 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Gathering and transportation costs per unit decreased $1.07 per Boe, or 26%, to $3.11 per Boe for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The decrease in per unit gathering and transportation was primarily due to a reduction of the contribution of production from higher cost project areas and higher total production in project areas in which we have a fixed component to our infield gathering rate.

Depreciation, depletion and amortization (DD&A). Our depreciation, depletion and amortization expense increased $8.3 million, or 148%, to $13.9 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase was primarily due to a 175% increase in production volumes partially offset by a decline in the DD&A rate. The DD&A rate declined $2.09 per Boe, or 10%, to $18.92 per Boe for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The decrease in the DD&A rate was due to an increase in associated proved developed reserve additions recorded within the period in proportion to the capital expenditures in the same period, in particular in Blacktail Ridge and North Monument Butte.

General and administrative expenses. Our general and administrative expenses increased $2.2 million, or 203%, to $3.2 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. This increase resulted primarily from compensation, benefits and other overhead associated with the additional personnel hired to execute our strategic shift to becoming an operator. As of December 31, 2010, we had 23 full-time employees compared to eight employees as of December 31, 2009.

Other income (expense)

Gains (losses) on commodity derivatives, net. As a result of our derivative activities, we incurred cash settlement gains of $1.1 million for the year ended December 31, 2010 and cash settlement losses of $0.9 million for the year ended December 31, 2009. In addition, as a result of forward oil price changes, we recognized $1.6 million of unrealized losses in 2010 and $0.9 million of unrealized losses during 2009.

Interest expense. Interest expense increased $0.2 million to $0.4 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. At December 31, 2010 the outstanding debt balance under our prior revolving credit facility was $10.0 million with a weighted average interest rate of 4.83%.

Year ended December 31, 2009 as compared to year ended December 31, 2008

Revenues

Oil, natural gas and natural gas liquids revenues. Our oil, natural gas and natural gas liquids sales revenues decreased $4.0 million, or 28%, to $10.1 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008. Our operating partners drilled fewer wells in 2009 as a result of the decline in commodity prices and our average daily production only increased 11 Boe/d to 730 Boe/d for the year ended December 31, 2009 as compared to the year ended December 31, 2008. Average oil sales prices, without realized derivatives, declined by $22.35 per barrel, or 32%, to $47.86 per barrel for the year ended December 31, 2009 as compared to the year ended December 31, 2008.

Operating expenses

Lease operating expenses. Our lease operating expenses decreased $0.4 million, or 19%, to $1.7 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008. This decrease was primarily due to the significant reduction in the number of new wells drilled and the shut-in of some wells during the first half of 2009 as a result of low oil prices. Per unit operating costs decreased $1.57 per Boe, or 20%, to $6.23 per Boe for the year ended December 31, 2009 as compared to the year ended December 31, 2008. Even as production for the year ended December 31, 2009 was relatively flat as compared to the year ended December 31, 2008, our per unit costs decreased partially due to a 21% lower water to oil production ratio. Water disposal is one of the largest operating costs and we produced less water on a similar level of oil production for the year ended December 31, 2009 as compared to the year ended December 31, 2008. In addition, our operating partners performed fewer workovers and repairs in the lower cost environment during the year ended December 31, 2009 as compared to the year ended December 31, 2008.

Production taxes. Our production taxes increased $1.0 million, or 101%, to $2.0 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008. Production taxes per unit, however, increased $3.71 per Boe, or 98%, to $7.50 per Boe for the year ended December 31, 2009 as compared to the year ended December 31, 2008 primarily due to the expiration of severance tax exemptions. Our operating partners drilled 60% fewer wells during the year ended December 31, 2009 as compared to the year ended December 31, 2008, and the severance tax holidays for many of the wells drilled in 2008 expired.

Gathering and transportation expense. Our gathering and transportation expenses increased $0.3 million, or 39%, to $1.1 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008. Per unit gathering and transportation expenses increased $1.13 per Boe, or 37%, to $4.18 per Boe for the year ended December 31, 2009 as compared to the year ended December 31, 2008, primarily due to decreases in natural gas production volumes in Wolf Flat and Section 36, which have a fixed component to the infield gathering rate.

Depreciation, depletion and amortization (DD&A). Our depreciation, depletion and amortization expense decreased $2.2 million, or 28%, to $5.6 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008. The DD&A rate declined $8.68 per Boe, or 29%, to $21.01 per Boe for the year ended December 31, 2009 as compared to the year ended December 31, 2008. The decrease in the cost per unit from 2008 to 2009 was primarily due to an increase in proved reserves proportional to the capital expenditures, which reduced the depletion rate.

Impairment of unproved and proved properties. During the years ended December 31, 2009 and 2008, we recorded a non-cash impairment charge of $0 and $1.4 million, respectively, on our proved oil and gas properties as a result of future cash inflows being less than the net book value of the properties.

General and administrative expenses. Our general and administrative expenses decreased $0.6 million, or 35%, to $1.1 million for year ended December 31, 2009 as compared to the year ended December 31, 2008. This decrease resulted from a cessation of drilling activities in the first half of 2009 due to low commodity prices during that time period and our parent's contracted management team focusing more of their resources on the midstream operations of our parent, which reduced the allocation of general and administrative cost to us.

Other income (expense)

Gains (losses) on commodity derivatives, net. For the years ended December 31, 2009 and 2008, we incurred cash settlement losses of $0.9 million and $0, respectively, on contract settlements of our crude oil derivative transactions. In addition, we recognized $0.9 million of unrealized losses during the year ended December 31, 2009 as compared to no unrealized gains or losses during the year ended December 31, 2008.

Interest expense. Interest expense remained relatively constant at approximately $0.3 million for the years ended December 31, 2009 and 2008 due to allocations of interest from our parent's borrowings under its credit facility.

Liquidity and Capital Resources

Our primary sources of liquidity to date have been capital contributions from our equity holders, borrowings under our parent's credit facilities, our prior revolving credit facility and a prior bridge loan provided by one of our equity holders and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Liquidity and cash flow

Our cash flows for the years ended December 31, 2008, 2009 and 2010 and for the nine months ended September 30, 2010 and 2011 are presented below:

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
			(In thousands)		
Net cash provided by (used in) operating activities	$ 9,659	$ (1,310)	$ 23,118	$ 15,027	$ 33,558
Net cash used in investing activities	(27,298)	(10,491)	(56,417)	(30,352)	(107,785)
Net cash provided by (used in) financing activities	17,649	11,955	33,205	18,615	74,377
Net change in cash	$ 10	$ 153	$ (95)	$ 3,290	$ 150

Net cash provided by operating activities was $15.0 million and $33.6 million for the nine months ended September 30, 2010 and 2011, respectively. The increase in cash flows from operations was primarily the result of increased oil and gas revenues from increased production volumes at higher crude oil prices.

Net cash provided by (used in) operating activities was $9.7 million, ($1.3) million and $23.1 million for the years ended December 31, 2008, 2009 and 2010, respectively. The decrease in cash flows from operations for the year ended December 31, 2009 compared to period ended December 31, 2008 was primarily the result of decreased revenues from oil and gas sales as a result of lower crude oil prices during 2009. Cash flows from operations during the year ended December 31, 2010 increased compared to 2009 due to increased oil and gas revenues from increased production volumes at higher realized crude oil prices.

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, please read "— Quantitative and Qualitative Disclosures About Market Risk" below.

Net cash used in investing activities was $30.4 million and $107.8 million during the nine months ended September 30, 2010 and 2011, respectively. This increase was primarily a result of increased capital expenditures for drilling and development costs and acquisitions in 2011, particularly related to our operated drilling program in

Randlett. Costs incurred in the development of our Randlett program were $43.5 million in 2011. Additionally, we incurred $19.4 million of leasehold and acquisition costs during the nine months ended September 30, 2011 compared to $0.4 million for the comparable period in 2010.

Net cash used in investing activities was $27.3 million, $10.5 million and $56.4 million during the years ended December 31, 2008, 2009 and 2010, respectively, primarily as a result of our capital expenditures for drilling and development costs. The decrease in cash flows used in investing activities during the year ended December 31, 2009 compared to the year ended December 31, 2008 was attributable to a decline in drilling activities during 2009 as a result of the depressed commodity prices of oil and natural gas. The increase in cash used in investing activities for the year ended December 31, 2010 compared to the year ended December 31, 2009 was attributable to increased drilling activity during 2010 in response to increased oil prices.

Our capital expenditures for the years ended December 31, 2008, 2009 and 2010 and the nine months ended September 30, 2011 are summarized in the following table:

	Year Ended December 31,			Nine Months Ended September 30,
	2008	2009	2010	2011
				(Unaudited)
		(In thousands)		
Drilling and completion of wells	$ 26,628	$ 13,876	$ 62,193	$ 101,249
Leasehold acquisitions	80	864	3,789	18,016
Construction of gathering infrastructure	–	–	–	2,985
Information technology and other	41	111	237	160
Total(1)	$ 26,749	$ 14,852	$ 66,219	$ 122,409

(1) Capital expenditures in the table above are presented on an accrual basis. Additions to property and equipment in the Statements of Cash Flows in this report reflect capital expenditures on a cash basis, when payments are made.

Net cash provided by financing activities was $18.6 million and $74.4 million for the nine months ended September 30, 2010 and 2011, respectively. For the nine months ended September 30, 2010 and 2011, the net cash provided by financing activities consisted primarily of proceeds from capital contributions from our parent's equity investors, a portion of which our parent contributed to us, and borrowings under our parent's credit facilities and our prior revolving credit facility. During the nine months ended September 30, 2010 and 2011, our parent's equity investors invested $61 million and $49 million, respectively, in our parent. Our long-term debt was $10.0 million at December 31, 2010 and $36.8 million at September 30, 2011.

Net cash provided by financing activities was $17.7 million, $12.0 million and $33.2 million for the years ended December 31, 2008, 2009 and 2010, respectively. For the years ended December 31, 2008, 2009 and 2010, the net cash provided by financing activities consisted primarily of proceeds from capital contributions from our parent and borrowings under our prior revolving credit facility. Our long-term debt was $10 million at December 31, 2010.

Capital resources

Parent credit facilities. During 2010 and 2011, we incurred indebtedness under the credit facilities described below to partially fund our drilling activities and lease acquisitions, including our recent Horseshoe Bend acquisition. Our historical financial information prior to 2010 reflects our share of indebtedness incurred by our parent and as transferred to us as a parent contribution and used to fund our operations. Please read "—Items Impacting Comparability of Our Financial Results."

- We repaid our prior revolving credit facility on May 27, 2011 with proceeds from a revolving credit facility at our parent, which we guaranteed. Our prior revolving credit facility included an initial $55.0 million borrowing base on our oil and gas reserves and a total borrowing base of $95.0 million. We used $30.7 million of proceeds from our parent's revolving credit facility to repay all of the outstanding borrowings and accrued interest on our prior revolving credit facility and paid $0.6 million of fees and expenses at closing. On December [●], 2011, the oil and gas borrowing base of our parent's revolving credit facility increased to $135 million on a $180 million global borrowing base.

- Our parent entered into a $50.0 million senior secured second lien credit facility on September 30, 2011. On September 30, 2011 our parent borrowed $24.5 million under this facility and on November 7, 2011, our parent borrowed the remaining $25.5 million in availability under this facility. Our parent contributed to our capital all of the proceeds of these borrowings in order to fund our drilling activities and acquisitions.

Immediately prior to the closing of this offering, we intend to assume approximately $ million in aggregate principal amount of the loans outstanding under our parent's credit facilities, which loans are secured by liens on substantially all of our properties. We will use a portion of the net proceeds from this offering to repay in full such assumed debt at the closing of this offering. Upon repayment in full of the loans, we will be released from any further obligations under our parent's credit facilities and the liens on our properties will be released.

New credit facility. In connection with this offering, we will enter into a new senior secured reserve-based revolving credit facility. The borrowing base under our new credit facility will be subject to periodic re-determination by the lenders at their sole discretion and consistent with their normal oil and gas lending criteria. Our new credit facility will be available for our general corporate purposes, including, without limitation, working capital for exploration and production operations. Our obligations under our new credit facility will be secured by substantially all of our assets. As of the closing of this offering, we expect to have no debt outstanding under our new credit facility.

Our new credit facility is expected to contain various covenants that will limit our ability to incur indebtedness, grant certain liens, make certain loans, advances and investments, make dividends, distributions or redemptions, merge or consolidate, engage in certain asset dispositions, including a sale of all or substantially all of our assets, enter into certain transactions with affiliates, grant negative pledges or agree to restrict dividends or distributions from subsidiaries, allow certain gas imbalances, take-or-pay or other prepayments with respect to our oil and gas properties or enter into certain hedging agreements.

Future capital requirements. Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by increasing our operated drilling activities and participating in wells drilled by our partners. We anticipate that acquisitions, including acquisitions of undeveloped leasehold interests, will continue to play a significant role in our business strategy as those opportunities periodically arise from time to time.

The amount and allocation of capital we spend may fluctuate materially based on drilling results, market conditions and drilling permit availability. To date, our 2011 capital budget has been funded from borrowings under our parent's credit facilities and capital contributions from our parent, which were made out of capital contributions of $100 million to our parent from its equity investors. We believe the net proceeds from this offering together with cash flows from operations and borrowings under our new credit facility should be more than sufficient to fund our 2012 capital expenditure budget.

Our total 2012 capital expenditure budget is expected to be $[●] million, consisting of:

- $[●] million for drilling and completing operated wells;
- $[●] million for drilling and completing non-operated wells;
- $[●] million for maintaining our leasehold position;
- $[●] million for constructing strategic infrastructure to support production in our core project areas; and
- $[●] million in unallocated funds for general corporate purposes.

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as continued commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit facility in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all.

Obligations and Commitments

We have the following contractual obligations and commitments as of September 30, 2011 (in thousands):

	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Allocated portion of our parent's senior secured revolving credit facility(1)	$ 12,347	$ –	$ –	$ 12,347	$ –
Allocated portion of our parent's second lien credit facility(1)	24,500	–	–	–	24,500
Operating leases(2)	3,005	341	2,218	446	–
Drilling rig commitments(2)	3,593	3,593	–	–	–
Asset retirement obligations(3)	1,705	–	–	–	1,705
Total contractual cash obligations	$ 45,150	$ 3,934	$ 2,218	$ 12,793	$ 26,205

(1) Amount excludes applicable interest during the periods presented.

(2) Please read Note [7] to our audited financial statements for a description of lease obligations and drilling contract commitments.

(3) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. Please read Note [5] to our audited financial statements.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. Please read Note [●] to our audited financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed as incurred. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as impairment expense in the statement of operations in our financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Revenue from our interests in producing wells is recognized when delivery to the purchaser has occurred, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. We report revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and record impairment expense for any decline in value.

We have historically recognized impairment expense for unproved properties at the time when the lease term has expired or sooner if, in management's judgment, the unproved properties have lost some or all of their carrying value. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- our evaluation of the continuing successful results from the application of completion technology by us or by other operators in areas adjacent to or near our unproved properties.

The assessment of unproved properties to determine any possible impairment requires managerial judgment.

Asset retirement obligations

In accordance with the Financial Accounting Standard Board's (FASB) authoritative guidance on asset retirement obligations, or ARO, we record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our statement of operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under Other Income (Expense) in our statement of operations.

Recent accounting pronouncements

Fair Value. In May 2011, the FASB issued authoritative guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011 and we are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and nonrecurring fair value measurements, and is effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The adoption of this guidance did not have a significant impact on our financial position, results of operations or cash flows.

Oil and Gas Reporting Requirements. In December 2008, the SEC released the final rule, "Modernization of Oil and Gas Reporting," which adopts revisions to the SEC's oil and gas reporting disclosure requirements. The disclosure requirements under this final rule require reporting of oil and gas reserves using the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months rather than year-end prices, and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are allowed, but not required, to disclose probable and possible reserves in SEC filings. In addition, companies are required to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. In January 2010, the FASB issued authoritative guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC's final rule. We have presented and applied this new guidance for our reserve estimates as of December 31, 2009 and 2010 and as of September 30, 2011. Reserve estimates as of December 31, 2008 were prepared consistent with the former rules and regulations of the SEC.

Business Combinations. In December 2010, the FASB issued an accounting standards update relating to disclosure of supplementary pro forma information for business combinations. This guidance provides clarification on disclosure requirements and amends current guidance to require entities to disclose pro forma revenue and earnings of the combined entity as though the acquisition date for all business combinations that occurred during the current year had been as of the beginning of the comparable prior annual reporting period. Qualitative disclosures describing the nature and amount of any material, nonrecurring pro forma adjustments directly attributable to the business combinations included in the reported pro forma revenue and earnings are also required. This guidance is effective for business combinations with acquisition dates on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, with early adoption permitted. This pronouncement affects only disclosures and did not impact our financial condition and results of operations.

Internal Controls and Procedures

Prior to the completion of this offering, we have been a private company with limited accounting personnel to adequately execute the accounting and reporting processes required to be a public company and other supervisory resources with which to address our internal control over financial reporting.

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to make our first assessment of our internal control over financial reporting until the year following our first annual report required to be filed with the SEC. To comply with the requirements of being a public company, we will need to upgrade our systems, including information technology, implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff.

Further, our independent registered public accounting firm is not yet required to formally attest to the effectiveness of our internal controls over financial reporting until the year following our first annual report required to be filed with the SEC. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended 2008, 2009 and 2010 or the nine months ended September 30, 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments (primarily swaps, costless collars and basis swaps) to manage risks related to changes in oil prices. We record all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

The following is a summary of our derivative contracts as of September 30, 2011:

	Remaining Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Oil positions(1):						
Swaps:						
Hedged volume (Bbls)	250,089	1,343,956	1,436,077	176,263	150,236	45,519
Weighted average price ($/Bbl)	$ 94.51	$ 94.65	$ 92.63	$ 91.48	$ 92.15	$ 98.13
Collars:						
Hedged volume (Bbls)	15,000	46,000	–	222,567	175,169	82,397
Weighted average floor price ($/Bbl)	$ 80.00	$ 80.00	$ –	$ 91.67	$ 91.67	$ 91.67
Weighted average ceiling price ($/Bbl)	$ 99.50	$ 99.50	$ –	$ 110.33	$ 110.33	$ 110.33
Natural gas positions(2):						
Henry Hub Swaps:						
Hedged volume (MMBtu)	101,500	359,004	–	–	–	–
Weighted average price ($/MMBtu)	$ 6.12	$ 6.09	$ –	$ –	$ –	$ –
Basis swaps:						
Hedged volume (MMBtu)	101,500	359,004	–	–	–	–
Weighted average price ($/MMBtu)	$ (0.53)	$ (0.59)	$ –	$ –	$ –	$ –
Rockies Swaps:						
Hedged volume (MMBtu)	53,200	165,200	423,500	358,300	261,600	–
Weighted average price ($/MMBtu)	$ 4.60	$ 4.60	$ 4.60	$ 4.60	$ 4.60	$ –

(1) The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude Oil.

(2) The Henry Hub natural gas swaps are settled based on the NYMEX monthly settlement price and the Rockies swaps are settled based on the Northwest Pipeline Corporation monthly settlement price as quoted in Platt's Inside FERC. The basis swap derivatives are settled based on the differential between the NYMEX gas price and the Northwest Pipeline Corporation price.

Interest rate risk. In May 2011, we refinanced our prior revolving credit facility, which bore interest at floating rates, with our parent's revolving credit facility. At September 30, 2011, we had allocated indebtedness outstanding under our parent's revolving credit facility of $12,347 million, which bore interest at floating rates, and $24,500 million outstanding allocated under our parent's second lien credit facility, which bore interest at a fixed margin and minimum LIBOR rate of 1.50%. For the three months ended September 30, 2011, the weighted average indebtedness outstanding on our parent's revolving credit facility and second lien credit facility bore weighted average interest rates of 2.5% and 8.5%, respectively. A 1.0% increase in each of the average LIBOR and federal funds rate for the three months ended September 30, 2011 would have resulted in an estimated $[●] million increase in interest expense for the three months ended September 30, 2011.

We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. For the nine months ended September 30, 2011, production from properties operated by Bill Barrett and Newfield was sold under their marketing arrangements and accounted for approximately 45% and 40%, respectively, of our total revenue. For the three months ended September 30, 2011, production from properties operated by Bill Barrett and Newfield accounted for approximately [43]% and [30]%, respectively, of our total revenue. We sell our operated crude oil production to two marketing companies. One marketing firm accounted for 23% and 10% of our total revenue for the three and nine months ended September 30, 2011, respectively. We expect the percentage of crude oil sold under those marketing arrangements to increase over time as our operated oil production increases as a percentage of our total production. Please read "Business — Marketing and Major Customers" for further detail about our significant customers. It is possible that one or more of our customers will become financially distressed and default on their obligations to us. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our derivative instruments currently in place are lenders under our parent's credit facilities with investment grade ratings. Several of our significant customers for oil and gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements. Please read "—Contractual Obligations" and Note [●] to our consolidated financial statements included elsewhere in this prospectus for a discussion of our commitments and contingencies, some of which are not recognized in the consolidated balance sheets under GAAP.

BUSINESS

Overview

We are an independent oil and natural gas company engaged in the exploration, development, production and acquisition of oil and natural gas reserves with a primary focus on acquiring and developing oil reserves. We have accumulated approximately 162,695 net leasehold acres in the established and highly prospective Uinta Basin, approximately 94% of which are undeveloped. We are currently focused on exploration and development in the Green River and Wasatch formations, which we believe have significant resource potential and are characterized by multiple oil producing horizons with long-life reserves. As of September 30, 2011, our estimated net proved reserves were 35.1 MMBoe, approximately 23% of which were classified as proved developed and approximately 88% of which were comprised of oil. For the three and nine months ended September 30, 2011, our average net daily production from our properties was 4,172 Boe/d and 3,408 Boe/d, respectively. For the month ended October 31, 2011, our average net daily production from our properties was 4,711 Boe/d.

The Ute Indian Tribe of the Uintah and Ouray Reservation formed our parent company, Ute Energy LLC, in 2005 to participate in the exploration and development of the Tribe's mineral estate in the Uinta Basin. The Tribe partnered with leading oil and gas operators in the Uinta Basin to develop its oil and natural gas properties. In 2007, Quantum Energy Partners and Quantum Resources Management made their initial investment in our parent company, which provided our parent with the capital to accelerate operations and fund the cost of developing its properties. We were formed by our parent in 2008 to manage the oil and natural gas operations distinctly from our parent's midstream activities.

During 2010, we shifted our focus from participating primarily in non-operated positions to establishing a significant portfolio of operated acreage and growing our asset base primarily through operated drilling activities. As a part of this strategy, we hired a management team and technical personnel with significant industry and operational experience. Since our strategic shift, we have increased our operated acreage position in the Uinta Basin through an active leasing and acquisition program and we have balanced our portfolio of tribal acreage with the addition of significant interests in fee, state, federal and allotted lands. As of September 30, 2011, we have 75,420 net operated acres, which represents 46% of our total net acreage position, and we have 64,827 net acres on fee, state, federal and allotted lands, which represents 40% of our total net acreage position. Additionally, we commenced drilling of our first operated well in our Randlett project area in April 2011. We had drilled 22 gross (22 net) operated wells as of September 30, 2011 with a 100% success rate, and we operated 32% of our average net daily production for the month ended September 30, 2011.

In addition to expanding our operated acreage position, we continue to derive substantial benefits from our non-operated properties throughout the Uinta Basin. As of September 30, 2011, we have participated in 326 gross (96.9 net) non-operated wells. These wells are operated by other leading operators in the basin, including Berry Petroleum, Bill Barrett and Newfield. Our participation in non-operated project areas offers attractive return opportunities and enables us to gain additional exposure to emerging resource plays without committing all of the capital required to drill the wells during the early-stage testing and refinement of drilling and completion techniques in emerging areas. For example, our operating partners are leading the development of an emerging horizontal play targeting the Uteland Butte producing zone of the lower Green River formation. Through November 2011, we have participated in eight gross (2.25 net) horizontal Uteland Butte wells drilled by our operating partners.

Our oil and natural gas properties are divided among multiple project areas within the Uinta Basin. These project areas are described in more detail under the heading "— Our Core Project Areas" beginning on page [●] of this prospectus. The following table presents a summary of acreage, reserves, production and identified potential drilling locations for each of our project areas as of the dates, and for the periods, indicated.

	Net Acreage as of September 30, 2011	Estimated Net Proved Reserves as of September 30, 211			Average Net Daily Production (Boe/d) for the Three Months Ended September 30, 2011	Identified Potential Drilling Locations as of September 30, 2011(2)	
		MMBoe(1)	% of Total Proved Reserves	% Oil		Gross	Net
Randlett	39,351	12.9	37%	93%	925	935	844.0

Horseshoe Bend	29,281	8.4	24%	100%	301	751	523.7
Rocky Point	10,789	-	-	-	-	472	205.0
Blacktail Ridge	28,569	7.6	22%	77%	1,451	594	290.6
North Monument Butte	11,724	5.3	15%	79%	816	1,027	256.8
Bridgeland	9,883	0.5	1%	58%	458	530	185.5
Lake Canyon	30,371	0.3	1%	69%	133	1,465	366.3
Other	2,727	0.1	0%	0%	88	17	8.2
Total	162,695	35.1	100%	88%	4,172	5,791	2,680.1

(1) One Boe is equal to one Bbl of oil or six Mcf of natural gas based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(2) Please read "— Identification of Potential Drilling Locations" for more information on how we identify our potential drilling locations.

We have a multi-year inventory of development drilling and exploration projects in the Uinta Basin. We believe that the size and concentration of our acreage will allow us to efficiently grow our reserves, production and cash flow over time. As of September 30, 2011, we have identified 5,791 gross (2,680.1 net) potential drilling locations (609 gross (340.1 net) of which are proved undeveloped), targeting multiple zones in the Green River and Wasatch formations. To accelerate our drilling program, we deployed a second operated drilling rig to the basin in November 2011, and we expect to deploy a third drilling rig by mid-year 2012. We may deploy additional operated drilling rigs to the basin should drilling results, market conditions and drilling permit availability allow us to further accelerate our drilling program in the near term. As of September 30, 2011, our partners were operating four drilling rigs in our non-operated project areas.

We plan to develop our identified potential drilling locations primarily through vertical drilling and utilization of multi-stage fracture stimulation techniques. We continue to evaluate the potential for horizontal drilling to target zones such as the Uteland Butte, the Mahogany Oil Shale and the Black Shale/G-1 Lime as well as the potential for enhanced recovery techniques, such as waterfloods, to improve results and increase oil and gas recoveries.

Our total 2012 capital expenditure budget is expected to be $[●] million, consisting of:

- $[●] million for drilling and completing operated wells;
- $[●] million for drilling and completing non-operated wells;
- $[●] million for maintaining our leasehold position;
- $[●] million for constructing strategic infrastructure to support production in our core project areas; and
- $[●] million in unallocated funds for general corporate purposes.

The amount and allocation of capital we spend may fluctuate materially based on drilling results, market conditions and drilling permit availability. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Identification of Potential Drilling Locations

To identify our potential drilling locations, we analyze both our own proprietary information as well as industry data available in the public domain. Specifically, petrophysical data derived from open hole logs and cores and production data from operated and non-operated wells provide the technical basis from which we identified the potential locations. We also adjust locations for topographical issues as well as environmental and cultural concerns. Our identified potential drilling locations are scheduled out over many years, and there is no guarantee that all or even a substantial portion of these potential drilling locations will be drilled. Based on our currently projected capital expenditure budget, we estimate that we will have drilled approximately 234 gross wells on these potential locations by the end of 2012 and approximately 2,209 by the end of 2016. In addition, we are not the operator of 68% of our gross (45% net) identified potential drilling locations, and because we are not the operator of these properties we have limited control over the timing of drilling of the wells, or whether wells will be drilled at all, on these properties.

Our Competitive Strengths

We believe the following competitive strengths will allow us to successfully execute our business strategies:

- *Large, regionally focused acreage position in an established and highly prospective oil resource area.* We have a substantial and concentrated acreage position of approximately 162,695 net acres in the Uinta Basin, approximately 94% of which is undeveloped. We believe our acreage position is highly prospective, primarily for crude oil within multiple target zones of the Green River and Wasatch formations, including the Uteland Butte. The Uinta Basin has a long history of exploration and development activity with substantial remaining resource potential. According to IHS, Inc., the Uinta Basin has produced 1.3 billion Boe of crude oil and natural gas since commercial production began in the 1940s, and, according to Wood Mackenzie, the Uinta Basin has remaining recoverable reserves, defined as proved plus probable reserves, of 3.1 billion Boe.

- *Multi-year inventory of identified potential drilling locations targeting crude oil zones.* We have an inventory of 5,791gross (2,680.1 net) identified potential drilling locations in the Uinta Basin. Our drilling activity focuses on producing crude oil, with all of our identified potential drilling locations targeting crude oil zones. For the nine months ended September 30, 2011, we drilled or participated in 100 gross (45.4 net) wells with a 100% success rate. We currently plan to drill 234 gross (160.5 net) wells within our existing project areas by the end of 2012.

- *Management and technical team with extensive public company experience in resource play development.* Our senior management and technical team has a successful record of identifying, acquiring and developing resource plays and has an average of over 25 years of oil and gas industry experience, with extensive operating experience in the Rocky Mountain region and particular experience in the Uinta Basin. Our technical team includes engineers, geoscientists, landmen and regulatory specialists. Our team has enabled us to expand our asset base and successfully execute our strategic shift to growing our operated production and acreage position. In addition, our team has significant public company experience as a result of prior work for companies such as Barrett Resources Corporation, The Williams Companies, Inc., Bill Barrett and Rosetta Resources Inc.

- *Significant liquidity and financial flexibility to fund our drilling program.* Following this offering, we expect to have no debt outstanding under our new $ million revolving credit facility, with approximately $ million available for borrowing and $ million of cash on hand. We expect that the cash proceeds from this offering and funds available under our new credit facility, together with the cash flows from our operations, will be sufficient to fund our anticipated capital expenditures. Moreover, as the operator of a significant portion of our acreage position, we expect to have control over the level and pace of a significant portion of our capital expenditures as we develop our properties. To allow for more predictable cash flows in the near term, we maintain an active hedging program with an average of 3,808 bbl/d of crude oil production hedged in 2012 at a weighted average minimum price of $94.16 per bbl as of November 30, 2011.

- *Strong relationship with the Tribe.* Approximately 60% of our acreage and 62% of our net identified potential drilling locations are located on Ute tribal lands or are leased from the Tribe. Our relationship with the Tribe has been instrumental in building an asset base that includes both high growth development properties and properties with exposure to emerging Uinta Basin resource plays. Following this offering, the Tribe will own approximately % of our outstanding common stock, which we believe may give us a competitive advantage in acquiring additional mineral interests on Ute tribal lands. Moreover, we believe that our relationship with the Tribe provides us with a significant competitive advantage in securing drilling and operating permits on Ute tribal lands and otherwise working with government entities with oversight authority for oil and natural gas exploration and production on Ute tribal lands.

Our Business Strategy

Our goal is to increase stockholder value by growing our reserves and increasing our production and cash flows by executing the following strategies:

- *Focus on aggressive expansion of operated drilling activities.* We intend to aggressively drill our current operated acreage to maximize the value of our resource potential. We have 75,420 net operated acres, which are 97% undeveloped with approximately 1,844 identified potential drilling locations. We believe that the concentration and growth of our operated properties will enable us to achieve economies of scale on drilling service costs and leasehold operating expenses. Our 2012 drilling program contemplates the drilling of approximately 133 gross (116.3 net) operated wells utilizing two operated drilling rigs for the full year. We expect to deploy a third drilling rig by the middle of 2012 to support the development of our Rocky Point and Horseshoe Bend properties. We may deploy additional drilling rigs to the basin should drilling results, market conditions and drilling permit availability allow us to accelerate our drilling program in the near term.

- *Apply operating experience to enhance returns.* We are focused on the continuous improvement of our operating practices and have significant experience in converting resource opportunities into cost-effective development projects. We intend to draw on our technical team's significant experience in utilizing modern drilling and completion techniques to optimize our resource recovery in a cost efficient manner. In the near term, our primary focus will be the use of vertical drilling and multi-stage fracturing techniques to potentially enhance resource recovery, and we will continue to evaluate the effectiveness of horizontal drilling, down-spacing and waterflooding as a means to further increase resource recovery.

- *Continue to participate in drilling on non-operated leasehold acreage.* Our participation in non-operated project areas offers attractive return opportunities and enables us to gain additional exposure to emerging resource plays without committing all of the capital required to drill the wells during the early-stage testing and refinement of drilling and completion techniques. For example, our operating partners are leading the development of an emerging horizontal play targeting the Uteland Butte producing zone of the lower Green River formation. Through November 2011, we have participated in eight gross (2.25 net) horizontal Uteland Butte wells drilled by our operating partners. We plan to apply the knowledge and expertise gained from participating in the drilling and completion of these wells to target prospective horizontal Uteland Butte or other prospective horizontal zones in our operated portfolio of oil and natural gas properties. In addition, we believe that the knowledge and expertise gained through our non-operated positions will enhance our ability to continue the efficient growth of our operated acreage positions throughout the Uinta Basin.

- *Allocate capital to strategic infrastructure to support our upstream operations.* We will continue to identify and fund strategic infrastructure projects to reduce risks, increase marketing flexibility and enhance the value of our business. For example, we are installing a high pressure gas gathering system within our Randlett project area, which will connect to a pipeline system that flows to the Chipeta natural gas processing plant. We have contracted capacity on this pipeline system and have secured 25,000 Mcf/d of processing capacity at the Chipeta plant. Our Randlett gathering system will provide an outlet for associated natural gas from our oil wells, which will minimize the risk of a curtailment of oil production due to lack of takeaway capacity for produced natural gas. In addition, the gathering system will enable us to realize additional value on our future natural gas production, as this production will be gathered and transported to the Chipeta plant where it will be processed to recover marketable natural gas liquids.

- *Pursue acquisitions in areas that leverage our operating strengths.* In the near term, we intend to identify and acquire additional acreage and producing properties in the Uinta Basin, with an emphasis on increasing our operated asset base. Over time, we may selectively target additional basins in the Rocky Mountain region or other resource opportunities with characteristics similar to our existing areas of operations to leverage our operating strengths in areas outside the Uinta Basin.

Horseshoe Bend Acquisition

On November 30, 2011, we acquired approximately 29,281 net fee, state and federal acres with 751 identified potential drilling locations in Horseshoe Bend and approximately 6,062 net fee and allotted acres in Randlett with 221 identified potential drilling locations, for approximately $100 million in cash, subject to customary post-closing purchase price adjustments. This acquisition significantly increased our operated leasehold acreage position from 32% to 46%, increased our identified potential drilling locations by 20%, and increased our net fee, state, federal and allotted acres by 120%. We operate all of the approximately 6,062 net acres acquired in Randlett and substantially all of the approximately 29,281 net acres acquired in Horseshoe Bend. However, operatorship with respect to approximately 3,993 net acres in Ouray Valley remains subject to a vote of the working interest owners.

In addition to significantly increasing our operated acreage position and our inventory of undeveloped acreage, the acquisition included 50 producing wells in our Horseshoe Bend project area with 8.4 MMBoe of proved reserves as of September 30, 2011. The average net daily production from these wells was 301 Boe/d for the three months ended September 30, 2011 and 415 Boe/d for the month ended September 30, 2011.

Our Operations

Estimated proved reserves

Unless otherwise specifically identified in this prospectus, the summary data with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firms, Cawley Gillespie and Ryder Scott, in accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. In this prospectus, proved reserve estimates do not include any value for probable or possible reserves which may exist. Our estimated proved reserves for the year ended December 31, 2008 were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserve reporting in effect during such period. For a definition of proved reserves under the SEC rules for the periods ending on or after December 31, 2009 and the fiscal years ending prior to December 31, 2009, please read the "Glossary of Oil and Natural Gas Terms" beginning on page A-1 of this prospectus. For more information regarding our independent reserve engineers, please read "—Qualifications of technical persons and internal controls over reserves estimation process" below.

The table below summarizes our estimated proved reserves and related PV-10 at December 31, 2009 and 2010 and at September 30, 2011 for each of our project areas. The reserve estimates presented as of December 31, 2009 and 2010 are based on reports prepared by Cawley Gillespie and Ryder Scott, respectively. In preparing their reports, Cawley Gillespie and Ryder Scott evaluated properties representing all of our PV-10 at December 31, 2009 and 2010 under the SEC's rules applicable to such periods. The reserve estimates presented as of September 30, 2011 in the table below give effect to the Horseshoe Bend acquisition and are based on evaluations prepared by our internal reserve engineers in accordance with the SEC's rules applicable to such period. For a description of the Horseshoe Bend acquisition, please read "— Horseshoe Bend Acquisition." For more information regarding our independent reserve engineers, please read "—Qualifications of technical persons and internal controls over reserves estimation process" below. The information in the following table does not give any effect to or reflect our commodity hedges.

	As of December 31, 2009		As of December 31, 2010		As of September 30, 2011	
Project Area	**Proved Reserves (MMBoe)**	**PV-10 (in millions)(1)**	**Proved Reserves (MMBoe)**	**PV-10 (in millions)(1)**	**Proved Reserves (MMBoe)**	**PV-10 (in millions)(1)**
Randlett	0.0	$ 0.0	0.0	$ 0.0	12.9	$ 258.6
Horseshoe Bend	0.0	0.0	0.0	0.0	8.4	104.5
Rocky Point	0.0	0.0	0.0	0.0	0.0	0.0
Blacktail Ridge	2.4	5.4	4.7	55.8	7.6	63.1
North Monument Butte	1.8	14.4	3.0	35.2	5.3	56.8
Bridgeland	0.5	4.6	2.2	20.3	0.5	7.8
Lake Canyon	0.2	1.2	0.1	1.0	0.3	5.3
Other	0.1	0.2	0.1	0.3	0.1	0.2
Total	5.0	$ 25.8	10.1	$ 112.6	35.1	$ 496.4

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because as of the period presented, we were a disregarded entity for federal income tax purposes not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our equity holders. However, in connection with the closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. As a result, we will be a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following table sets forth more information regarding our estimated proved reserves at December 31, 2008, 2009 and 2010 and September 30, 2011. The information presented at September 30, 2011 gives effect to the Horseshoe Bend acquisition.

	As of December 31,			As of September 30,
	2008	2009	2010	2011
Reserve Data(1):				
Estimated proved reserves:				
Oil (MMBbls)	0.9	3.5	7.1	30.9
Natural gas (Bcf)	3.6	8.4	17.3	22.5
Natural gas liquids (MMBbls)	0.0	0.1	0.2	0.5
Total estimated proved reserves (MMBoe)	1.5	5.0	10.2	35.1
Estimated proved developed reserves:				
Oil (MMBbls)	0.8	0.9	2.5	6.7
Natural gas (Bcf)	3.4	2.8	7.1	8.0
Natural gas liquids (MMBbls)	0.0	0.0	0.1	0.2
Total estimated proved developed reserves (MMBoe)	1.4	1.4	3.7	8.2
Percent developed	96%	27%	37%	23%
Estimated proved undeveloped reserves:				
Oil (MMBbls)	0.0	2.6	4.6	24.2
Natural gas (Bcf)	0.1	5.6	10.2	14.4
Natural gas liquids (MMBbls)	0.0	0.1	0.1	0.3
Total estimated proved undeveloped reserves (MMBoe)	0.1	3.6	6.4	26.9
PV-10 (in millions)(2)	$ 14.1	$ 25.8	$ 112.6	$ 496.4
Standardized Measure (in millions)(3)	14.1	25.8	112.6	496.4

The following table sets forth the benchmark prices used to determine our estimated proved reserves from proved oil and natural gas reserves on a historical basis for the periods indicated.

	As of December 31,			As of September 30, 2011
	2008	2009	2010	
Oil and Natural Gas Prices (1):				
Oil (per Bbl)	$ 44.60	$ 61.18	$ 79.43	$ 94.50
Natural gas (per MMBtu)	$ 5.71	$ 3.87	$ 4.38	$ 4.16

(1) Benchmark prices for oil and natural gas at September 30, 2011 and at December 31, 2010 and 2009 reflect the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months, using NYMEX WTI posted prices for oil and NYMEX Henry Hub prices for natural gas. At December 31, 2008, the year-end benchmark prices for oil and natural gas reflect NYMEX WTI prices for oil and NYMEX Henry Hub prices for natural gas were used. For oil and natural gas liquids volumes, the benchmark WTI posted price is adjusted for quality, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 17%. For gas volumes, the Henry Hub spot price is adjusted for energy content, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 3%.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because as of the period presented, we were a disregarded entity for federal income tax purposes not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our equity holders. However, in connection with the

closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. As a result, we will be a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(3) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depreciation, depletion and amortization, discounted at 10% per annum to reflect timing of future cash flows. As a disregarded entity for federal income tax purposes, we are not subject to federal income taxes and thus make no provision for federal income taxes in the calculation of our Standardized Measure. In connection with the closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. Future calculations of Standardized Measure will include the effects of income taxes on future net revenues. Standardized Measure does not give effect to derivative transactions. We expect to continue to hedge a substantial portion of our future estimated production from total proved producing reserves. For further discussion of income taxes, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Estimated proved reserves at September 30, 2011, after giving effect to the Horseshoe Bend acquisition, were 35.1 MMBoe, a 244% increase from reserves of 10.2 MMBoe at December 31, 2010. At September 30, 2011 estimated proved reserves increased 25.0 MMBoe over our December 31, 2010 estimated reserves primarily due to the addition of 21.3 MMBoe of proved reserves in Randlett and Horseshoe Bend, which had no associated proved reserves as of December 31, 2010. In Randlett, we commenced operated drilling and production during 2011 and had 12.9 MMBoe of proved reserves as of September 30, 2011. We acquired our Horseshoe Bend properties on November 30, 2011 and had pro forma proved reserves of 8.4 MMBoe as of September 30, 2011. The remaining increase was due to the drilling activities of our operating partners and higher oil price assumptions at September 30, 2011. Our commodity price assumption for oil increased $15.07 per Bbl to $94.50 per Bbl as of September 30, 2011 from $79.43 per Bbl at December 31, 2010. Our proved developed producing reserves increased 4.5 MMBoe, or 122%, to 8.2 MMBoe as of September 30, 2011 from 3.7 MMBoe as of December 31, 2010 due to increased operated and non-operated drilling activity and our increased oil price assumption. Our proved undeveloped reserves increased to 26.9 MMBoe as of September 30, 2011 from 6.4 MMBoe as of December 31, 2010 primarily due to recording offset undeveloped locations in our Randlett project area and our acquired Horseshoe Bend project area, which were added in 2011.

Estimated proved reserves at December 31, 2010 were 10.2 MMBoe, a 104% increase from reserves of 5.0 MMBoe at December 31, 2009. Our 2010 estimated proved reserves increased 5.2 MMBoe over our 2009 estimated reserves due to our participation in increased drilling activity by our operating partners during 2010 and higher oil price assumptions at December 31, 2010. Our commodity price assumption for oil increased $18.25 per Bbl to $79.43 per Bbl at December 31, 2010 from $61.18 per Bbl at December 31, 2009. Our proved developed reserves increased 2.4 MMBoe, or 184%, to 3.7 MMBoe as of December 31, 2010 from 1.4 MMBoe as of December 31, 2009 due to increased non-operated drilling activity. Our proved undeveloped reserves increased to 6.4 MMBoe as of December 31, 2010 from 3.6 MMBoe as of December 31, 2009 due to the recognition of additional proved undeveloped drilling locations as a result of our non-operated drilling activity.

Estimated proved reserves at December 31, 2009 were 5.0 MMBoe, a 403% increase from reserves of 1.0 MMBoe at December 31, 2008. Our estimated proved reserves increased 3.5 MMBoe to 5.0 MMBoe as of December 31, 2009 from 1.5 MMBoe as of December 31, 2008 due primarily to the effect of higher oil price assumptions on proved undeveloped reserves. Our commodity price assumption for oil increased $16.58 per Bbl to $61.18 per Bbl at December 31, 2009 from $44.60 per Bbl at December 31, 2008. Our proved developed producing reserves remained at 1.4 MMBoe as of both December 31, 2009 and December 31, 2008 as a result of natural production decline offsetting production from new drilling activity. Our proved undeveloped reserves increased from 0.1 MMBoe at December 31, 2008 to 3.6 MMBoe at December 31, 2009 due to the addition of proven offset drilling locations as a result of higher oil price assumptions.

The PV-10 of our estimated proved reserves at September 30, 2011 was $496.4 million, a 341% increase from PV-10 of $112.6 million at December 31, 2010. Our PV-10 of estimated proved reserves at September 30, 2011 increased $383.7 million over the PV-10 at December 31, 2010 due to the commencement of operated drilling activities in Randlett, acquisitions, including Horseshoe Bend, ongoing drilling activities by our operating partners and higher oil price assumptions.

The PV-10 of our estimated proved reserves at December 31, 2010 was $112.6 million, a 337% increase from PV-10 of $25.8 million at December 31, 2009. Our PV-10 of estimated proved reserves at December 31, 2010 increased $86.8 million over the PV-10 at December 31, 2009 due to higher oil prices and increased non-operated developmental drilling activity as a result of the higher oil prices.

The following table sets forth the estimated future net revenues, excluding derivatives contracts, from proved reserves, the present value of those net revenues (PV-10), and the expected benchmark prices used in projecting net revenues at December 31, 2008, 2009 and 2010 and September 30, 2011 (in millions). The information presented at September 30, 2011 gives effect to the Horseshoe Bend acquisition.

	As of December 31,			As of September 30, 2011
	2008	2009	2010	
Future net revenues	$ 10,345	$ 56,800	$ 190,394	$ 1,078,432
Present value of future net revenues:				
Before income tax (PV-10)(1)	8,597	25,590	112,608	496,428
After income tax (Standardized Measure)	8,597	25,590	112,608	496,428
Benchmark oil price(2)($/Bbl)	$ 44.60	$ 61.18	$ 79.43	$ 94.50

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because as of the period presented, we were a disregarded entity for federal income tax purposes not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our equity holders. However, in connection with the closing of this offering, we will convert into a corporation that will be a taxable entity for federal income tax purposes. As a result, we will be a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Benchmark prices for oil and natural gas at September 30, 2011 and at December 31, 2010 and 2009 reflect the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months, using NYMEX WTI posted prices for oil and NYMEX Henry Hub prices for natural gas. At December 31, 2008, the year-end benchmark prices for oil and natural gas reflect NYMEX WTI prices for oil and NYMEX Henry Hub prices for natural gas were used. For oil and natural gas liquids volumes, the benchmark WTI posted price is adjusted for quality, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 17%. For gas volumes, the Henry Hub spot price is adjusted for energy content, transportation fees and regional price differentials. The adjustment varies by project area, and the prices used to calculate estimated reserves as of September 30, 2011 reflected a weighted average discount from benchmark prices of 3%.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2008 are based on costs and prices in effect at December 31, 2008, without giving effect to derivative transactions, and are held constant throughout the life of the properties. Such calculations at December 31, 2009 and 2010 and September 30, 2011 are based on costs in effect at December 31, 2009 and 2010 and September 30, 2011, respectively, and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the periods January 2009 through December 2009, January 2010 through December 2010 and October 2010 through September 2011, respectively, without giving effect to derivative transactions, and are held constant throughout the life of the properties. We cannot assure you that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Reserve estimates

Our estimated reserves and related future net revenues and PV-10 at September 30, 2011 are based on evaluations prepared by our internal reserve engineers in accordance with Society of Petroleum Engineering (“SPE”) principles and definitions and current guidelines established by the SEC. Our estimated reserves and related future net revenues and PV-10 at December 31, 2010 are based on a report prepared by Ryder Scott in accordance with SPE engineering and evaluation principles and definitions and current guidelines established by the SEC, and our estimated reserves and related future net revenues and PV-10 at December 31, 2009 and 2008 are based on reports prepared by Cawley Gillespie in accordance with SPE engineering and evaluation principles and definitions and current guidelines established by the SEC. Ryder Scott and Cawley Gillespie are independent reserve engineers. Copies of the reports of Ryder Scott and Cawley Gillespie have been filed as exhibits to the registration statement containing this prospectus.

Technology used to establish proved reserves

Under the SEC's rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, Ryder Scott, Cawley Gillespie and our internal reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps, available downhole and production data, seismic data, and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques. For wells and locations targeting the Green River and Wasatch formations, the evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the Green River and Wasatch formations were used to estimate original oil in place.

Qualifications of technical persons and internal controls over reserves estimation process

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated our proved reserve information at December 31, 2010, and Cawley Gillespie, our former independent reserve engineers, estimated our proved reserve information at December 31, 2009 and 2009. The technical persons responsible for preparing the reserves estimates presented herein at December 31, 2010, 2009 and 2008 meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserves estimation process. Robert A. Gardner, our Engineering Manager, and James T. Jaggers, our Reservoir Engineer, are the technical personnel within the company primarily responsible for overseeing the preparation of our reserves estimates. Our Engineering Manager has over 20 years of industry experience with positions of increasing responsibility in engineering and reserve evaluations and holds both a Bachelor of Science degree and Master of Science degree in mechanical engineering. Our Reservoir Engineer has over six years of industry experience, holds a Bachelor of Science degree in petroleum engineering and is a Licensed Petroleum Engineer. Our Engineering Manager reports directly to our Chief Operating Officer.

Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. Our internal professional staff works closely with Ryder Scott to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide Ryder Scott other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our Chief Operating Officer with representatives of our independent reserve engineers and internal technical staff. Following the consummation of this offering, we anticipate that our Audit Committee will conduct a similar review on an annual basis.

Production, revenues and price history

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth summary data with respect to our production results, average sales prices and production costs on a historical and pro forma basis for the periods presented. The information presented for the nine and three months ended September 30, 2011 gives effect to the Horseshoe Bend acquisition as if it had occurred on January 1, 2011. For additional information on price calculations, please read "Management's Discussion and Analysis of Financial Condition and Results of Operation."

	Year Ended December 31,			Nine Months Ended September 30,	Pro Forma	
	2008	2009	2010	2010	Nine Months Ended September 30, 2011	Three Months Ended September 30, 2011
Operating data:						
Net production volumes:						
Oil (MBbls)	148.8	164.9	510.9	342.4	708.3	301.6
Natural gas (MMcf)	636.2	571.3	1,275.6	835.8	1,196.1	437.7
Natural gas liquids (MBbls)	7.6	6.2	8.8	7.0	22.7	9.3
Oil equivalents (MBoe)	262.4	266.3	732.3	488.7	930.3	383.8
Average daily production (Boe/d)	719	730	2,006	1,790	3,408	4,172
Average sales prices:						
Oil, without realized derivatives (per Bbl)	$ 62.07	$ 42.43	$ 67.64	$ 67.36	$ 69.34	$ 75.45
Oil, with realized derivatives(1) (per Bbl)	62.38	47.86	66.66	65.57	70.88	77.23
Natural gas, without realized derivatives (per Mcf)	7.40	3.48	4.11	4.26	4.76	4.56
Natural gas, with realized derivatives (per Mcf)	7.28	3.48	3.55	3.84	4.18	5.06
Natural gas liquids (per Bbl)	95.55	38.93	56.95	55.71	73.88	72.94
Costs and expenses (per Boe of production):						
Lease operating expenses	8.04	6.36	6.23	5.12	7.94	8.04
Production taxes	3.75	6.51	3.95	4.76	3.36	4.28
Gathering and transportation expenses	3.05	4.18	3.11	3.16	3.85	4.91
Depletion, depreciation and amortization	29.69	22.14	18.73	17.50	21.54	21.21

(1) Realized prices include realized gains or losses on cash settlements for our commodity derivatives.

The following table sets forth information regarding our average daily production during the year ended December 31, 2010, the nine months ended September 30, 2011 and the three months ended September 30, 2011.

Information presented for the three and nine months ended September 30, 2011 gives effect to the Horseshoe Bend acquisition.

	Average Daily Production for the Year Ended December 31, 2010				Average Daily Production for the Nine Months Ended September 30, 2011				Average Daily Production for the Three Months Ended September 30, 2011			
	Oil (Bbls)	NGL (Bbls)	Gas (Mcf)	Boe	Oil (Bbls)	NGL (Bbls)	Gas (Mcf)	Boe	Oil (Bbls)	NGL (Bbls)	Gas (Mcf)	Boe
Randlett	–	–	–	–	326	–	112	345	869	–	334	925
Horseshoe Bend	–	–	–	–	281	–	–	281	301	–	–	301
Rocky Point	–	–	–	–	–	–	–	–	–	–	–	–
Blacktail Ridge	595	–	1,087	777	975	68	1,296	1,259	1,112	86	1,521	1,451
North Monument Butte	431	14	843	585	618	6	1,073	803	651	5	960	816
Bridgeland	319	5	688	439	328	2	1,170	525	256	1	1,204	458
Lake Canyon	20	4	328	79	48	6	292	102	77	7	297	133
Other	33	2	548	127	18	1	438	92	12	2	443	87
Total	1,676	24	3,495	2,282	2,594	83	4,381	3,408	3,278	101	4,758	4,172

Productive wells

The following table presents the total gross and net productive wells by project area and by oil or gas completion as of September 30, 2011. The information in the following table gives effect to the Horseshoe Bend acquisition.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Randlett	27	27.0	0	0.0	27	27.0
Horseshoe Bend	46	31.2	4	2.7	50	33.9
Rocky Point	0	0.0	0	0.0	0	0
Blacktail Ridge	43	16.6	0	0.0	43	16.6
North Monument Butte	166	41.5	0	0.0	166	41.5
Bridgeland	82	28.7	0	0.0	82	28.7
Lake Canyon	19	5.0	0	0.0	19	5.0
Other	1	0.5	5	0.9	6	1.4
Total	384	150.5	9	3.6	393	154.1

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of September 30, 2011 for each of our project areas. The information in the following table gives effect to the Horseshoe Bend acquisition.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Randlett	1,282	1,165	44,415	38,186	45,697	39,351
Horseshoe Bend	2,000	1,509	42,277	27,774	44,277	29,281
Rocky Point	0	0	26,613	10,789	26,613	10,789
Blacktail Ridge	7,407	3,459	53,767	25,110	61,174	28,569
North Monument Butte	6,720	1,680	40,178	10,044	46,898	11,724
Bridgeland	4,359	1,148	33,165	8,735	37,524	9,883
Lake Canyon	2,160	540	119,326	29,831	121,486	30,371
Other	636	146	6,486	2,579	7,122	2,727
Total	24,564	9,647	366,227	153,048	390,791	162,695

Acreage expirations

The following table sets forth tribal and fee, state federal and allotted net acreage as of September 30, 2011 that will expire over the course of the next three years unless production is established within the spacing units covering the acreage or extension payments are paid prior to the expiration dates:

	Expiring 2012		Expiring 2013		Expiring 2014	
	Tribal	**Fee(1)**	**Tribal**	**Fee(1)**	**Tribal**	**Fee(1)**
Randlett	0	1,653	0	3,409	0	7,339
Horseshoe Bend(2)	0	0	0	0	0	0
Rocky Point	0	120	0	375	0	24
Blacktail Ridge	21,289	1,026	0	1,216	0	554
North Monument Butte	8,416	0	0	0	0	0
Bridgeland	0	0	3,044	1,504	0	2,180
Lake Canyon	0	0	0	0	31,118	0
Other	0	0	0	0	0	0
Total	29,705	2,799	3,044	6,504	31,118	10,097

(1) Includes acreage on fee, state, federal and allotted lands.

(2) Held by production.

The EDAs governing our exploration and development on tribal lands provide for an initial five year term and generally require that we or our operating partners commence drilling of a minimum number of obligation wells during each year within the five year term. So long as we continue to satisfy the minimum obligation well requirements, we will have the option to extend each agreement for two additional five year terms. The minimum annual obligation well requirement continues in effect during each five year extension and allows us to continue to drill and earn leases on lands for which leases have not yet been earned. If we drill obligation wells in excess of the minimum obligation well requirement for a certain year within a term of an EDA, those wells are generally carried forward and are applied to future minimum obligation well requirements in the next year. Each extension of an EDA requires an extension payment equal to the unearned net acres multiplied by the initial bonus amount per acre stated in the EDA. Once a well has been completed or plugged and abandoned on a section, a lease is earned with respect to that section. Earned leases have a five year primary term, which can be extended if commercial production continues. In general, we earn leases on each 640 acre section of tribal land after drilling a well in a section, except in Rocky Point where the leases were issued upon signing the EDA. As of September 30, 2011, we had 21,289 net acres expiring in Blacktail Ridge in 2012, 8,416 net acres expiring in North Monument Butte in 2012 and 3,044 net acres expiring in Bridgeland in 2013 with two five year extension periods available for each EDA, and we had 31,118 net acres expiring in Lake Canyon in 2014 with one five year extension period available.

With respect to our properties on fee, state, federal and allotted lands, many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities, or if we negotiate extensions to the leases with the respective mineral owners. We will attempt to drill wells on expiring tracts of land or negotiate extensions based on our strategic priorities and well drilling schedules.

While we may attempt to secure a new lease upon the expiration of certain of our fee, state, federal and allotted acreage, there are some third-party leases that may become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date. We have options to extend some of these leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. Our leases on fee, state, federal and allotted lands are mainly fee leases with three to five years of primary term. We believe that these leases are similar to our competitors' fee lease terms as they relate to primary term and reserve royalty interests.

Drilling activity

The following table summarizes our drilling activity for years ended December 31, 2008, 2009 and 2010 and the nine months ended September 30, 2011. Gross wells reflect the sum of all wells in which we own an interest.

Net wells reflect the sum of our working interests in gross wells. Information presented for the nine months ended September 30, 2011 gives effect to the Horseshoe Bend acquisition.

	2008		2009		2010		Nine Months Ended September 30, 2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells								
Oil	50	18.8	19	6.1	155	47.1	97	44.6
Gas	0	0	0	0	0	0	0	0
Dry	1	0.5	1	0.3	0	0	0	0
Total development wells	51	19.3	20	6.4	155	47.1	97	44.6
Exploratory wells								
Oil	0	0	0	0	0	0	3	0.9
Gas	0	0	0	0	0	0	0	0
Dry	0	0	0	0	0	0	0	0
Total exploratory wells	0	0	0	0	0	0	3	0.9
Total wells	51	19.3	22	6.4	155	47.1	100	45.5

Our drilling activity has increased each year since our inception. There was relatively little drilling activity in our project areas in 2009 due to low commodity prices. Drilling activity by our non-operated partners increased significantly in 2010 due to an increase in oil prices. Drilling further increased in 2011 as a result of the commencement and expansion of our operated activities in 2011.

For the three years ended December 31, 2010, we had a total of 2 gross (0.8 net) developmental wells that were deemed dry wells. As of September 30, 2011, there were 13 gross (7.8 net) development wells and no gross or net exploratory wells in the process of drilling or completion. For the nine months ended September 30, 2011, we drilled or participated in 87 gross (37.7 net) wells with a 100% success rate.

Our core project areas

We have interests in seven core project areas which expose us to a diverse portfolio of geologic targets across the Uinta Basin. Historically, we maintained non-operated positions with leading operators in the basin, but we shifted focus in the middle of 2010 to acquiring and developing operated assets. We are the operator in three project areas – Randlett, Horseshoe Bend and Rocky Point. We hold a 100% working interest in Randlett, and we commenced operated drilling activities in Randlett in April 2011. We operate almost all of Horseshoe Bend with an average working interest of 66%. We jointly operated Rocky Point with Newfield and have a 75% working interest in the township we operate and a 30% working interest in the townships operated by Newfield.

In addition to our operated activities, we continue to derive substantial benefits from our non-operated positions throughout the Uinta Basin. As of September 30, 2011, we have participated in 326 gross (96.9 net) non-operated wells. We believe our non-operated positions complement our total portfolio of oil and natural gas properties in the Uinta Basin, even as we continue to grow our operated acreage positions.

As of September 30, 2011, we had 35.1 MMboe of proved reserves with an extensive inventory of drilling locations throughout the Uinta Basin. Our substantial, extensive acreage position of approximately 162,695 net acres is largely undeveloped.

Randlett

We operate all of our properties in our Randlett project area and have approximately 39,351 net leasehold acres with an average 86% working interest. We acquired our initial acreage in Randlett in December 2010 and commenced drilling activities in April 2011. As of September 30, 2011, we had drilled a total of 22 wells, with 18 wells completed and producing and four wells awaiting completion. All of our wells drilled in Randlett have been vertically drilled wells targeting the Green River formation, and we expect to have commenced drilling three wells targeting the Wasatch formation by the end of 2011.

We have completed all of our Randlett wells in the Uteland Butte zone of the Green River formation, which is one of several zones we currently complete in our vertical drilling program. We believe this area may also be prospective for a horizontal drilling program targeting the Uteland Butte zone. In addition, we anticipate implementing a pilot waterflood program as part of our 2012 capital expenditure budget. Other operators are currently utilizing this secondary recovery technique in nearby fields.

Horseshoe Bend

We acquired our Horseshoe Bend properties in November 2011. We operate substantially all of our Horseshoe Bend properties, and have approximately 29,281 net leasehold acres with an average working interest of 66% and 50 gross (33.9 net) producing wells. Operatorship with respect to approximately 3,993 net leasehold acres in Ouray Valley remains subject to a vote of the working interest owners. The Horseshoe Bend project area abuts the northwest corner of Randlett and represents a substantial expansion of our operated leasehold and drilling inventory. We plan to commence operated drilling activities in this area during the second half of 2012, primarily targeting the Green River and Wasatch formations with vertically drilled wells. We believe this area may also be prospective for a horizontal drilling program targeting the Black Shale/G-1 Lime and Uteland Butte zones of the Green River formation and provide additional opportunities for future waterflooding.

Rocky Point

We operate 50% of our approximately 10,789 net leasehold acres in the Rocky Point project area, and Newfield operates the remaining 50%. Our operated leasehold acres are adjacent to the western boundary of Randlett. We hold a 75% working interest in our operated position and a 30% working interest in our non-operated position. We expect to commence drilling in Rocky Point by mid-year 2012 with our initial drilling program primarily targeting the lower Green River and Wasatch formations.

Blacktail Ridge

We have a non-operated interest in approximately 28,569 net leasehold acres in our Blacktail Ridge project area. Our working interests in our Blacktail Ridge wells are typically either 25% or 50%, depending on participation in prior wells. Bill Barrett operates our Blacktail Ridge acreage position and has historically drilled vertical wells primarily targeting the Wasatch formation. We believe this area may also be prospective for a horizontal drilling program targeting the Uteland Butte and Black Shale zones. We participated in Bill Barrett's first horizontal well in Blacktail Ridge targeting the Uteland Butte zone, which was completed in November 2011.

North Monument Butte

We hold a 25% working interest covering approximately 11,724 net leasehold acres in the North Monument Butte project area. Newfield operates North Monument Butte, and the wells in this project area primarily target the Green River formation. Newfield recently began testing the deeper Wasatch formation. We believe North Monument Butte provides additional opportunities for both horizontal drilling of multiple zones and waterflooding of the Green River formation to increase recovery of reserves.

Bridgeland

We hold a 35% working interest covering approximately 9,883 net leasehold acres in the Bridgeland project area. Newfield operates Bridgeland, and the wells in this project area primarily target the Green River formation. Newfield is currently testing the Wasatch formation.

Lake Canyon

We hold a 25% working interest covering approximately 30,371 net leasehold acres in the Lake Canyon project area. Bill Barrett and Berry Petroleum operate Lake Canyon, and the wells in this project area primarily target the Green River and Wasatch formations. The operators are evaluating the emerging horizontal Uteland Butte play in Lake Canyon. To date, we have participated in five gross (1.25 net) horizontal Uteland Butte wells drilled by Bill Barrett and two gross (0.50 net) horizontal Uteland Butte wells drilled by Berry Petroleum.

Other

Our other project areas represent a combined 2,727 net leasehold acres in various areas throughout the Uinta Basin which are 53% operated by us.

For more information on our reserves, operations and operating areas, please read "Business — Our Operations."

Motivated management team with proven Uinta Basin experience

Our senior management and technical team is led by Joseph N. Jaggers, an industry veteran with over 30 years of experience managing oil and gas operations. Mr. Jaggers has significant experience operating in the Rocky Mountains in both conventional and unconventional resources. Most recently, Mr. Jaggers served as President and Chief Operating Officer of Bill Barrett. Prior to that, he served as Regional Vice President - Exploration and Production for The Williams Companies, Inc. and as President and Chief Operating Officer for Barrett Resources Corporation. Mr. Jaggers has a long record of achieving production and reserve growth and has operational experience in many basins of the Rocky Mountain region, including the Uinta basin.

Mr. Jaggers leads a highly experienced and well-rounded management team with deep engineering, geosciences, land, environmental and financial capabilities. The team's top executives represent over 150 years of combined industry experience. Our senior management team has extensive expertise in the oil and gas industry as a result of prior work for companies such as Barrett Resources Corporation, Bill Barrett, The Williams Companies, Inc., and Rosetta Resources Inc. Our senior management and technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in other North American and international basins. Specifically, our Chief Executive Officer, Chief Operating Officer and other of our executive officers were involved in the acquisition, operation or execution of a number of successful resource conversion plays with specific experience in the Rocky Mountain Region.

Marketing and major customers

We principally sell our oil and natural gas production to marketers and other purchasers that have access to nearby refining facilities. Our oil is primarily transported by truck to refiners in the Salt Lake City area. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, please read "Risk Factors — There is limited transportation and refining capacity for our yellow and black wax crude oil, which may limit our ability to sell our current production or to increase our production."

For the nine months ended September 30, 2011, production from properties operated by Bill Barrett and Newfield accounted for approximately 45% and 40%, respectively, of our total revenue and were sold under their marketing arrangements. For the three months ended September 30, 2011, production from properties operated by Bill Barrett and Newfield accounted for approximately 43% and 30%, respectively, of our total revenue. We sell our operated crude oil production to two marketing companies. One marketing firm accounted for 10% and 23% of our total revenue for the nine and three months ended September 30, 2011, respectively. Our crude oil marketing firms have capacity arranged with four of the five refiners in the Salt Lake City area.

With respect to our operated production, we sell all of our oil directly at the wellhead at prevailing market prices under contracts that normally provide for us to receive a market based price, which incorporates regional differentials that may include, but are not limited to, transportation costs and adjustments for product quality. Our production is dedicated to the marketing firms based on acreage dedications. One of our oil marketing contracts extends through November 30, 2012 and the other extends through December 31, 2014. Furthermore, we do not currently have any material oil and natural gas delivery commitments.

Crude oil produced and sold in the Uinta Basin has historically sold at a discount to the price quoted for West Texas Intermediate (WTI) crude oil due to transportation costs, takeaway capacity and gravity and quality of the crude oil we produce. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available transportation and refining capacity in the area or due to market shocks. The last such period was late 2008 through early 2009 when oil prices declined significantly.

Since most of our oil and natural gas production is sold under market based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, the condition of the United States economy, foreign imports, political conditions in other oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries, and domestic government regulation, legislation and policies. Please read “Risk Factors— A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.” Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flows. Please read “Risk Factors— If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.”

Although we are not currently experiencing any significant involuntary curtailment of our oil or natural gas production, market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please read “Risk Factors— There is limited transportation and refining capacity for our yellow and black wax crude oil, which may limit our ability to sell our current production or to increase our production.”

Title to Properties

Tribal Lands

We acquire our mineral interests from the Tribe through our EDAs, which have the essential attributes of a conventional oil and gas lease. Much like a conventional oil and gas lease, an EDA creates an operating interest in the Tribe’s minerals, has a primary term, requires payment of initial lease bonuses, royalties and rentals, reserves to the mineral owner the right to take royalty production in kind, and requires the operator to undertake all the exploration and production risks as to capital and operating costs. Like a conventional oil and gas lease, an EDA grants the operator an interest in real property to enter the lands and conduct exploration and production activities, as well as rights to obtain permits for surface use and infrastructure required to support exploration, development and production. An EDA represents a recordable interest in real estate under Utah law which can be collateralized and made subject to a deed of trust for purposes of financing. Under federal regulations, an EDA is classified as a lease that requires approval by the Tribe and the Bureau of Indian Affairs (the “BIA”).

Our EDAs provide for an initial five year primary term and generally require that we or our operating partners commence drilling of a minimum number of obligation wells during each year within the five year primary term. So long as we continue to satisfy the minimum obligation well requirements, our EDAs provide the option to extend the initial primary term for two additional five year terms. The minimum obligation well requirement continues in effect during each five year extension and allows us to continue to drill and earn leases on lands for which leases have not yet been earned. If we drill obligation wells in excess of the minimum obligation well requirements for a certain year within a term of an EDA, those wells are generally carried forward and are applied to future minimum obligation well requirements in the next year. Once a well has been completed or plugged and abandoned on a section, a lease is earned with respect to that section. Earned leases have a five year primary term, which is extended if commercial production continues. In general, we earn leases on each 640 acre section on tribal land after drilling a well in that section, except in Rocky Point where the leases were issued upon the signing of the EDA. Each of our EDAs and leases has been approved by the Tribe, the Ute Distribution Corporation (the “UDC”) and the BIA. Our EDAs and our leases are enforceable in Utah federal courts pursuant to a limited waiver of sovereign immunity found in each EDA.

Fee, State, Federal and Allotted Lands

Ute Energy has obtained federal oil and gas leases from the Bureau of Land Management (the “BLM”) on minerals owned by the United States, state oil and gas leases from the Utah State Institutional Trust Lands Administration for minerals owned by the State of Utah, tribal oil and gas leases from the BIA for individual Ute tribal “allottees” who own their minerals separately from the Tribe on lands previously allotted to Ute tribal members, and oil and gas leases from non-tribal individuals who own their minerals in fee simple. The leases are generally on standardized lease forms from the BLM, the BIA and the State of Utah and on various versions of lease forms from private owners. Title is documented by review of the records of the BLM, BIA and the State of Utah and through detailed record checks by experienced oil and gas lease field landmen in the county courthouse or the appropriate governmental office. Prior to drilling a well on any given tract of land covered by an oil and gas lease, title is confirmed and documented via a thorough review of all documents that have historically been recorded against the tract in the records of the county or appropriate governmental office by a licensed title attorney who prepares a drilling title opinion. The drilling title opinion confirms the mineral ownership, the validity of the oil and gas leases covering the mineral interest as well as the current owner of the oil and gas leases. These oil and gas leases provide for the granting of a present interest in real property to us. These leases allow us to enter the subject lands and conduct exploration and production activities, and provide us rights to obtain permits for surface infrastructure required to support exploration, development and production.

Please read “Risk Factors — We may incur losses as a result of title defects in the properties in which we invest.”

Seasonality

Winter weather conditions can have an adverse impact on takeaway capacity available for the oil and natural gas we produce. Certain lease stipulations can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations during certain times of the year. In addition, in certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties and the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please read “Risk Factors — Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel. In addition, because we are a relatively small company, we may be disproportionately affected by adverse operational, financial and other events in the ordinary course of our business.”

Laws and Regulations Pertaining to Oil and Gas Operations on the Uintah & Ouray Reservation

General. Laws and regulations pertaining to oil and gas operations on Reservation lands derive from both Ute tribal law and federal law, including federal statutes, regulations and court decisions, generally referred to as federal Indian law.

The federal trust responsibility. The federal government has a general trust responsibility to Native American tribes regarding lands and resources that are held in trust for such tribes. Various federal agencies within the U.S. Department of the Interior, particularly the BIA, the BLM and the Office of Natural Resources Revenue, assist in the performance of this trust responsibility. Together with the applicable tribe, these federal agencies promulgate and enforce laws, regulations and/or other approval requirements pertaining to oil and natural gas operations on Native American tribal lands. These legal requirements may include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment contactor preferences and numerous other matters. The trust responsibility may be a consideration in courts’ resolution of disputes regarding Native American trust lands and the development of oil and gas resources on Native American reservations. Courts may consider the compliance of the Secretary of the U.S. Department of the Interior ("Interior Secretary") with trust duties in determining whether leases, rights-of-way, or contracts relative to tribal land are valid and enforceable.

Tribal sovereignty and dependent status. The United States Constitution vests in Congress the power to regulate the affairs of Native American tribes. Native American tribes hold a sovereign status that allows them to manage their internal affairs, subject to the ultimate legislative power of Congress. Tribes are therefore often described as domestic dependent nations, retaining all attributes of sovereignty that have not been removed by Congress. Retained sovereignty includes the authority and power to enact laws and safeguard the health and welfare of the tribe and its members and the ability to regulate commerce on the reservation. In many instances, tribes have the inherent power to levy taxes and have been delegated authority by the United States to administer certain federal health, welfare and environmental programs.

Because of their sovereign status, Native American tribes also enjoy sovereign immunity from suit and may not be sued in their own courts or in any other court absent Congressional abrogation or a valid tribal waiver of such immunity. The United States Supreme Court has ruled that for a Native American tribe to waive its sovereign immunity from suit, such waiver must be clear, explicit and unambiguous. Even when sovereign immunity has been effectively waived, a tribal court is, in certain instances, the only court that has jurisdiction to adjudicate disputes involving a tribe, tribal lands or resources or business conducted on tribal lands or with tribes.

The Tribe is a federally recognized Indian tribe organized under the Indian Reorganization Act of 1934. The Uintah Valley Reservation was established by executive order in 1861 and the Uncompahgre Reservation was established by executive order in 1882. Under the Indian Reorganization Act of 1934 the Ute Bands adopted a constitution and the two separate reservations were consolidated into one reservation to include the exercise of jurisdiction over all areas within the newly established Uintah & Ouray Reservation with the exception of what later came to be known as the "Hagen" lands, which are identified as those lands that were opened to non-Indian settlement under the Homestead Act. As a sovereign nation, the Tribe establishes all policies regarding its energy state and is responsible for the implementation and coordination of the federal government's policies which affect the mineral development activities on the Reservation. The Reservation is subject to the joint management process set forth at 25 C.F.R. Part 217. The execution of mineral agreements by the Tribe and the UDC is conducted in accordance with the Ute Partition and Termination Act of 1954.

There are slightly more than 3,100 Ute tribal members, with the majority of the members living on the Reservation. Pursuant to the Tribe's constitution, the Tribe is governed by a six-member Business Committee. The Tribe represents the merger of three Ute bands: the White River, the Uncompahgre and the Uintah. Each band elects two members to the tribal Business Committee and each member serves a term of four years. Elections are staggered to provide for one representative of each band to be elected every two years. The Tribal Chairman and Vice Chairman are selected from and appointed by the Business Committee members.

All Ute tribal EDAs to which we are a party have been approved by the United States Department of the Interior and are intended to satisfy all legal provisions that the Department of the Interior administers, including those under the Indian Mineral Development Act of 1982. Jurisdictional remedies have been made under and construed in accordance with federal law, and to the extent not governed by federal law, the law of the State of Utah. Pursuant to all of our EDAs, should the law differ between federal Circuit Courts of Appeals, the law of the Court of Appeals for the Tenth Circuit shall control. Nothing in the EDAs is construed to limit the sovereign authority of the Tribe to regulate activities conducted on Ute tribal Lands.

Federal approvals of certain transactions regarding tribal lands. Under current federal law, the Interior Secretary (or the Interior Secretary's appropriate designee) must approve any contract with a Native American tribe that encumbers, or could encumber, for a period of seven years or more, (1) lands owned in trust by the United States for the benefit of a Native American tribe or (2) tribal lands that are subject to a federal restriction against alienation. Failure to obtain such approval, when required, renders the contract void.

Some of our right-of-ways and assignments of the same to us have been approved by the Interior Secretary, and others are in various stages of application for renewal and/or approval. It is common for these approvals and/or renewals to take an extended period of time, but such approvals and/or renewals are routine and we believe that all required approvals and/or renewals will be obtained in due course.

Federal management and oversight. Pursuant to the federal trust relationship with Native American tribes, the BIA exercises oversight of certain matters on the Reservation pertaining to health, welfare and trust assets of the Tribe. The BIA must approve all leases, rights-of-way, applications for permits to drill, seismic permits and other permits and agreements relating to development of oil and gas resources held in trust for the Tribe. While we have been successful in facilitating the receipt of approvals in a timely manner from the BIA, such future receipt of approvals, or receipt of such approvals in a timely manner is not guaranteed and thus obtaining such approvals in the future could result in delays or even an inability to partially or fully develop the our EDAs.

The Tribe's Energy and Minerals Department. The day-to-day operation of the Tribe's minerals program, including the initial negotiation of agreements, applications for approval of assignments, exercise of tribal preferential rights and most other permits and licenses relating to oil and gas development, is managed by the professional staff of the Tribe's Energy and Minerals Department. The Tribe's Business Committee typically defers to the Energy and Minerals Department in decisions to approve leases and other agreements relating to oil and gas resources held in trust for the Tribe. While we have been successful thus far in facilitating timely action and favorable recommendations from the Energy and Minerals Department for our operations, such timeliness is not guaranteed and obtaining future approvals may cause delays in developing the properties covered by our EDAs.

Taxation by the Tribe. In certain instances, a single event or transaction may be taxable at each of the federal, state and Tribe levels. State taxes are rarely applicable within the Reservation except as authorized by Congress or when the application of such taxes does not adversely affect the interests of the Tribe. Federal taxes of general application are applicable within the Reservation, unless specifically exempted by federal law. We pay severance tax to the Tribe pursuant to Tribal Ordinance 88-07 at a rate of 10% per barrel of oil equivalent based on the wellhead value of production after a twelve month first production exemption. The severance tax is reduced 50% on wells with twelve months of average production below a threshold depending on well depth.

Royalties from production on Ute tribal lands. Under our agreements and leases with the Tribe, we pay royalties to the Tribe and the UDC. The Tribe is entitled to take its royalties in kind, but it currently does not. The Office of Natural Resources Revenue of the United States Department of the Interior has the responsibility for managing and overseeing royalty payments to the Tribe and has the right to audit such royalty payments.

Ute Tribal Employment Rights Ordinance. The Tribe's Business Committee has enacted the Ute Tribal Employment Rights Ordinance 11-002 ("UTERO"), which requires preferential hiring of Ute tribal members and other Native Americans by non-governmental employers operating within the boundaries of the Reservation. UTERO requires employers on Reservation lands to give preference in hiring to Ute tribal candidates meeting job description requirements, and provides that Ute tribal employees can only be terminated, penalized or disciplined for "just cause." UTERO also requires a written affirmative action plan that must be filed with the UTERO office, establishes the UTERO Commission as a forum to resolve employment disputes and gives authority to the UTERO Commission to establish wage rates on construction projects. UTERO also requires companies doing business on the Reservation to give preference to certified Ute and Native American-owned businesses by giving them a first opportunity and contracting preference for all contracts performed on the Reservation. While this law does not apply to the granting of mineral leases, subleases, permits, licenses and transactions governed by other applicable Ute tribal and federal law, we treat this law as applicable to our material non-mineral contracts and procurement agreements relating to our business activities on the Reservation.

Other Regulation of the Oil and Natural Gas Industry

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

Regulation of Drilling and Production. Our operations are subject to various types of regulation at federal, state, local and Tribe levels. These types of regulations include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities, the Tribe and other Native American tribes also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled by us and other third-parties;
- the plugging and abandoning of wells; and
- notice to surface owners and other third-parties.

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

Regulation of transportation of oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index ceiling slightly, effective July 2001. FERC reviews the annual indexing factor every five years. For the five-year period commencing July 1, 2011, the annual indexing factor is equal to the Producer Price Index for Finished Goods plus 2.65%. We cannot predict whether or to what extent the index factor may change in the future

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. On June 19, 2008, the FERC issued Order No. 712, and subsequently issued orders on rehearing and clarification. Among other things, Order No. 712 revised the FERC's transportation pricing policy by waiving price ceilings for interstate pipeline capacity released from one shipper to another for a period of one year or less, if the release is to take effect on or before one year from the date on which the pipeline is notified of the release.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission, or the CFTC. Please read below the discussion of "—Other federal laws and regulations affecting our industry — Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please read below the discussion of "Other federal laws and regulations affecting our industry — FERC Market Transparency Rules."

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a nonjurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. To the extent that the FERC issues an order which reclassifies transmission facilities as gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Other federal laws and regulations affecting our industry.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005, or the EPAct 2005. EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as service under Section 311 of the NGPA, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental, Health and Safety Regulation

Our exploration, development and production operations are subject to various federal, regional, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way we handle or dispose of our wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this trend will continue in the future.

The following is a summary of the more significant existing U.S. federal and state environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and waste

The federal Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the Superfund law and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA.

We also generate solid and hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes under RCRA.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air emissions

The Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. For instance, on July 1, 2011, the EPA promulgated a final FIP that implements federal NSR pre-construction air pollution control requirements for facilities emitting pollutants in Indian Country. The FIP establishes two rules to protect air quality in Indian lands. The first rule is the Minor NSR rule, which applies to new and modified minor stationary sources and to minor modifications at existing major stationary sources found on Indian lands. The second rule is the Non-Attainment Major NSR rule, which applies to new and modified major stationary sources in areas of Indian lands that do not meet National Ambient Air Quality Standards ("NAAQS") established by the EPA under the federal Clean Air Act. Under the rules, a source owner or operator will need to apply for a permit before building a new facility or expanding an existing one if the facility increases emissions above applicable limits included in the rules. The permitting authority, which may be the EPA or a tribe (should the tribe accept delegation of the federal program or develop and implement an EPA-approved Tribal Implementation Plan), will review the application and grant or deny the air emissions permits. These permits will undergo public notice and comment as part of the review process. With regard to our operations upon the Reservation, promulgation of the FIP and establishment of the two permit programs will require us to acquire air emissions permits prior to well construction, which could result in delays in siting and development of wells and increase the costs of development and production although, at this point, we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities on Indian lands. Obtaining permits has the potential to delay the development of oil and natural gas projects.

While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations. For example, on July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production activities. The proposed rules also would establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. The EPA must take final action on the rules by April 3, 2012. Any such requirements could increase the costs of development and production, though at this point, we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

In addition, the EPA and several other agencies are pursuing or planning to pursue monitoring studies to assess elevated levels of wintertime ground-level ozone found in the recent past in the Uinta Basin, the results of which studies could result in the adoption and implementation of restrictions relating to current or future oil and gas development in the basin. Ambient concentrations of ground-level ozone were measured in the Uinta Basin between January and March 2010 at levels in excess of the NAAQS of 75 parts per billion for an eight-hour average established by the EPA in 2008. No final determination has been made for the occurrence of elevated concentrations of ozone in the Uinta Basin during the wintertime but a contributing factor could be oil and gas production in the region. The EPA, Utah Department of Environmental Quality, U.S. Fish & Wildlife Service and the BLM, among other agencies, are pursuing or are planning to pursue, individually or collectively, long-term wintertime monitoring for ozone and key "precursors" to the chemical formation of ground-level ozone in the Uinta Basin. Any imposition of federal, state, regional or local restrictions relating to oil and gas development in the basin may result in increased costs to install added air pollution control equipment and the possibility of partial or total delays or bans in such developmental activities in certain areas of the basin.

Climate change

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another which requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. On May 12, 2010, the EPA also issued a new "tailoring" rule, which makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the Clean Air Act. On September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. In addition, on November 30, 2010, the EPA published a final rule that expands its existing GHG emissions reporting rule to include certain owners and operators of onshore oil and natural gas production to monitor GHG emissions beginning in 2011 and to report those emissions beginning in 2012. We are currently conducing monitoring of GHG emissions from our operations in accordance with the GHG emissions reporting rule but must evaluate the data from those monitoring activities to determine whether we exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level, we will report the emissions beginning in 2012. Also, Congress has from time to time considered legislation to reduce emissions of GHGs and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with operations or could adversely affect demand for our production.

Water discharges

The Federal Water Pollution Control Act, as amended, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and federal navigable waters. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, as amended, or the OPA, which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We anticipate that most, if not all, of the wells we plan to drill will involve hydraulic fracturing of the producing formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. We follow applicable industry standard practices and legal requirements for groundwater protection in our hydraulic fracturing activities. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. In addition, the U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the U.S. Securities & Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have not been any citations, suits or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Endangered Species Act

The federal Endangered Species Act, as amended, the ESA, restricts activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the Endangered Species Act. Under the September 9, 2011 settlement, the U.S. Fish and Wildlife Service is required to begin issuing decisions with respect to the 250 candidate species by the end of 2011. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

National Environmental Policy Act

Performance of oil and gas exploration and production activities on federal lands including Indian lands may be subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BIA and the BLM to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Our current and proposed exploration and production activities upon the Reservation or other federal lands require governmental permits that are subject to the requirements of NEPA. Currently, the BIA is pursuing a programmatic environmental assessment with respect to our planned drilling of approximately 500 wells in the Randlett project area and also is pursuing an environmental assessment with respect to our planned 30-well exploratory program in the Rocky Point project area. Completion of the Randlett and Rocky Point environmental assessments are currently anticipated to occur by early 2013 and early 2012, respectively. Our development of the Randlett project area and exploration of the Rocky Point project area are subject to completion of these environmental assessments and any delays in such completion could result in delays in our exploration or production programs. Also, depending on the mitigation strategies recommended in the environmental assessments, we could incur added costs, which could be substantial.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended the OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

Employees

As of September 30, 2011, giving effect to our corporate reorganization, we employed 44 people, including three employees in geology, 14 in operations and engineering, eight in accounting and finance and five in land. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

We currently lease 21,925 square feet of office space in Denver, Colorado at 1875 Lawrence Street, Suite 200, where our principal offices are located. The lease for our Denver office expires in July 2013. We also lease a field office from the Tribe in Fort Duchesne, Utah, which is approximately 10,771 square feet of office, training and storage space.

MANAGEMENT

Directors, Executive Officers and Other Key Employees

The following table sets forth information regarding our directors and executive officers as of [●], 2011.

Name	Age	Title
Joseph N. Jaggers	58	President and Chief Executive Officer, Director
Gregory S. Hinds	48	Chief Operating Officer
Laurie A. Bales	39	Chief Financial Officer and Secretary
Todd R. Kalstrom	54	Vice President Land and Business Development
Mark A. Shelby	51	General Counsel and Assistant Secretary
S. Wil VanLoh, Jr.	41	Director

The following table sets forth information regarding other key employees as of [●], 2011.

Name	Age	Title
Christopher M. Conley	54	Vice President Midstream Operations and Facilities
Cameron J. Cuch	37	Vice President Governmental Affairs and Corporate Development
John Martin, Jr.	38	Treasurer
Andrew P. Sandage	34	Controller
Robert A. Gardner	43	Engineering Manager
Daniel J. Berberick	51	Manager, Geosciences
Rachel E. Garrison	45	Regulatory Manager
Michael A. Maser	62	Area Production Superintendent

Set forth below is the description of the backgrounds of our directors, executive officers and other key employees.

Joseph N. Jaggers has served as President and Chief Executive Officer of Ute Energy since July 2010. Mr. Jaggers began his career in the oil and gas industry in 1981, when he joined Amoco Production Company ("Amoco") in Lake Charles, Louisiana. Mr. Jaggers worked for 19 years with Amoco and its successor, BP p.l.c., holding positions of increasing responsibility, including operations, engineering and executive assignments, in a number of domestic and international locations. In July 2000, Mr. Jaggers joined Barrett Resources Corporation as President and Chief Operating Officer and served in that capacity until Barrett Resources Corporation's merger with The Williams Companies, Inc. in 2001. Mr. Jaggers remained with The Williams Companies, Inc. as Regional Vice President until 2006. Mr. Jaggers served as President, Chief Operating Officer and Director of Bill Barrett from 2006 until joining Ute Energy in July 2010. In October 2009, Mr. Jaggers was elected into the Wildcatter Hall of Fame for his distinguished work and contributions to the oil and gas industry by the Independent Producers Association of the Mountain States. Mr. Jaggers graduated from the United States Military Academy at West Point in 1975 with a bachelor of sciences degree, after which he served his country for six years as a member of the United States Army.

Gregory S. Hinds has served as our Chief Operating Officer since February 2011. Mr. Hinds served in various capacities for Bill Barrett from June 2002 until February 2011, beginning as a geologist and ultimately serving as Vice President for the Uinta Basin. While at Bill Barrett, Mr. Hinds managed the development of both producing and exploratory plays in the Uinta Basin and was credited with the Discovery of the Year for 2005 by Oil & Gas Investor magazine. His prior experience includes work at Marathon Oil Corporation, Pennaco Energy, Inc. and Barrett Resources Corporation. Mr. Hinds graduated from Louisiana State University in 1986 where he earned a B.S. in geology. He earned an M.S. in geology from Texas A&M University in 1990.

Laurie A. Bales has served as our Chief Financial Officer since September 2010. Ms. Bales served as director of corporate development at Mariner Energy Inc., which was acquired by Apache Corp., from March 2010 until September 2010. From February 2009 until March 2010, Ms. Bales was a private investor with a focus on oil and gas investments. From July 2001 to February 2009, Ms. Bales worked at Credit Suisse Securities as an investment banker. While at Credit Suisse, Ms. Bales focused on securities offerings and mergers and acquisitions dealing primarily in the energy space, specifically oil and gas. Ms. Bales began her tenure in 2001 as an associate, was promoted to vice president in 2005 and ultimately served as director beginning in 2008 until she left the firm in 2009. Her prior experience includes public accounting with Price Waterhouse LLP, including audit clients in the energy industry. Ms. Bales earned her B.S. in economics from The Wharton School at the University of Pennsylvania in May 1994 and her M.B.A. in finance from The Wharton School at the University of Pennsylvania in May 2001. Ms. Bales is a licensed C.P.A. in the State of Texas.

Todd R. Kalstrom has served as the Vice President of Land and Business Development of Ute Energy since August 2010. He previously worked for Elk Resources, Inc. as Vice President of Land and Negotiations during its initial asset acquisition period in 2005, Orion Energy Partners as Land Manager from September 2005 until its successful termination and sale of assets in November of 2009 and Axia Energy, LLC as Vice President of Land from November of 2009 to August 2010. Mr. Kalstrom has over 32 years of industry experience focused on onshore U.S. domestic exploration projects with the last seven years being focused on small private equity firms. Following graduation from the University of Colorado where he earned a B.S. in Minerals Land Management in 1979, Mr. Kalstrom was employed by Marathon Oil Company from 1979 to 1982 and The Anschutz Corporation from 1982 to 2004, leaving as Director of Land and Business Development for Anschutz Exploration Corporation in December 2004. Mr. Kalstrom is an active member in both the Denver Association of Petroleum Landmen and in the Rocky Mountain Mineral Law Foundation.

Mark A. Shelby has served as our general counsel and assistant secretary since May 2011. Mr. Shelby was of counsel with the energy law firm of Beatty & Wozniak, P.C. from June 2010 until he left to join Ute Energy. From April 2006 until June 2010, Mr. Shelby was an oil and gas lawyer with the law firm of Patton & Boggs LLP. He has prior in-house legal experience with Qwest Communications International and The Williams Companies, Inc., where he began his legal career in 1992 and worked for over ten years. Mr. Shelby has focused his career on oil and gas matters and corporate law and has represented numerous international and domestic exploration and production and midstream operators, including operators in the Uinta Basin. Mr. Shelby earned his B.S.B.A. in accounting in 1982 and his M.S. in accounting in 1984 from Oklahoma State University, his juris doctor in 1991 from The University of Tulsa College of Law and his master of laws in taxation from Emory University School of Law in 1992. Mr. Shelby is an admitted member of the state bar in each of Colorado, New York and Oklahoma.

S. Wil VanLoh, Jr. is a member of the board of directors. Mr. VanLoh is the President and Chief Executive Officer of Quantum Energy Partners, which he co-founded in 1998. Quantum Energy Partners manages a family of energy-focused private equity funds, with more than $6.5 billion of capital under management. Mr. VanLoh is responsible for the leadership and overall management of the firm. Additionally, he leads the firm's investment strategy and capital allocation process, working closely with the investment team to ensure its appropriate implementation and execution. He oversees all investment activities, including origination, due diligence, transaction structuring and execution, portfolio company monitoring and support and transaction exits. Prior to co-founding Quantum Energy Partners, Mr. VanLoh co-founded Windrock Capital, Ltd., an energy investment banking firm specializing in providing merger, acquisition and divestiture advice to and raising private equity for energy companies. Prior to co-founding Windrock in 1994, Mr. VanLoh worked in the energy investment banking groups of Kidder, Peabody & Co. and NationsBank Corp. Mr. VanLoh currently serves on the boards of a number of portfolio companies of Quantum Energy Partners, all of which are private energy companies. Mr. VanLoh also serves on the board of the general partner of QR Energy, LP. Mr. VanLoh served on the board of directors of the general partner of Legacy Reserves LP from its founding to August 1, 2007 and was also involved in the founding of Linn Energy, LLC. Mr. VanLoh has served as a board member and Treasurer of the Houston Producer's Forum and on the Finance Committee of the Independent Petroleum Association of America ("IPAA"). We believe that Mr. VanLoh's extensive experience, both from investing in the energy industry since 1998 and serving as director for numerous private energy companies, brings important and valuable skills to the board of directors.

Chris M. Conley has served as our Vice President of Midstream Operations and Facilities since September 2010. Mr. Conley served as Manager of Gathering and Facilities for Berry Petroleum Company from [month] 2005 to [month] 2010, where he managed midstream business development, engineering and operational support. Mr. Conley's prior experience includes work at Wilbanks Resources Corporation, Conley Engineering, Inc., Bear Paw Energy LLC and KN Energy Inc. Mr. Conley graduated from Oklahoma State University in 1979 where he earned a B.S. in mechanical engineering. Mr. Conley is a Registered Professional Engineer in the State of Colorado. Additionally, Mr. Conley has been elected to serve as the upcoming 2012 President of the Gas Processors Association, Rocky Mountain Chapter.

Cameron J. Cuch has served as our Vice President of Governmental Affairs and Corporate Development since February 2011. Mr. Cuch joined Ute Energy upon its inception in 2005 and held positions of increasing responsibility, including Business Analyst and General Manager, until being named Vice President of Governmental Affairs and Corporate Development in February 2011. Prior to joining Ute Energy, Mr. Cuch was employed by the Ute Indian Tribe as Director of the Ute Tribe Education Department and Chief Administrative Officer for the Tribe's state licensed charter high school for four years. Mr. Cuch also served on the Board of Directors of the National Indian Education Association from 2004 through 2007. Mr. Cuch is an enrolled member of the Ute Indian Tribe of the Uintah & Ouray Reservation, Utah and has Wampanoag descent from Martha's Vineyard, Massachusetts. Mr. Cuch has experience with both the business aspects of the development of Indian natural resources and the statutory and regulatory requirements applicable to such development. Mr. Cuch has over 13 years of experience working with Indian tribal governments and over six years of industry experience developing Indian natural resources. Mr. Cuch earned a B.A. in political science from the University of Massachusetts in 1996 and a master's degree in education from the University of Utah in 1999.

John Martin, Jr. has served as our Treasurer since January 2011 and previously as our Controller from August 2007 through December 2010. Mr. Martin started with us as an accountant in November 2006. Prior to working with Ute Energy, Mr. Martin worked for GHP Horwath LLC ("GHP") from 2002 to 2006. While at GHP, Mr. Martin worked in litigation support and assurance services, concentrating on the calculation of economic damages and business valuation. Mr. Martin graduated from Fort Lewis College where he earned a B.A. in Accounting and B.A. in Finance in 2001. Prior to college, Mr. Martin worked for the Ute Indian Tribe as a staff accountant from 1992 until he was promoted to Assistant Controller in 1996. He served as Assistant Controller from 1996 to 1998 before attending college full time.

Andrew P. Sandage has served as our Controller since December 2010. Mr. Sandage served as Consulting Manager for Opportune LLP ("Opportune") from December 2008 to December 2010. While at Opportune, Mr. Sandage worked with various clients in the energy industry on SEC compliance issues, the restructuring of an exploration and production company and various complex financial reporting and due diligence issues. Mr. Sandage worked at Cimarex Energy Co. ("Cimarex") from March 2006 to October 2008 as Internal Audit Manager, where he managed the creation and development of Cimarex's internal audit department and compliance with Sarbanes-Oxley. Mr. Sandage was a Manager at Deloitte & Touche LLP prior to joining Cimarex and served several public exploration and production clients. Mr. Sandage graduated from the University of Northern Colorado in 2000 where he earned a B.S. in business administration with an emphasis in accounting. Mr. Sandage is a licensed C.P.A. in the state of Colorado.

Robert A. Gardner has served as our Engineering Manager since December, 2010. Prior to joining Ute Energy, Mr. Gardner served as an Engineering Advisor for Rosetta Resources Inc. from July 2009 to December 2010, where he had responsibility for drilling and recompletion programs in the Sacramento Basin. From October 2007 to July 2009, Mr. Gardner served as Vice President – Engineering for Samson Oil and Gas USA, Inc ("Samson"). While at Samson, he had direct responsibility for reserve assets and operational oversight for the drilling, completion and production of Samson operated well projects. Mr. Gardner's prior experience also includes work served as Gulf Coast Business Manager for Aspect Energy, LLC from April 2004 to October 2007. Mr. Gardner received a B.S. in Mechanical Engineering from Colorado State University in 1992, a M.S. in Mechanical Engineering from the University of Colorado in 1996 and an M.B.A. with emphasis in Finance from the University of Denver in 1998.

Daniel J. Berberick has served as our Manager, Geosciences since May 2011. Mr. Berberick's responsibilities at Ute Energy include development, operations, and acquisition and divestment geoscience. Prior to joining Ute Energy, Mr. Berberick worked for Bill Barrett for over seven years in several capacities. Most recently, Mr. Berberick was Project Team Lead, Geology and Geophysics from February 2010 to May 2011, where he conducted the exploration and development of the emerging Niobrara play in the Denver Basin. From January 2008 to May 2011, he conducted exploration and development of the emerging shale play in the Paradox Basin of Colorado and Utah. Mr. Berberick also worked on the exploration of leaseholds acquired by Bill Barrett from January 2007 to May 2011. His prior experience includes work at Barrett Resources Corporation for six years and The Williams Companies, Inc. for two years. Mr. Berberick received a B.S. in Geophysical Engineering from Colorado School of Mines in 1983 and an M.S. in Radiological Physics from the University of Colorado, Health Sciences Center in 1992.

Rachel E. Garrison has served as our Regulatory Manager since October 2010. Prior to joining Ute Energy, Ms. Garrison worked with Noble Energy, Inc. ("Noble") as a National Environmental Policy Act ("NEPA") and Regulatory Contractor from May 2010 to October 2010. While at Noble, Ms. Garrison provided NEPA and regulatory support for their Colorado and Wyoming asset teams. Ms. Garrison's prior experience also includes work as Sr. NEPA Project Manager for SWCA Environmental Consultants ("SWCA") from September 2008 to April 2010. At SWCA, Ms. Garrison managed multiple energy development NEPA documents across the Rocky Mountain region, client and regulatory agency relations, budget and an environmental staff. Ms. Garrison also worked as a Regulatory Analyst at The Williams Companies, Inc. from 2004 to September 2008, where she managed all aspects of planning, NEPA and regulatory components for their Colorado asset team. Ms. Garrison earned a B.A. in political science from Denver Metropolitan State University in 2009. She also has a GIS Certificate from the University of Colorado at Denver.

Michael A. Maser has served as our Area Production Superintendent since September 2010. Mr. Maser has 32 years of experience in the oil and gas industry, most recently with Baker Energy ("Baker"), where he served as a Consultant Project Manager from August 2007 to January 2010. While at Baker, Mr. Maser assisted with process improvement and operations and maintenance activities. Mr. Maser was retired from 2004 to August 2007, before joining Baker. From 2002 to 2004, Mr. Maser worked for BP p.l.c.'s Prudhoe Bay Maintenance Strategy Team in Alaska and was an Integral Team Member in developing a maintenance strategy for the Prudhoe Bay Field. His prior experience also includes work at Amoco Corporation and Halliburton Company.

Board of Directors

Our board of directors currently consists of two members, including Joseph N. Jaggers, our President and Chief Executive Officer, and S. Wil VanLoh, Jr., a designee of Quantum. We expect to increase the number of members on our board of directors in connection with the completion of this offering.

We intend to appoint independent directors to our board of directors contemporaneously with and following the completion of this offering. We also expect that our board will review the independence of our current directors using the independence standards of the NYSE.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct the affairs and business of the company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Following the completion of this offering, our directors will be divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2013, 2014 and 2015, respectively. ***[NTD: discuss classified board structure]*** At each annual meeting of stockholders held after the initial classification, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Committees of the Board of Directors

Upon the conclusion of this offering, we intend to have an audit committee, compensation committee and nominating and governance committee of our board of directors, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

We will establish an audit committee prior to completion of this offering. We anticipate that the audit committee will consist of three directors, each of whom will be independent under the rules of the SEC. SEC rules also require that a public company disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. We anticipate that at least one of our independent directors will satisfy the definition of "audit committee financial expert."

This committee will oversee, review, act on and report on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee will oversee our compliance programs relating to legal and regulatory requirements. We have adopted an Audit Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee

We will establish a compensation committee prior to completion of this offering. We anticipate that the compensation committee will consist of three directors, each of whom will be "independent" under the rules of the SEC. This committee will establish salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee will also administer our incentive compensation and benefit plans. Upon formation of the compensation committee, we expect to adopt a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Nominating and Governance Committee

We will establish a nominating and corporate governance committee shortly after completion of this offering. We anticipate that the nominating and corporate governance committee will consist of three directors. This committee will identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management succession plan. Upon formation of the nominating and corporate governance committee, we expect to adopt a nominating and corporate governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee Interlocks and Insider Participation

None of our officers or employees will be members of the compensation committee. None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board or compensation committee. No member of our board is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

To the extent any members of our compensation committee and affiliates of theirs have participated in transactions with us, a description of those transactions is described in "Certain Relationships and Related Party Transactions."

Code of Business Conduct and Ethics

Our board of directors will adopt a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

Our board of directors will adopt corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Overview of Executive Compensation

As a private company, our compensation arrangements with our executive officers have been determined on an individual basis, generally based on negotiations between the individual and our chief executive officer (our "CEO"). Our CEO's compensation arrangements were determined based on direct negotiations with Quantum, our private equity sponsor and significant equity owner. All of our executive officers have been employed by Ute Energy Management LLC, a subsidiary of Ute Energy LLC, and many of our executive officers have entered into employment agreements which we are evaluating in connection with this offering.

Historically, our executive officers have performed services for Ute Energy LLC and its subsidiaries. Consequently, the compensation payable to our executive officers has been attributable to services performed for both Ute Energy Upstream Holdings LLC and Ute Energy Midstream Holdings LLC (and its subsidiaries). In connection with this offering, all employees performing services on our behalf will be transferred to and employed directly by Ute Energy Corporation.

We have begun the process of analyzing our executive compensation program with the goal of modifying it to be more suitable for a public company. Going forward, we believe that our executive compensation program will help us attract, motivate and retain key executives and reward executives for creating and increasing the value of our company. To aid in this process, we engaged Longnecker & Associates ("Longnecker"), a nationally recognized compensation consulting firm with experience in assisting similar companies that own and operate upstream oil and natural gas assets. We are working with Longnecker to refine our executive compensation to ensure (i) that our total executive compensation is in line with executive compensation within our peer group and (ii) that our overall compensation aligns our executives' interests with those of our equity holders by tying a meaningful portion of each executive's cash and equity compensation to the achievement of performance targets and by including time-based vesting requirements in our long-term equity grants. The process of modifying our executive compensation policies and practices is in its inception, but we anticipate receiving recommendations from Longnecker by year end 2011 that will be implemented in connection with this offering.

We have not historically had a formal compensation committee. In connection with, and prior to, this offering our board of directors will form a compensation committee composed of independent directors. We anticipate that upon formation the compensation committee our independent directors will begin working directly with Longnecker and all final decisions with regard to the compensation program that will be enacted in connection with this offering will be made by our compensation committee.

Goals of the Compensation Program

We are focused on establishing an executive compensation program that is intended to attract, motivate, and retain key executives and to reward executives for creating and increasing the value of our company. In meeting those objectives, we intend to work closely with Longnecker to identify an appropriate peer group of similarly situated U.S.-based oil and natural gas exploration and production companies and to identify appropriate comparative performance factors in order to establish a competitive compensation program.

In 2010 and 2011, however, with respect to our executive officers who were party to employment agreements, our executive compensation program was dictated by the terms of the executives' employment agreements. As is described in greater detail below, a significant portion of our historic compensation has been payable through long term equity awards the value of which is dependent upon an increase in the value of (and distributions upon the liquidation of) Ute Energy LLC.

Components of Our Executive Compensation Program

The employment agreements that we have entered into with many of our executive officers have substantially the same terms and provide for three principal elements of compensation: base salary, cash bonuses and equity. We believe this mix of compensation appropriately aligns our executives' compensation with our short term and long term goals. The employment agreements govern essentially all terms of compensation, including the equity-based compensation awards that the executives have received. While we feel that these agreements have historically been beneficial to both the executive and the company, the agreements are being evaluated in connection with this offering.

Below is a description of each of the principal elements of our current compensation program and our current view on these elements going forward. We recognize that in connection with the formation of our compensation committee, the goals themselves and the methods of implementing those goals may change.

Base Salary

2010 and 2011. Each executive officer's base salary is a fixed component of compensation for each year, adjusted for the level of performance achieved. As described above, our executive officers' base salaries were originally set pursuant to negotiations with our CEO (or, in the case of our CEO, negotiations with Quantum), based on the knowledge and experience of our CEO and Quantum of prevailing salaries within the industry.

2012 and going forward. For 2012 and subsequent years, we anticipate we will analyze the appropriateness of all of our executive officers' base salaries in light of the base salaries of the peer group we identify with the assistance of Longnecker, both on a standalone basis and as a component of total compensation. In the future, we expect to review base salaries on an annual basis to determine if the company's financial and operational performance and the executive officer's personal performance (both individually and as a leader of his respective team) support any adjustment to base salary.

Cash Bonus

2010 and 2011. Many of our executive officers are party to an employment agreement that sets a bonus potential expressed as a percentage of base salary. The board of managers of Ute Energy LLC generally establishes an aggregate cash bonus pool as part of our annual budget. Our CEO has historically had discretion to allocate these amounts for each of our executive officers and other eligible employees based upon individual performance. Our CEO's annual bonus has been determined in consultation with certain members of the board of managers of Ute Energy LLC. No objective targets have historically been established or communicated to executive officers.

2012 and going forward. For 2012 and subsequent years, we intend to continue to provide annual incentive cash bonuses to reward achievement of financial or operational goals so that total compensation more accurately reflects actual company and individual performance. We expect that our compensation committee will establish appropriate goals to be used in determining cash bonuses that will align our executive officers' compensation with the performance of the company as a whole. The goals will be established in connection with the review of the data to be provided by Longnecker.

Long-Term Incentives

We have historically offered long-term incentives to our executive officers through grants of Management Incentive Units in Ute Energy LLC. The Management Incentive Units are intended to create incentives for the management team to reach a return hurdle, defined as the return of aggregate capital contributions plus a preferred rate on those capital contributions. The Management Incentive Units represent an interest in the future profits of Ute Energy LLC and are intended to be treated as "profits interests" for federal income tax purposes. They are subject to time-vesting requirements. In addition to tax distributions on the Management Incentive Units, which are paid if those holders are allocated taxable income in any quarter and are calculated based on a predetermined formula, after the other equity holders of Ute Energy LLC have received distributions equal to the capital contributed by such holders plus an annual internal rate of return equal to 8%, the Management Incentive Units participate in a percentage of the total distributions to all equity holders.

As part of our reorganization in connection with this offering, we expect that the Management Incentive Units will be converted into long term equity awards of Ute Energy Corporation. To create incentives for our executive officers to continue to grow our company, we are in the process of evaluating a formal long-term incentive plan that will be adopted in connection with the conversion of the Management Incentive Units. We intend to adopt the formal plan in connection with the completion of this offering. We believe that having an equity component to our compensation program is vital to align our executive officers' interests with our equity holders' interests through shared ownership. Longnecker will help us design the long-term incentive plan by providing a survey of the main components of long-term incentive plans for similarly-situated public companies.

Impact of Financial Reporting and Tax Accounting Rules

Historically, we have not been required to recognize any compensation cost relating to the Management Incentive Units. Going forward, we will recognize compensation costs relating to any share-based payments, which will be measured based on the fair value of the equity issued after taking into account any vesting requirements or forfeiture obligations. We anticipate that recognition of this compensation cost will result from equity grants under any long-term incentive plan and that the fair market value of these awards will be based on the closing price of our common stock as reported by the NYSE.

Section 162(m) of the Internal Revenue Code of 1986, as amended, limits the deductibility of certain compensation expenses in excess of $1,000,000 to any one individual in any fiscal year. Compensation that is "performance based" is excluded from this limitation. For compensation to be "performance based," it must meet certain criteria, including predetermined objective standards approved by a compensation committee. We believe that maintaining the discretion to evaluate the performance of our executive officers is an important part of our responsibilities and benefits our public stockholders, but it could potentially fail to meet the predetermined objective standards requirement. Regardless, section 162(m) provides that certain compensation will not be subject to the deduction limitations of section 162(m) for a transition period following an initial public offering. We anticipate that our annual bonuses and certain awards of equity compensation will satisfy the requirements of this exception during the transition period.

Severance Benefits

We maintain employment agreements with many of our executive officers with limited severance protections. Specifically, our executive officers who are party to an employment agreement are entitled to receive salary continuation for a period of one year following their termination without "cause". We believe that severance protection provisions create important retention tools for us, as post-termination payments allow employees to leave our employment with value in the event of certain terminations of employment that were beyond their control. Post-termination payments allow management to focus their attention and energy on making the best objective business decisions that are in our interest without allowing personal considerations to cloud the decision-making process. Further, because the severance provided is only one year of salary continuation, our executive officers are not provided with an economic windfall upon termination. In addition, the employment agreements preclude the executives from soliciting employees or competing with us for a period of 12 months following termination. In connection with the review performed by Longnecker we intend to evaluate the employment agreements and severance provided to ensure the agreements will meet our requirements as a public company.

Other Compensation Elements

We offer participation in broad-based retirement, health and welfare plans to all of our employees. We currently maintain a plan intended to provide benefits under section 401(k) of the Internal Revenue Code of 1986, as amended, where employees are allowed to contribute portions of their base compensation into a retirement account. We provide a matching contribution in amounts up to 6% of the employees' eligible compensation.

We do not generally provide perquisites to our executive officers.

Risk Assessment

The board of managers of Ute Energy LLC has reviewed our compensation policies as generally applicable to our employees and believes that our policies do not encourage excessive and unnecessary risk-taking and that the level of risk that they do encourage is not reasonably likely to have a material adverse effect on us due to the discretionary nature of the annual bonus plan. Further, our historic long term equity awards are subject to a lengthy vesting schedule and distributions, if any, are made only to the extent distributions are made to equity holders generally.

Because our compensation philosophy applies to all of our employees and is tied to base salary, annual bonus and long-term equity-based award as the sole components and because the annual bonuses are fixed at a maximum amount each year, our historic compensation program encourages growth without taking material undue risks.

EXECUTIVE COMPENSATION

Summary Compensation Table

The table below sets forth the annual compensation earned during the 2010 fiscal year by our "named executive officers" as of December 31, 2010:

Name and Principal Position (a)	Year (b)	Salary ($)(c)	Bonus ($)(d)	Stock Awards ($)(e)	Option Awards ($)(f)	Non-Equity Incentive Plan Compensation ($)(g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (4)(h)	All Other Compensation ($)(i)	Total ($)(j)
Principal executive officer	2010								
Principal financial officer	2010								
Additional executive officer 1	2010								
Additional executive officer 2	2010								
Additional executive officer 3	2010								

Grants of Plan-Based Awards for the 2010 Fiscal Year

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name (a)	Grant Date (b)	Threshold ($)(c)	Target ($)(d)	Maximum ($)(e)	Threshold (#)(f)	Target (#)(g)	Maximum (#)(h)	All Other Stock Awards: Number of Shares of Stock or Units (#)(i)	All Other Option Awards: Number of Securities Underlying Options (#)(j)	Exercise or Based Price of Options Awards ($/Sh)(k)	Grant Date Fair Value of Stock and Option Awards ($)(l)
Principal executive officer											
Principal financial officer											
Additional executive officer 1 ...											
Additional executive officer 2 ...											
Additional executive officer 3 ...											

Outstanding Equity Awards at 2010 Fiscal Year-End

The following table provides information on the current stock option and stock award holdings by the named executive officers.

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)(d)	Option Exercise Price ($)(e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#)(g)	Market Value of Shares or Units of Stock That Have Not Vested ($)(h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have not Vested (#)(i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(j)
Principal executive officer									
Principal financial officer									
Additional executive officer 1									
Additional executive officer 2									
Additional executive officer 3									

Option Exercises and Stock Vested in the 2010 Fiscal Year

The following table provides information, on an aggregate basis, about stock options that were exercised and stock awards that vested during the fiscal year ended December 31, 2010 for each of the named executive officers.

	Option Awards		Stock Awards	
Name (a)	Number of Shares	Value Realized on	Number of Share	Value Realized on

	Acquired on Exercise (#)(b)	Exercise ($)(c)	Acquired on Vesting (#)(d)	Vesting ($)(e)
Principal executive officer				
Principal financial officer				
Additional executive officer 1				
Additional executive officer 2				
Additional executive officer 3				

Pension Benefits

We have not, and do not currently maintain a defined benefit pension plan.

Nonqualified Deferred Compensation

We have not, and do not currently maintain a nonqualified deferred compensation plan.

Potential Payments upon Termination or a Change in Control

Many of our executive officers are party to an employment agreement with limited severance protections. Specifically, such executive officers who are terminated without "cause" receive salary continuation for a period of one year. In addition, the employment agreements preclude the executives from soliciting employees or competing with us for a period of 12 months following termination. We do not provide any additional benefits upon a "Change in Control", and the employment agreements with our executive officers do not provide for enhanced severance following a "Change in Control". However, as described above, we are in the process of evaluating the employment agreements in connection with this offering.

Director Compensation

We did not award any compensation to our non-employee directors during 2010 or to date during 2011. Going forward, we believe that attracting and retaining qualified non-employee directors will be critical to the future value of our growth and governance. We also believe that the compensation package for our non-employee directors should require that a portion of the total compensation package be equity-based to align the interests of these directors with our equity holders.

We will be reviewing with Longnecker the non-employee director compensation paid by our peers in establishing the appropriate mix and amount of compensation payable to our non-employee directors in the future.

We anticipate that directors who are also our employees will not receive any additional compensation for their service on the board of directors.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Since January 1, 2010, other than as described below there has not been, nor is there currently proposed, any transaction or series of similar transactions to which we were or are a party in which the amount involved exceeded or exceeds $120,000 and in which any of our directors, executive officers, holders of more than 5% of any class of our voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, other than compensation arrangements with directors and executive officers, which are described in "Executive Compensation and Other Information," and the transactions described or referred to below.

We lease our current Utah field office from the Tribe for $6,000 per month. We entered into the lease with them in November 2011, and the lease expires in November 2016. The aggregate amount of all payments due to the Tribe through the term of the lease is $0.4 million.

Since January 1, 2010, we have made royalty payments as an operator of $0.9 to the Tribe.

Procedures for Approval of Related Person Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;
- any person who is known by us to be the beneficial owner of more than 5.0% of our common stock;
- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5.0% of our common stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5.0% of our common stock; and
- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10.0% or greater beneficial ownership interest.

Our board of directors will adopt a written related party transactions policy prior to the completion of this offering. Pursuant to this policy, the Audit Committee will review all material facts of all Related Party Transactions and either approve or disapprove entry into the Related Party Transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a Related Party Transaction, the Audit Committee shall take into account, among other factors, the following: (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (2) the extent of the Related Person's interest in the transaction. Further, the policy requires that all Related Party Transactions required to be disclosed in our filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

PRINCIPAL AND SELLING STOCKHOLDERS

The following table sets forth information with respect to the beneficial ownership of our common stock as of December [●], 2011 after giving effect to our corporate reorganization by:

- each of our named executive officers;
- each of our directors;
- all of our directors and executive officers as a group;
- the selling stockholders; and
- each stockholder known by us to be the beneficial owner of more than 5% of our outstanding shares of common stock.

Except as otherwise indicated, the person or entities listed below have sole voting and investment power with respect to all shares of our common stock beneficially owned by them, except to the extent this power may be shared with a spouse. All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more stockholders, as the case may be.

	Shares Beneficially Owned Prior to the Offering		Shares Being	Shares Beneficially Owned After the Offering	
Name of Beneficial Owner(1)	**Number**	**Percentage**	**Offered**	**Number**	**Percentage**
Selling Stockholders and 5% Stockholders:					
Ute Energy Holdings LLC					
QEP Ute LLC					
QR Ute Partners					
Directors and Executive Officers:					
Joseph N. Jaggers					
Gregory S. Hinds					
Laurie A. Bales					
Todd R. Kalstrom					
Mark A. Shelby					
S. Wil VanLoh, Jr.					
All directors and executive officers as a group (six persons)					

(1) The address of Ute Energy Holdings LLC is [●]. The address of each of Joseph N. Jaggers, Gregory S. Hinds, Laurie A. Bales, Todd R. Kalstrom and Mark A. Shelby is 1875 Lawrence Street, Suite 200, Denver, Colorado 80202. The address of of QEP Ute LLC and S. Wil VanLoh, Jr. is 5 Houston Center, 1401 McKinney Street, Suite 2700, Houston, Texas 77010 and the address of QR Ute Partners is 5 Houston Center, 1401 McKinney Street, Suite 2400, Houston, Texas 77010.

DESCRIPTION OF CAPITAL STOCK

Upon completion of this offering, the authorized capital stock of Ute Energy Corporation will consist of shares of common stock, $[●] par value per share, of which shares will be issued and outstanding, and shares of preferred stock, $[●] par value per share, of which no shares will be issued and outstanding.

We will adopt a certificate of incorporation and bylaws concurrently with the completion of this offering. The following summary of the capital stock and certificate of incorporation and bylaws of Ute Energy Corporation does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our certificate of incorporation and bylaws, which are filed as exhibits to the registration statement of which this prospectus is a part.

Common Stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock, as such, are not entitled to vote on any amendment to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the General Corporation Law of the State of Delaware. Subject to preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable, and the shares of common stock to be issued upon completion of this offering will be fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of preferred stock, if any.

Preferred Stock

Our certificate of incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $[●] per share, covering up to an aggregate of shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by the board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Anti-Takeover Effects of Provisions of Our Certificate of Incorporation, Our Bylaws and Delaware Law

Some provisions of Delaware law, and our certificate of incorporation and our bylaws described below, will contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

We will be subject to the provisions of Section 203 of the Delaware General Corporation Law, or DGCL, regulating corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 defines "business combination" to include the following:

- any merger or consolidation involving the corporation and the interested stockholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation involving the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;
- any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or
- the receipt by the interested stockholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons.

A Delaware corporation may "opt out" of Section 203 with an express provision in its original certificate of incorporation or an express provision in its certificate of incorporation or bylaws resulting from amendments approved by the holders of at least a majority of the corporation's outstanding voting shares. We do not intend to "opt out" of the provisions of Section 203. The statute could prohibit or delay mergers or other takeover or change in control attempts and, accordingly, may discourage attempts to acquire us.

Certificate of Incorporation and Bylaws

Among other things, upon the completion of this offering, our certificate of incorporation and bylaws will:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

- provide that the authorized number of directors may be changed only by resolution of the board of directors;

- provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

- provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock (prior to such time, provide that such actions may be taken without a meeting by written consent of holders of common stock having not less than the minimum number of votes that would be necessary to authorize such action at a meeting);

- provide that directors may be removed only for cause and only by the affirmative vote of holders of at least 80% of the voting power of our then outstanding common stock (prior to such time, provide that directors may be removed only for cause and only by the affirmative vote of the holders of at least a majority of our then outstanding common stock);

- provide our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock (prior to such time, provide that our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of a majority of our then outstanding common stock);

- provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board (prior to such time, provide that a special meeting may also be called by stockholders holding a majority of the outstanding shares entitled to vote);

- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. For more information on the classified board of directors, please read "Management." This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

- provide that we renounce any interest in the business opportunities of Quantum Energy Partners or any private fund that it manages or advises or any of its officers, directors, agents, stockholders, members, partners, affiliates and subsidiaries (other than Ute Energy directors that are presented business opportunities in their capacity as a Ute Energy director) and that they have no obligation to offer us those opportunities; and

- provide that our bylaws can be amended or repealed at any regular or special meeting of stockholders or by the board of directors.

Limitation of Liability and Indemnification Matters

Our certificate of incorporation limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our certificate of incorporation and bylaws also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. Our certificate of incorporation and bylaws also permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person’s actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. We intend to enter into indemnification agreements with each of our current and future directors and officers. These agreements will require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision in our certificate of incorporation and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Corporate Opportunity

Our certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to Quantum Energy Partners or its affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is [American Stock and Transfer Company].

Listing

We intend to apply to list our common stock on the NYSE under the symbol “UTE.”

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. Future sales of our common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect market prices prevailing from time to time. As described below, only a limited number of shares will be available for sale shortly after this offering due to contractual and legal restrictions on resale. Nevertheless, sales of a substantial number of shares of our common stock in the public market after such restrictions lapse, or the perception that those sales may occur, could adversely affect the prevailing market price at such time and our ability to raise equity-related capital at a time and price we deem appropriate.

Sales of Restricted Shares

Upon the closing of this offering, we will have outstanding an aggregate of shares of common stock. Of these shares, all of the shares of common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, unless the shares are held by any of our "affiliates" as such term is defined in Rule 144 of the Securities Act. All remaining shares of common stock held by existing stockholders will be deemed "restricted securities" as such term is defined under Rule 144. The restricted securities were issued and sold by us in private transactions and are eligible for public sale only if registered under the Securities Act or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

As a result of the lock-up agreements described below and the provisions of Rule 144 and Rule 701 under the Securities Act, all of the shares of our common stock (excluding the shares to be sold in this offering) will be available for sale in the public market upon the expiration of the lock-up agreements, beginning 180 days after the date of this prospectus (subject to extension) and when permitted under Rule 144 or Rule 701.

Lock-up Agreements

We, all of our directors and officers, certain of our principal stockholders and the selling stockholders have agreed not to sell or otherwise transfer or dispose of any common stock for a period of 180 days from the date of this prospectus, subject to certain exceptions and extensions. Please read "Underwriting" for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 as currently in effect, once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares, subject only to the availability of current public information about us. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

Once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares that does not exceed the greater of one percent of the then outstanding shares of our common stock or the average weekly trading volume of our common stock reported through the New York Stock Exchange during the four calendar weeks preceding the filing of notice of the sale. Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

Employees, directors, officers, consultants or advisors who purchase shares from us in connection with a compensatory stock or option plan or other written compensatory agreement in accordance with Rule 701 before the effective date of the registration statement are entitled to sell such shares 90 days after the effective date of the registration statement in reliance on Rule 144 without having to comply with the holding period requirement of Rule

144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Stock Issue Under Employee Plans

We intend to file a registration statement on Form S-8 under the Securities Act to register stock issuable under our Long-Term Incentive Plan. This registration statement is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, shares registered under such registration statement will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described above.

Registration Rights

Prior to the consummation of this offering, we expect to enter into a registration rights agreement with the selling stockholders, which will require us to file and effect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering.

MATERIAL U.S. FEDERAL INCOME AND ESTATE TAX CONSIDERATIONS TO NON-U.S. HOLDERS[1]

The following is a general discussion of the material U.S. federal income tax consequences of the acquisition, ownership and disposition of our common stock by a non-U.S. holder. Except as specifically provided below (please read "— Estate Tax"), for the purpose of this discussion, a non-U.S. holder is any beneficial owner of our common stock that is not for U.S. federal income tax purposes any of the following:

- an individual citizen or resident of the U.S.;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized under the laws of the U.S. or any state or the District of Columbia;
- an estate whose income is subject to U.S. federal income tax regardless of its source; or
- a trust (x) whose administration is subject to the primary supervision of a U.S. court and which has one or more U.S. persons who have the authority to control all substantial decisions of the trust or (y) that has made a valid election to be treated as a U.S. person.

This discussion assumes that a non-U.S. holder will hold our common stock issued pursuant to the offering as a capital asset (generally, property held for investment). This discussion does not address all aspects of U.S. federal income taxation or any aspects of state, local, gift, estate (except as expressly provided herein under "—Estate Tax") or non-U.S. taxation, nor does it consider any U.S. federal income tax considerations that may be relevant to non-U.S. holders that may be subject to special treatment under U.S. federal income tax laws, including, without limitation, U.S. expatriates, insurance companies, tax-exempt or governmental organizations, dealers in securities or currency, banks or other financial institutions, partnerships or other pass-through entities or the owners of interests therein, controlled foreign corporations, passive foreign investment companies, and investors that hold our common stock as part of a hedge, straddle or conversion transaction. Furthermore, the following discussion is based on current provisions of the Internal Revenue Code of 1986, as amended, and Treasury Regulations and administrative and judicial interpretations thereof, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect.

If a partnership (or an entity treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership will generally depend on the status of the partner and upon the activities of the partnership. Accordingly, we urge partnerships that hold our common stock and partners in such partnerships to consult their tax advisors.

We urge each prospective investor to consult a tax advisor regarding the U.S. federal, state, local and non-U.S. income and other tax consequences of acquiring, holding and disposing of shares of our common stock.

Dividends

We do not plan to make distributions on our common stock for the foreseeable future. However, if we do make distributions on our common stock, those payments will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those distributions exceed our current and accumulated earnings and profits, they will constitute a return of capital and will first reduce a holder's adjusted tax basis in the common stock, but not below zero, and then will be treated as gain from the sale of the common stock (please read "— Gain on Disposition of Common Stock).

Any dividend (out of earnings and profits) paid to a non-U.S. holder of our common stock generally will be subject to U.S. withholding tax either at a rate of 30% of the gross amount of the dividend or at such lower rate as may be specified by an applicable tax treaty. To receive the benefit of a reduced treaty rate, a non-U.S. holder must provide us with an IRS Form W-8BEN or other appropriate version of IRS Form W-8 certifying qualification for the reduced rate.

[1] To be reviewed by V&E Tax

Dividends received by a non-U.S. holder that are effectively connected with a U.S. trade or business conducted by the non-U.S. holder (and, if required by an applicable tax treaty, are attributable to a permanent establishment maintained by the non-U.S. holder in the United States) are exempt from such withholding tax. To obtain this exemption, the non-U.S. holder must provide us with an IRS Form W-8ECI properly certifying such exemption. Such effectively connected dividends, although not subject to withholding tax, will be subject to U.S. federal income tax net of certain deductions and credits at the same graduated rates generally applicable to U.S. persons, subject to any applicable tax treaty providing otherwise. In addition to the income tax described above, dividends received by corporate non-U.S. holders that are effectively connected with a U.S. trade or business of such holder may be subject to a branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

A non-U.S. holder of our common stock may obtain a refund of any excess amounts withheld if the non-U.S. holder is eligible for a reduced rate of United States withholding tax and an appropriate claim for refund is timely filed with the Internal Revenue Service.

Gain on Disposition of Common Stock

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

- the gain is effectively connected with a U.S. trade or business of the non-U.S. holder and, if required by an applicable tax treaty, is attributable to a U.S. permanent establishment maintained by such non-U.S. holder;

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met; or

- our common stock constitutes a U.S. real property interest by reason of our status as a "U.S. real property holding corporation," or "USRPHC," for U.S. federal income tax purposes. Generally, a corporation is a USRPHC if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we are, and will remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes.

Unless an applicable tax treaty provides otherwise, gain described in the first bullet point above will be subject to U.S. federal income tax on a net income basis (that is, after allowance for any applicable deductions) at the same graduated rates generally applicable to U.S. persons. Corporate non-U.S. holders also may be subject to a branch profits tax equal to 30% (or such lower rate as may be specified by an applicable tax treaty) of such gain.

Gain described in the second bullet point above (which may be offset by certain U.S. source capital losses recognized in the same taxable year in which such gain was recognized) will generally be subject to a 30% U.S. federal tax (or such lower rate as may be specified by an applicable tax treaty).

With respect to the third bullet point above, if we are or become a USRPHC, so long as our common stock is regularly traded on an established securities market (within the meaning of applicable Treasury Regulations), shares of our common stock will be treated as U.S. real property interests only with respect to a non-U.S. holder who holds or has held, directly or indirectly, at any time within the shorter of the five-year period preceding the disposition or the non-U.S. holder's holding period, more than 5% of our common stock. If the exception described above does not apply to gain recognized by a non-U.S. holder, unless an applicable tax treaty provides otherwise, such gain generally will be subject to U.S. federal income tax on a net income basis at the same graduated rates generally applicable to U.S. persons.

Backup Withholding and Information Reporting

Payments of dividends to a non-U.S. holder may be subject to backup withholding (currently at a 28% rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, backup withholding may apply if either we or our paying agent has actual knowledge, or reason to know, that the beneficial owner is a U.S. person that is not an exempt recipient.

Generally, we must report annually to the IRS the amount of dividends paid to each non-U.S. holder, the name and address of the recipient, and the amount, if any, of tax withheld with respect to those dividends. A similar report is sent to each non-U.S. holder. These information reporting requirements apply even if withholding was not required. Pursuant to tax treaties or other agreements, the IRS may make its reports available to tax authorities in the recipient's country of residence.

Payments of the proceeds from sale or other disposition by a non-U.S. holder of our common stock effected outside the U.S. by or through a foreign office of a broker generally will not be subject to information reporting or backup withholding. However, information reporting (but not backup withholding) will apply to those payments if the broker does not have documentary evidence that the holder is a non-U.S. holder, an exemption is not otherwise established, and the broker has certain relationships with the United States.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, information reporting and backup withholding may apply if the broker has actual knowledge, or reason to know, that the holder is a U.S. person that is not an exempt recipient.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained, provided that the required filings are timely made with the IRS.

Estate Tax

Our common stock owned or treated as owned by an individual who is not a citizen or resident of the U.S. (as specifically defined for U.S. federal estate tax purposes) at the time of death will be includible in the individual's gross estate for U.S. federal estate tax purposes and may be subject to U.S. federal estate tax unless an applicable estate tax treaty provides otherwise.

Legislation Affecting Common Stock Held Through Foreign Accounts

Legislation enacted in 2010, but not yet effective, may impose a withholding tax on certain types of U.S. source payments made to "foreign financial institutions" and certain other non-U.S. entities. The legislation generally will impose a 30% withholding tax on dividends on, or gross proceeds from the sale or other disposition of, our common stock paid to a foreign financial institution or to a foreign non-financial entity, unless (1) the foreign financial institution undertakes certain diligence and reporting obligations or (2) the foreign non-financial entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner. If applicable, the withholding tax is imposed whether the foreign entity receives a payment as beneficial owner or as agent and whether the beneficial owner is a U.S. holder or a non-U.S. holder. If the payee is a foreign financial institution, in order to avoid withholding under these provisions, it must enter into an agreement with the U.S. Treasury Department requiring, among other things, that it undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to account holders whose actions prevent it from complying with these reporting and other requirements. Under certain circumstances, a non-U.S. holder may be eligible for refunds or credits of such taxes. Although this legislation by its terms is applicable to payments made after December 31, 2012, in recent guidance the IRS has indicated that Treasury Regulations will be issued providing that the withholding provisions described above will first apply to payments of dividends on our common stock made on or after January 1, 2014 and to payments of gross proceeds from a sale or other disposition of such stock on or after January 1, 2015. Non-U.S. holders are encouraged to consult their tax advisors regarding the potential application of this new legislation to, and its effects on, their ownership and disposition of our common stock.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated , 2012 we and the selling stockholders have agreed to sell to the underwriters named below, for whom Credit Suisse Securities (USA) LLC and Goldman, Sachs & Co. are acting as representatives, the following respective numbers of shares of common stock:

Underwriter	Number of Shares
Credit Suisse Securities (USA) LLC	
Goldman, Sachs & Co	
Total	

The underwriting agreement provides that the underwriters are obligated to purchase all the shares of common stock in the offering if any are purchased, other than those shares covered by the option to purchase additional shares described below. The underwriting agreement also provides that if an underwriter defaults, the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated.

The selling stockholders have granted to the underwriters a 30-day option to purchase on a pro rata basis up to additional shares at the initial public offering price less the underwriting discounts and commissions.

The underwriters propose to offer the shares of common stock initially at the public offering price on the cover page of this prospectus and to selling group members at that price less a selling concession of $ per share. The underwriters and selling group members may allow a discount of $ per share on sales to other broker/dealers. After the initial public offering the representatives may change the public offering price and concession and discount to broker/dealers. The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters' right to reject any order in whole or in part.

The following table summarizes the compensation and estimated expenses we and the selling stockholders will pay:

	Per Share		Total	
	Without option to purchase additional shares	With option to purchase additional shares	Without option to purchase additional shares	With option to purchase additional shares
Underwriting Discounts and Commissions paid by us	$	$	$	$
Expenses payable by us	$	$	$	$
Underwriting Discounts and Commissions paid by selling stockholders	$	$	$	$
[Expenses payable by the selling stockholders]	$	$	$	$

The representatives have informed us that they do not expect sales to accounts over which the underwriters have discretionary authority to exceed 5% of the shares of common stock being offered.

We have agreed that we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the SEC a registration statement under the Securities Act relating to any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any offer, sale, pledge, disposition or filing, without the prior written consent of [Credit Suisse Securities (USA) LLC and Goldman, Sachs & Co.] for a period of 180 days after the date of this prospectus[, except issuances pursuant to the exercise of employee stock options outstanding on the date hereof.][2] However, in the event that either (1) during the last 17 days of the "lock-up" period, we release earnings results or material news or a material event relating to us occurs or (2) prior to the expiration of the "lock-up" period, we

[2] ***[NTD: other carve outs to be discussed.]***

announce that we will release earnings results during the 16-day period beginning on the last day of the ‘lock-up’ period, then in either case the expiration of the ‘lock-up” will be extended until the expiration of the 18-day period beginning on the date of the release of the earnings results or the occurrence of the material news or event, as applicable, unless [Credit Suisse Securities (USA) LLC and Goldman, Sachs & Co.] waive, in writing, such an extension.

Our officers and directors, the selling stockholders and the non-selling stockholders have agreed that they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction that would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any offer, sale, pledge or disposition, or to enter into any transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of [Credit Suisse Securities (USA) LLC and Goldman, Sachs & Co.] for a period of 180 days after the date of this prospectus. However, in the event that either (1) during the last 17 days of the “lock-up” period, we release earnings results or material news or a material event relating to us occurs or (2) prior to the expiration of the “lock-up” period, we announce that we will release earnings results during the 16-day period beginning on the last day of the “lock-up” period, then in either case the expiration of the “lock-up” will be extended until the expiration of the 18-day period beginning on the date of the release of the earnings results or the occurrence of the material news or event, as applicable, unless [Credit Suisse Securities (USA) LLC and Goldman, Sachs & Co.] waive, in writing, such an extension.

We and the selling stockholders have agreed to indemnify the underwriters against liabilities under the Securities Act, or contribute to payments that the underwriters may be required to make in that respect.

We will apply to list the shares of common stock on the New York Stock Exchange under the symbol “UTE.”

In connection with the listing of the common stock on the New York Stock Exchange, the underwriters will undertake to sell round lots of 100 shares or more to a minimum of 400 beneficial owners.

[NTD: insert disclosure re: DSP as applicable]

Prior to this offering, there has been no public market for our common stock. The initial public offering price for our common stock will be determined by negotiation between us, the selling stockholders and the underwriters. The principal factors to be considered in determining the initial public offering price include the following:

- the general condition of the securities markets;
- market conditions for initial public offerings;
- the market for securities of companies in businesses similar to ours;
- the history and prospects for the industry in which we compete;
- our past and present operations and earnings and our current financial position;
- the history and prospects for our business;
- an assessment of our management; and
- other information included in this prospectus and otherwise available to the underwriters.

We cannot assure you that the initial public offering price will correspond to the price at which our common stock will trade in the public market subsequent to this offering or that an active trading market will develop and continue after this offering.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for us, for which they received or will receive customary fees and expenses. ***[NTD: add/identify specific relationships between banks and issuer]***

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

In connection with the offering the underwriters may engage in stabilizing transactions, short sales, syndicate covering transactions, and penalty bids in accordance with Regulation M under the Exchange Act.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Short sales involve sales by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of shares sold by the underwriters is not greater than the number of shares that they may purchase in the option to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in the option to purchase additional shares. The underwriters may close out any covered short position by either exercising their option to purchase additional shares and/or purchasing shares in the open market.

- Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the option to purchase additional shares. If the underwriters sell more shares than could be covered by the option to purchase additional shares, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

A prospectus in electronic format may be made available on the web sites maintained by one or more of the underwriters, or selling group members, if any, participating in this offering and one or more of the underwriters participating in this offering may distribute prospectuses electronically. The representatives may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the underwriters and selling group members that will make internet distributions on the same basis as other allocations.

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), each underwriter has represented and agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date) it has not made and will not make an offer of shares to the public in that Relevant Member State prior to the publication of a prospectus in relation to the shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of shares to the public in that Relevant Member State at any time:

(a) to legal entities which are authorised or regulated to operate in the financial markets or, if not so authorised or regulated, whose corporate purpose is solely to invest in securities;

(b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last annual or consolidated accounts;

(c) to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representatives for any such offer; or

(d) in any other circumstances which do not require the publication by the Issuer of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of shares to the public" in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe the shares, as the same may be varied in that Relevant Member State by any measure implementing the Prospectus Directive in that Relevant Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

United Kingdom

Each underwriter has represented and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 200 or "FMSA") received by it in connection with the issue or sale of the shares in circumstances in which Section 21(1) of the FSMA does not apply to the Issuer; and

(b) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the shares in, from or otherwise involving the United Kingdom.

Hong Kong

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

Japan

The securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

LEGAL MATTERS

The validity of our common stock offered by this prospectus will be passed upon for Ute Energy Corporation by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

The financial statements of Ute Energy Upstream Holdings LLC as of and for the year ended December 31, 2010, have been included herein in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon on the authority of said firm as experts in auditing and accounting.

The financial statements of Ute Energy Upstream Holdings LLC as of December 31, 2009 and for the years ended December 31, 2008 and 2009 included in this prospectus have been so included in reliance on the report of Ehrhardt Keefe Steiner & Hottman PC, Denver, Colorado, independent registered public accounting firms, given on the authority of said firm as experts in auditing and accounting

The information included in this prospectus regarding estimated quantities of proved reserves, the future net revenues from those reserves and their present value is based, in part, on estimates of the proved reserves and present values of proved reserves as of December 31, 2010, 2009 and 2008. The reserve estimates are based on reports prepared by Ryder Scott and Cawley Gillespie, independent reserve engineers. These estimates are included in this prospectus in reliance upon the authority of such firms as an expert in these matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act, with respect to the shares of our common stock offered hereby. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information with respect to us and the common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed therewith. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of this contract, agreement or other document. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. A copy of the registration statement, and the exhibits and schedules thereto, may be inspected without charge at the public reference facilities maintained by the SEC at 100 F Street NE, Washington, D.C. 20549. Copies of these materials may be obtained, upon payment of a duplicating fee, from the Public Reference Section of the SEC at 100 F Street NE, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facility. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the SEC's website is http://www.sec.gov.

After we have completed this offering, we will file annual, quarterly and current reports, proxy statements and other information with the SEC. We expect to have an operational website concurrently with the completion of this offering and we expect to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus. You may read and copy any reports, statements or other information on file at the public reference rooms. You can also request copies of these documents, for a copying fee, by writing to the SEC, or you can review these documents on the SEC's website, as described above. In addition, we will provide electronic or paper copies of our filings free of charge upon request.

INDEX TO FINANCIAL STATEMENTS

Insert auditors’ reports – KPMG and EKS&H

UTE ENERGY UPSTREAM HOLDINGS LLC
BALANCE SHEETS

	December 31, 2010	December 31, 2009
ASSETS	**(in thousands)**	
Current assets:		
Cash and cash equivalents	$ 67	$ 162
Accounts receivable	9,035	1,328
Commodity derivative assets	582	-
Other current assets	116	63
Total current assets	9,800	1,552
Property and equipment (successful efforts method), at cost:		
Proved oil and gas property costs	112,514	48,081
Unproved oil and gas property costs	4,862	1,073
Other property and equipment	74	-
Less: accumulated depletion, depreciation and amortization	(28,605)	(14,858)
Total property and equipment, net	88,845	34,296
Other noncurrent assets:		
Commodity derivative assets	344	-
Unamortized debt issue costs	672	-
Advances to operators and other assets	-	1,558
Total other noncurrent assets	1,016	1,558
Total assets	$ 99,661	$ 37,407
LIABILITIES AND OWNER'S EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 18,667	$ 4,501
Commodity derivative liabilities	1,153	490
Total current liabilities	19,820	4,991
Long-term liabilities:		
Long-term debt	10,000	-
Commodity derivative liabilities	2,324	446
Asset retirement obligations	966	636
Total noncurrent liabilities	13,290	1,082
Commitments and contingencies (Note X)		
Owner's equity:		
Parent investment	66,551	31,334
Total owner's equity	66,551	31,334
Total liabilities and owner's equity	$ 99,661	$ 37,407

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC
STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	**2009**	**2008**
	(in thousands)		
Oil and gas revenue	$ 38,834	$ 10,119	$ 14,124
Operating expenses:			
Lease operating expenses	4,466	1,658	2,046
Production taxes	2,860	1,998	996
Gathering and transportation expenses	2,274	1,113	800
Depreciation, depletion and amortization	13,852	5,594	7,792
Impairment of proved properties	-	-	1,354
Exploration expenses	60	40	-
General and administrative expenses	3,237	1,067	1,653
Total operating expenses	26,749	11,470	14,641
Income (loss) from operations	12,085	(1,351)	(517)
Other income (expense):			
Net loss on commodity derivatives	(534)	(1,832)	-
Interest expense	(439)	(274)	(339)
Interest and other income	35	38	76
Total other expense	(938)	(2,068)	(263)
Net income (loss)	$ 11,147	$ (3,419)	$ (780)
Pro forma information:			
Net income as reported	$ 11,147	$ (3,419)	$ (780)
Pro forma adjustment for income tax (expense) benefit	(3,807)	1,395	411
Pro forma net income	$ 7,340	$ (2,024)	$ (369)
Basic and diluted net income (loss) per share			
Weighted average number of shares outstanding:			
Basic			
Diluted			

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC
STATEMENTS OF CHANGES IN OWNER'S EQUITY

	Parent investment (in thousands)
Balance at December 31, 2007	$ 5,928
Parent contributions	17,649
Net loss	(780)
Balance at December 31, 2008	$ 22,796
Parent contributions	11,955
Net loss	(3,418)
Balance at December 31, 2009	$ 31,334
Parent contributions	24,071
Net income	11,146
Balance at December 31, 2010	$ 66,551

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC

STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010	2009	2008
	(in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 11,146	$ (3,418)	$ (780)
Adjustments to reconcile net income (loss) to cash flows from operating activities:			
Depreciation, depletion and amortization	13,852	5,594	7,792
Impairment of proved properties	-	-	1,354
Other	(67)	-	-
Unrealized loss on commodity derivative activities	1,616	936	-
Change in operational assets and liabilities:			
Accounts receivable	(7,707)	(780)	299
Other assets	1,505	(1,347)	(274)
Accounts payable and accrued expenses	2,773	(2,295)	1,269
Net cash provided by operating activities	23,118	(1,310)	9,660
Cash flows from investing activities:			
Additions to oil and gas properties	(53,010)	(9,197)	(27,247)
Leasehold and acquisition costs	(3,407)	(1,294)	(51)
Net cash (used in) investing activities	(56,417)	(10,491)	(27,298)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	21,500	-	-
Repayments of borrowings under credit facilities	(11,500)	-	-
Contributions from Parent	24,071	11,955	17,649
Debt issue costs	(866)	-	-
Net cash provided by financing activities	33,205	11,955	17,649
Net increase (decrease) in cash and cash equivalents	(94)	153	10
Cash and cash equivalents, beginning of period	163	10	-
Cash and cash equivalents, end of period	$ 69	$ 163	$ 10
Supplemental cash flow information:			
Cash interest paid	168	-	-
Supplemental non-cash investing activities:			
Current liabilities incurred to finance oil and gas properties	12,466	1,869	3,443
Asset retirement obligations from new wells	485	104	217

UTE ENERGY UPSTREAM HOLDINGS LLC
NOTES TO FINANCIAL STATEMENTS

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in thousands of dollars.

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Ute Energy Upstream Holdings LLC, a Delaware limited liability company formed on April 15, 2008, is an independent oil and natural gas company engaged in the exploration, development, production and acquisition of crude oil and natural gas reserves focused primarily on developing crude oil reserves in the Uinta Basin in Utah. Unless the context requires otherwise, references to "we", "us", "our", "Ute" or "the Company" are intended to reference Ute Energy Upstream Holdings LLC. Our parent company, Ute Energy LLC ("Parent"), was formed by the Ute Indian Tribe of the Uintah and Ouray Reservation (the "Tribe") in 2005 to participate in the exploration and development of the Tribe's mineral estate in the Uinta Basin. Although we were formed in 2008, we had no assets or operating activities until March 2010. In March 2010, our Parent assigned all of its oil and gas participation rights and other oil and gas assets as well as the related costs to theCompany.Oil and gas assets subsequently acquired by our Parent were also assigned to us. This transfer of interests was accounted for as a transaction between entities under common control which requires us to record the conveyances at our Parent's historical basis applied retrospectively to the financial statements of all prior periods of the Company beginning January 1, 2008.

Basis of Presentation

Throughout the periods covered by these financial statements, our Parent has provided working capital to fund our operations through capital contributions and allocations of borrowings under its credit facility. The effect of this activity is reflected as Parent contributions or borrowings under Parent credit facility in the accompanying financial statements.

The accompanying financial statements and related notes present our financial position as of December 31, 2010 and 2009, and the results of our operations,cash flows and changes in owner's equity for the years ended December 31, 2010, 2009 and 2008.We have prepared our financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP").

In preparing the accompanying financial statements, we have reviewed, as determined necessary by us, events that have occurred after December 31, 2010, up until the issuance of the financial statements. See Note[11].

Note 2—Accounting Policies and Related Matters

*Allocation of Costs.*These financial statements include the direct costs of operations and employees dedicated to the Upstream operations, as well as an allocation of indirect general and administrative costs in accordance with Staff Accounting Bulletin ("SAB") Topic 1-B "Allocations of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity." The Parent allocations include charges in addition to those direct costs that were incurred by the upstream operations based upon estimates of activities related to the operation and administration of the upstream operations. Additionally, our Parent has funded our operations through cash contributions and has allocated to us interest costs on the related long-term debt on a basis consistent with its cost of capital.As a result, certain assumptions and estimates were made in order to allocate a reasonable share of such expenses to us, so that the amounts included in the accompanying financial statements attributable reflect substantially all of the costs of doing business. Such allocations may or may not reflect future costs associated with our operations.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimates relating to certain oil and natural gas revenues and expenses, (2) estimating oil and gas reserve quantities which impacts DD&A and impairment, (3) developing fair value assumptions, including estimates of future cash flows and discount rates, (4) estimating our asset retirement obligations, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) the allocation of certain corporate costs from our Parent. Actual results may differ materially from estimated amounts.

*Cash and Cash Equivalents.*Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Accounts Receivable and Concentration of Credit Risk. The Company's accounts receivables consist mainly of receivables from oil and gas purchasers on our operated properties and from partners on our non-operated properties for our share of oil and gas sales. Although diversified among several companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. The Company records an allowance for doubtful accounts on a case-by-case basis once there is evidence that collection is not probable. Receivables are not collateralized. As of December 31, 2010, and 2009, the Company had no allowance for doubtful accounts recorded.

Derivative Instruments. We use commodity derivative instruments to manage our exposure to oil and gas price volatility. All of the commodity derivative instruments are utilized to manage price risk attributable to our expected oil and gas production, and we do not enter into such instruments for speculative trading purposes. We do not designate any derivative instruments as hedges for accounting purposes. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We record realized gains and losses from the settlement of commodity derivative instruments and unrealized gains and losses from the change in fair value of the derivatives as components of other income and expense. We currently do not utilize any derivatives to manage our exposure to variable interest rates, but may do so in the future.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note [3] for a more detailed discussion of our derivative activities.

Oil and Gas Properties and Other Equipment

Proved Oil and Gas Properties. We follow the successful efforts method of accounting for our oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying statements of cash flows. The costs of development wells are capitalized whether those wells are successful or unsuccessful. Geological and geophysical costs, delay rentals and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization ("DD&A") of capitalized costs related to proved oil and gas properties is calculated on a project area-by-project area basis using the units-of-production method based upon proved developed reserves. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major improvements, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

We review our proved oil and gas properties for impairment whenever events and circumstances indicate that the carrying value of the properties may not be recoverable. When determining whether impairment has occurred, the expected undiscounted future cash flows of our oil and gas properties are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to the estimated fair value. The factors used to determine fair value are subject to management's judgment and include, but are not limited to, recent sales prices of comparable properties, estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. These assumptions represent Level 3 inputs, as further discussed in Note [4]. We recorded no impairment on proved oil and natural gas properties for the years ended December 31, 2010 and 2009 and recorded $1.4 million for the year ended December 31, 2008.

Unproved Oil and Gas Properties. Unproved oil and natural gas property costs are transferred to proved oil and natural gas properties if the properties are subsequently determined to be productive and are assigned proved reserves. Unproved properties consist of costs incurred to acquire unproved leases. Lease acquisition costs are capitalized until the leases expire or when specifically identified leases revert to the lessor, at which time the associated lease acquisition costs are expensed. Unproved properties are periodically evaluated for impairment on a property-by-property basis based on several factors, including remaining lease terms, drilling results or future plans to develop acreage and we record impairment expense for any decline in value. We recorded no impairment charge for the years ended December 31, 2010, 2009 and 2008.

*Oil and Gas Reserves.*The estimates of proved oil and natural gas reserves utilized in the preparation of the financial statements are estimated in accordance with the rules established by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB"), which subsequent to December 31, 2008 require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. TheCompany's annual reserve estimates were prepared by third-party petroleum engineers. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

In January 2010, the FASB issued an Accounting Standards Update ("ASU"), Oil and Gas Reserve Estimations and Disclosures. This update aligns the current oil and natural gas reserve estimation and disclosure requirements of ASC Topic 932, Extractive Activities — Oil and Gas, with the requirements in the SEC's final rule, Modernization of Oil and Gas Reporting Requirements (the "Final Rule"), which was issued on December 31, 2008 and was effective for the year ended December 31, 2009. The Final Rule was designed to modernize and update the oil and natural gas disclosure requirements to align with current practices and changes in technology.

The Final Rule permits the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Final Rule will also allow, but not require, companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009. The Company's 2009 and 2010 depletion calculations were based upon proved reserves that were determined using the new reserve rules.The depletion calculation in 2008 was based on the prior SEC methodology.

Sales of Proved and Unproved Properties. The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent the sales price exceeds the carrying amount of the unproved property. A gain or loss is recognized for all other sales of nonproducing properties and is included in the results of operations.

Other Property and Equipment. Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets which range from one to three years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt under the effective interest method.

Asset Retirement Obligations ("*AROs*"). We recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. We deplete the amount added to proved oil and gas property costs and recognize expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Refer to Note [5].

*Income Taxes.*We are not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our Parent's individual members.

These financial statements have been prepared in anticipation of a proposed initial public offering ("IPO") of our common stock. In connection with the IPO, we will convert into a Delaware corporation and will be treated as a corporation under the Internal Revenue Code and will be subject to federal income taxes. Accordingly, a pro forma income tax provision has been disclosed as if we were a corporation for all periods presented. We have computed pro forma tax expense using a 35% corporate-level federal tax rate. The effective tax rate includes a corporate level state income tax rate with consideration to apportioned income for each state of operation. This combined rate is adjusted for permanent differences.

Revenue Recognition. We earn revenue primarily from the sale of produced crude oil and natural gas. We report revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we estimate the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of properties, their historical performance, anticipated effect of weather conditions during the month of production, New York Mercantile Exchange ("NYMEX") and local spot market prices, and other factors as the basis for these estimates. We use the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company.

Recent Accounting Pronouncements

In December 2010, the FASB issued an accounting standards update relating to disclosure of supplementary pro forma information for business combinations. This guidance provides clarification on disclosure requirements and amends current guidance to require entities to disclose pro forma revenue and earnings of the combined entity as though the acquisition date for all business combinations that occurred during the current year had been as of the beginning of the comparable prior annual reporting period. Qualitative disclosures describing the nature and amount of any material, nonrecurring pro forma adjustments directly attributable to the business combinations included in the reported pro forma revenue and earnings are also required. This guidance is effective for business combinations with acquisition dates on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, with early adoption permitted. This pronouncement affects only disclosures and did not impact our financial condition and results of operations.

In May 2011, the FASB issued an accounting standards update related to fair value measurements and disclosures to improve the comparability offair value measurements presented and disclosed in financial statements prepared in accordance with United States GAAP and International FinancialReporting Standards. This guidance includes amendments that clarify the intent about the application of existing fair value measurement requirements, while other amendments change a principle or requirement for measuring fair value or for disclosing information about fair value measurements. Specifically, the guidance requires additional disclosures for fair value measurements that are based on significant unobservable inputs. The updated guidance is to be applied prospectively and is effective for our interim and annual periods beginning January 1, 2012. The adoption of this guidance is not expected to have a material impact on our financial condition, results of operations or cash flows.

In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and nonrecurring fair value measurements, and is effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The adoption of this guidance did not have a significant impact on our financial position, results of operations or cash flows.

Note 3—Commodity Derivative Instruments

We hedge a portion of our crude oil sales using derivative instruments that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude. This exposes us to a market basis differential risk if the NYMEX futures do not move in exact parity with our underlying sales of crude oil produced in the Uinta Basin. Additionally, we use both NYMEX futures based upon the sale of Henry Hub ("HH") natural gas as well as fixed price and basis swaps for natural gas sold on the Rocky Mountains Northwest pipeline ("NWPL") index.

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using risk adjusted discounted cash flow calculations. Cash flows are based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair values of our derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of instruments in a liability position include a measure of our own nonperformance risk. Due to the volatility of commodity prices, the estimated fair values of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. Refer to Note [4].

At December 31, 2010, the notional volumes of our commodity derivatives and their settlement periods were as follows:

Commodity	Index	Instrument	Unit	2011	2012	2013	2014	2015
Oil	WTI	Swap	Bbl	159,100	87,800	105,250	88,000	64,400
Oil	WTI	Collar	Bbl	36,000	46,000	-	-	-
Natural Gas	HH	Swap	MMBtu	450,000	108,000	-	-	-
Natural Gas	NWPL	Basis Swap	MMBtu	450,000	359,004	-	-	-
Natural Gas	NWPL	Swap	MMBtu	259,000	416,204	423,500	358,300	261,600

The following schedules reflect the fair values of derivative instruments in our financial statements:

Derivative Assets			Derivative Liabilities		
Balance Sheet Location	Fair Value 2010	Fair Value 2009	Balance Sheet Location	Fair Value 2010	Fair Value 2009
Current assets	$ 582	$ -	Current liabilities	$ 1,153	$ 490
Long-term assets	344	-	Long-term liabilities	2,324	446
	$ 926	$ -		$ 3,477	$ 936

As we do not apply hedge accounting, our earnings are affected by the use of the mark-to-market method of accounting for derivative financial instruments. The changes in fair value of these instruments are recognized through earnings as other income or expense rather than being deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. The ultimate gain or loss upon settlement of these transactions is also recognized in earnings as other income or expense.

We recognized the following gains (losses) in earnings for the years indicated:

		Amount of gain (loss) recognized in income Year Ended December 31,		
	Location of gain (loss)	2010	2009	2008
Gain (loss) on settled commodity derivatives	Other income (expense)	$ 1,082	$ (896)	$ -
Loss on unrealized commodity derivatives	Other income (expense)	(1,616)	(936)	-
		$ (534)	$ (1,832)	$ -

Commodity Price Risk

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of oil and natural gas. The prices of oil and natural gas are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on our business.

In an effort to reduce the variability of our cash flows we have hedged the commodity prices associated with a portion of our expected oil and natural gas volumes for the years 2011 through 2015 by entering into derivative financial instruments including swaps and zero cost collars. With swaps, we typically receive an agreed upon fixed price for a specified notional quantity of oil or natural gas and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. We utilize zero cost collars by obtaining a put (floor) and call (ceiling) to mitigate additional price volatility. Our commodity derivatives may expose us to the risk of financial loss in certain circumstances. Our derivative arrangements provide us protection on the hedged volumes if market prices decline below the prices at which these derivatives are set. If market prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Derivative Counterparty Risk

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by our counterparties.

Our counterparty credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to us at the reporting date. These outstanding instruments expose us to credit risk in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of December 31, 2010, affiliates of BP accounted for all of our counterparty credit exposure related to commodity derivative instruments. BP is a major integrated oil and gas company possessing investment grade credit ratings based upon minimum credit ratings assigned by Standard& Poor's Ratings Services.

Note 4—Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value of financial and non-financial assets and liabilities. Financial assets and liabilities are measured at fair value on a recurring basis. Non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, are recognized at fair value on a non-recurring basis.

We categorize the inputs to the fair value of our financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date; Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include non-exchange-traded derivatives such as over-the-counter forwards, swaps and options.

- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value and we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2010 and 2009. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

As of December 31, 2010	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 926	$ -	$ 926	$ -
Liabilities from commodity derivative contracts	3,477	-	3,477	-

As of December 31, 2009	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ -	$ -	$ -	$ -
Liabilities from commodity derivative contracts	936	-	936	-

Fair Value of Other Financial Instruments

The carrying value of our credit facilities approximates their fair values, as the interest rates are based on prevailing market rates.The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments.

Assets and Liabilities Measured on a Non-recurring Basis

We review our proved and unproved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Our analysis takes into account several factors, including future cash flows, the determination of the values of any possible or probable reserves, and, if applicable, appropriate risk-weighting discounts, all of which would be classified within Level 3.

Additionally, we use fair value to determine the inception value of its asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates for costs that would be incurred to restore leased property to the contractually stipulated condition and would generally be classified within Level 3.

Note 5—Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost.

Our asset retirement obligations are included in our balance sheets as a component of other long-term liabilities. The changes in our aggregate asset retirement obligations at the dates indicated are as follows:

	Year ended December 31,		
	2010	2009	2008
Beginning of period	$ 636	$ 491	$ 129
Additions	485	104	217
Change in cash flow estimate	(260)	-	-
Accretion expense	105	41	145
End of period	$ 966	$ 636	$ 491

Note 6—Debt Obligations

Credit Facility

On March 9, 2010, weentered into a credit agreement which provided for a three-year $100.0 million credit facility. This facility matures March 9, 2013. The borrowing base is required to be redetermined twice per year. Future borrowing bases will be computed based on proved natural gas and oil reserves, hedge positions and estimated future cash flows from those reserves, as well as any other outstanding debt of the Company.

Borrowings under the facility bear interest, at the Company's election, at a London Interbank Offered Rate ("LIBOR") or a base rate (as defined in the Upstream Facility), plus in each case an applicable margin based on the utilization percentage of the facility. The applicable margin varied from 2.75% to 3.50% for LIBOR rate loans and 1.75% to 2.50% for base rate loans. LIBOR and base rate loans are subject to a floor of 2.00%. The Company paid an annual commitment fee of 0.5% of the unused amount of the commitments. The weighted average interest rate on the Upstream Facility was 4.9% during 2010.

The facility is secured by oil and natural gas properties representing at least 80% of the value of our proved reserves, a pledge of our stock and a parent guarantee from Ute Energy LLC. The facility contains certain covenants, including among others, restrictions on indebtedness, restrictions on liens, restrictions on mergers, restrictions on investments, restrictions on dividends and payments to our Parent, and restrictions on hedging activity. The financial covenants require Upstream to maintain a current ratio (as defined) of at least 1.0 to 1.0, an interest coverage ratio (as defined) of at least 3.0 to 1.0 and a leverage ratio (as defined) not greater than 3.0 to 1.0. We were in compliance with its financial covenants as of December 31, 2010.

As of December 31, 2010, we had $10.0 million drawn out of $25.0 million available under the borrowing base on the facility.

Subsequent to year-end, this facility was paid down and closed in conjunction with our Parent entering into a new global credit facility. Refer to Note [X].

Note 7—Management Incentive Units

Our Parent sponsors an Amended Management Incentive Plan ("the Amended Plan") authorized in 2010 in which Management Incentive Units ("MIUs") may be granted to employees, contractors and strategic partners at the discretion of management. The MIUs are considered profits interests and participate in certain distribution events of the Parent only after certain return thresholds are met by all other classes of member interests. The Amended Plan provides for up to 2.6 million of MIUs to be issued.

Compensation expense for these awards will be recognized when all performance, market and service conditions are probable of being satisfied. Accordingly, no fair value was assigned to the MIUs upon issuance and as the payout is still uncertain there is deemed to be no fair value at December 31, 2010.

Note 8—Commitments and Contingencies

We entered into various office space leases, and other leases of property and equipment under non-cancelable agreements that require fixed monthly rental payments and expire at various periods in the future. As of December 31, 2010, we had the following non-cancelable commitments:

2011	$	1,047
2012 (1)		329
2013		10,329
2014		
2015		
Thereafter		-
Total	$	11,705

(1) Includes the repayment of the current amounts outstanding under our Upstream Facility at maturity in 2013.

Legal Proceedings

We are not a party to any legal proceedings, regulatory proceedings, or claims, suits or complaints which, if resolved unfavorably, would have a material effect on our financial position, results of operations, or cash flows.

Note 9—Related-Party Transactions

Relationship with the Ute Indian Tribe

The Tribe holds three of seven Board of Managers seats and owns51% of our Parent. We occasionally enter into transactions with the Tribe and its affiliates.We incurred $0.1 million, $0.1 million and $[X.X] million in transactions with the Tribe during 2010, 2009 and 2008.

Relationship with Quantum

Quantum Energy Partners and Quantum Resources Management (collectively, "Quantum"), own 49% of Upstream based upon their equity ownership in our Parent. We incurred $[0.7] million, $[0.5] million and $[0.9] million in expenses with Quantum in 2010, 2009 and 2008.

Note 10—Unaudited Supplemental Oil and Gas Disclosures (Unaudited)

Costs Incurred

The following table sets forth the capitalized costs incurred in our oil and gas production, exploration and development activities:

	Year ended December 31,		
	2010	2009	2008
Development costs	$ 61,945	$ 10,226	$ 27,738
Asset retirement obligation	485	104	217
Acquisition of unproved properties	3,789	255	571
	$ 66,219	$ 10,585	$ 28,526

Oil and Gas Reserve Quantities

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2010, 2009 and 2008 that were prepared by internal petroleum engineers in accordance with guidelines established by the SEC and were audited by the Company's independent petroleum engineering firm Ryder Scott Company, LPin 2010 and Cawley Gillespie and Associates, Inc. in 2009 and 2008

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Our proved reserves are located entirely within the United States.

The following table sets forth information regarding the Company's estimated net total proved and proved developed oil and gas reserve quantities:

	Oil (MBbls)	Gas (MMcf)	Liquids (MBbls)	Total (Mboe)
Proved reserves:				
Balance December 31, 2007				
Acquisitions of reserves				
Extensions, discoveries and other additions				
Revisions of previous estimates				
Sales of reserves				
Production				
Balance December 31, 2008	627	2,434	14	1,046
Acquisitions of reserves	-	-	-	-
Extensions, discoveries and other additions	1,078	2,640	44	1,562
Revisions of previous estimates	1,998	4,349	39	2,762
Sales of reserves	(3)	(150)	-	(28)
Production	(165)	(571)	(6)	(266)
Balance December 31, 2009	3,535	8,702	91	5,076
Acquisitions of reserves	-	-	-	-
Extensions, discoveries and other additions	4,579	10,714	111	6,476
Revisions of previous estimates	(513)	(859)	(9)	(664)
Sales of reserves	-	-	-	-
Production	(509)	(1,241)	(8)	(724)
Balance December 31, 2010	7,092	17,316	185	10,164
Proved developed reserves				
December 31, 2008				
December 31, 2009	905	3,055	37	1,451
December 31, 2010	2,493	7,077	73	3,747
Proved undeveloped reserves				
December 31, 2008				
December 31, 2009	2,630	5,647	54	3,625
December 31, 2010	4,599	10,239	111	6,417

During 2010, the Company increased its total proved reserves by 5.1 MMBOE. Proved developed reserves increased 2.3 MMBOE, or 45% of the total increase in proved reserves. Proved undeveloped reserves increased 2.8 MMBOE or 55% of total increased in proved reserves.

ADD TO NARRATIVE FROM MD&A – and create 2008 analysis

The Company's proved developed reserve additions were a result of ongoing development drilling in the Blacktail Ridge, Bridgeland and Monument Butte EDAs. The increase in the Company's proved undeveloped reserves results subsequent drilling location availability as a result of development drilling in the previously mentioned areas.

Standardized Measure of Discounted Future Net Cash Flows

For the years ended December 31, 2010, 2009 and 2008, future cash inflows are calculated by applying the current SEC 12-month average pricing of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. For the year ended December 31, 2010, calculations were made using SEC prices of $67.87 per Bbl WTI index for oil, $3.82 per MMBtu Henry Hub index for gas and $56.40 per Bbl Mt. Belvieu index for NGLs For the year ended December 31, 2009, calculations were made using SEC prices of $61.18 per Bbl WTI index for oil, $3.87 per MMBtu for Henry Hub index for gas and $42.83 per Bbl Mt Belvieu index for NGLs.

The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

A 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves. As a limited liability company, we are a pass through entity for tax purposes. The effect of future net income taxes has been excluded from the standardized measure of discounted future net cash flows.

The following table presents the standardized measure of discounted net cash flows related to proved oil and gas reserve for the periods indicated:

	Year ended December 31,		
	2010	**2009**	**2008**
Future cash inflows	$ 557,962	$ 203,702	
Future production costs	(250,506)	(77,948)	
Future development costs	(117,062)	(59,938)	
Future net cash flows	190,394	65,817	-
10% annual discount	(77,786)	(36,302)	
Standardized measure of discounted future net cash flows	$ 112,608	$ 29,515	$ -

The present value (at a 10% annual discount) of future net cash flows from the Company's proved reserves is not necessarily the same as the current market value of its estimated oil and natural gas reserves. The Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs in effect on the day of estimate in accordance with the applicable accounting guidance. However, actual future net cash flows from its oil and natural gas properties will also be affected by factors such as actual prices the Company receives for oil and natural gas, the amount and timing of actual production, supply of and demand for oil and natural gas and changes in governmental regulations or taxation.

The timing of both the Company's production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% annual discount factor the Company uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry in general.

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year ended December 31,		
	2010	2009	2008
Standardized measure of discounted future net cash flows, beginning of period	$ 29,515	$ 10,278	
Sales of oil and gas, net of production costs and taxes	(31,907)	(3,716)	
Extensions, discoveries and improved recovery, less related costs	70,681	11,808	
Revisions of previous quantity estimates	(4,047)	6,887	
Net changes in prices and production costs	21,811	144	
Previously estimated development costs incurred during the period	7,470	425	
Changes in estimated future development costs	5,640	1,078	
Accretion of discount	2,951	1,028	
Acquisitions of reserves	-	-	
Sales of reserves	-	(261)	
Changes in production rates (timing) and other	10,494	1,844	
Standardized measure of discounted future net cash flows, end of period	$ 112,608	$ 29,515	$ -

Note 10—-Subsequent Events

Revolving Credit Facility

On May 27, 2011, our Parent paid down the outstanding balance on our credit facility in connection with our Parent entering into a new revolving credit facility. Unamortized debt issue costs of $0.8 million were written-off and charged to expense at the pay-off date.

The Parent credit facility had an initial global borrowing base of $90 million comprised of an oil and gas borrowing base of $[X] million and a midstream borrowing base of $[X] million. As of the date of this report, the Parent facility had a $180 million borrowing base of which $135 million was based on the upstream oil and gas assets.

Randlett Acquisition

On April 20, 2011, we acquired approximately5,291net acres and seven producing wells in the Randlett area of the Uinta Basin. The fair value of the assets acquired was $5.0 million and the purchase price wascomprised of a $2.5 million cash payment and a conditional obligation of $2.5 million, subject to closing adjustments. The conditional obligation was resolved in July 2011 by the action of one of our shareholders.The remaining $2.5 million was recognized in equity as a capital contribution.

Bridgeland Acreage Acquisition

On June, 15, 2011, we acquired approximately 3,964 undeveloped net acres under an Area of Mutual Interest election in our Bridgeland project area of the Uinta Basin for $12.1 million.

Horseshoe Bend Acquisition

On November 30, 2011, we acquired approximately 29,281 net acres and 50 producing wells in the Horseshoe Bend project area and approximately 6,062 net acres in the Randlett project area of the Uinta Basin for $100 million in cash, subject to customary post-closing adjustments. Refer to the Horseshoe Bend Acquisition Properties financial statements elsewhere in this prospectus.

UTE ENERGY UPSTREAM HOLDINGS LLC

BALANCE SHEETS

(UNAUDITED)

	September 30, 2011	December 31, 2010
ASSETS	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 217	$ 67
Accounts receivable	14,165	9,035
Commodity derivative assets	13,485	582
Materials inventory	529	-
Other current assets	46	116
Total current assets	28,441	9,800
Property and equipment (successful efforts method), at cost:		
Proved oil and gas property costs	216,748	112,514
Unproved oil and gas property costs	22,877	4,862
Other property and equipment	234	74
Less: accumulated depletion, depreciation and amortization	(49,022)	(28,605)
Total property and equipment, net	190,837	88,845
Other noncurrent assets:		
Commodity derivative assets	20,330	344
Unamortized debt issue costs	2,214	672
Total other noncurrent assets	22,544	1,016
Total assets	$ 241,823	$ 99,661
LIABILITIES AND OWNER'S EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 35,376	$ 18,667
Commodity derivative liabilities	7	1,153
Total current liabilities	35,383	19,820
Long-term liabilities:		
Long-term debt	36,847	10,000
Commodity derivative liabilities	184	2,324
Asset retirement obligations	1,705	966
Total noncurrent liabilities	38,736	13,290
Owner's equity:		
Parent investment	167,704	66,551
Total owner's equity	167,704	66,551
Total liabilities and owner's equity	$ 241,823	$ 99,661

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC

STATEMENTS OF OPERATIONS

(UNAUDITED)

	Nine Months Ended September 30,	
	2011	**2010**
	(in thousands)	
Oil and gas revenue	$ 56,871	$ 26,434
Operating expenses:		
Lease operating expenses	7,503	2,539
Production taxes	2,741	2,437
Gathering and transportation expenses	3,586	1,546
Depreciation, depletion and amortization	20,508	9,313
Exploration expense	68	59
General and administrative expenses	5,235	1,635
Total operating expenses	39,641	17,530
Income from operations	17,229	8,904
Other income (expense):		
Net gain on commodity derivatives	35,657	3,383
Interest expense	(945)	(283)
Write-off deferred debt issue costs	(814)	-
Interest and other income (expense)	-	(16)
Total other income	33,898	3,084
Net income	$ 51,127	$ 11,988
Pro forma information:		
Net income as reported	$ 51,127	$ 11,988
Pro forma adjustment for income tax (expense) benefit	(18,699)	(4,306)
Pro forma net income	$ 32,428	$ 7,682
Basic and diluted net income (loss) per share		
Weighted average number of shares outstanding:		
Basic		
Diluted		

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC
STATEMENTS OF CHANGES IN OWNER'S EQUITY
(UNAUDITED)

		Parent investment
Balance at December 31, 2009	$	31,334
Parent contributions		24,071
Net income		11,146
Balance at December 31, 2010	$	66,551
Parent contributions		50,027
Net income		51,126
Balance at September 30, 2011	$	167,704

The accompanying notes are an integral part of these financial statements.

UTE ENERGY UPSTREAM HOLDINGS LLC
STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30,	
	2011	**2010**
Cash flows from operating activities:	**(in thousands)**	
Net income	$ 51,126	$ 11,988
Adjustments to reconcile net income to cash flows		
from operating activities:		
Depreciation, depletion and amortization	20,508	9,313
Write-off deferred debt issue costs	814	-
Amortization of debt issue costs	141	154
Unrealized gain on commodity derivative activities	(36,175)	(2,271)
Change in operational assets and liabilities:		
Accounts receivable	(5,130)	(5,655)
Other assets	71	1,573
Accounts payable and accrued expenses	2,202	(76)
Net cash provided by operating activities	33,557	15,026
Cash flows from investing activities:		
Additions to oil and gas properties	(88,394)	(29,994)
Leasehold and acquisition costs	(19,391)	(357)
Net cash (used in) investing activities	(107,785)	(30,351)
Cash flows from financing activities:		
Debt borrowed under Parent credit facility	36,847	-
Borrowings under credit facility	22,500	11,500
Repayments of borrowings under credit facility	(32,500)	(11,500)
Contributions from Parent	50,027	19,409
Debt issue costs	(2,497)	(793)
Net cash provided by financing activities	74,377	18,615
Net increase in cash and cash equivalents	149	3,290
Cash and cash equivalents, beginning of period	67	162
Cash and cash equivalents, end of period	$ 216	$ 3,452
Supplemental cash flow information:		
Cash interest paid	239	131
Supplemental non-cash investing activities:		
Current liabilities incurred to finance oil and gas properties	22,670	17,780
Asset retirement obligations from new wells	630	468

UTE ENERGY UPSTREAM HOLDINGS LLC
NOTES TO FINANCIAL STATEMENTS
(UNAUDITED)

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in thousands of dollars.

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Ute Energy Upstream Holdings LLC, a Delaware limited liability company formed on April 15, 2008, is an independent oil and natural gas company engaged in the exploration, development, production and acquisition of crude oil and natural gas reserves focused primarily on developing crude oil reserves in the Uinta Basin in Utah. Unless the context requires otherwise, references to "we", "us", "our", "Ute" or "the Company" are intended to reference Ute Energy Upstream Holdings LLC. Our parent company, Ute Energy LLC ("Parent"), was formed by the Ute Indian Tribe of the Uintah and Ouray Reservation (the "Tribe") in 2005 to participate in the exploration and development of the Tribe's mineral estate in the Uinta Basin. Although we were formed in 2008, we had no assets or operating activities until March 2010. In March 2010, our Parent assigned all of its oil and gas participation rights and other oil and gas assets as well as the related costs to theCompany. Oil and gas assets subsequently acquired by our Parent were also assigned to us. This transfer of interests was accounted for as a transaction between entities under common control which requires us to record the conveyances at our Parent's historical basis applied retrospectively to the financial statements of all prior periods of the Company beginning January 1, 2008.

Basis of Presentation

Throughout the periods covered by these financial statements, our Parent has provided working capital to fund our operations through capital contributions and allocations of borrowings under its credit facility. The effect of this activity is reflected as Parent contributions or borrowings under Parent credit facility in the accompanying financial statements.

The accompanying unaudited financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information. Pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"), they do not include all of the information and footnotes required by GAAP for complete financial statements. In the opinion of management, the accompanying unaudited financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of September 30, 2011, the Company's results of operations, changes in owner's equity and cash flows for the nine months ended September 30, 2011 and 2010. Operating results for the nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas and oil, natural production declines, timing of development and exploration activities, the uncertainty of exploration and development drilling results and other factors. For a more complete understanding of the Company's operations, financial position and accounting policies, these financial statements should be read in conjunction with the Company's audited financial statements included elsewhere in this report.

In preparing the accompanying financial statements, we have reviewed, as determined necessary by us, events that have occurred after September 30, 2011, up until the issuance of the financial statements. See Note [9].

Note 2—Accounting Policies and Related Matters

*Allocation of Costs.*These financial statements include the direct costs of operations and employees dedicated to the Upstream operations, as well as an allocation of indirect general and administrative costs in accordance with Staff Accounting Bulletin ("SAB") Topic 1-B "Allocations of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity." The Parent allocations include charges in addition to those direct costs that were incurred by the upstream operations based upon estimates of activities related to the operation and administration of the upstream operations. Additionally, our Parent has funded our operations through cash contributions and have allocated to us interest costs on the related long-term debt on a basis consistent with their cost of capital. As a result, certain assumptions and estimates were made in order to allocate a reasonable share of such expenses to us, so that the amounts included in the accompanying financial statements attributable reflect substantially all of the costs of doing business. The debt allocations made at September 30, 2011 were made based upon actual draws on the Parent facility made to fund our operations. Such allocations may or may not reflect future costs associated with our operations.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimates relating to certain oil and natural gas revenues and expenses, (2) estimating oil and gas reserve quantities which impacts DD&A and impairment, (3) developing fair value assumptions, including estimates of future cash flows and discount rates, (4) estimating our asset retirement obligations, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) the allocation of certain corporate costs from our Parent. Actual results may differ materially from estimated amounts.

*Cash and Cash Equivalents.*Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Accounts Receivable and Concentration of Credit Risk. The Company's accounts receivables consist mainly of receivables from oil and gas purchasers on our operated properties and from partners on our non-operated properties for our share of oil and gas sales. Although diversified among several companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. The Company records an allowance for doubtful accounts on a case-by-case basis once there is evidence that collection is not probable. Receivables are not collateralized. As of September 30, 2011 and December 31, 2010, the Company had no allowance for doubtful accounts recorded.

Derivative Instruments. We use commodity derivative instruments to manage our exposure to oil and gas price volatility. All of the commodity derivative instruments are utilized to manage price risk attributable to our expected oil and gas production, and we do not enter into such instruments for speculative trading purposes. We do not designate any derivative instruments as hedges for accounting purposes. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We record realized gains and losses from the settlement of commodity derivative instruments and unrealized gains and losses from the change in fair value of the derivatives as components of other income and expense. We currently do not utilize any derivatives to manage our exposure to variable interest rates, but may do so in the future.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note [3] for a more detailed discussion of our derivative activities.

Oil and Gas Properties and Other Equipment

Proved Oil and Gas Properties. We follow the successful efforts method of accounting for our oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying consolidated statements of cash flows. The costs of development wells are capitalized whether those wells are successful or unsuccessful. Geological and geophysical costs, delay rentals and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization ("DD&A") of capitalized costs related to proved oil and gas properties is calculated on a project-by-project basis using the units-of-production method based upon proved developed reserves. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major improvements, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

We review our proved oil and gas properties for impairment whenever events and circumstances indicate that the carrying value of the properties may not be recoverable. When determining whether impairment has occurred, the expected undiscounted future cash flows of our oil and gas properties are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to the estimated fair value. The factors used to determine fair value are subject to management's judgment and include, but are not limited to, recent sales prices of comparable properties, estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. We recorded no impairment on proved oil and natural gas properties for the nine months ended September 30, 2011 and 2010.

Materials Inventory. The Company's materials inventory is primarily comprised of tubular goods and well equipment to be used in future drilling operations. Inventory is charged to specific wells and transferred into oil and gas properties when used. Materials inventory is valued at the lower of cost or market and totaled $0.6 million at September 30, 2011. We had no inventory at December 31, 2010. There were no materials inventory write downs for the nine months ended September 30, 2011.

*Oil and Gas Reserves.*The estimates of proved oil and natural gas reserves utilized in the preparation of the financial statements are estimated in accordance with the rules established by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB"), which subsequent to December 31, 2008 require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. TheCompany's annual reserve estimates were prepared by third-party petroleum engineers. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Unproved Oil and Gas Properties. Unproved oil and natural gas property costs are transferred to proved oil and natural gas properties if the properties are subsequently determined to be productive and are assigned proved reserves. Unproved properties consist of costs incurred to acquire unproved leases. Lease acquisition costs are capitalized until the leases expire or when specifically identified leases revert to the lessor, at which time the associated lease acquisition costs are expensed. Unproved properties are periodically evaluated for impairment on a property-by-property basis based on several factors, including remaining lease terms, drilling results or future plans to develop acreage and records impairment expense for any decline in value. We recorded no impairment charge for the nine months ended September 30, 2011 and 2010.

Sales of Proved and Unproved Properties. The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent the sales price exceeds the carrying amount of the unproved property. A gain or loss is recognized for all other sales of nonproducing properties and is included in the results of operations.

Other Property and Equipment. Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets which range from one to three years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt under the effective interest method.

Asset Retirement Obligations ("*AROs*"). We recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. We deplete the amount added to proved oil and gas property costs and recognize expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Refer to Note [5].

*Income Taxes.*We are not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our Parent's individual members.

These financial statements have been prepared in anticipation of a proposed initial public offering ("IPO") of our common stock. In connection with the IPO, we will convert into a Delaware corporation and will be treated as a corporation under the Internal Revenue Code and will be subject to federal income taxes. Accordingly, a pro forma income tax provision has been disclosed as if we were a corporation for all periods presented. We have computed pro forma tax expense using a 35% corporate-level federal tax rate. The effective tax rate includes a corporate level state income tax rate with consideration to apportioned income for each state of operation. This combined rate is adjusted for permanent differences.

Revenue Recognition. We earn revenue primarily from the sale of produced crude oil and natural gas. We report revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we estimate the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of properties, their historical performance, anticipated effect of weather conditions during the month of production, New York Mercantile Exchange ("NYMEX") and local spot market prices, and other factors as the basis for these estimates. We use the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company.

Note 3—Commodity Derivative Instruments

We hedge a portion of our crude oil sales using derivative instruments that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude. This exposes us to a market basis differential risk if the NYMEX futures do not move in exact parity with our underlying sales of crude oil produced in the Uinta Basin. Additionally, we use both NYMEX futures based upon the sale of Henry Hub ("HH") natural gas as well as fixed price and basis swaps for natural gas sold on the Rocky Mountains Northwest pipeline ("NWPL") index.

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using risk adjusted discounted cash flow calculations. Cash flows are based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair values of our derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of instruments in a liability position include a measure of our own nonperformance risk. Due to the volatility of commodity prices, the estimated fair values of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. Refer to Note [4].

At September 30, 2011, the notional volumes of our commodity derivatives and their settlement periods were as follows:

Commodity	Index	Instrument	Unit	2011	2012	2013	2014	2015	2016
Oil	WTI	Swap	Bbl	250,089	1,343,956	1,436,077	176,263	150,236	45,519
Oil	WTI	Collar	Bbl	15,000	46,000	-	222,567	175,169	82,397
Natural Gas	HH	Swap	MMBtu	101,500	359,004	-	-	-	-
Natural Gas	NWPL	Basis Swap	MMBtu	101,500	359,004	-	-	-	-
Natural Gas	NWPL	Swap	MMBtu	53,200	165,200	423,500	358,300	261,600	-

The following schedules reflect the fair values of derivative instruments in our financial statements:

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
Balance Sheet Location	September 30, 2011	December 31, 2010	Balance Sheet Location	September 30, 2011	December 31, 2010
Current assets	$ 13,485	$ 582	Current liabilities	$ 7	$ 1,153
Long-term assets	20,330	344	Long-term liabilities	184	2,324
	$ 33,815	$ 926		$ 191	$ 3,477

The fair value of derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets.

As we do not apply hedge accounting, our earnings are affected by the use of the mark-to-market method of accounting for derivative financial instruments. The changes in fair value of these instruments are recognized through earnings as other income or expense rather than being deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. The ultimate gain or loss upon settlement of these transactions is also recognized in earnings as other income or expense.

We recognized the following gains (losses) in earnings for the periods indicated:

		Amount of gain (loss) recognized in income Nine Months Ended September 30,	
	Location of gain (loss)	**2011**	**2010**
Gain (loss) on settled commodity derivatives	Other income (expense)	$ (518)	$ 1,112
Gain on unrealized commodity derivatives	Other income (expense)	36,175	2,271
		$ 35,657	$ 3,383

Note 4—Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value of financial and non-financial assets and liabilities. Financial assets and liabilities are measured at fair value on a recurring basis. Non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, are recognized at fair value on a non-recurring basis.

We categorize the inputs to the fair value of our financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date; Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include non-exchange-traded derivatives such as over-the-counter forwards and options.

- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value andwe do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

As of September 30, 2011	**Total**	**Level 1**	**Level 2**	**Level 3**
Assets from commodity derivative contracts	$ 33,815	$ -	$ 33,815	$ -
Liabilities from commodity derivative contracts	191	-	191	-

As of December 31, 2010	**Total**	**Level 1**	**Level 2**	**Level 3**
Assets from commodity derivative contracts	$ 926	$ -	$ 926	$ -
Liabilities from commodity derivative contracts	3,477	-	3,477	-

Fair Value of Other Financial Instruments

The carrying value of our credit facilities approximates their fair values, as the interest rates are based on prevailing market rates. The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments.

Assets and Liabilities Measured on a Non-recurring Basis

We review our proved and unproved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Our analysis takes into account several factors, including future cash flows, the determination of the values of any possible or probable reserves, and, if applicable, appropriate risk-weighting discounts, all of which would be classified within Level 3.

Additionally, we use fair value to determine the inception value of its asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates for costs that would be incurred to restore leased property to the contractually stipulated condition and would generally be classified within Level 3.

Note 5—Asset Retirement Obligations

Our asset retirement obligations are included in our consolidated balance sheets as a component of other long-term liabilities. The changes in our aggregate asset retirement obligations at the dates indicated are as follows:

	Nine Months Ended September
Beginning of period	$ 966
Additions	647
Accretion expense	91
End of period	$ 1,704

Note 6—Debt Obligations

Credit Facility

On March 9, 2010, we entered into a credit agreement which provided for a three-year $100.0 million credit facility. This facility matures March 9, 2013. The borrowing base is required to be redetermined twice per year. Future borrowing bases will be computed based on proved natural gas and oil reserves, hedge positions and estimated future cash flows from those reserves, as well as any other outstanding debt of the Company.

Borrowings under the facility bear interest, at the Company's election, at a London Interbank Offered Rate ("LIBOR") or a base rate (as defined in the creditfacility), plus in each case an applicable margin based on the utilization percentage of the facility. The applicable margin varied from 2.75% to 3.50% for LIBOR rate loans and 1.75% to 2.5% for base rate loans. LIBOR and base rate loans are subject to a floor of 2.00%. The Company pays an annual commitment fee of 0.5% of the unused amount of the commitments. The weighted average interest rate on the Upstream Facility was 4.9% during 2010.

On May 27, 2011, we repaid the outstanding balance on our credit facility in connection with our Parent entering into a new consolidated credit facility. The remaining $0.8 million of unamortized debt issue costs were written-off and recognized in the statement of operations for the nine months ended September 30, 2011.

Allocated Debt from Parent

Our Parent has allocated a portion of the amount due under its credit facility to us as we intend to assume a portion of this debt upon the consumation of the offering transaction. At September 30, 2011, we had $36.8 million of debt allocated to us by our Parent. Additionally, our Parent has allocated interest expense and a portion of the deferred debt issue costs associated with the facility to us. For the nine months ended September 30, 2011, we have recognized $0.9 million in interest expense. At September 30, 2011, we had recorded $2.2 million of allocated debt issue costs on our balance sheet.

Our Parent entered into the new facility on May 27, 2011 which initially provided for a five-year $300 million credit facility with an initial borrowing base of 95 million. This borrowing base was increased through subsequent redeterminations and at December [X], 2011 had a total borrowing base of $180 million, $135 million of which is based on the upstream oil and gas assets.

Borrowings under the facility bear interest at a London Interbank Offered Rate ("LIBOR") or a base rate (as defined in the agreement, plus in each case an applicable margin based on the utilization percentage of the facility. The applicable margin varied from 2.0% to 3.0% for LIBOR rate loans and 1.0% to 2.0% for base rate loans. The weighted average interest rate on the facility was 4.9% for the nine months ended September 31, 2011.

The facility is secured by oil and natural gas properties representing at least 80% of the value of our proved reserves, a pledge of our stock and a parent guarantee from Ute Energy LLC. The facility contains certain covenants, including among others, restrictions on indebtedness, restrictions on liens, restrictions on mergers, restrictions on investments, restrictions on dividends and payments to our Parent, and restrictions on hedging activity. We were in compliance with its financial covenants as of December 31, 2010.

Note 7–-Subsequent Events

Horseshoe Bend Acquisition

On November 30, 2011 we closed on an acquisition of 35,343 acres and 50 producing wells in the Horseshoe Bend area of the Uinta Basin for $100 million in cash, subject to customary post-closing adjustments.

HOG AUDIT OPINION

HORSESHOE BEND ACQUISITION PROPERTIES
STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES
(in thousands)

	Year Ended December 31,		Nine Months Ended September 30	
	2010	2009	2011	2010
			(unaudited)	
Oil and gas revenue	$ 6,522	$ 2,762	$ 6,044	$ 5,112
Direct operating expenses	1,476	1,167	1,370	1,166
Revenues in excess of direct operating expenses	$ 5,046	$ 1,595	$ 4,674	$ 3,946

The accompanying notes are an integral part of these financial statements.

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in thousands of dollars.

Note 1—Organization, Operations and Basis of Presentation

Basis of Presentation

On October 14, 2011, Ute Energy Upstream Holdings LLC ('the Company," "we" or "us") entered into a definitive purchase and sale agreement ("PSA") to acquire approximately 35,343 acres of properties along with 50 producing wells in the Horseshoe Bend area of the Uinta Basin in Utah ("Horseshoe Bend Properties"). The aggregate purchase price is approximately $100 million in cash, subject to customary post-closing adjustments, and closed on November 30, 2011.

The accompanying historical statements of operating revenues and direct operating expenses were prepared by us based on carved out financial information and data from Horseshoe Bend's historical accounting records. These statements are not intended to be a complete presentation of the results of operations of Horseshoe Bend as they do not include general and administrative expenses, interest income or expense, depreciation, depletion, and amortization, any provision for income tax expenses and other income and expense items not directly associated with operating revenues from oil and gas. Historical financial statements reflecting financial position, results of operations, and cash flows required by accounting principles generally accepted in the United States are not presented as such information is not readily available on an individual property basis and not meaningful to the acquired properties. Accordingly, the accompanying statements are presented in lieu of the financial statements required under Rule 3–05 of Securities and Exchange Commission Regulation S–X.

Certain indirect expenses, as further described in Note 2, were not allocated to the Horseshoe Bend Properties and have been excluded from the accompanying statements. Any attempt to allocate these expenses would require significant and judgmental allocations, which would be arbitrary and may not be indicative of the performance of the properties on a stand-alone basis.

Note 2—Accounting Policies and Related Matters

Use of Estimates. The preparation of the statements of operating revenues and direct operating expenses in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of operating revenues and direct operating expenses during the respective reporting periods. Actual results may differ from the estimates and assumptions used in the preparation of the statements of operating revenues and direct operating expenses.

Revenue Recognition. The Horseshoe Bend properties use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. There were no significant imbalances with other revenue interest owners during any of the periods presented in these statements.

*Direct Operating Expenses.*Direct expenses, which are recognized on an accrual basis, relate to the direct expenses of operating the Horseshoe Bend properties. The direct expenses include lease operating, ad valorem tax and production tax expense. Lease operating expenses include lifting costs, well repair expenses, surface repair expenses, well workover costs and other field expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment and facilities directly related to oil and natural gas production activities.

*Contingencies.*The activities of the Horseshoe Bend properties are subject to potential claims and litigation in the normal course of operations. We do not believe that any liability resulting from any pending or threatened litigation will have a materially adverse effect on the operations or financial results of theHorseshoe Bend properties.

Excluded Expenses. The Horseshoe Bend Properties were part of a much larger enterprise prior to the date of the sale. Indirect general and administrative expenses, interest, income taxes, and other indirect expenses were not allocated to the Horseshoe Bend Properties and have been excluded from the accompanying statements. In addition, any allocation of such indirect expenses may not be indicative of costs which would have been incurred by the Horseshoe Bend Properties on a stand-alone basis. Also, depreciation, depletion, and amortization have been excluded from the accompanying statements of revenues and direct expenses as such amounts would not be indicative of the depletion calculated on the Horseshoe Bend Properties on a stand-alone basis.

Note 3—Supplemental Oil and Gas Reserve Information (Unaudited)

Estimated quantities of proved oil and gas reserves for Horseshoe Bend were derived from reserve estimates prepared by the Company as prior year reserve studies were not available. In preparing reserve data for the years ended December 31, 2010 and 2009, we developed these disclosures based on an internal reserve study dated September 30, 2011, adjusting for actual production and changes in prices for the intervening periods. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated quantities of oil and gas to be produced in the future. The resulting future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor. Future operating costs are determined based on estimates of expenditures to be incurred in producing the proved oil and gas reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus overhead incurred. Future development costs are determined based on estimates of capital expenditures to be incurred in developing proved oil and gas reserves.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. Reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The following reserve quantity and future net cash flow information was prepared by the Company based on information provided by the Horseshoe Bend properties.

	Oil (MBbls)	Gas (MMcf)	Total (Mboe)
Proved reserves:			
Balance December 31, 2008	385	1	385
Acquisitions of reserves	-	-	-
Extensions, discoveries and other additions	3,139	-	3,139
Revisions of previous estimates	57	-	57
Sales of reserves	-	-	-
Production	(61)	-	(61)
Balance December 31, 2009	3,521	1	3,520
Acquisitions of reserves	-	-	-
Extensions, discoveries and other additions	4,111	-	4,111
Revisions of previous estimates	219	-	219
Sales of reserves	-	-	-
Production	(101)	-	(101)
Balance December 31, 2010	7,750	1	7,749
Proved developed reserves			
December 31, 2009	511	1	511
December 31, 2010	706	1	706
Proved undeveloped reserves			
December 31, 2009	3,010	-	3,010
December 31, 2010	7,044	-	7,044

As of December 31, 2010 and 2009, Horseshoe Bend had estimated proved reserves of 7,750Mboe and 3,521 MBoe with a present value discounted at 10% of $45.9 million and $14.1 million. Horseshoe Bend's reserves are comprised almost entirely of crude oil.

The following values for the 2010 oil reserves are based on the 12 month arithmetic average first of month price January through December 31, 2010 crude oil price of $79.43 per barrel (West Texas Intermediate price). All prices are then further adjusted for transportation, quality and basis differentials.

The following table presents the standardized measure of discounted net cash flows related to proved oil and gas reserve for the periods indicated:

	Year ended December 31, 2010	Year ended December 31, 2009
Future cash inflows	$ 504,795	$ 176,654
Future production costs	(180,089)	(71,618)
Future development costs	(161,126)	(55,159)
Future net cash flows	163,581	49,876
10% annual discount	(117,653)	(35,796)
Standardized measure of discounted future net cash flows	$ 45,927	$ 14,080

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year ended December 31, 2010	Year ended December 31, 2009
Standardized measure of discounted future net cash flows, beginning of period	$ 14,080	$ 4,974
Sales of oil and gas, net of production costs and taxes	(4,927)	(1,594)
Extensions, discoveries and improved recovery, less related costs	8,773	7,850
Revisions of previous quantity estimates	2,624	936
Net changes in prices and production costs	24,441	2,108
Previously estimated development costs incurred during the period	900	-
Changes in estimated future development costs	-	-
Accretion of discount	1,408	497
Acquisitions of reserves	-	-
Sales of reserves	-	-
Changes in production rates (timing) and other	(1,372)	(691)
Standardized measure of discounted future net cash flows, end of period	$ 45,927	$ 14,080

UTE ENERGY CORPORATION
UNAUDITED CONDENSED COMBINED PRO FORMA FINANCIAL STATEMENTS

Introduction

The following tables present our unaudited pro forma condensed combined statements of operations for the year ended December 31, 2010 and for the nine months ended September 30, 2011, and our unaudited pro forma condensed combined balance sheet as of September 30, 2011.

Our unaudited pro forma condensed combined financial statements have been developed by applying pro forma adjustments to our historical financial statements appearing elsewhere in this prospectus. The unaudited pro forma condensed combined statements of operations data for the periods presented give effect to our conversion from a Delaware limited liability company to a Delaware corporation and the Horseshoe Bend Properties Acquisition ("Horseshoe Bend"), which closed on November 30, 2011, as if they had been completed on January 1, 2010. The unaudited pro forma condensed combined balance sheet data gives effect to the conversion and the Horseshoe Bend acquisition as if they had occurred on September 30, 2011. We describe the assumptions underlying the pro forma adjustments in the accompanying notes, which should be read in conjunction with these unaudited pro forma condensed combined financial statements.

The pro forma adjustments related to the purchase price allocation of the Horseshoe Bend acquisition are preliminary and are subject to revision as additional information becomes available. Revisions to the preliminary purchase price allocation may have a significant impact on the pro forma amounts of total assets, total liabilities and owner's equity, and depreciation, depletion and amortization expense. The pro forma adjustments related to the Horseshoe Bend acquisition reflect the fair values allocated to our assets as of November 30, 2011 and do not necessarily reflect the fair values that would have been recorded if the acquisition had occurred on January 1, 2010.

The unaudited pro forma condensed combined financial statements should be read in conjunction with the information contained in "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes thereto, included elsewhere in this prospectus.

The unaudited pro forma condensed consolidated financial statements are included for informational purposes only and do not purport to reflect our results of operations or financial position that would have occurred had the Horseshoe Bend acquisition and conversion occurred on the dates assumed, and they therefore should not be relied upon as being indicative of our results of operations or financial position had the conversion or the Horseshoe Bend acquisition occurred on the dates assumed. The unaudited condensed combined pro forma financial statements are also not a projection of our results of operations or financial position for any future period or date.

UTE ENERGY CORPORATION
PRO FORMA CONDENSED COMBINED BALANCE SHEET
September 30, 2011
(UNAUDITED)

	Ute Energy Upstream Holdings LLC	Horseshoe Bend Adjustments		Conversion Adjustments		Pro Forma
		(in thousands)				
ASSETS						
Current assets:						
Cash and cash equivalents	$ 217	$ 99,950	(a)			$ 217
		(99,950)	(b)			
						-
						-
Accounts receivable	14,165	-				14,165
Commodity derivative assets	13,485	-				13,485
Materials Inventory	529	-				529
Other current assets	46	-				46
Total current assets	28,442	-		-		28,442
Property and equipment (successful efforts method), at cost:						
Proved oil and gas property costs	216,748	40,091	(b)			256,839
Unproved oil and gas property costs	22,877	60,434	(b)			83,311
Other property and equipment	234					234
Less: accumulated depletion, depreciation and amortization	(49,022)	-				(49,022)
Total property and equipment, net	190,838	100,525		-		291,363
Other noncurrent assets:						
Commodity derivative assets	20,330	-				20,330
Unamortized debt issue costs	2,214	-				2,214
Total other noncurrent assets	22,544	-		-		22,544
Total assets	$ 241,823	$ 100,525		$ -		$ 342,348
LIABILITIES AND OWNER'S EQUITY						
Current liabilities:						
Accounts payable and accrued expenses	$ 35,376	$ -				$ 35,376
Deferred income tax liability	-	-		4,717	(c)	4,717
Commodity derivative liabilities	7	-		-		7
Total current liabilities	35,383	-		4,717		40,100
Long-term liabilities:						
Long-term debt	36,847	23,450	(a)			85,797
		25,500	(a)			
Deferred income tax liability	-	-		63,717	(c)	63,717
Commodity derivative liabilities	184	-				184
Asset retirement obligations	1,705	575	(b)	-		2,280
Total noncurrent liabilities	38,736	49,525		63,717		151,978
Commitments and contingencies (Note X)						
Owner's equity:						
Common stockholders' equity	-	51,000	(a)	-		(17,434)
				(68,434)	(g)	
Parent investment	167,704	-		-		167,704
Total owner's equity	167,704	51,000		(68,434)		150,270
Total liabilities and owner's equity	$ 241,823	$ 100,525		$ -		$ 342,348

See accompanying notes to unaudited pro forma combined financial statements

UTE ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

NINE MONTHS ENDED SEPTEMBER 30, 2011

	Ute Energy Upstream Holdings LLC	Horseshoe Bend Adjustments		Conversion Adjustments		Pro Forma
	(In thousands, except per share data)					
Oil and gas revenue	$ 56,871	$ 6,044		$ -		$ 62,914
Operating expenses:						
Lease operating expenses	7,503	1,073		-		8,576
Production taxes	2,741	263		-		3,004
Gathering and transportation expenses	3,586	34		-		3,620
Depreciation, depletion and amortization	20,508	1,585		-		22,093
Exploration expenses	68	-		-		68
General and administrative expenses	5,235	-		-		5,235
Total operating expenses	39,642	2,955		-		42,597
Income (loss) from operations	17,229	3,088		-		20,317
Other income (expense):						
Net loss on commodity derivatives	35,657	-		-		35,657
Interest expense	(945)	(2,150)				(3,095)
Write-off deferred debt issue costs	(814)	-		-		(814)
Total other expense	33,898	(2,150)		-		31,748
Income before income taxes	51,126	939		-		52,065
Income tax expense	-	(293)	**(b)**	(18,773)	**(c)**	(19,066)
Net income (loss)	$ 51,126	$ 646		$ (18,773)		$ 32,999
Net income per common share - basic and diluted						
Weighted average common shares outstanding - basic and diluted						

See accompanying notes to unaudited pro forma combined financial statements

UTE ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

YEAR ENDED DECEMBER 31, 2010

	Ute Energy Upstream Holdings LLC	Horseshoe Bend Adjustments		Conversion Adjustments		Pro Forma
	(In thousands, except per share data)					
Oil and gas revenue	$ 38,834	$ 6,522		$ -		$ 45,356
Operating expenses:						
Lease operating expenses	4,466	1,259		-		5,725
Production taxes	2,860	192		-		3,052
Gathering and transportation expenses	2,274	24		-		2,299
Depreciation, depletion and amortization	13,852	2,078		-		15,931
Exploration expenses	60	-		-		60
General and administrative expenses	3,237	-		-		3,237
Total operating expenses	26,750	3,554		-		30,304
Income (loss) from operations	12,084	2,968		-		15,052
Other income (expense):						
Net loss on commodity derivatives	(534)	-		-		(534)
Interest expense	(439)	(2,866)				(3,305)
Interest and other income	35	-		-		35
Total other expense	(938)	(2,866)		-		(3,804)
Income before income taxes	11,146	101		-		11,248
Income tax (expense) benefit	-	56	**(b)**	(3,765)	**(c)**	(3,709)
Net income (loss)	$ 11,146	$ 158		$ (3,765)		$ 7,538
Net income per common share - basic and diluted	$ -					
Weighted average common shares outstanding - basic and diluted	-					

See accompanying notes to unaudited pro forma combined financial statements

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in thousands of dollars.

Note 1—Basis of Presentation

The following tables present our unaudited pro forma condensed combined statements of operations for the year ended December 31, 2010 and for the nine months ended September 30, 2011, and our unaudited pro forma condensed combined balance sheet as of September 30, 2011.

Our unaudited pro forma condensed combined financial statements have been developed by applying pro forma adjustments to our historical financial statements appearing elsewhere in this prospectus. The unaudited pro forma condensed combined statements of operations data for the periods presented give effect to our conversion from a Delaware limited liability company to a Delaware corporation and the Horseshoe Bend Properties Acquisition ("Horseshoe Bend"), which closed on November 30, 2011, as if they had been completed on January 1, 2010. The unaudited pro forma condensed combined balance sheet data gives effect to the conversion and the Horseshoe Bend acquisition as if they had occurred on September 30, 2011.

Note 2—Pro Forma Adjustments and Assumptions

Horseshoe Bend Properties Acquisition

(a) Reflects sources of cash to fund the Horseshoe Bend acquisition consisting of the following:

Borrowings under Parent's 1st lien facility	$ 23,450
Borrowings under Parent's 2nd lien facility	25,500
Parent contribution	51,000
	$ 99,950

(b) Reflects our purchase of the Horseshoe Bend properties for approximately $100 million in cash. The following table shows our preliminary fair value determination of the assets acquired and liabilities assumed in the acquisition:

Proved oil and gas properties	$ 40,091
Unproved oil and gas properties	60,434
Asset retirement obligations	(575)
	$ 99,950

The purchase price allocation for the acquisition is preliminary and subject to customary post-closing adjustments.

Also reflects:

- Depreciation, depletion, amortization and accretion expense ("DD&A") based upon our estimates of proved reserves for the Horseshoe Bend properties and historical production volumes;
- Interest expense on approximately $80 million of borrowings pursuant to (a) above, allocated from our Parent's credit facility at an estimated annual rate of 2.98% on the 1st lien and 8.5% on the 2nd lien borrowings. A one percentage point change in the interest rate would change pro forma interest expense by $0.8 million for the year ended December 31, 2010 and $0.6 million for the nine months ended September 30, 2011.
- Income tax expense impacts pursuant to the conversion discussed below.

Conversion

(c) Reflects our conversion into a Delaware corporation for the periods presented. Prior to the conversion, we have been treated as a partnership for federal income tax purposes and therefore have not directly paid income taxes on our income nor have we benefitted from losses. Instead, our income and other tax attributes have been passed through to our owners for federal and, where applicable, state income tax purposes. Following the conversion, we will be treated as a corporation for tax purposes and will be required to pay federal and state income taxes. The unaudited pro forma condensed combined statements of operations reflect: (1) the tax expense we would have incurred had we been subject to tax as a corporation in the historical periods presented (those pro forma adjustments being presented in the conversion column), and (2) the tax effect of the acquisition accounting adjustments (those pro forma adjustments being presented in the Horseshoe Bend column). The unaudited pro forma condensed combined balance sheet reflects the impact of the conversion on our financial position to record deferred taxes related to the differences in the book and tax carrying values of our assets and liabilities as of September 30, 2011. As required under GAAP, upon completion of our conversion, the impact of recognizing deferred tax assets and liabilities will be recorded as a charge to income in the fiscal quarter in which the conversion occurs. As of September 30, 2011, the amount of the charge would have been $18.6 million.

Note 3—Pro Forma Net Income per Share

Pro forma net income per common share is determined by dividing the pro forma net income by the weighted average number of common shares expected to be outstanding. All shares were assumed to be outstanding since January 1, 2010.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this prospectus:

"*Bbl.*" One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"*Bcf.*" One billion cubic feet of natural gas.

"*Boe.*" Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"*British thermal unit.*" The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"*Basin.*" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion.*" The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Developed acreage.*" The number of acres that are allocated or assignable to productive wells or wells capable of production.

"*Developed reserves.*" Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well.

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

"*Dry hole.*" A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Economically producible.*" A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"*Environmental assessment.*" An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

"*Exploratory well.*" A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined below.

"*Field.*" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

"*Formation.*" A layer of rock which has distinct characteristics that differ from nearby rock.

"*Horizontal drilling.*" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*MBbl.*" One thousand barrels of crude oil, condensate or natural gas liquids.

"*MBoe.*" One thousand barrels of oil equivalent.

"*Mcf.*" One thousand cubic feet of natural gas.

"*MMBbl.*" One million barrels of crude oil, condensate or natural gas liquids.

"*MMBoe.*" One million barrels of oil equivalent.

"*MMBtu.*" One million British thermal units.

"*MMcf.*" One million cubic feet of natural gas.

"*NYMEX.*" The New York Mercantile Exchange.

"*Net acres.*" The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"*PV-10.*" When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Commission.

"*Productive well.*" A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Proved developed reserves.*" Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"*Proved reserves.*"

Under SEC rules for fiscal years ending on or after December 31, 2009, proved reserves are defined as:

Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Under SEC rules for fiscal years ending prior to December 31, 2009, proved reserves are defined as:

The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

"*Proved undeveloped reserves.*" Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"*Reasonable certainty.*" A high degree of confidence.

"*Recompletion.*" The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"*Reserves.*" Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.

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

"Service well." A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"*Spacing.*" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Stratigraphic test well.*" A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) exploratory-type, if not drilled in a proved area, or (ii) development-type, if drilled in a proved area.

"*Unit.*" The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore.*" The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

"*Working interest.*" The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Ute Energy

Part II

INFORMATION NOT REQUIRED IN PROSPECTUS

ITEM 13. *Other Expenses of Issuance and Distribution*

The following table sets forth an itemized statement of the amounts of all expenses (excluding underwriting discounts and commissions) payable by us in connection with the registration of the common stock offered hereby. With the exception of the Registration Fee, FINRA Filing Fee and New York Stock Exchange listing fee), the amounts set forth below are estimates. [The selling stockholders will not bear any portion of such expenses.]

SEC Registration Fee	$
FINRA Filing Fee	
New York Stock Exchange listing fee	
Accountants' fees and expenses	
Legal fees and expenses	
Printing and engraving expenses	
Transfer agent and registrar fees	
Total	$

ITEM 14. *Indemnification of Directors and Officers*

Our certificate of incorporation provides that a director will not be liable to the corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (1) for any breach of the director's duty of loyalty to the corporation or its stockholders, (2) for acts or omissions not in good faith or which involved intentional misconduct or a knowing violation of the law, (3) under section 174 of the DGCL for unlawful payment of dividends or improper redemption of stock or (4) for any transaction from which the director derived an improper personal benefit. In addition, if the DGCL is amended to authorize the further elimination or limitation of the liability of directors, then the liability of a director of the corporation, in addition to the limitation on personal liability provided for in our certificate of incorporation, will be limited to the fullest extent permitted by the amended DGCL. Our bylaws provide that the corporation will indemnify, and advance expenses to, any officer or director to the fullest extent authorized by the DGCL.

Section 145 of the DGCL provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses, including attorneys' fees, judgments, fines and amounts paid in settlement in connection with specified actions, suits and proceedings whether civil, criminal, administrative, or investigative, other than a derivative action by or in the right of the corporation, if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification extends only to expenses, including attorneys' fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation. The statute provides that it is not exclusive of other indemnification that may be granted by a corporation's certificate of incorporation, bylaws, disinterested director vote, stockholder vote, agreement or otherwise.

Our certificate of incorporation also contains indemnification rights for our directors and our officers. Specifically, our certificate of incorporation provides that we shall indemnify our officers and directors to the fullest extent authorized by the DGCL. Further, we may maintain insurance on behalf of our officers and directors against expense, liability or loss asserted incurred by them in their capacities as officers and directors.

We have obtained directors' and officers' insurance to cover our directors, officers and some of our employees for certain liabilities.

We will enter into written indemnification agreements with our directors and officers. Under these proposed agreements, if an officer or director makes a claim of indemnification to us, either a majority of the independent directors or independent legal counsel selected by the independent directors must review the relevant facts and make a determination whether the officer or director has met the standards of conduct under Delaware law that would permit (under Delaware law) and require (under the indemnification agreement) us to indemnify the officer or director.

ITEM 15. ***Recent Sales of Unregistered Securities***

[Furnish information required by S-K Item 701 w/ respect to all unregistered sales of securities within the last three years]

ITEM 16. ***Exhibits and Financial Statement Schedules***

(a) Exhibits

Exhibit Number	Description
*1.1	Form of Underwriting Agreement.
*3.1	Form of Certificate of Incorporation of Ute Energy Corporation.
*3.2	Form of Bylaws of Ute Energy Corporation.
*4.1	Form of Common Stock Certificate.
*5.1	Opinion of Vinson & Elkins L.L.P. as to the legality of the securities being registered.
10.1	Limited Liability Company Agreement of Ute Energy Upstream Holdings LLC.
10.2	First Amendment to Limited Liability Company Agreement of Ute Energy Upstream Holdings LLC.
*10.3	[Form of Ute Energy Corporation Credit Facility].
10.4	Employment Agreement between Ute Energy LLC and Joseph N. Jaggers.
10.5	Employment Agreement between Ute Energy LLC and Gregory S. Hinds.
10.6	Employment Agreement between Ute Energy LLC and Laurie A. Bales.
10.7	Employment Agreement between Ute Energy LLC and Todd R. Kalstrom.
10.8	Employment Agreement between Ute Energy LLC and Mark A. Shelby.
*10.9	Form of Employment Agreement between Ute Energy Corporation and each of the executive officers thereof.
*10.10	Form of Long-Term Incentive Plan of Ute Energy Corporation.
*10.11	Form of Indemnification Agreement between Ute Energy Corporation and each of its directors.
*21.1	List of Subsidiaries of Ute Energy Corporation.
23.1	Consent of KPMG.
23.2	Consent of Ehrhardt Keefe Steiner & Hottman PC.
23.3	Consent of Vinson & Elkins L.L.P. (included as part of Exhibit 5.1 hereto).
24.1	Power of Attorney (included on the signature page of the initial filing of the registration statement).
99.1	Report of Cawley Gillespie & Associates, Inc. for reserves as of December 31, 2008.
99.2	Report of Cawley Gillespie & Associates, Inc. for reserves as of December 31, 2009.
99.3	Report of Ryder Scott Company, L.P. for reserves as of December 31, 2010.

* To be filed by amendment.

ITEM 17. ***Undertakings***

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Denver, State of Colorado, on December [●], 2011.

UTE ENERGY UPSTREAM HOLDINGS LLC

By: /s/ Joseph N. Jaggers
Joseph N. Jaggers
President and Chief Executive Officer

Power of Attorney

Each person whose signature appears below appoints Joseph N. Jaggers and Laurie A. Bales, and each of them, any of whom may act without the joinder of the other, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this registration statement and any registration statement (including any amendment thereto) for this offering that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or either of them or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Joseph N. Jaggers Joseph N. Jaggers	President and Chief Executive Officer, Manager (Principal Executive Officer)	December [●], 2011
/s/ Laurie A. Bales Laurie A. Bales	Chief Financial Officer and Secretary (Principal Financial Officer) (Principal Accounting Officer)	December [●], 2011
/s/ S. Wil VanLoh Jr. S. Wil VanLoh, Jr.	Manager	December [●], 2011

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* To be filed by amendment.

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Uintah Basin Revitalization Fund

Overview

The Uintah Basin Revitalization Fund was created to maximize the long term benefit of oil and gas severance taxes derived from lands held in trust by the Federal Government for the Ute Tribe of the Uintah and Ouray Reservation. It was construed to promote cooperation and coordination between the state, its political subdivisions and the tribe.

Statutory Authority

The Uintah Basin Revitalization Fund (UBRF) is a program of the State of Utah authorized in Section 35A-8-1601, et seq. The goal of the UBRF is to provide grants and/or loans (primarily grants) to agencies of county and tribal government in the Uintah Basin, which are impacted by the development of oil and gas interests held in trust for the Ute Indian Tribe of the Uintah and Ouray Reservation and its members.

Board Membership

The UBRF is controlled by a five-member board (The Board) comprised of a governor's designee, a Duchesne County Commissioner, a Uintah County Commissioner and two representatives of the Ute Indian Tribe's Business Committee.

The Housing and Community Development Division (HCD) within the Utah Department of Workforce Service (DWS) provides administrative and operational support to the UBRF. This is accomplished through an application, contracting and tracking system at HCD. HCD administers the application, contracting, financial processes and all day to day operations of the fund.

Eligible Applicants

The UBRF Board may authorize grants and/or loans to agencies of Duchesne County, Uintah County or the Ute Indian Tribe that are or may be socially or economically impacted, directly or indirectly, by development of oil and gas interests held in trust for the Ute Indian

Program Information

- Community Impact Board
- Contact Us
- Permanent Community Impact Fund
- Uintah Basin Revitalization Fund
- Navajo Revitalization Fund
- Regional Planning Program
- Related Links

Tribe.

Formal applications for UBRF grants are submitted by the respective county commissions or the tribal Business Committee to HCD. HCD prepares the meeting agendas and arranges all meetings. The Board approves all applications and all decisions of the Board require four affirmative votes.

Eligible Projects

• Capital projects, including subsidized and low-income housing, and other one-time need projects and programs.

• Projects and programs associated with the geographic area where the oil and gas are produced.

Prohibited Activities

• Start-up or operational costs of private business ventures.

• General operating budgets of Duchesne County, Uintah County or the Ute Indian Tribe.

Funding Process

• The UBRF reviews applications and authorizes funding assistance on a periodic basis. Meetings are generally held quarterly. The majority of funded activities are for public facilities followed by utilities and housing.

Funding Guidelines

• Each year, generally at the August meeting, the UBRF allocates its annual revenue between the three eligible entities based on a statutory formula that allocates an equal amount to Duchesne and Uintah County and a higher amount to the Tribe. For 2016 the fund was statutorily capped at $6,620,210.

For more information, contact Jess Peterson at 801-468-0145.

Funding Update

The number of projects funded and the amount of money allocated from the fund hit an historic high in 2011. This was due not only to increased oil and gas production but also to a significant increase in effort by the Ute Tribe to allocate and spend available funding. The board and staff continue to work diligently in conjunction with the Ute Business Committee to increase the expenditure rate of funds. This effort has resulted in annual expenditures that exceed annual revenues due to unallocated and unspent funds being allocated to new projects.

For more information, contact Keith Heaton at 801-468-0133.

Approved Projects FY14–16

Project Category	#	2014 UBRF $	#	2015 UBRF $	#	2016 UBRF $
Planning					1	175,435
Housing	2	210,000	2	360,000	3	3,723,000

Public Facility	2	800,000	1	97,577	6	4,788,259
Public Safety	3	1,730,000	2	925,000	3	840,000
Recreation/Culture	4	1,569,440	6	2,406,644	7	935,050
Transportation	2	122,000	1	80,000	1	1,803,050
Utility	1	75,000	1	281,000	0	0
Totals	14	4,506,440	13	4,150,221	21	*12,264,794

* Annual allocation exceeds annual revenue due to un-allocated and re-allocated funds

UBRF Board Members

(As of 4/17/17)

Member

- Keith Heaton, Chairman - Governor's Representative
- Ron Wopsock - Ute Tribe Business Committee
- Edred Secakuku - Ute Tribe Business Committee
- Commissioner Brad Horrocks - Uintah County
- Commissioner Ron Winterton - Duchesne County

Select Language

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AGREEMENT

THIS AGREEMENT is made and entered into this 16th day of October, 1995, by and between UINTAH COUNTY, DUCHESNE COUNTY, political subdivisions of the State of Utah, the STATE OF UTAH and the UTE INDIAN TRIBE OF THE UINTAH AND OURAY RESERVATION, by authority of the Interlocal Cooperation Act, Chapter 13, Title 11, Utah Code Annotated, 1953, as amended, (hereafter the "Interlocal Cooperation Act").

RECITALS

WHEREAS, Sections 9-11-101 through 9-11-108 of the Utah Code creates the Uintah Basin Revitalization Fund; and

WHEREAS, Section 59-5-116 of the Utah Code and Section 14 of the Severance Tax Amendments Act of 1995 allocate for disposition by the Uintah Basin Revitalization Fund Board a portion of those oil and gas severance taxes collected by the State of Utah from lands held in trust by the United States for the benefit of the Ute Indian Tribe and its members; and

WHEREAS, the Counties of Uintah and Duchesne, the State of Utah and the Ute Indian Tribe desire to establish rules, procedures and requirements for the Uintah Basin Revitalization Fund Board and its activities;

NOW, THEREFORE, in consideration of the mutual covenants and promises of the State of Utah, Uintah County, Duchesne County and the Ute Indian Tribe, the parties hereto agree as follows:

SECTION ONE
DEFINITIONS

For the purposes of this Agreement, the following terms shall have the meaning ascribed, unless the context clearly requires otherwise.

"Authorizing Legislation" means, as appropriate, Sections 9-11-101 through 9-11-108 or 59-5-216 of the Utah Code.

"Board" means the Uintah Basin Revitalization Fund Board.

"Business Committee" means the Uintah and Ouray Tribal Business Committee of the Ute Indian Tribe.

"Business Committee Member(s)" means an elected member(s) of the Uintah and Ouray Tribal Business Committee or an authorized representative(s) of that body.

"Counties" means, collectively, the Counties of Uintah and Duchesne.

"Commissioner" means an elected member of the County Commission of Uintah or Duchesne County or such Commission's authorized representative.

"Fund" means those monies deposited for administration by the Board pursuant to Section 59-5-116 of the Utah Code and Section 14 of the Severance Tax Amendments Act of 1995.

"Governor" means the governor of the State of Utah or his/her authorized representative.

"State" means the State of Utah.

"Tribe" means the Ute Indian Tribe of the Uintah and Ouray Reservation, Utah.

"Trust lands" means those lands held in trust by the United States for the benefit of the Tribe or its members.

"UBRF" means the Uintah Basin Revitalization Fund.

SECTION TWO
ESTABLISHMENT OF THE UINTAH BASIN
REVITALIZATION FUND

Pursuant to the Authorizing Legislation, there is hereby created a legal and administrative entity or association which shall be known as the UBRF, for the purpose of making grants and loans from the Fund to the Counties and the Tribe to mitigate the social and economic impacts, both direct and indirect, arising from oil and gas development on trust lands.

SECTION THREE
CREATION, COMPOSITION AND PROCEDURES OF BOARD

A. Board - The business and affairs of the UBRF shall be managed by the Board. The Board may adopt such rules and regulations for the conduct of its meetings and the management of the business affairs of the UBRF as it deems proper; provided, that such rules and regulations shall not be inconsistent or conflict with this Agreement, any By-Laws of the UBRF or the Authorizing Legislation.

B. Composition of Board and Terms of Office - The Board shall be composed of five (5) members. The members shall consist of: (i) a Commissioner of the Uintah County Commission; (ii) a Commissioner of the Duchesne County Commission; (iii) the Governor; and (iv) two (2) Business Committee Members. Unless a member of the Board shall have his/her appointment withdrawn by the governmental entity making the appointment, the terms of office of members of the Board shall run concurrently with the terms of office for the Governor, the Commissioners of the Counties, and that of the Business Committee Members.

C. Officers of Board - The Chair of the Board shall be the Governor. The Board shall select from within its membership a Vice-Chair, who shall represent the Board and shall have all the duties and powers of the Chair in his/her absence. The Vice-Chair shall serve a term of one (1) year, the term of office commencing on the first day of January of each calendar year. The Board shall also select, from within or without its membership, a Secretary of the Board.

D. Voting and Quorum - Each member of the Board shall be entitled to one vote on the matters that come before it for decision. A quorum shall exist if four (4) members of the Board are present, and no action may be taken by the Board in the absence of a quorum. All issues shall be determined by an affirmative vote of at least four (4) members of the Board.

E. Meetings - The Board shall hold such regular meetings as it deems necessary for the conduct of and proper handling of the business of the UBRF. Meetings of the Board shall be subject to the provisions of the Utah Open and Public Meetings Act.

F. By-Laws - The Board may adopt By-Laws by which the UBRF and the Board will be bound. If adopted, the By-Laws may be amended from time to time in accordance with their terms, but in no event shall any provision of the By-Laws be valid if contrary to any of the terms and conditions of this Agreement or the Authorizing Legislation.

G. Principal Office - The principal office of the Board shall be the offices of the State Division of Community Development or such other office as may be determined by the Board.

SECTION FOUR
RECORDS

A. Location and Inspection - Books of account and other records, whether stored in the form of data on electronic media or otherwise, of the transactions and business of the Board and of the UBRF shall be kept at the principal office of the Board and shall be available at reasonable times for inspection by the State, Tribe or Counties. If loans are made by the Board, the loan documents and repayment records shall be deposited with and maintained by the State Division of Finance, as required by State law. The records may be inspected by the public as allowed by law.

B. Record Entries - The Board shall cause to be entered upon the books of the UBRF an accurate account of all dealings, receipts and expenditures for or on account of the UBRF.

SECTION FIVE
POWERS OF BOARD

A. Authorities of Board - The Board shall have all rights granted by the Interlocal Cooperation Act and the Authorizing Legislation which are not inconsistent with this Agreement and are otherwise in compliance with State law. Specifically, the Board shall:

1. Establish procedures for the application and award of grants and loans, including:

(a) eligibility criteria;

(b) a preference that capital projects and other one-time need projects have a priority over other projects; and

(c) a preference to projects and programs that are associated with the geographic area where the oil and gas were produced; and

(d) coordination of projects and programs with other projects and programs funded by federal, state and local governmental entities;

(e) a procedure whereby grants and loans from the UBRF, as far as practicable and if in accordance with the funding criteria of Board, are allocated on the basis of the following general guidelines:

(1) seventy-five percent (75%) of annual deposits to the Fund being committed to projects and activities of the Tribe;

(2) twelve and one-half percent (12.5%) of annual deposits to the Fund being committed to projects and activities of Uintah County; and

(3) twelve and one-half percent (12.5%) of annual deposits to the Fund being committed to projects and activities of Duchesne County.

2. Determine the order in which projects are to be funded.

3. Ensure that loan repayments and interest are deposited

into the UBRF.

B. Ownership of Property - In the event Board or the UBRF shall operate or manage facilities or improvements on behalf of one (1) or more of the parties to this Agreement, the Counties, the State and the Tribe shall retain title to all real and personal property now owned by that entity.

C. Employees - The Board shall utilize the employees, agents and representatives of the State Division of Community Development unless and until, in the judgment of the Board and State Division of Community Development, it is deemed appropriate and necessary to hire staff in order to carry out the duties of the Board or those of the UBRF. Administrative costs incurred by the Divisions of Community Development and Finance not exceeding the limit set forth in Section 9-11-107(3) of the Utah Code may be invoiced to the Board and approved for payment out of the Fund. The Counties and Tribe shall absorb any administrative costs connected with their participation in the UBRF.

D. Acquisition of Funds - The Board, acting on behalf of the UBRF, is authorized to apply for, receive and oversee grants, donations, gifts and pledges from any and all sources.

SECTION SIX
MANNER OF FINANCING

The business of the Board and that of the UBRF shall be financed by the Fund and by such additional funds as may be provided by the Counties, State and the Tribe, or by grants, donations, gifts, and pledges. The Board shall have no authority to levy or collect taxes. The Board shall be subject to the procedures and requirements under Title 51, Chapter 7, State Money Management Act.

SECTION SEVEN
LOANS AND GRANTS

A. Approval of Grants and Loans - Pursuant to the Authorizing Legislation, upon receipt of a formal application containing such information as the Board may require, it is empowered to approve loans and grants to Duchesne County, Uintah County and the Tribe, or any combination thereof, from the UBRF. With regard to such loans and grants, the Board:

1. shall review each application for a loan or grant before approving it;

2. may approve a loan or grant application subject to the applicant's compliance with any conditions imposed by the Board;

3. ensure that each loan specifies the terms of repayment; and

4. secure loan proceeds from any general obligation, special assessment or revenue bonds, notes or other obligations of the entity receiving the loan proceeds.

B. Non-Qualifying Activities - The Board shall not make a loan or grant to any political subdivision of the State that has failed to comply with the State Tax Commission's factoring directives and shall not fund:

1. start-up or operational costs of private business ventures; or

2. the operating budgets of the Counties or of the Tribe.

C. Qualifying Activities - The Board shall entertain applications for loans and grants from Uintah County, Duchesne County or the Tribe, or any combination thereof, for facilities, services or improvements authorized by law, including but not limited to the following:

1. buildings and grounds;
2. housing provision or improvement;
3. education;
4. health care;
5. parks and recreation;
6. police and fire protection;
7. transportation;
8. streets and roads;
9. utilities;
10. culinary water;
11. sewage disposal;
12. social services;
13. solid waste disposal;

D. Report to the Legislature - The Board shall submit, not less than annually, a report to the Legislature of the State, such report to be made available to the public on request, setting forth the funding of projects funded during the year preceding the annual report.

E. Audits - The Fund and all projects funded thereby, in whatever fashion or by whatever means, shall be subject to audit by the Auditor of the State, an auditor under contract to him and/or the State Division of Community Development on proper and adequate notice. In addition, the Board may direct that such other audits as it deems necessary be performed at any time.

SECTION EIGHT
TERMINATION OF AGREEMENT

This Agreement shall remain in full force and effect unless and until one of the following events occurs:

(1) One or more of the parties hereto provides notice of its intent to terminate its participation in the Board or the UBRF. Such notice must be provided in writing to all parties to this Agreement not less than six (6) months prior to the proposed date of termination.

(2) There is not deposited to the credit of the UBRF those funds dedicated and allocated under the Authorizing Legislation in those percentages set forth therein.

(3) All of the parties hereto consent in writing to terminate this Agreement on a date certain.

SECTION NINE
CONSIDERATION AND PARTICIPATION
IN FUND

The Tribe and the Counties acknowledge and agree that establishment of the Fund and its financing with a portion of the severance taxes of the State is the direct result of the Tribe's and Counties' agreement not to impose a business or activity fee or business or activity tax based upon the gross receipts of a license holder or taxpayer. In the event the Tribe, Duchesne County or Uintah County imposes a business or activity fee or business or activity tax based on gross receipts of a license holder or taxpayer, the governmental entity imposing such a business or activity fee or business or activity tax shall automatically become ineligible to participate in the Fund or to receive monies therefrom.

SECTION TEN
MISCELLANEOUS PROVISIONS

A. Entire Agreement and Modification - This Agreement constitutes the entire agreement between the State, Counties and the Tribe with regard to the Board and the UBRF and may not be rescinded, supplemented, amended or modified without the written consent of all of the parties.

B. Headings - The headings to the various sections and paragraphs of this Agreement are inserted only for convenience of reference and are not intended, nor shall they be construed to modify, define, limit or expand the intent of the parties.

C. Authority - The parties represent that the person executing this Agreement on each party's behalf has been duly authorized by all necessary and appropriate action to enter into this Agreement.

IN WITNESS WHEREOF, the STATE OF UTAH, DUCHESNE COUNTY, UINTAH COUNTY and the UTE INDIAN TRIBE have caused this Agreement to be executed on the day and year first above written.

UINTAH COUNTY

ATTEST:

By: Connie Lee, Deputy
Clerk/Auditor

By: Lorin J. Maxwell
H. GLEN McKEE, Chairman
Uintah County Commission

DUCHESNE COUNTY

ATTEST:

By: Pat Thatcher
Clerk

By: Larry S. Ross
LARRY S. ROSS, Chairman
Duchesne County Commission

UTE INDIAN TRIBE

ATTEST:

By: Dora West
Secretary

By: Ruby Atwine
RUBY ATWINE, Chair
Uintah and Ouray Tribal
Business Committee

STATE OF UTAH

ATTEST:

By: Deborah L. Lamoreaux

NOTARY PUBLIC
DEBORAH L. LAMOREAUX
Uintah Basin Applied Tech
1100 East Lagoon
Roosevelt, Utah 84066
My Commission Expires 7/15/99
STATE OF UTAH

By: Michael O. Leavitt
MICHAEL O. LEAVITT, Governor
State of Utah

The undersigned attorneys, for and on behalf of the parties to this Agreement, certify that the above-agreement has been submitted to them; that they have examined the same; and find the same is proper in form and compatible with the laws of their respective jurisdictions.

JoAnn B. Stringham
UINTAH COUNTY ATTORNEY

Herbert Gillespie
DUCHESNE COUNTY ATTORNEY

Philip C. Pugsley, Asst. Atty Gen.
ATTORNEY GENERAL - UTAH

Robert H. Ross
GENERAL COUNSEL - UTE TRIBE

Uintah Basin Revitalization Fund and Board statute,
Utah Code 9-10-101 et seq

9-10-101. Definitions.

As used in this chapter:

(1) "Board" means the Uintah Basin Revitalization Fund Board.

(2) "Capital projects" means expenditures for land, improvements on the land, and equipment intended to have long-term beneficial use.

(3) "County" means:

(a) Duchesne County; or

(b) Uintah County.

(4) "Division" means the Division of Housing and Community Development.

(5) "Revitalization Fund" means the Uintah Basin Revitalization Fund.

(6) "Tribe" means the Ute Indian Tribe of the Uintah and Ouray Reservation.

9-10-102. Legislative intent -- Uintah Basin Revitalization Fund -- Deposits and contents.

(1) In order to maximize the long-term benefit of severance taxes derived from lands held in trust by the United States for the Tribe and its members by fostering funding mechanisms that will, consistent with sound financial practices, result in the greatest use of financial resources for the greatest number of citizens of the Uintah Basin, and in order to promote cooperation and coordination between the state, its political subdivisions, Indian tribes, and individuals, firms, and business organizations engaged in the development of oil and gas interests held in trust for the Tribe and its members, there is created a restricted special revenue fund entitled the "Uintah Basin Revitalization Fund."

(2) The fund consists of all money deposited to the Revitalization Fund under this part and Section **59-5-116**.[1]

(3) (a) The Revitalization Fund shall earn interest.

(b) All interest earned on fund money shall be deposited into the fund.

9-10-103. Uintah Basin Revitalization Fund Board created -- Members -- Terms -- Chair -- Quorum -- Expenses.

(1) There is created within the division the Revitalization Board composed of five members as follows:

(a) the governor or his designee;

(b) a Uintah County commissioner;

(c) a Duchesne County commissioner; and

(d) two representatives of the Business Committee of the Tribe.

(2) The terms of office for the members of the board shall run concurrently with the terms of office for the governor, commissioners, and Business Committee of the Tribe.

(3) The governor, or his designee, shall be the chair of the board.

[1] This statutory provision (59-5-116) follows after the Uintah Basin Revitalization Fund and Board statute.

(4) Four board members are a quorum.

(5) All decisions of the board require four affirmative votes.

(6) A member may not receive compensation or benefits for the member's service, but may receive per diem and travel expenses in accordance with:

(a) Section **63A-3-106**;

(b) Section **63A-3-107**; and

(c) rules made by the Division of Finance pursuant to Sections **63A-3-106** and **63A-3-107**.

9-10-104. Duties -- Loans -- Interest.

(1) The board shall:

(a) subject to the other provisions of this chapter and an agreement entered into under Title 11, Chapter 13, Interlocal Cooperation Act, among the state, the counties, and the Tribe, make recommendations to the division for grants and loans from the revitalization fund to county agencies and the Tribe that are or may be socially or economically impacted, directly or indirectly, by mineral resource development;

(b) establish procedures for application for and award of grants and loans including:

(i) eligibility criteria;

(ii) subject to Subsection **9-10-106**(2)(b), a preference that capital projects, including subsidized and low-income housing, and other one-time need projects and programs have priority over other projects;

(iii) a preference for projects and programs that are associated with the geographic area where the oil and gas were produced; and

(iv) coordination of projects and programs with other projects and programs funded by federal, state, and local governmental entities;

(c) determine the order in which projects will be funded;

(d) allocate the amount to be distributed from the revitalization fund for grants or loans to each county and the Tribe during a fiscal year as follows:

(i) up to and including the first $3,000,000 that is approved for distribution by the board during a fiscal year, the board may allocate the amount in accordance with the interlocal agreement described by Subsection (1)(a), except that the board may not allocate less than 75% of the amount under the interlocal agreement to the Tribe unless the interlocal agreement is further modified by statute; and

(ii) beginning with fiscal year 2007-08, any amount approved for distribution by the board during that fiscal year in excess of $3,000,000 shall be allocated equally amongst each county and the Tribe so that each receives 1/3 of the amount approved for distribution by the board in excess of $3,000,000;

(e) qualify for, accept, and administer grants, gifts, loans, or other funds from the federal government and from other sources, public or private; and

(f) perform other duties assigned to it under the interlocal agreement described in Subsection (1)(a) that are not prohibited by law or otherwise modified by this chapter.

(2) The board shall ensure that loan repayments and interest are deposited into the

revitalization fund.

(3) The interlocal agreement described in Subsection (1)(a) shall be consistent with the following statutes, including any subsequent amendments to those statutes:

(a) this chapter;

(b) Title 11, Chapter 13, Interlocal Cooperation Act;

(c) Section **59-5-116**; and

(d) any other applicable provision of this Utah Code.

9-10-105. Powers.

(1) The board may:

(a) appoint a hearing examiner or administrative law judge with authority to conduct any hearings, make determinations, and enter appropriate findings of facts, conclusions of law, and orders under authority of the Interlocal Cooperation Act; and

(b) make rules under Title 63G, Chapter 3, Utah Administrative Rulemaking Act, if necessary to perform its responsibilities.

(2) The board shall:

(a) be subject to the procedures and requirements under Title 52, Chapter 4, Open and Public Meetings Act; and

(b) be subject to the procedures and requirements under Title 51, Chapter 7, State Money Management Act.

9-10-106. Eligibility for assistance -- Applications -- Review by board -- Terms -- Security.

(1) Counties or the Tribe that wish to receive loans or grants from the board shall submit formal applications to the board containing the information required by the board.

(2) The board may not fund:

(a) start-up or operational costs of private business ventures; and

(b) general operating budgets of the counties or the Tribe, except that the Tribe may use a grant or loan to fund costs associated with the management and administration of energy or mineral development on:

(i) lands held in trust by the United States for the Tribe and its members; or

(ii) lands owned by the Tribe.

(3) (a) The board shall review each application for a loan or grant before approving it.

(b) The board may approve loan or grant applications subject to the applicant's compliance with certain conditions established by the board.

(c) The board shall:

(i) ensure that each loan specifies the terms for repayment; and

(ii) secure the loans by proceeds from any general obligation, special assessment, or revenue bonds, notes, or other obligations of the appropriate subdivision.

9-10-107. Division to distribute money -- Annual report -- Administration costs.

(1) The division shall distribute loan and grant money if the loan or grant is approved by the board.

(2) The division shall make an annual report concerning the number and type of loans and grants made as well as a list of recipients of this assistance to:

(a) the Native American Legislative Liaison Committee, created in Section **36-22-1**; and

(b) the governor.

(3) The division, with board approval, may use fund money for the administration of the fund, but this amount may not exceed 2% of the annual receipts to the fund.

9-10-108. Deposits into fund -- Unallocated balance nonlapsing.

(1) (a) All money received under Section **59-5-116** shall be deposited in the Revitalization Fund provided that no business or activity fee or tax based on gross receipts has been imposed by a county or the Tribe on oil and gas activities.

(b) (i) Nothing in this Subsection (1) prohibits a county from imposing a charge described in Subsection (1)(a) with respect to any gathering, transmission, or local distribution pipeline in which the county owns an interest.

(ii) Nothing in this Subsection (1) prohibits the Tribe from imposing a charge described in Subsection (1)(a) with respect to any gathering, transmission, or local distribution pipeline in which the Tribe owns an interest.

(2) Any unallocated balance in the fund at the end of each fiscal year shall be nonlapsing.

Utah Code 59-5-116, in Chapter 5, Severance Tax on Oil, Gas, and Mining

59-5-116. Disposition of certain taxes collected on Ute Indian land.

(1) Except as provided in Subsection (2), there shall be deposited into the Uintah Basin Revitalization Fund established in Section **9-10-102**:

(a) for taxes imposed under this part, 33% of the taxes collected on oil, gas, or other hydrocarbon substances produced from a well:

(i) for which production began on or before June 30, 1995; and

(ii) attributable to interests:

(A) held in trust by the United States for the Tribe and its members; or

(B) on lands identified in Pub. L. No. 440, 62 Stat. 72 (1948);

(b) for taxes imposed under this part, 80% of taxes collected on oil, gas, or other hydrocarbon substances produced from a well:

(i) for which production began on or after July 1, 1995; and

(ii) attributable to interests:

(A) held in trust by the United States for the Tribe and its members; or

(B) on lands identified in Pub. L. No. 440, 62 Stat. 72 (1948); and

(c) for taxes imposed under this part, 80% of taxes collected on oil, gas, or other hydrocarbon substances produced from a well:

(i) for which production began on or after January 1, 2001; and

(ii) attributable to interests on lands conveyed to the tribe under the Ute-Moab Land Restoration Act, Pub. L. No. 106-398, Sec. 3303.

(2) (a) The maximum amount deposited in the Uintah Basin Revitalization Fund may not exceed:

(i) $3,000,000 in fiscal year 2005-06;

(ii) $5,000,000 in fiscal year 2006-07;

(iii) $6,000,000 in fiscal years 2007-08 and 2008-09; and

(iv) for fiscal years beginning with fiscal year 2009-10, the amount determined by the commission as described in Subsection (2)(b).

(b) (i) The commission shall increase or decrease the dollar amount described in Subsection (2)(a)(iii) by a percentage equal to the percentage difference between the consumer price index for the preceding calendar year and the consumer price index for calendar year 2008; and

(ii) after making an increase or decrease under Subsection (2)(b)(i), round the dollar amount to the nearest whole dollar.

(c) For purposes of this Subsection (2), "consumer price index" is as described in Section 1(f)(4), Internal Revenue Code, and defined in Section (1)(f)(5), Internal Revenue Code.

(d) Any amounts in excess of the maximum described in Subsection (2)(a) shall be deposited into the General Fund.