

# Technically Driven Growth

2010 Annual Report

Oil & Gas Production

Completion Expertise



Known Plays

Projects of Scale



NE: TSXV



This year marked several firsts for Nextraction. We combined experience with youth and determination and perseverance with the application of new technological advances. We also combined disciplined fiscal responsibility with strategic risk management to advance our existing properties into production. Acquiring new properties enabled us to go forward as a balanced light oil and liquids-rich natural gas company. In fact, development was so rapid in 2010, each quarter resulted in achieving significant milestones and market value gains of over 200% by mid-year.

As a new face in the Canadian oil and gas markets, we utilized our knowledge and experience to structure a tightly held, debt-free company poised to advance at a very quick pace. We then expanded the management team to add a dimension of youth to benefit from the cutting edge of technological advancements that a new generation of explorationists has added to the industry. Nextraction quickly joined the ranks of junior oil and gas companies generating positive cash flow, with natural gas flowing into the pipeline on both of our unconventional gas plays and oil tankers hauling condensate from our North Pinedale site. This is quite a feat for a company our size as we compete in areas dominated by large independents and major companies. Even more remarkably, we raised capital to drill natural gas wells in a time that coincided with the worst economic downturn since the great depression. At times, nothing short of perseverance advanced the drilling of a 4,652 meter (14,888 feet) well in North Pinedale as natural gas commodity prices failed to recover as had been predicted - perseverance, that is, coupled with a supportive group of shareholders that share the vision of advancing asset development knowing commodity pricing fluctuates dramatically and having a belief that natural gas prices are bound to recover in the near term.

With an early focus on multi-horizon, liquids-rich unconventional gas resource plays, advancing the

development of our Pinedale and Appalachian projects was the focus in the first half of 2010. Production was established on these projects, then our focus shifted to identifying light oil projects to add to our inventory. We accomplished this objective by acquiring two oil projects we plan to drill and develop in 2011, noting that one of those projects already has production.

We are very excited about our future as we set plans to commence this summer's planned drilling program. We now have four outstanding focus areas that provide us the luxury of investing capital in the plays that generate the greatest rates of return and corporate value.

As we move forward to this year's drilling season, we envision significant growth and exciting new results on the horizon.

We are fortunate to employ an effective staff, who are also shareholders, that works diligently and is fully committed to realizing Nextraction's potential for growth.

We also realize that success in the oil and gas marketplace requires a strong foundation of shareholder support and we are very fortunate to have a solid base of "partners" in our early exploration endeavors and development. We appreciate your continued support as we prepare to generate value organically by "turning the bit to the right" in 2011! We look forward to an exciting year of new achievements as we advance concepts on exploration trends into the next round of production on known plays.



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Mark S. Dolar  
Director, President and CEO  
Nextraction Energy Corporation

## The Future

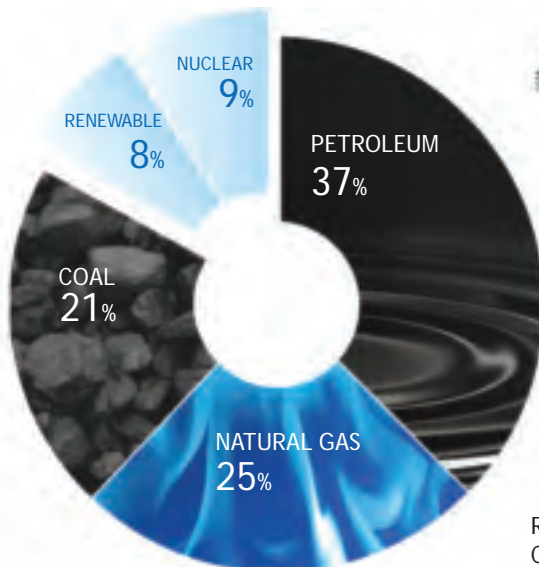
The oil and gas industry of 2010 can best be described by author Charles Dickens' famous words, "It was the best of times; it was the worst of times."<sup>1</sup> Entering into the year, both oil and gas commodity markets seemed poised for a rebound from the market pitfalls of late 2008. As the year exited and was written in the record books, commodity prices for oil performed as forecasted while a perceived over-supply of future shale gas in the United States drove natural gas to record low pricing.

Fossil fuels remain the source for over eighty percent of the globe's energy supply. Demand from a recovering United States economy and the acceleration of increased consumption of fossil fuels in developing markets make it difficult to imagine the international community's "addiction to oil" ending in the near future. In fact, rapid growth of renewable energies will, at best, only assist fossil fuels in the world's demands for energy.

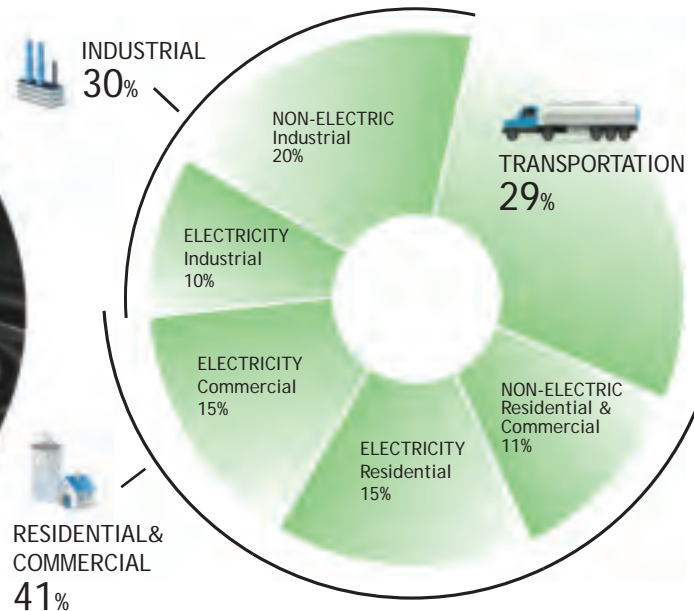
Oil prices consistently increased in value through 2010 and average price projections of \$105 - \$110 per barrel of oil are on schedule for fiscal year 2011.

Fossil fuels currently comprise 83% of US energy. Demand is broadly distributed among major sectors. 2009 Total US Energy use = 94.6 quadrillion BTUs.

Energy Supply<sup>2</sup>



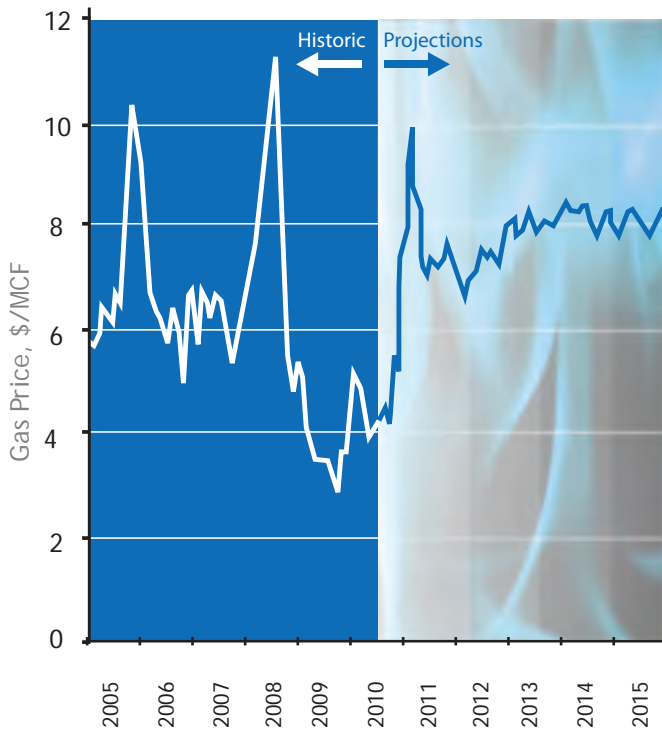
Energy Demand<sup>2</sup>



EIA Future Price Projections  
Commodity price projections for oil and gas are favorable

Projected Gas Pricing

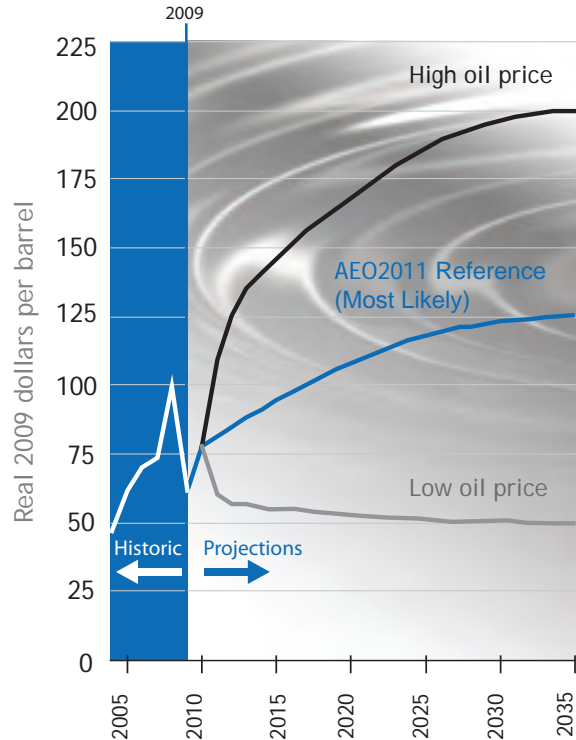
Note: Historic data from DOE/IEA and projections with market disruptions



While many factors can influence the recovery of natural gas pricing and result in dramatic price swings; extreme weather conditions, causing a drawdown of current gas storage levels, a significant change in market conditions, worldwide political instability and unforeseen events of nature. Should any of these events cause a disruption in market conditions, the United States Energy Administration predicts a rapid recovery of prices starting in the winter months of 2011 - 2012, as indicated in the graph above.

Projected Oil Pricing

Annual average price of low sulfur crude oil <sup>3</sup>



Further projections for oil commodities indicate strong market demands will continue. The December 2010 U.S. Energy Information Administration Energy Outlook indicates that future pricing for oil should steadily increase in the year ahead.<sup>2</sup>

Nextraction has strategically balanced its approach to deploy capital in the marketplace based on future pricing of both oil and gas. This strategy allows Nextraction to prepare for the sale of reserves in accordance with generating a favourable internal rate of return.

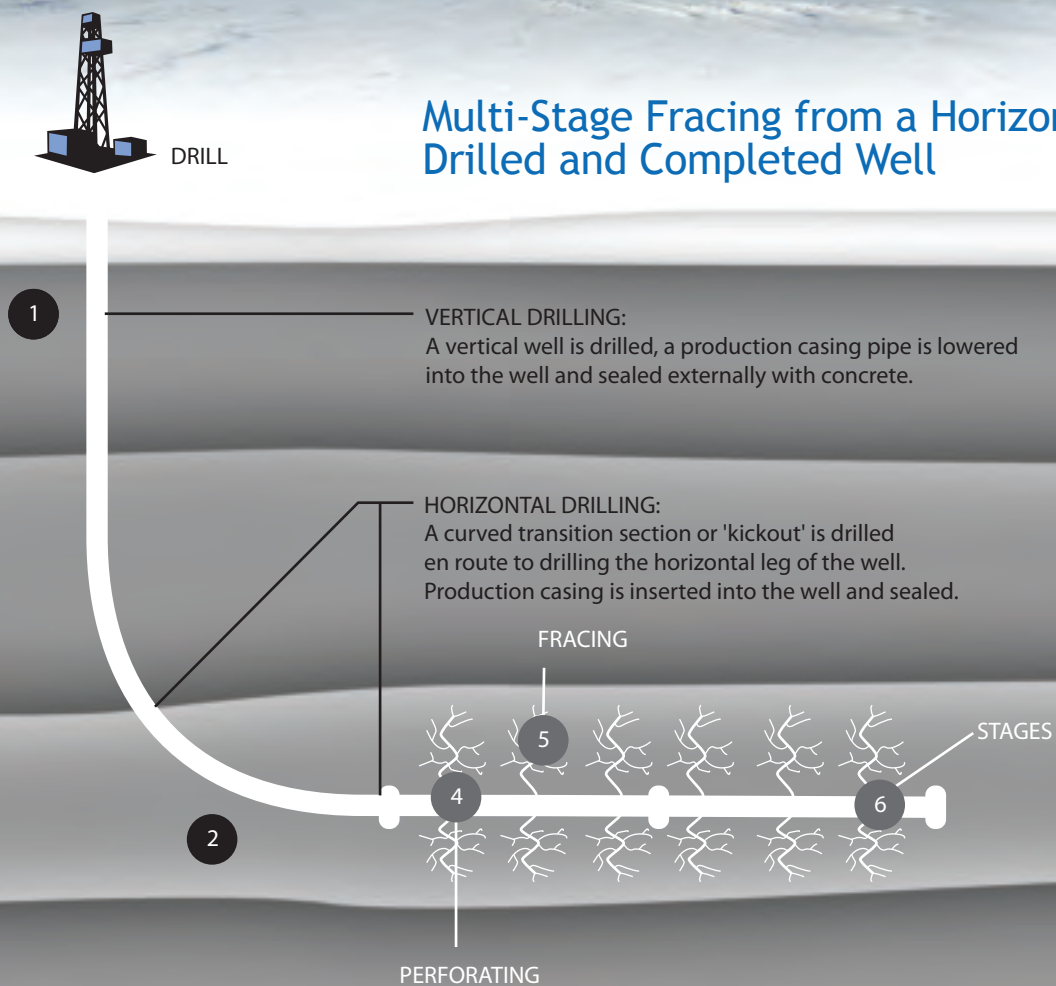
Sources of information:

- 1 Dickens, Charles. "A Tale of Two Cities". London: Chapman and Hall, 1859.
- 2 Newell, Richard, "Annual Energy Outlook 2011", 12/16/2010, United States Energy Information Administration, Washington DC
- 3 EIA, Annual Energy Outlook 2011

## Oil & Gas Extraction

Next extraction's next round of extraction on known plays is predicated on our ability to harness expertise in a specific area and on a specific project to efficiently and economically extract the oil and gas from below the surface, at times from great depths or long horizontal legs.

Fracing (hydraulic fracture stimulation) is a process used to fracture rock and is performed from a wellbore into the surrounding tight sand or shale rock. The aim is to increase the rate and ultimate recovery of oil and natural gas/condensates. The technique of hydraulic fracturing is used to increase or restore the rate at which oil and gas can be produced from a reservoir, including unconventional reservoirs such as shale. Hydraulic fracturing enables the production of natural gas and oil from rock formations deep below the earth's surface. There may not be sufficient porosity (storage) and/or permeability (flow) to allow oil and natural gas to flow from the rock into the wellbore at economic rates.



### Multi-Stage Fracing from a Horizontally Drilled and Completed Well

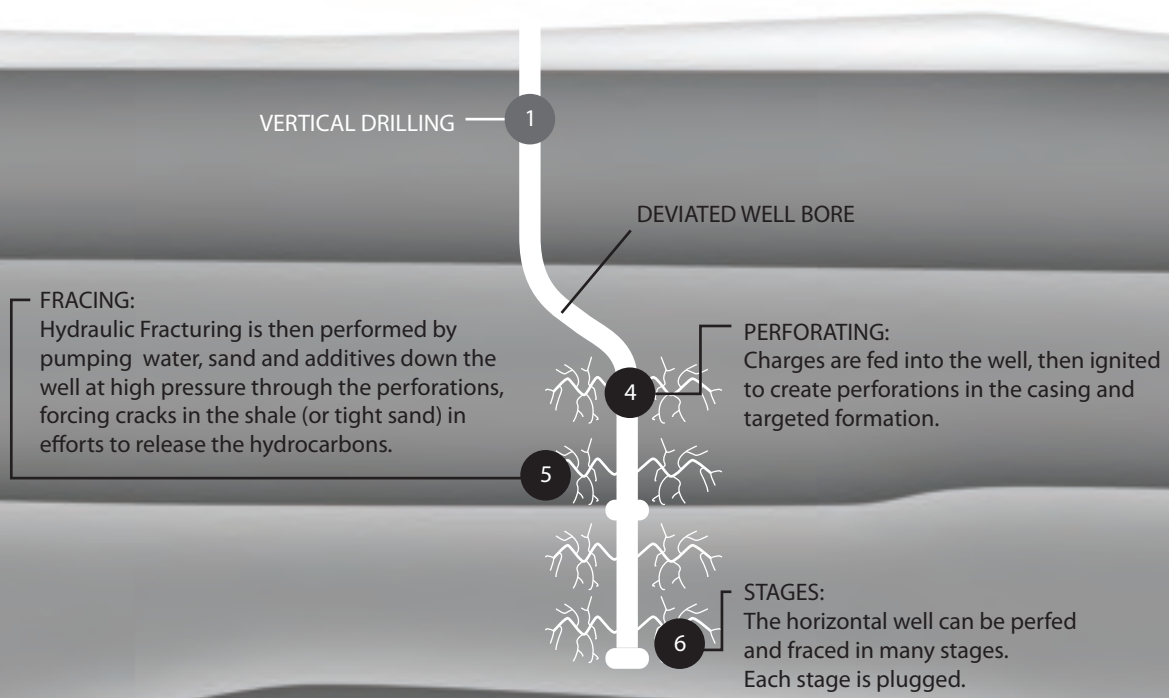
A technology called deviated drilling, or “S” curves, is utilized when recovering reserves from formations where producing zones are lenticular in nature and are deposited in horizontal layers. The “S” curve deviated drilling program is required to enter into sand packages when developing vertical wellbores. This application of new technologies allows multiple subsurface wells to be developed from one surface location and assists in the recovery of tight gas sands while greatly decreasing the footprint on the surface.

Horizontal drilling is a technique involving an intentional horizontal deviation or ‘kickout’ from a vertical wellbore, which permits contact and

intersection with a larger portion of the reservoir than conventional vertical drilling.

Horizontal drilling with multi-stage fracture stimulation completions (“multi-stage fracs”) involves the pumping of sand and solvent at high pressure into the well and along the horizontal wellbore, cracking the oil/gas-rich shale and sandstone, allowing the oil/gas to flow out. Unconventional extraction technologies are associated with enhanced operational efficiencies including increased production rates, greater recovery of hydrocarbons and reduced drilling costs as one horizontal well can achieve a multiple gross production volume than a vertical well (The International Resource Journal, 2009).

## Multi-Stage Fracing from an “S” Curve Vertical Well



# Our Projects

Alberta, Canada

## PROVOST FIELD

4 Producing Wells  
3.25 Sections  
10 - 20 Horizontal well potential

Montana, USA

## SATURN PROJECT

20,000 acres  
31 Sections  
20-50 potential wells  
Multi-horizon oil play

Wyoming, USA

## NORTH PINEDALE

5.5 Sections; 1 Producing Well  
32 possible well locations

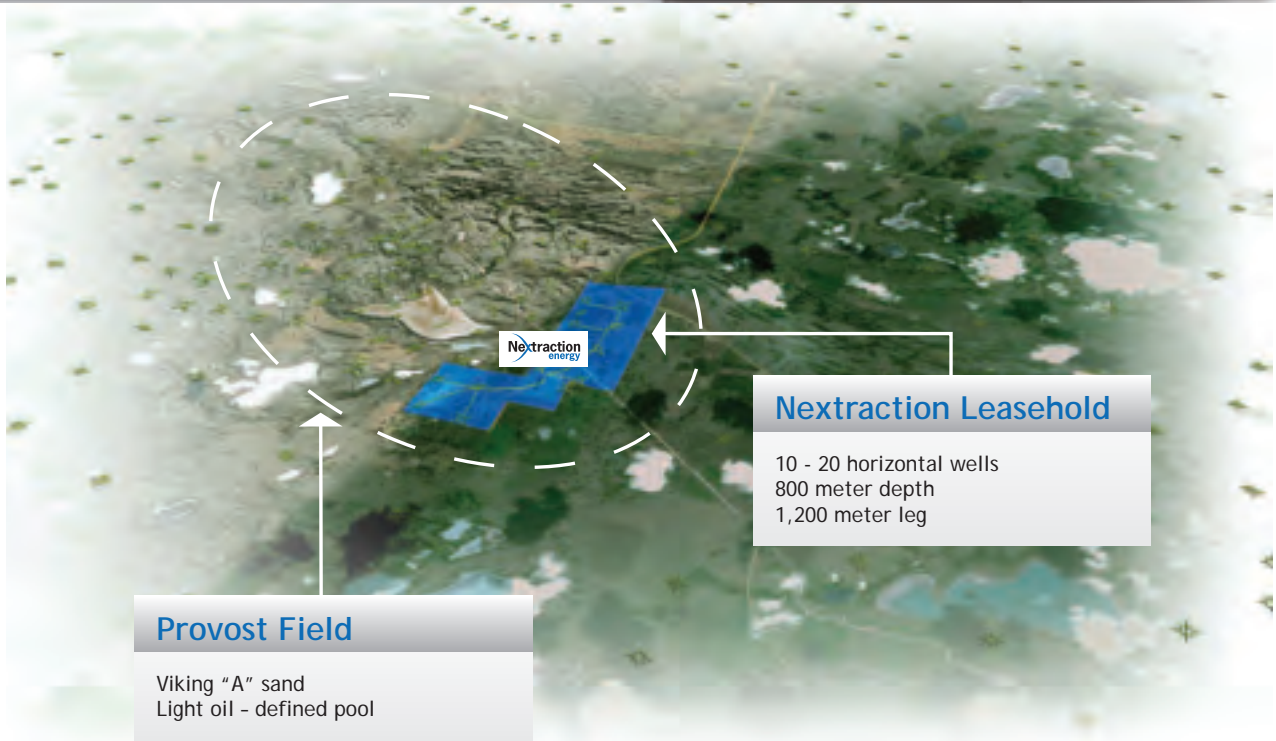
Tennessee / Kentucky, USA

## APPALACHIAN BASIN

70,000 acres  
109 Sections  
Up to 500 possible locations  
in shale gas resource play

Oil

Gas



## Provost Field, Viking Pool

In accomplishing a Provost light oil field acquisition, we successfully obtained our first light oil play in Alberta, importantly and strategically earning into a play with the rights to drill and develop offset locations to some of the field's best wells.

The Provost Field is known for its prolific Viking formation where some vertical wells have produced almost 300,000 barrels of oil. In 1968, a unitization study of the Viking pool in the Provost Field was performed by McDaniel Consultants and submitted to the Energy Resources Conservation Board (ERCB). This study indicated that the pool contained over 80 million barrels of oil in place and to date approximately three million barrels of oil had been recovered from the field, primarily from vertical wells drilled over the past 20 years. Less than 4% of the oil in place has been produced. Our Nextraction JV area accounts for 15% of the lands covered in the Viking pool identified in the McDaniels report.

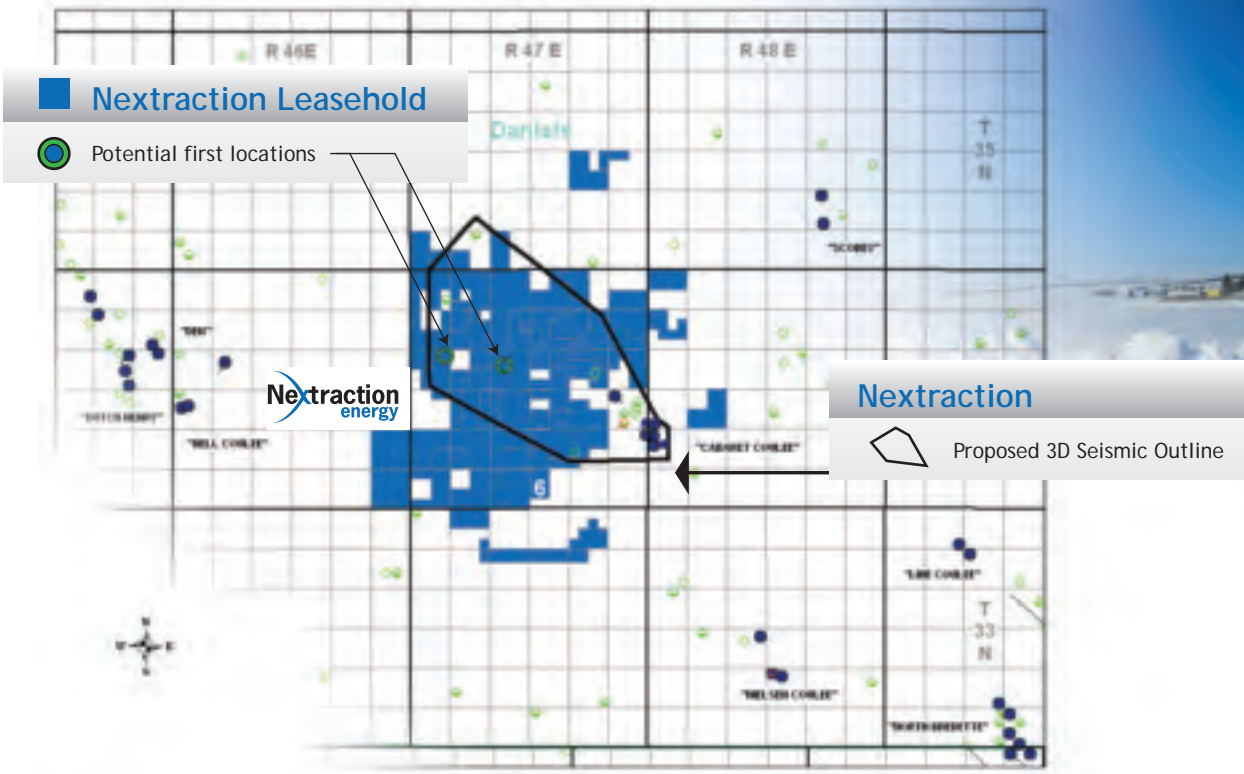
The internal rates of return opportunities are astounding, with payout on investment being projected within 9-18 months. Thus, we plan to focus much of our 2011 exploration budget on the development of these assets. Combining direct

experience in this area and the knowledge of how to apply unique completion strategies, the Provost property provides an excellent vehicle to gain positive cash flow in this prolific play.

The Provost field acquisition highlights our corporate strategy: we are extending the next round of extraction on this known play. Horizontal drilling, the implementation of new frac designs and strategic re-completion programs all point to recovery rates from the pool possibly exceeding 15%.

Situated in a mature region of the eastern Alberta light oil fields, the infrastructure facilities are in place to market and sell hydrocarbons immediately after well completion. Under current market conditions and favourable development opportunities, we predict the Viking pool will become a stellar asset in the near to long term growth of our Company.

Provost-Viking Metrics :	
Play Size:	3.25 sections
Formation Depth:	800 meters
Horizontal Leg:	600-1,200 meters
Net Pay:	4-6 meters
Oil Gravity:	38 api
Well Projections:	10 - 20 horizontal wells



## Saturn Project Area

Nextraction, having entered into a seismic and farm-out deal, is excited to have added such a large property lease package with multi-horizon oil producing zones. These lands are located in the Williston Basin of northeastern Montana, where new completion techniques in the Bakken shale formation have created significant production from the Williston Basin area over the last decade.

We have over 35 sections to develop, plan to acquire three dimensional (3-D) seismic to identify geological structures known as “seismic highs” and then continue with a drilling program designed to develop both the Bakken shale and the conventional formations that have produced in the past - all at depths less than 2,340 meters.

The plan for this play is to develop the Bakken formation through horizontal drilling while the conventional zones, including the Ratcliffe, McGowan, Mission Canyon and Nisku, which are known to produce oil from structural high closures, will be defined by the 3-D seismic survey for potential conventional production.

The Saturn play is a perfect textbook example for us of the necessary checklist required for developing a project from conception to drilling. First we define an area of focus and then acquire the rights to a substantial lease position. Our technical experts compile all historical data of record, such as wells, core and test results and interpret that data. Geologic mapping is generated and a seismic program undertaken to enhance the structural knowledge of the area to determine the best possible drilling locations. Drilling the wells follows the seismic interpretation and that leads to the design of a progressive completion and fracing program to achieve the best possible results.

Saturn Project Metrics:	
Play Size:	35 sections
Formation Depth:	2,340 meters
Horizontal Leg:	1,000+ meters
Net Pay:	10-30 meters
Oil Gravity:	35+ api
Well Projections:	20-50 wells

## The Pinedale Anticline

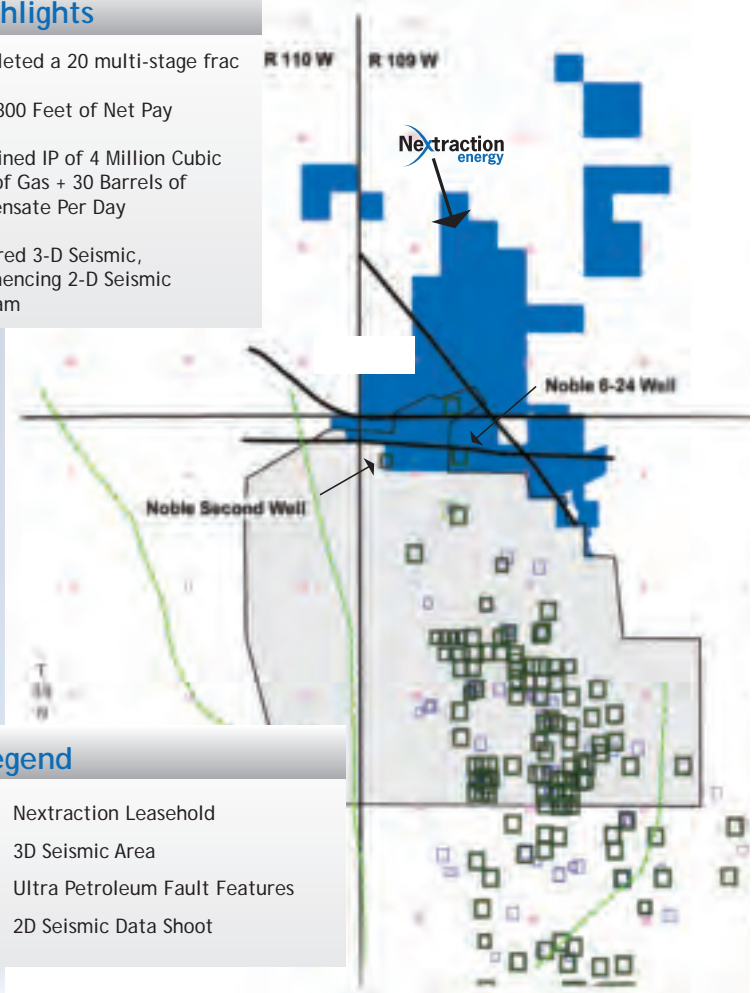
On the opening days of the third quarter of 2010, we established the much-anticipated first production sales at our Noble 6-24 well on the Pinedale Anticline, located in Wyoming, USA.

Accomplishing this milestone in less than 18 months from conception of the Company was a monumental goal achieved by Nextraction for its shareholders, as we immediately commenced the sale of natural gas and condensate from that well.

More importantly, by extending production along the northern extent of the Anticline, we proved our 5.5 section leasehold holds the ability to generate sustained long term revenue for the Company. The Noble 6-24 well was completed with a 21 multi-stage frac in the producing intervals of the Tertiary, Lance and Mesaverde formations at a total depth of 4,652 meters. In a strategic move, the lower zones of the well were completed in July, 2010, the upper zones completed in December, 2010, giving us a combined initial production rate of 4.05 million cubic feet of gas and 30 barrels of condensate over a 24 hour test.

### Highlights

- Completed a 20 multi-stage frac
- Over 800 Feet of Net Pay
- Combined IP of 4 Million Cubic Feet of Gas + 30 Barrels of Condensate Per Day
- Acquired 3-D Seismic, Commencing 2-D Seismic Program



### Legend

- Nextraction Leasehold
- 3D Seismic Area
- Ultra Petroleum Fault Features
- 2D Seismic Data Shoot



Over the past dozen years there have been new technological advancements in multi-stage completions utilizing propellant fracing materials. These have been instrumental in developing the Pinedale Anticline field to become the second largest natural gas producing field in the United States, with an estimated 38 trillion cubic feet of gas in producible reserves. The northern extent of the field is known for its liquids-rich content and produces approximately 20-30 barrels of condensate per million cubic feet of gas, thereby increasing economic returns by up to 40% of dry gas values. In following our corporate strategy, we are excited

about successfully implementing the next round of extraction on this known play and are now focused on strategies to develop resources in a cost-effective manner in efforts to enhance shareholder value.

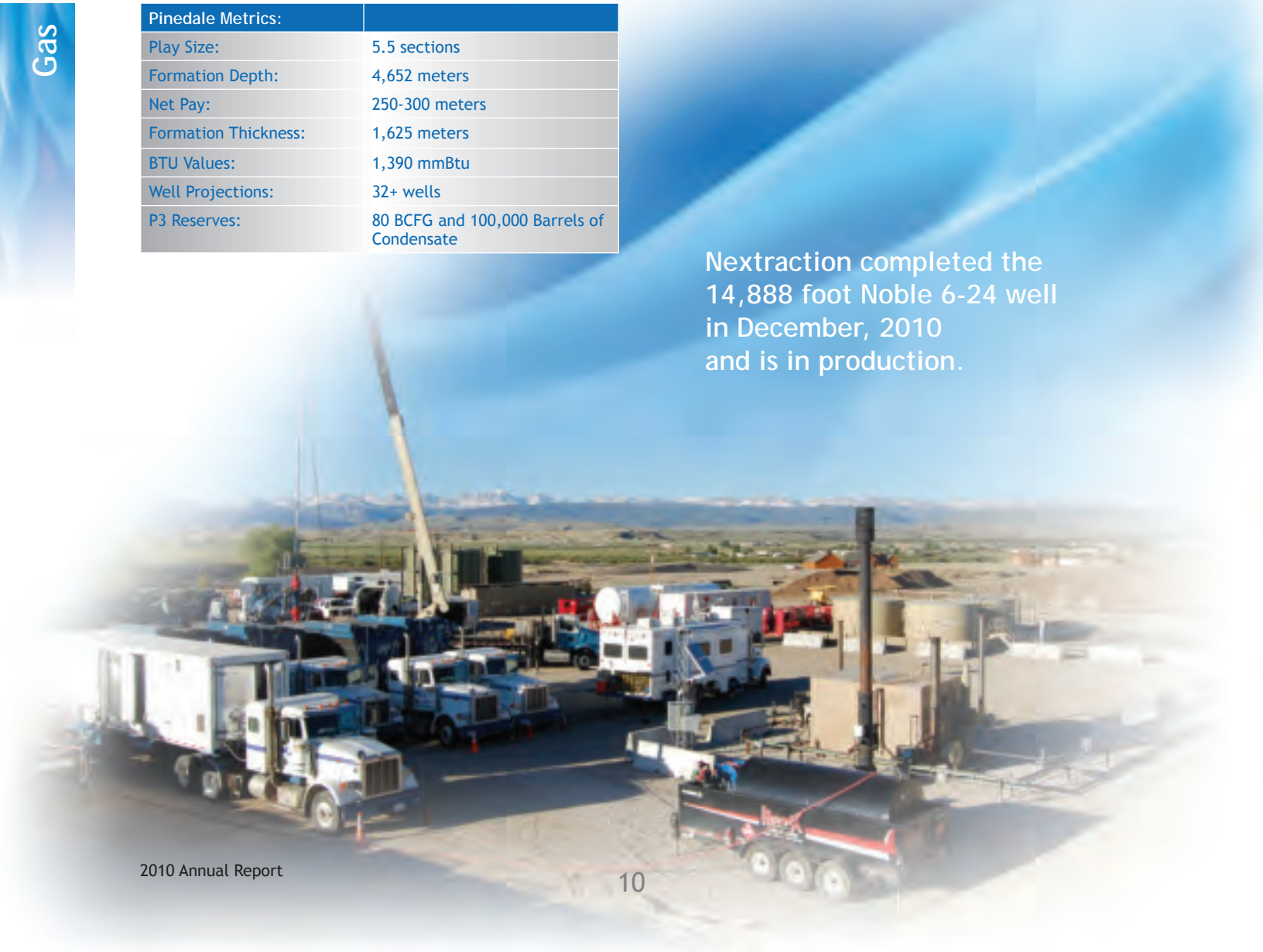
Of note, the Noble 6-24 well is an important first step in providing evidence to the market of our ability to execute and deliver our defined strategy - on time and within budget.

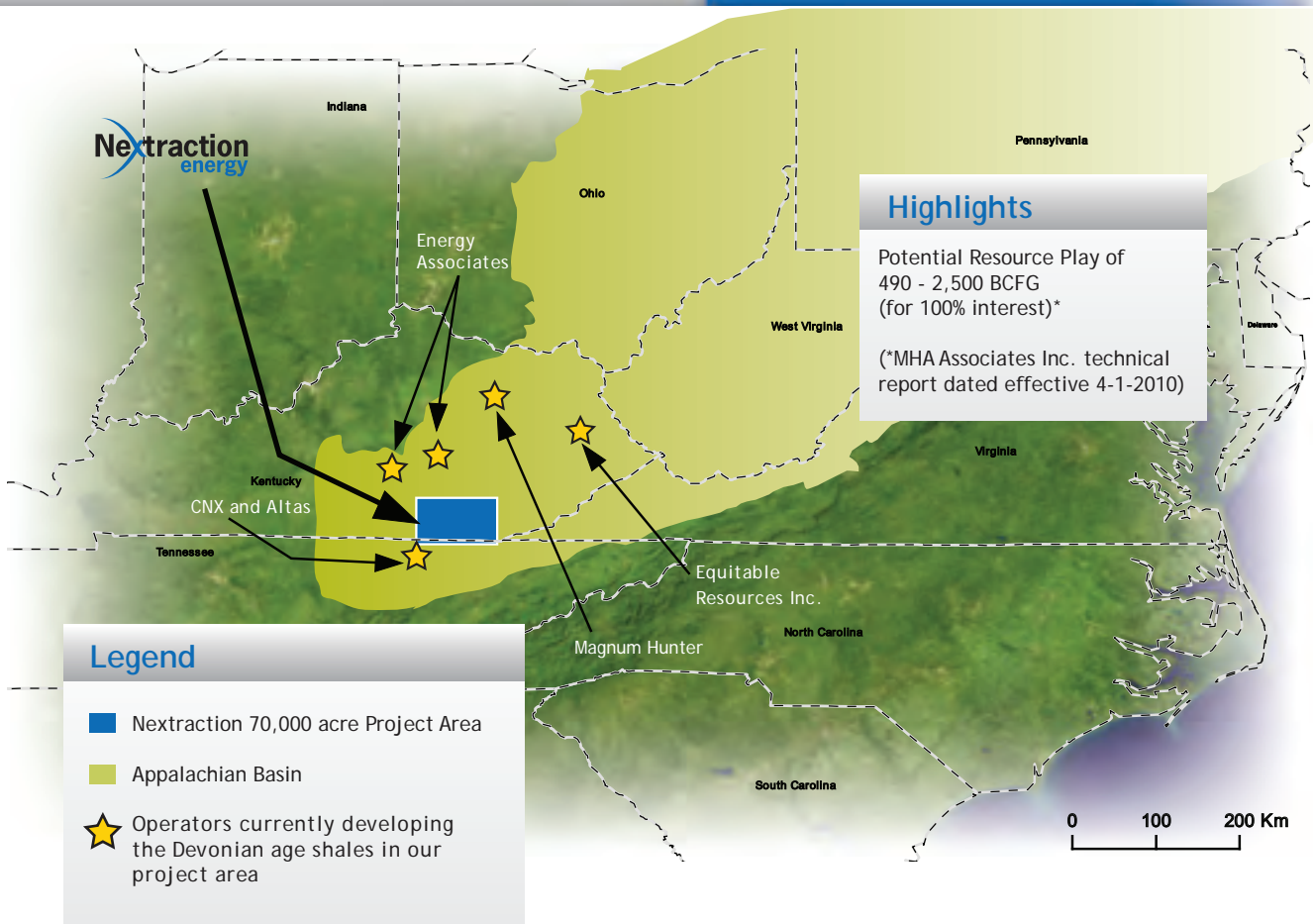
The Pinedale Anticline will serve as a legacy asset with large scale resources capable of generating revenue for more than 30 years.

Pinedale Metrics:	
Play Size:	5.5 sections
Formation Depth:	4,652 meters
Net Pay:	250-300 meters
Formation Thickness:	1,625 meters
BTU Values:	1,390 mmBtu
Well Projections:	32+ wells
P3 Reserves:	80 BCFG and 100,000 Barrels of Condensate

Next extraction completed the 14,888 foot Noble 6-24 well in December, 2010 and is in production.

Gas





## Appalachian Basin - Chattanooga Shale

Coring of the George Brown #3 well in the Chattanooga Shale resulted in identifying a "sleeping giant" awaiting discovery. The Chattanooga Shale's Devonian age big brother, the Marcellus formation, has already defined the Appalachian Basin shale plays as a significant unconventional gas discovery in parts of Pennsylvania and West Virginia. In northeastern Kentucky, the time equivalent Huron Shale, located in the Big Sandy field is also receiving renewed interest in development through horizontal drilling and the application of new completion techniques.

We followed the coring effort with the drilling and completing of a vertical well to verify the productive viability of the shale. We then re-completed two existing wells using separate methods of advanced completion techniques, as we prepare to drill and complete our horizontal program.

Our first NI-51-101 report for the area indicated that the Joint Venture area holds significant undiscovered resource potential. The report concluded a range of 490 - 2,500 BCFG (for 100% interest) is underlying our vast 109 section / 70,000 acre leasehold.

We utilized 2010 to map and identify development and completion strategies to drill 25 wells over the next 18 months. Although over 70 wells had penetrated the Chattanooga Shale in the 1970's, completion technology had not advanced to a point where commercial production was achievable. Several established operators in the region have applied advanced fracing procedures and found varying degrees of success, as initial flow rates have ranged as high as 3.5 million cubic feet of gas per day, with an average of 500 thousand cubic feet of gas per day. We have entered into data sharing agreements with other Operators and are collectively designing the next round of fracing applications, aimed at improving production volumes from the Chattanooga Shale.

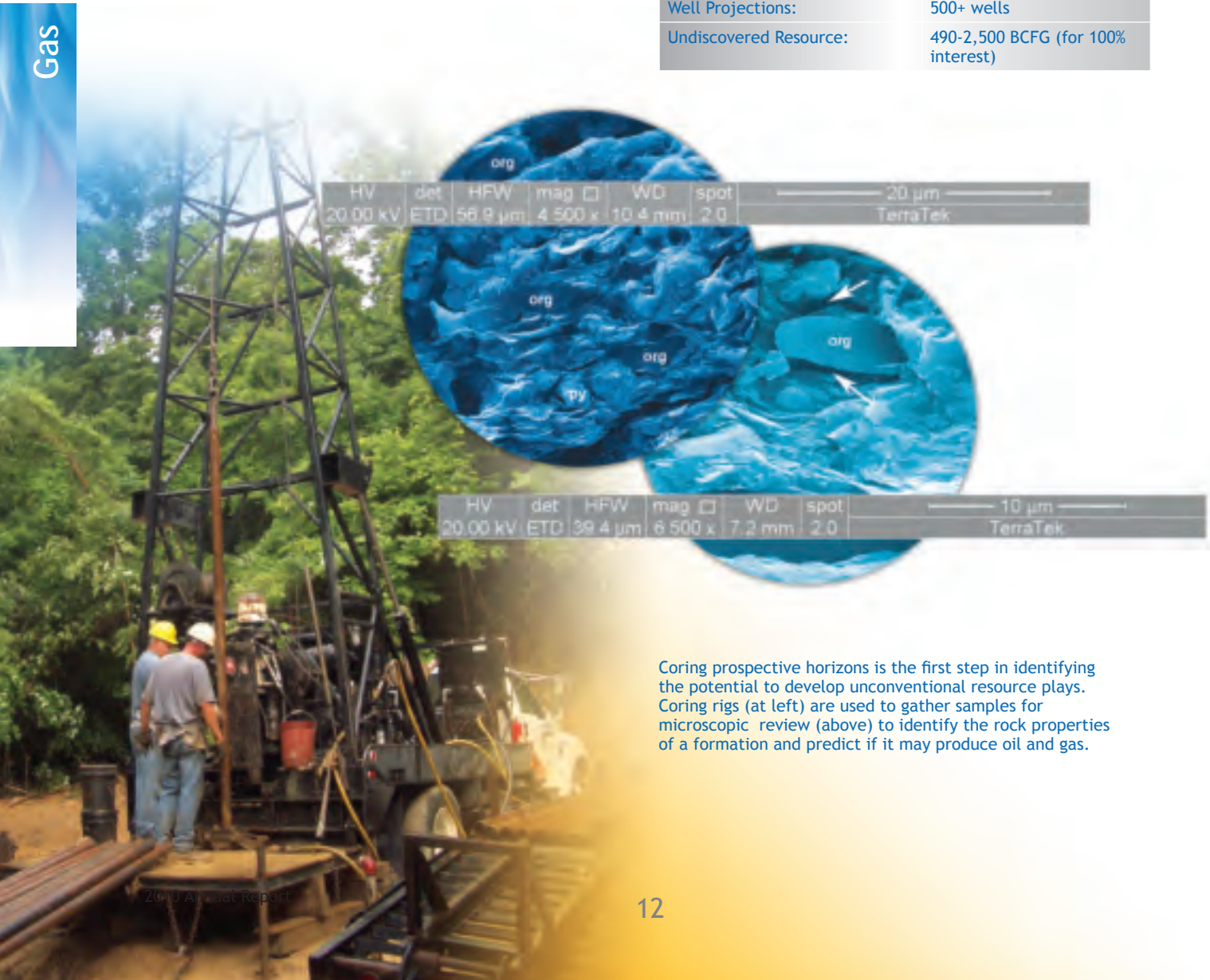
Independent studies of the Chattanooga shale by the Wood McKenzie research team have resulted in a projected average of 800 million cubic feet of gas, per well, from the formation. With over 500 wells to drill and success rates of 90%, this resource play has the real potential to generate remarkable long-term revenues as natural gas commodity prices average over \$5.00 per thousand cubic feet.

above the Chattanooga Shale at depths of 600-700 meters. The Chattanooga Shale gas charges these overlying formations. These zones produce when wellbores penetrate lineaments and fractures in vertical wells. When productive, the potential exists to produce up to an additional 500 million cubic feet of gas per well.

The play also contains secondary targets, which include the Big Lime, Granger Sand and Waverly Shale formations. These formations are located

Chattanooga Shale Metrics:	
Play Size:	109 sections
Formation Depth:	780 meters
Horizontal Lengths:	300-1,000 meters
Formation Thickness:	40 meters
BTU Values:	1,200 mmBtu
Well Projections:	500+ wells
Undiscovered Resource:	490-2,500 BCFG (for 100% interest)

Gas



Coring prospective horizons is the first step in identifying the potential to develop unconventional resource plays. Coring rigs (at left) are used to gather samples for microscopic review (above) to identify the rock properties of a formation and predict if it may produce oil and gas.

## CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

This Annual Report contains “forward-looking statements” or “forward-looking information” (collectively, “forward-looking statements”) within the meaning of applicable securities legislation. Such forward-looking statements include, without limitation, forecasts, estimates, expectations and objectives for future operations that are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company. Often, but not always, forward-looking statements can be identified by the use of words such as “plans”, “expects” or “does not expect”, “is expected”, “budget”, “scheduled”, “estimates”, “forecasts”, “intends”, “anticipates” or “does not anticipate”, or “believes” or variations of such words and phrases or words and phrases that state or indicate that certain actions, events or results “may”, “could”, “would”, “might” or “will” be taken, occur or be achieved. Although management believes that the assumptions made and the expectations represented by such forward-looking statements are reasonable, there can be no assurance that a forward-looking statement herein will prove to be accurate. Forward-looking statements by their nature are based on assumptions and involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These statements speak only as of the date of this Annual Report, unless otherwise noted to be as of a different date, and are as of the date of the MD&A or Audited Annual Consolidated Financial Statements with respect to information derived from those documents and included herein and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this Annual Report contains forward-looking statements, pertaining to, among other things, the following:

- the quantity of reserves;
- petroleum and natural gas production;
- capital expenditure programs;
- anticipated benefits resulting from various farm-out and joint venture agreements relating to petroleum and natural gas properties;
- results of exploration and development activities and dates by which certain areas may be developed or may come on-stream;
- market prices and costs;
- supply and demand for petroleum and natural gas;
- operating, general and administrative and income taxes;
- expectations regarding the Company’s ability to raise capital and to continually add to reserves through acquisition and development; and
- treatment under government regulatory and taxation regimes.

The Company’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Report:

- general economic conditions;
- volatility in the market prices for petroleum and natural gas;
- stock market volatility;
- uncertainties associated with estimating resources;
- geological, technical, drilling and processing problems;
- ability to explore, develop, produce and transport crude oil and natural gas to markets;
- title to oil and gas leases;
- dependence upon farm-out and joint venture partners;
- liabilities and risks, including environmental liabilities and risks, inherent in the oil and gas industry;
- fluctuations in currency and interest rates;
- economic conditions in the countries and regions in which the Company carries on business;
- competition for, among other things, capital, acquisition of reserves, equipment, undeveloped lands and skilled personnel;
- lack of availability of additional financing and farm-out or joint venture partners; and
- unpredictable weather conditions

Should one or more of these risks and uncertainties materialize, or should the underlying assumptions prove incorrect, actual results may vary materially from those described in forward-looking statements, readers should not place undue reliance on forward-looking statements. Except as may be required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

## Management's Discussion and Analysis

of NEXTRACTION ENERGY CORP. for the Year Ended December 31, 2010

### SELECTED ANNUAL INFORMATION

The following table shows selected consolidated financial information for the years ended December 31, 2010, 2009 and 2008.

	2010	2009	2008
	\$	\$	\$
Daily average sales volumes (BOE/d)	35	-	-
Petroleum and natural gas revenue, net of royalties	355,126	-	-
Net loss and comprehensive loss	1,549,572	1,021,496	357,770
Basic and diluted loss per share	0.10	0.13	0.11
Oil and gas properties	9,151,709	1,013,879	375,215
Total assets	12,583,805	5,579,610	3,291,792
Total liabilities	1,132,183	390,196	273,527
Working capital <sup>1</sup>	2,457,238	578,993	2,643,050
Shareholders' equity	11,451,622	5,189,414	3,018,265
Weighted average common shares outstanding	16,213,811	8,055,119	3,391,468
Securities outstanding:			
Common shares	20,639,326	11,393,513	7,606,514
Shareholder warrants	2,120,000	6,643,003	4,787,003
Stock options	2,110,000	1,695,000	1,125,000

<sup>1</sup> Working capital is defined as current assets less current liabilities excluding deferred revenue.

The Company began producing and marketing petroleum and natural gas in the second half of 2010. The net loss is due to the increase in exploration and development activities and corporate development initiatives in 2010. The Company will continue to incur losses until it has a sufficient number of successfully developed wells in commercial production.

### OVERVIEW

Nextraction Energy Corp. ("Nextraction" or the "Company") is a growth-oriented junior oil and gas company operating in the United States and Canada. The Company's business strategy is focused on targeting large size multi-horizon conventional and resource type plays in North America to find the next round of extraction on known plays that have upside for production and reserve growth through low-risk well optimization and development drilling.

During January 2010, Nextraction began drilling its first petroleum and natural gas well on the North Pinedale Anticline in Wyoming (the "Noble 6-24 well").

During March 2010, Nextraction successfully drilled, logged and set production casing on the Mountain Minerals #5 vertical well as part of the initial evaluation and development of the Company's ongoing unconventional shale gas program in the Appalachian Basin.

During March, 2010, Nextraction closed a private placement whereby the Company issued and sold 4,240,000 units at a price of \$1.00 per unit for aggregate proceeds of \$4,240,000. Each unit consisted of one common share and one-half of one common share purchase warrants.

During May 2010, Nextraction completed a pilot test well, the Mountain Minerals #5, located in the Company's Appalachian Basin Project.

During July 2010, Nextraction successfully completed a 13-stage frac in the lower productive zones of the Noble 6-24 well and entered commercial production. Nextraction acquired an additional 1,023 acre leasehold in the North Pinedale Project.

During October and November 2010, shareholders of Nextraction exercised a total of 3,458,713 warrants at an exercise price of \$0.65 per warrant for gross proceeds to the Company of \$2,248,163.

During December 2010, Nextraction entered into a Seismic Option and Farm-out Agreement with a joint venture partner, whereby Nextraction can earn an interest in 20,000 acres in the Saturn Prospect located in Daniels County, Montana. The property hosts the highly prospective Mission Canyon, McGowan, Bakken and Three Fork formations. Nextraction will earn its interest in exchange for funding 3-D seismic work and the completion of wells to exploit these formations.

During November and December 2010, Nextraction completed fracing the upper zones of the Noble 6-24 well with an eight-stage program that flowed 3 million cubic feet of gas per day on a 24 hour test using a ½ inch choke.

*This Management's Discussion and Analysis ("MD&A") provides management's comments on the financial condition and results of operations of Nextraction Energy Corp. for the year ended December 31, 2010. In this MD&A, "Nextraction" or "the Company" refers to Nextraction Energy Corp. and its subsidiary.*

*This MD&A should be read in conjunction with the Company's audited consolidated financial statements and related notes thereto, for the years ended December 31, 2010 and 2009, which are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Unless otherwise stated, all amounts in this MD&A and our audited consolidated financial statements are expressed in Canadian dollars.*

Additional information about the Company is available on our website at [www.nextraction.com](http://www.nextraction.com) and on the SEDAR website at [www.sedar.com](http://www.sedar.com).

## DATE

This Management's Discussion and Analysis is prepared as of May 2, 2011.

## BARRELS OF OIL EQUIVALENT PRESENTATION

Natural gas volumes have been converted to barrels of oil equivalent ("boe") at a ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil. This conversion ratio is based upon an energy equivalent conversion method primarily at the burner tip and does not represent equivalence at the wellhead. Furthermore, this conversion ratio is not intended to represent commodity price equivalents between natural gas and oil. Boe figures may be misleading, particularly if used in isolation.

## NON-GAAP MEASURES

The MD&A contains the term "operating netback". This term is not a recognized measure under GAAP. Nextraction's management believes that in addition to net loss, it finds operating netback a useful supplemental measure. Operating netback is a benchmark used in the oil and natural gas industry to measure the contribution of petroleum and natural gas sales following the deduction of royalties, operating expenses and transportation costs. Users are cautioned, however, that this measure should not be construed as an alternative to net earnings (loss) determined in accordance with GAAP as an indication of the Company's performance.

## RESULTS OF OPERATIONS

### Sales Volumes

	Three months ended <sup>1</sup> December 31		Years ended <sup>1</sup> December 31	
	2010	2009	2010	2009
Production:				
Petroleum and NGL (bbls/d)	4.5	-	4.0	-
Natural gas (mcf/d)	186	-	185	-
Total (boe/d)	36	-	35	-
Total (boe)	3,270	-	12,760	-
% natural gas	87%		88%	

<sup>1</sup> Barrels per day conversions have been calculated over the full calendar period for the three months ended and year ended periods. However, actual production days realized by the Company were 55 days for the three months ended December 31, 2010 and 155 days for the year ended December 31, 2010.

During the fourth quarter of 2010 the Company successfully completed the upper productive zones of the Middle Lance, Upper Lance, and Tertiary formations of the initial Noble 6-24 well but was still recovering the frac fluids at year end.

Petroleum and natural gas production for all of 2010 was 12,760 boe, resulting in gross revenue of \$439,453 compared to \$Nil in 2009. 100% of the 2010 boe production and revenue was generated in the 3rd and 4th quarters of the year. Production for the first two months of 2011 has averaged 90 boe/d. Full year production is expected to be approximately 36,000 boe (104 boe/d) with the acquisition in March 2011 of four producing light oil wells in the Provost Field in eastern Alberta. Expected production excludes results from well work-overs and drilling of new wells.

### Revenue

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Natural gas revenue	\$ 57,658	\$ -	\$ 246,662	\$ -
Oil revenue	29,798	-	99,491	-
NGL revenue	30,588	-	93,300	-
<b>Total petroleum and natural gas revenue</b>	<b>\$ 118,044</b>	<b>\$ -</b>	<b>\$ 439,453</b>	<b>\$ -</b>

Petroleum and natural gas revenues for the year ending December 31, 2010 were \$439,453 compared to \$Nil for the year ended December 31, 2009. The Company began producing and marketing petroleum and natural gas in the second half of 2010 as it entered commercial production with the successful completion of its initial well in the North Pinedale Project. The Company received an average price of \$3.64/Mcf of natural gas and \$67.37/bbl of petroleum and natural gas liquids during the year ended December 31, 2010.

Petroleum and natural gas revenues for the three month period ended December 31, 2010 were \$118,044 compared to \$Nil for the comparative period.

Revenues for 2011 cannot be determined due to the volatile nature of commodity prices. To date in 2011, crude oil prices have remained strong while natural gas prices remain relatively weak.

### Royalties

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Total royalties expense	\$ 23,915	\$ -	\$ 84,327	\$ -
<b>\$ Per boe</b>	<b>7.31</b>	<b>-</b>	<b>6.60</b>	<b>-</b>
Royalties expense as a % of petroleum and natural gas revenue:				
<b>Total royalty rate</b>	<b>20%</b>	<b>-</b>	<b>19%</b>	<b>-</b>

Royalties paid on petroleum and natural gas production for the year ended December 31, 2010 were \$84,327 compared to \$Nil for the year ended December 31, 2009. Royalties will correlate to the Company's production volumes that coincide with the sale of petroleum and natural gas products.

Royalties paid on petroleum and natural gas production for the three months ended December 31, 2010 were \$23,915 compared to \$Nil for the three months ended December 31, 2009.

Nextraction anticipates its total royalty rate to range between 15% to 20% for 2011 given its current production forecast and commodity price outlook.

### Operating expenses

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Total operating expenses	\$ 137,624	\$ -	\$ 312,635	\$ -
<b>\$ Per boe</b>	<b>42.08</b>	<b>-</b>	<b>24.50</b>	<b>-</b>

Operating expenses for the year ended December 31, 2010 were \$312,635 compared to \$Nil for the year ended December 31, 2009. Operating costs are directly correlated to petroleum and natural gas production.

Operating expenses for the three month period ended December 31, 2010 were \$137,624 compared to \$Nil for the three month period ended December 31, 2009. During the fourth quarter of 2010 the Company shut-in its Noble 6-24 well to allow for equipment to be moved to the wellhead to assist with optimization of flow-back rates. As such, substantially lower production volumes in the fourth quarter of 2010 as compared to the third quarter of the 2010 resulted in an increase of the average operating cost per boe being realized.

Nextraction is targeting average operating expenses of approximately \$22.00 boe in 2011. This is based upon assumptions of the benefits to be realized from the Company's capital projects and other field optimization and cost-cutting initiatives, and is based on expected average sales volumes of 200-300 boe/d.

### Operating Netbacks

(\$ Per boe)	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Average realized price	\$ 36.10	-	\$ 34.44	-
Royalties expenses	(7.31)	-	(6.60)	-
Operating expenses	(42.08)	-	(24.50)	-
Operating Netback	\$ (13.29)	-	\$ 3.34	-

Nextraction uses operating netbacks, which presents the per boe equivalent of the Company's revenues and operating expenses to evaluate its operating performance and profitability relative to commodity prices.

Operating netbacks of \$3.34 boe for the year ended December 31, 2010 were negatively impacted by higher operating costs incurred on optimization activities on the Noble 6-24 well to stabilize flow-back rates and assist in artificial lift.

During the fourth quarter of 2010 the Company shut in its Noble 6-24 well to allow for equipment to be moved to the wellhead to assist with optimization of flow-back rates. As such substantially lower production volumes in the fourth quarter of 2010 as compared to the third quarter of the 2010 resulted in an increase of the average operating cost per boe being realized.

Operating netbacks for 2011 cannot be determined due to the volatile nature of commodity prices. To date in 2011, crude oil prices have remained strong while natural gas prices remain relatively weak.

### General and administrative

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Total general and administrative expenses	\$ 383,478	\$ 126,173	\$ 1,084,530	\$ 482,678
\$ Per boe	117.27	-	84.99	-

The main components of the Company's general and administrative expenses are salaries and related benefits, office rent, consulting fees and professional fees and shareholder communications.

General and administrative expenses for the year ended December 31, 2010 totaled \$1,084,530 as compared to \$482,678 for the year ended December 31, 2009. During fiscal 2010 the Company experienced significant growth as it increased its exploration and development activities and focused on corporate development initiatives. This involved the hiring of additional personnel, use of third party resources for corporate development initiatives, a greater need for accounting, audit and legal services and an increase in rental space to accommodate this growth.

General and administrative expenses for the three month period ended December 31, 2010 were \$383,478, as compared to \$126,173 for the three month period ended December 31, 2009. The increase in general and administrative expense is a result of the factors discussed above. Substantially lower production volumes in the fourth quarter of 2010 as compared to the third quarter of the 2010 resulted in an increase of the average general and administrative expense per boe being realized.

Nextraction is targeting average general and administrative and operating expenses of \$25.00 boe in 2011. This is based upon assumptions of the benefits to be realized from the Company's capital projects and other field optimization and cost-cutting initiatives, continued corporate development programs, a full year of production volumes and an expected average sales volume of 200-300 boe/d.

### Stock-Based Compensation

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Total stock-based compensation	\$ 99,299	\$ 328,467	\$ 345,098	\$ 481,116
\$ Per boe	30.36	-	27.05	-

Stock-based compensation expense represents the amortization of the fair value of stock options granted to directors, officers, employees and consultants, over the vesting period of the options.

The Company recorded stock-based compensation for the year ended December 31, 2010 of \$345,098 as compared to \$481,116 for the year ended December 31, 2009. The decrease in stock-based compensation during the year ended December 31, 2010 is related to a lower number of stock options being granted with greater vesting periods as compared to the year ended December 31, 2009.

Stock-based compensation for the three month period ended December 31, 2010 totaled \$99,299 as compared to \$328,467 for the three month period ended December 31, 2009. The decrease in stock-based compensation during the three month period ended December 31, 2010 is related to a lower number of stock options being granted with greater vesting periods as compared to the three month period ended December 31, 2009.

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Number of stock options granted	140,000	570,000	500,000	570,000
Expected life of stock options (years)	2 to 5	2 to 5	2 to 5	2 to 5
Vesting period of stock options (years)	0 to 1	0	0 to 1	0
Expected volatility (%)	87.77%	84.74%	64.06%	75.26%
Risk-free interest rate (%)	2.47%	2.74%	1.71%	2.38%
Expected dividend yield (%)	0	0	0	0
Calculated fair value per option (\$)	0.66	0.55	0.36	0.41

#### Depletion, Depreciation and Accretion ("DD&A")

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Total depletion, depreciation and accretion	\$ 75,430	\$ -	\$ 182,243	\$ -
\$ Per boe	23.06	-	14.28	-

Depletion of petroleum and natural gas properties and depreciation of equipment, including the capitalized portion of asset retirement obligations, is calculated on the unit-of-production basis using depletable capital costs, production and estimated proved reserves. The Company estimates depletion and depreciation on a quarterly basis using management estimates and independent inputs (such as reserve reports) when available. The present value of Nextraction's asset retirement obligations is reported on the Company's balance sheet and is increased each reporting period due to the passage of time with the amount of accretion charged to the statement of operations in the period.

DD&A expenses for the year ended December 31, 2010 were \$182,243 compared to \$Nil for the year ended December 31, 2009. Depletion, depreciation and accretion charges are directly correlated to petroleum and natural gas production coming on-stream in the second half of 2010 as the Company entered commercial production with the successful completion of its initial well within the North Pinedale Project.

DD&A expenses for the three month period ended December 31, 2010 were \$75,430 compared to \$Nil for the three month period ended December 31, 2009. The increase in DD&A expense is a result of the factors discussed above.

The DD&A rate will fluctuate period-over-period depending on the amount and type of capital expenditures in the period and the amount and types of reserves added.

#### Taxes

Nextraction did not incur cash income taxes in 2010 or 2009. The Company does not expect to pay cash income taxes in 2011 based on expected commodity prices, existing tax pools, planned capital expenditures and forecast taxable income. Taxes payable beyond 2011 will primarily be a function of capital expenditures and cash flows. At December 31, 2010, Nextraction had estimated tax pools of \$8,820,180.

The Company has calculated a future income tax asset on the value of its tax pools, however no tax asset has been recorded in the financial statements as the Company does not believe it currently meets the recognition criteria of the losses being utilized as "more likely than not".

### Net Loss

For the year ended December 31, 2010, Nextraction recorded a net loss of \$1,549,572 (\$0.10 per share) compared to a net loss of \$1,021,496 (\$0.13 per share). Cash flow used in operating activities for the year ended December 31, 2010 was \$1,089,449 (\$0.07 per share) compared to funds used in operating activities of \$585,432 (\$0.07 per share) in the year ended December 31, 2009. The amounts per share are based on a weighted average number of shares outstanding of 16,213,811 for the year ended December 31, 2010 and 8,055,119 for the year ended December 31, 2009.

During the year ended December 31, 2010 the Company experienced significant growth as it increased its exploration and development activities and focused on corporate development initiatives. The increase in corporate expenses were offset by revenues earned from the Noble 6-24 well that was successfully brought on-stream in the third quarter of 2010.

For the three months ended December 31, 2010, Nextraction recorded a net loss of \$631,778 (\$0.03 per share) compared to a net loss of \$513,882 (\$0.07 per share) for the three months ended December 31, 2009. Cash flow used in operating activities for the three months ended fiscal 2010 was \$168,438 (\$0.01 per share) compared to funds used in operating activities of \$53,996 (\$0.01 per share) in the three months ended December 31, 2009. The amounts per share are based on a weighted average number of shares outstanding of 19,355,718 for the three month period ended December 31, 2010 and 8,071,175 for the three month period ended December 31, 2009.

### CAPITAL EXPENDITURES

In the year ended December 31, 2010, Nextraction incurred capital expenditures of \$8,317,152. This compares to \$664,584, for the corresponding period for fiscal 2009.

Capital expenditures for the three and twelve months ended December 31, 2010 and 2009 were as follows:

	Three months ended December 31		Years ended December 31	
	2010	2009	2010	2009
Land	86,962	40,666	224,343	127,423
Geological and geophysical	76,298	69,593	199,332	105,724
Drilling, completion, acquisition and facilities	1,529,724	256,610	7,893,477	431,437
<b>Total capital expenditures</b>	<b>1,692,984</b>	<b>366,869</b>	<b>8,317,152</b>	<b>664,584</b>

### North Pinedale Project (Sublette County, Wyoming)

In 2010 the Company participated in the first initial well under a Joint Venture Drilling Program to develop its North Pinedale Project in Sublette County, Wyoming. During the third quarter of 2010 the Company successfully completed the lower productive zones of the Lower Lance and Mesaverde and entered commercial production. In the fourth quarter the Company completed the upper productive zones of the Middle Lance, Upper Lance, and Tertiary formations of the initial well on the Pinedale Anticline. Nextraction paid 100% of the drilling, completing, and equipping costs of the Noble 6-24 well, and in doing so the Company earned a 100% interest in the revenues from the well and its 154 acre pooled area. Under the terms of the original Farm-out Agreement between the Company and its joint venture partner, the Company shall receive production revenue equal to 150% of gross expenditures at which time the joint venture partner will have the option to acquire a 23.25% interest in the well and the Company's interest in the well will decrease to 76.75%. Terms of the Farm-out Agreement provide for a second well to be drilled under the same terms as the Noble 6-24 well. The Company is required to commence drilling the second well prior to November 30, 2011. Failure to drill the second well would result in the Company reverting to its original interest. For all subsequent wells, the joint venture partner will participate as a 75% interest owner and the Company will participate as a 25% interest owner.

The Company also owns a 100% interest in an additional 1,040 acres in the North Pinedale area. The Company is currently conducting a seismic program to assist the Company in high grading new well locations on the leased lands. The development strategy for the overall North Pinedale Project is expected to be a combination of wells on 100% owned and 25% owned properties.

### Saturn Seismic Option and Joint Venture Agreement (Daniels County, Montana)

In December 2010 the Company entered into a Seismic Option and Farm-out Agreement ("SOFA") with a joint venture party to develop the Saturn Oil Project in Montana's Williston Basin. The SOFA has advanced the Company's goal to add additional oil reserves to its reserve base. The prospect includes over 34 sections of property rights in a region known

for its prospective oil production from the Bakken shale formation. Cores of wells analyzed by the Company in the area of the prospect indicate the acreage is also highly prospective for commercial production from conventional zones in the Ratcliffe, Mission Canyon, McGowan and Nisku formations.

In the first quarter of 2011 the Company commenced the permitting process to conduct the seismic program. The seismic program will start as soon as weather conditions permit. After interpretation of the seismic data, the Company plans to permit, drill, complete and equip its first well.

#### *Appalachian Basin (Whitley and McCreary Counties, Kentucky and Campbell County, Tennessee)*

The Company utilized much of 2010 to continue geological mapping to identify focus areas for a future 25 well development program. Confirmation of the optimal fracturing techniques were also required to enhance the recovery rates of gas in place. The Company re-entered two existing wells previously completed in the Chattanooga Shale formation through a vertical wellbore, and conducted a "propellant frac" to determine if this type of stimulation would generate economic gas flow rates from wells that had ceased producing several years earlier.

The Company was pleased to discover the initial flow back rates of one well increased by 150%. The second well remains shut in until meter equipment is installed to determine producing volumes from this well. The information gathered from the propellant frac successfully advanced the knowledge of the Chattanooga shale formation. After reviewing sustained flow back rates, the Company will design a new completion procedure for the two re-entered wells, and its future horizontal development program.

During 2010 the Company drilled, completed and began production at the Mountain Minerals #5 well, the first vertical in the Farm-out Pilot Project. This well was drilled and completed for data collection on fracturing vertical Chattanooga Shale wells and was not expected to become a major economic producer.

## CONTRACTUAL COMMITMENTS

### *Farm-In Agreements*

Under the terms of the Provost Joint Venture Agreement the Company has the option to drill two horizontal wells in the Provost Viking play as follows: first well is planned to be spudded by June 30, 2011, and the second well is planned to be spudded within thirty days of completing the first well. Failure to drill one, or both, of these wells will result in the Company losing all future interest in the properties with the exception of a 50% working interest in the currently producing wells, and a 50% interest in the battery and injection well. For all subsequent operations the Company will have a 50% interest.

Under the terms of the North Pinedale Property Farm-Out Agreements, the Company has the option to earn a greater effective interest in return for the funding of the costs of drilling and completing two wells. The first well, the Noble 6-24, has been drilled and was completed in 2010. Should the Company fail to fund 100% of the costs of the second well the parties will revert back to their original working interest percentages.

Under the terms of the Saturn Seismic and Option Farmout Agreement the Company plans to conduct a seismic program that covers at least 15,000 acres at an estimated net cost to the Company of \$900,000. Within sixty days after completion of the seismic program (but no later than September 15, 2011) the Company has the option to spud a test well, and must complete and equip or plug and abandon the well to earn 100% of two sections of property leases. Failure to drill will result in Nextraction forfeiting all rights to earn any interest on the Farm-Out lands. Within 90 days of rig release of the test well, and on a continuous ninety day rolling option thereafter, the Company has the option to spud another well on the Farm-Out lands.

### *Other Commitments*

The Company is obligated under the terms of a gas gathering agreement that allows the operator of a gathering pipeline to be reimbursed for the construction costs (approximately US\$550,000) of the gathering pipeline from future gathering fees paid, with a minimum monthly fee of US \$20,000 until 110% (US\$605,000) of the construction costs have been re-paid. During the year ended December 31, 2010, the Company paid US\$120,000 (2009 - \$Nil) in gas gathering fees and the estimated remaining amount is US\$485,000.

As at December 31, 2010, the Company leases office space on a month to month basis and is obligated to give three months' notice to terminate the lease.

Effective July 1, 2008, the Company entered into a three year agreement with an officer and director of the Company, for management consulting services. In the event that the contract is terminated by the Company within the three year period, this officer and director shall be entitled to a 0.5% overriding royalty interest in the oil and gas properties the Company acquired from a company controlled by this officer and director. In addition the Company is obligated to pay to this related company, an additional US\$300,000 cash, or 300,000 common shares of Nextraction or a combination of both, once Nextraction has generated a 15% rate of return from its investment in the first two wells of the Pinedale project. The form of the additional payment is at the option of the officer and director.

## RELATED PARTY TRANSACTIONS

The Company had the following transactions with directors, officers and companies related by virtue of directors in common:

Years ended December 31	2010	2009
Petroleum and natural gas properties		
Geological consulting	\$ 13,870	\$ 15,198
	\$ 13,870	\$ 15,198
Expenses		
Accounting fees	\$ 56,667	\$ -
Administration fees	38,500	18,000
Management and consulting fees	240,157	222,415
Rent	88,640	12,000
Property investigation costs	565	3,271
	\$ 424,529	\$ 255,686

For the year ended December 31, 2010, the Company paid or accrued \$13,870 (2009 - \$15,198) for engineering, operational and supervisory consulting, \$565 (2009 - \$3,271) for property investigation, \$38,500 (2009 - \$18,000) for administrative fees, \$56,667 (2009 - \$Nil) for accounting fees, \$64,953 (2009 - \$41,000) for management consulting fees and \$88,640 (2009 - \$12,000) for rent to companies related by virtue of common directors. These transactions were measured at fair market rates which is the amount agreed upon by the transacting parties.

For the year ended December 31, 2010, the Company also paid or accrued \$175,204 (2009 - \$181,415) for consulting fees to a company related by virtue of a common officer and director. These transactions were measured at fair market rates which is the amount agreed upon by the transacting parties.

Nextraction expects to continue to use these services in the future.

### Liquidity and Capital Resources

Nextraction currently forecasts a 2011 capital expenditure budget of \$5.1 million, as approved by its board of directors. Fluctuations in commodity prices or other factors may make it necessary to adjust forecasted capital expenditures.

The Company does not generate sufficient revenue to support its operations. To date, the Company's ongoing operations have been predominately financed by the sale of its equity securities and the subsequent exercise of share purchase warrants. However, the exercise of warrants is dependent on a number of factors, many of which the Company cannot control. This situation is unlikely to change until the Company has a sufficient number of successfully completed developed wells in commercial production.

Nextraction plans to fund its 2011 capital expenditure program through a combination of current working capital supplemented with equity financings.

To the extent that external sources of equity financing are insufficient or unavailable to fund the Company's capital program, the Company has the flexibility to adjust the scale of its capital expenditures. Nextraction operates a significant portion of the assets to which the capital program is directed, allowing for significant flexibility over the scale and timing of the program. Following is a more detailed discussion of the Company's working capital and equity structure.

### Working Capital

As of December 31, 2010, the Company had working capital of \$2,457,238 million, as compared to working capital of \$578,993 as at December 31, 2009. The Company defines its working capital as current assets less current liabilities excluding deferred revenue. At December 31, 2010, the most significant component of the Company's current assets is

\$3,153,390 of cash and cash equivalents that is not restricted in its use. The most significant component of the Company's current liabilities are trade payables and accruals due on account of the Company's capital program and operations. Included in current assets is \$171,146 of restricted cash assigned to trade payables. The increase in working capital surplus at year-end 2010 from year-end 2009 reflects gross proceeds of \$2,248,163 from the exercise of share purchase warrants in October and November 2010.

### Equity

The Company's equity structure currently consists of common shares, outstanding stock options and outstanding share purchase warrants. The Company's common shares trade on the Toronto Venture Stock Exchange under the trading symbol "NE".

The following common shares, share purchase warrants and stock options were outstanding:

	May 2, 2011	December 31, 2010	December 31, 2009
Weighted average number of common shares outstanding			
Basic and diluted	n/a	16,213,811	8,055,119
Securities outstanding			
Common shares	26,194,864	20,639,326	11,393,513
Share purchase warrants	-	2,120,000	6,643,003
Total stock options	2,230,000	2,110,000	1,695,000
Exercisable stock options	2,022,500	1,910,000	1,132,500

On March 10, 2011, the Company completed a non-brokered private placement of 1,620,369 units at a price of \$2.16 per unit for aggregate gross proceeds of \$3,499,999. Each unit consists of one common share of the Company priced at \$1.0005 each and one common share issued on a flow-through basis under the Income Tax Act (Canada) priced at \$1.1595 each. The Company has paid a finder's fee of \$97,943.

On March 24, 2011, the Company completed a brokered private placement on a bought deal basis for 1,157,400 units at a price of \$2.16 per unit for aggregate gross proceeds of \$2,499,984. Each unit consists of one common share of the Company priced at \$1.0005 each and one common share issued on a flow-through basis under the *Income Tax Act* (Canada) priced at \$1.1595 each. The Company paid underwriter commissions of \$149,999.

Subsequent to December 31, 2010, the share purchase warrants expired on March 29, 2011, unexercised.

Subsequent to December 31, 2010, the Company granted 120,000 stock options, vesting equally over six and 12 months and expiring in 5 years, at an exercise price of \$1.00 per share. Also, an additional 112,500 stock options have vested as of May 2, 2011.

Subsequent to year end management has proposed to the shareholders to vote at the upcoming Annual General Meeting to be held on June 24, 2011, to consider and, if thought fit, to pass an ordinary resolution, approving the adoption of a new stock option plan to replace the Company's current incentive stock option plan and reserving for the grant of options of up to 10% of the issued and outstanding shares of the Company at the time of any stock option grant. The current stock option plan provides for a maximum of 3,308,742 common shares of the Company to be made available for issuance.

### OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any off-balance sheet arrangements.

### PROPOSED TRANSACTIONS

In the normal course of business, as an ongoing part of the exploration process, the Company investigates petroleum and gas properties which are submitted to the Board of Directors for consideration.

### OUTLOOK

In the fourth quarter of 2011, the Company advanced the development of its existing projects and entered into a Seismic Option and Farmout Agreement with a third party to develop the Bakken Shale in the Saturn Project located in the northwestern Williston Basin of Daniels County, Montana. Prior to year-end, the Company also successfully fraced and completed the upper eight zones in the Noble 6-24 well on the Pinedale Anticline in the Upper Lance and Tertiary

formations, and conducted propellant fracing operations in two vertical wells in the Appalachian Basin Chattanooga Shale. The acquisition of the Saturn Project with light oil potential moved the Company closer to its goal of producing both light oil and liquids rich natural gas.

The Company is excited about its future prospects, including its emerging Viking light oil play within the Provost Acquisition and Development Project.

#### *Provost Viking Oil Acquisition and Development Project*

In the first quarter of 2011, the Company entered into a Joint Venture Agreement to acquire properties located in the Provost Field of eastern Alberta. The Provost Field is known for its prolific Viking A formation where vertical wells have produced up to 300,000 barrels of oil per well.

The acquisition includes four producing wells with cumulative average production of 30 barrels of oil per day. The acquisition also includes 3.25 sections of undeveloped leasehold with the potential to drill 12-21 horizontal wells in the defined pool.

The Company plans to re-enter existing wellbores to frac and complete less productive wells in the field by applying advanced completion technologies, or fracing non-productive intervals in the Viking sand formation to establish new producing horizons. The Company also plans to drill and complete two horizontal wells, with the first well to commence before July 2011.

## SUMMARY OF QUARTERLY RESULTS

The following table is a summary of the most recently completed eight quarters. Figures are in thousands of dollars, except for per share amounts.

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue, net of royalties	\$261	\$94	\$-	\$-	\$-	\$-	\$-	\$-
Interest income	\$3	\$1	\$1	\$-	\$-	\$1	\$2	\$6
Net loss	\$632	\$414	\$223	\$281	\$514	\$156	\$205	\$147
Net loss per common share - basic and diluted	\$0.03	\$0.02	\$0.01	\$0.02	\$0.02	\$0.02	\$0.03	\$0.02

The Company began commercial production on the Noble 6-24 well in July 2010. Oil and gas revenues will fluctuate in future periods depending upon the number of producing wells, production from the wells and commodity prices. Interest was earned on available cash balances and fluctuated based on the amount of cash on hand and interest rates in effect each quarter. The net income or loss for the future quarters will fluctuate based upon oil and gas revenues, related operating costs and depletion charges as well as general and administrative costs.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with Canadian GAAP require management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates.

#### *Petroleum and Gas Accounting*

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of-production method based on estimated proved petroleum and natural gas reserves.

#### *Petroleum and Natural Gas Reserves*

Under National Instrument 51-101 ("N.I. 51-101"), proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable, i.e., that it is likely that the actual remaining quantities of recovered will exceed the estimated proved reserves. In accordance with this definition, the level of certainty targeted by the Company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case

of probable reserves, which are obviously less certain to be recovered than proved reserves, N.I. 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the Company must believe that there is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of N.I. 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

The petroleum and natural gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans.

#### *Withheld Costs*

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or in the ceiling test for impairment, for which any write-down would be charged to depletion and depreciation expense.

#### *Impairment of Petroleum and Natural Gas Assets*

The Company is required to review the carrying value of petroleum and natural gas assets for potential impairment. Impairment is indicated if the carrying value of petroleum and natural gas assets is not recoverable by the future undiscounted funds from operations. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the petroleum and natural gas properties is charged to earnings. The assessment of impairment is dependent on estimates of reserves, production rates, prices, future costs and other relevant assumptions.

#### *Asset Retirement Obligations*

The Company is required to provide for future abandonment and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts and other policies. These estimated costs are charged to petroleum and natural gas properties and the appropriate liability account over the expected life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with the abandonment and site restoration, and review of potential abandonment methods.

#### *Stock-Based Compensation*

The Company uses the fair value method for valuing stock option grants. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants: a zero dividend yield as the Company does not issue dividends. The volatility is a calculation based on past trading history. The risk-free rate is from the Bank of Canada.

#### *Warrants*

The Company uses the fair value method for valuing warrants granted. The fair value of each warrant granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants: a zero dividend yield as the Company does not issue dividends. The volatility is a calculation based on past trading history. The risk-free rate is from the Bank of Canada.

#### *Legal, Environmental Remediation and Other Contingent Matters*

The Company is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

#### *Income Tax Accounting*

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations

often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessments after the lapse of considerable time. Future tax assets and liabilities are booked using the substantively enacted future income tax rates which include rate reductions over several years. The rate used by the Company is based on estimated reversals of temporary differences. Accordingly, the actual income tax liability may differ significantly from the estimates made by management.

## CHANGES IN ACCOUNTING POLICIES

The Company's significant accounting policies are set out in Note 3 of the Company's audited consolidated financial statements for the year ended December 31, 2010.

### *Convergence with International Reporting Standards*

In February, 2008, the Canadian Accounting Standards Board (AcSB) confirmed the changeover to International Financial Reporting Standards (IFRS) from Canadian GAAP will be required for publicly accountable enterprises' interim and annual financial statements for fiscal years beginning on or after January 1, 2011. The Company will adopt IFRS as the basis for preparing its consolidated financial statements effective January 1, 2011. The adoption date of January 1, 2011 will require the restatement for comparative purposes of all quarterly results reported by the Company for the year ended December 31, 2010 as well as an opening IFRS balance sheet as of January 1, 2010.

The transition to IFRS is being managed by internal staff with outside consultants and consultation with the Company's auditors as required. The Company's transition to IFRS is planned in four stages:

- Phase 1 - a high-level IFRS impact and assessment phase which includes the identification of significant differences between IFRS and the Company's current accounting policies under Canadian GAAP;
- Phase 2 - a detailed assessment and design phase which includes the identification, evaluation and selection of accounting policies under IFRS; the assessment of IFRS 1, *First-Time Adoption of IFRS*, elections; the identification of any business impacts resulting from the identified accounting differences; training analysis and information system analysis;
- Phase 3 - an implementation phase, which includes implementing all of the required changes necessary for compliance under IFRS; and
- Phase 4 - post implementation stage.

### *Phase 1*

By the end of June 2010, the Company had completed a high level IFRS impact and analysis assessment of the Company's current accounting policies under Canadian GAAP as compared to IFRS.

The following areas were identified as having the greatest potential impact to its reported financial position and results of operations:

- exploration and development expenditures
- property, plant and equipment
- stock-based compensation

### *Phase 2*

In the fall of 2010, the Company completed a detailed assessment and design phase which included the identification, evaluation and selection of accounting policies under IFRS. This included an assessment of elections under IFRS 1, *First-Time Adoption of IFRS*; the identification of any business impacts resulting from the identified accounting differences; training analysis and information system analysis. IFRS 1, along with the issues identified in phase 1 were analyzed further with the following results obtained:

#### *1. IFRS 1 - First-time Adoption of IFRS*

IFRS 1 provides a framework for the first time adoption of IFRS and outlines that, in general, a company must apply all the principles under IFRS retrospectively and recognize the changes directly in retained earnings for adjustments prior to the transition date. IFRS 1 does however provide a number of mandatory exceptions which prohibit retrospective application of IFRS. We will be in compliance with all the mandatory exceptions and anticipate electing the following optional exemptions at the date of transition:

- Business combinations - the business combination exception which allows us to avoid having to apply IFRS 3 *Business Combination* retrospectively to past business combinations. As a result we will not be restating any business combinations that took place prior to the transition date.
- If a company elects to apply IFRS 3 retrospectively, IAS 27 - *Consolidated and Separate Financial Statements* must also be applied retrospectively. As the Company will elect to apply IFRS 3 retrospectively, it will also apply IAS 27 retrospectively.
- Cumulative translation adjustments - IFRS 1 allows for all cumulative translation adjustments of foreign operations to be deemed zero at the date of transition to IFRS, (with the balance being transferred to opening retained earnings at the date of transition). The Company has chosen to apply this election. If, subsequent to adoption, a foreign operation is disposed of, the translation differences that arose before the date of transition to IFRS shall be excluded from the gain or loss on disposal.
- Use of deemed cost for oil and gas assets - IFRS 1 allows the use of deemed cost for oil and gas assets by companies that followed the full cost method of accounting for oil and gas operations. This allows the Company to elect to use the recorded amount under Canadian GAAP as the deemed cost for oil and gas assets on transition to IFRS. These amounts can then be distributed on a pro-rata basis based on proven reserves.
- Share based transactions - the share based compensation exemption allows the Company to value equity instruments granted after November 7, 2002 but before the transition date at January 1, 2010, at the same value as determined under Canadian GAAP.

## 2. *Exploration and development expenditures and property, plant and equipment*

The Company currently follows the full-cost method of accounting for oil and gas properties. Under the full-cost method of accounting, all costs related to the acquisition, exploration and development of oil and gas properties are capitalized. Under IFRS 6, *Exploration for and Evaluation of Mineral Resources* and IAS 16, *Property, Plant and Equipment*, the Company's oil and gas assets will be required to be grouped into three groups:

- Pre-exploration;
- Exploration and evaluation; and
- Development expenditures.

### a) *Exploration and development expenditures*

Under IFRS, IFRS 6, *Exploration for and Evaluation of Mineral Resources*, pre-exploration costs in areas where a legal right to explore has not been obtained are expensed as incurred with the exception that certain costs incurred to acquire the legal right to explore, such as lease acquisition costs, can be capitalized.

All previously capitalized expenditures under Canadian GAAP now classified as 'pre-exploration' expenditures *must* be expensed to retained earnings under IFRS. Upon review of the costs capitalized, it was determined that approximately \$119,000 for the Appalachian Basin project and \$40,000 for the North Pinedale project would be expensed to retained earnings.

Under a July 2009 amendment to IFRS 1 "First-time adoption of IFRS", a first-time adopter that used the full-cost method of accounting under Canadian GAAP may elect to carry forward the previously capitalized exploration and evaluation expenditures and the development and production expenditures at the amount determined previously under Canadian GAAP. The Company intends to adopt this exemption as management believes it may provide greater consistency and comparability of the financial statements as well as saving time and resources as the Company converts to IFRS.

### b) *Property plant and equipment*

Once the technical feasibility and commercial viability of a property has been established, development expenditures meeting the definition of a property, plant and equipment or intangible assets under other IFRS standards will be capitalized as appropriate. Under IFRS, IAS 16, *Property, Plant and Equipment*, each part of an item of property, plant and equipment with a cost that is significant in relation to the total costs of the item is depreciated separately.

Development and production assets are split into significant components and depreciated/depleted separately in accordance with IAS 16, *Property Plant and Equipment*. However IAS 16 states that if the life of a group of assets is tied directly to a given reserve, it may be appropriate to depreciate the assets using the unit of production method over the life of the reserve. Management intends to use the unit of production method where available to them.

Impairment testing on the properties will be performed at a lower level under IFRS than Canadian GAAP. Impairment testing is done on Cash Generating Units (CGU's). CGU's are considered to be groupings of assets that generate cash inflows, which are largely independent of other asset groupings. The Company has identified three CGU's: North Pinedale, Appalachian Basin and Montana.

### 3. Stock-based compensation

Under Canadian GAAP, the Company accounts for stock-based compensation using the fair value method. Under this method, compensation expense for stock options granted is measured at fair value at the grant date and expensed over the vesting period of the options granted using the straight-line method. Under IFRS, IFRS 2, *Share-based Payments*, entities are required to account for stock options using the fair value method but the straight-line method of vested stock options will no longer be acceptable. Stock options with multiple vesting dates must be treated as separate grants and are valued separately and expensed over their respective vesting periods. In addition, the estimated forfeiture rate must be applied to the fair value in determining the annual expense and options granted to non-employees are measured based on the fair value of goods or services received in exchange for the options.

Under IFRS 1, First-time Adoption of IFRS, the Company will have to retrospectively apply IFRS 2 to the stock options granted on December 5, 2008 as these options vested over a period of two years.

After the preliminary impact assessment phase, the Company does not anticipate any significant changes to its information technology, disclosure controls and procedures or its business activities as a result of the adoption of IFRS. The Company anticipates minimal changes to its internal controls over financial reporting resulting from the change in accounting policies relating to exploration and evaluation expenditures and development expenditures with the modifications involving the application of the new accounting standards, not a change to the existing design of the internal controls already in place. The Company's audit committee members, management and certain staff involved in the transition to IFRS have attended IFRS seminars and will have further education and training as necessary.

#### Phase 3

In this phase, management has implemented the changes to affect accounting policies and practices, business processes, systems and internal controls. The changes have been tested prior to the formal reporting requirements under IFRS to ensure all significant differences are properly addressed in time for the changeover.

During this phase management prepared the 2010 opening balance sheet. Two adjustments were made as at January 1, 2010:

- A decrease in oil and gas properties of \$208,000 which includes the expense of pre-exploration costs and foreign exchange effects on oil and gas properties.
- An increase in contributed surplus which reflects the prior period increase in stock-based compensation expenses recognized on grants which continue to vest in 2010.

March, June and September 2010 IFRS financial statements have been prepared at the time of writing of this document. Adjustments made on the opening balance sheet above are flowed through to each quarter with further adjustments being made to stock-based compensation and the foreign exchange effects of a foreign denominated subsidiary. Further mandatory adjustments to the asset retirement obligations and capitalized oil and gas assets now in the development and production stage have also been recorded as they arose throughout 2010. Draft 2010 year-end IFRS financial statements are also complete at the time of writing allowing management adequate time to comply with reporting under IFRS in the first quarter of 2011.

#### Phase 4

A post implementation review will be performed early in 2011 to ensure full compliance with IFRS.

## RISKS FACTORS

The Company is subject to a number of risk factors and uncertainties. While the Company strives to manage such risks to the extent possible and practical, there may be risk factors that cannot be predicted or foreseen. The following are the risk factors which the Company's management believes are most significant to the Company's business.

## OPERATIONAL RISKS

The most significant operational risks to the Company include:

### *Finding, developing and acquiring petroleum and natural gas reserves on an economic basis*

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Company's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Company's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Company must be able to replace reserves over time at a lessor cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Company mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

### *Production performance*

Nextraction is subject to the risk that production rates of its producing wells may decrease in an unpredictable and uncontrollable manner, which could result in a material decrease in the Company's overall production and associated revenues. In addition, drilling hazards, environmental damage, extreme weather and other operational problems could temporarily delay production and thus delay the realization of revenues. Aging infrastructure of gathering systems and pressure vessels in certain of the Company's areas may result in failures and "downtime" required for repairs, and thus may also impede production volumes. The Company mitigates production risk with diligent well supervision and effective maintenance operations.

### *Marketing of the Company's products*

In addition to producing its petroleum and natural gas, Nextraction must also successfully market its petroleum and natural gas to prospective buyers at designated sales points. Nextraction's production passes through third party facilities prior to it being ready for transfer to designated sales points. Nextraction will likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related operational problems with such pipelines and facilities. To mitigate these risks, Nextraction utilizes in-house marketing expertise and purchases business interruption insurance policies.

### *Competition*

The petroleum and natural gas industry is intensely competitive and the Company will compete for land, capital resources, qualified employees and supply of services and equipment with a substantial number of other companies, many of which may have greater resources. The success of the Company depends in large part on key managerial and technical personnel, and there can be no assurance that the Company will be able to attract the personnel required to execute the Company's exploration and development plans. The Company designs its compensation plans to motivate and retain existing personnel and attract new staff as a measure to mitigate this risk. In addition, the supply of services and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce them in an economic and timely fashion. In periods of increased industry activity, these services and supplies can become difficult and costly to obtain. The Company mitigates this risk by developing strong long-term relationships with suppliers.

### *Title*

Although title reviews will be done according to industry standards to the purchase of petroleum and natural gas properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Company in certain wells or lands which could result in a reduction of production and ultimately cash flows of the Company.

### *Reliance on operators, management and key personnel*

Successfully exploring for, developing and commercializing petroleum and natural gas interest depends on a number of factors, not the least of which is the technical skill of the personnel involved. Nextraction's success will be, in part, dependent on the performance of its key managers and consultants. Failure to retain the managers and consultants, or to

attract or retain additional key personnel, with the necessary skills and experience could have a material adverse impact on Nextraction's growth and profitability. Nextraction does not carry key person insurance. To the extent Nextraction is not the operator of its petroleum and natural gas properties, Nextraction will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

#### *Seasonality and climate*

The level of activity in the petroleum and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access to Nextraction's properties and, as a result, reduced operations or a cessation of operations. Municipalities and regional transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

#### *Pipeline capacity*

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the petroleum and natural gas industry and limit the ability to produce and market petroleum and natural gas production.

## FINANCIAL RISKS

The most significant financial risks to the Company include:

#### *Petroleum and natural gas prices*

Demand for petroleum and natural gas produced by the Company exists primarily within United States and Canada. However, petroleum prices are affected by worldwide supply and demand fundamentals, while natural gas prices are primarily affected by North American supply and demand fundamentals. Volatility in petroleum and natural gas prices is a risk for all producers in the petroleum and natural gas industry. Deterioration of petroleum and natural gas prices received would reduce the Company's cash flows, which could result in the Company reducing its planned capital program.

#### *Foreign Currency*

General and administrative costs incurred by the Company are generally paid in Canadian dollars while operating and capital costs incurred are generally paid in United States dollars. World oil prices are quoted in United States dollars and the price received by the Company is therefore affected by the Canadian/U.S. dollar exchange rate which can materially fluctuate over time. A material decrease in the value of the Canadian dollar may negatively impact the Company's net production revenue. The Company does not use financial instruments to hedge this risk.

#### *Inflation risks*

Inflation risks subject the Company to potential erosion of product netbacks. For example, prices for petroleum and natural gas equipment and services can inflate the Company's operating and capital costs.

#### *Third-party credit risk*

Nextraction is or may be exposed to third-party credit risk through its contractual arrangements with its current or future joint interest partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Nextraction, such failure could have a material adverse effect on Nextraction and its funds from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint interest partner's willingness to participate in Nextraction's ongoing capital program, potentially delaying the program and the result of such program until Nextraction finds a suitable alternative partner. To mitigate this risk, the Company performs regular reviews of receivables to minimize default or non-payment.

#### *Access to capital and credit markets*

Since Nextraction spends the majority of its cash flow on operations and capital spending, the Company must finance major acquisition activity with equity. As such, Nextraction is dependent to a certain extent on continued access to

capital markets. The Company is listed on the Toronto Venture Stock Exchange and maintains an active investor relations program. Continued access to capital is dependent on Nextraction's ability to continue to perform at a level of that meets market expectations. However, the strength of capital markets generally and other factors beyond the control of the Company may restrict the Company's ability to continue to access capital markets.

## REGULATORY RISKS

The most significant regulatory risks to the Company include:

### *Environmental, health and safety*

Nextraction endeavours to conduct its operations with due regard for the potential on the environment and the safety of the Company's workers. However, the operation of petroleum and natural gas wells involves a number of natural hazards which may result in blowouts, pollution or other unexpected or dangerous conditions resulting in liability to the Company and possibly liability to third parties. In particular, Nextraction is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or in transporting production could result in releases of fluid substances that pollute or contaminate lands at or near its properties which could result in significant liability to the Company for costs of clean up, remediation and reclamation of contaminated lands. To mitigate these risks, the Company hires consultants with the requisite skills and expertise to help develop and manage these safety risks. In addition, Nextraction carries insurance to cover a portion of pollution, property losses and liability to others. It should be noted, however, that in accordance with industry practice, the Company is not fully insured against all such risks, nor are all such risks insurable.

### *Government Regulation*

Petroleum and natural gas operations are subject to extensive legislation, regulations and programs imposed by various levels of government, which are subject to change from time-to-time. These include processes of obtaining drilling and other licenses, royalty regimes, drilling and royalty incentive programs, environmental regulation and orders, taxation law and climate change regulation. Of significance, government legislation requires that well sites be abandoned and restored to the satisfaction of authorities. A breach in legislation may result in fines or the issuance of clean-up orders. The Company makes a reasonable provision for abandonment and restoration liabilities according to government-published cost guides and other estimates; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. Additionally, production operations are very susceptible to regulatory compliance and government inspections pose a risk if the Company is not pro-active to complying with regulations. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition. Nextraction does its best to remain knowledgeable regarding changes to the regulatory regimes under which it operates.

### *Additional Information*

Additional information relating to Nextraction is available on the Company's website at [www.nextraction.com](http://www.nextraction.com) and all of Nextraction's continuous disclosure filings are available through SEDAR at [www.sedar.com](http://www.sedar.com). Information can also be obtained by contacting Nextraction Energy Corp., Bentall Tower 5, Suite 328, 550 Burrard Street, Vancouver, Canada, V6C 2B5.

KPMG LLP  
Chartered Accountants  
PO Box 10426 777 Dunsmuir Street  
Vancouver BC V7Y 1K3  
Canada

Telephone (604) 691-3000  
Fax (604) 691-3031  
Internet www.kpmg.ca

## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Nextraction Energy Corp.

We have audited the accompanying consolidated financial statements of Nextraction Energy Corp., which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of operations and comprehensive loss and deficit, and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

### *Management's Responsibility for the Consolidated Financial Statements*

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### *Auditors' Responsibility*

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### *Opinion*

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Nextraction Energy Corp. as at December 31, 2010 and 2009 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.



Chartered Accountants

April 29, 2011  
Vancouver, Canada

## Consolidated Balance Sheets

As at December 31	2010	2009
<b>Assets</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 3,153,390	\$ 740,626
Restricted cash (note 5)	171,146	212,971
Accounts receivable	71,609	12,684
Prepaid expenses and deposits	35,951	2,908
	3,432,096	969,189
Petroleum and natural gas properties (note 6)	9,151,709	1,013,879
Restricted cash (note 5)	-	3,596,542
	<b>\$ 12,583,805</b>	<b>\$ 5,579,610</b>
<b>Liabilities and Shareholders' Equity</b>		
<b>Current liabilities:</b>		
Accounts payable and accrued liabilities (note 12)	\$ 974,858	\$ 390,196
Deferred revenue	75,264	-
	1,050,122	390,196
Asset retirement obligations (note 7)	82,061	-
<b>Shareholders' equity:</b>		
Share capital (note 8)	13,020,852	5,281,582
Warrants (note 8)	426,224	898,215
Contributed surplus (note 9)	1,056,930	512,429
Deficit	(3,052,384)	(1,502,812)
	11,451,622	5,189,414
Commitments (note 15)		
Subsequent events (note 18)		
	<b>\$ 12,583,805</b>	<b>\$ 5,579,610</b>

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board:

Signed:    
 Frank Hallam  
 Director  
 R. Michael Jones  
 Director

## Consolidated Statements of Operations, Comprehensive Loss and Deficit

Years ended December 31	2010	2009
<b>Revenues:</b>		
Petroleum and natural gas	\$ 439,453	\$ -
Royalties	(84,327)	-
	355,126	-
<b>Expenses (income)</b>		
Operating	312,635	-
Interest	(5,424)	(8,686)
General and administrative	1,084,530	482,678
Foreign exchange (gain) loss	(14,384)	66,388
Stock-based compensation	345,098	481,116
Depletion, depreciation and accretion	182,243	-
	1,904,698	1,021,496
<b>Net loss and comprehensive loss</b>	<b>(1,549,572)</b>	<b>(1,021,496)</b>
Deficit, beginning of year	(1,502,812)	(481,316)
<b>Deficit, end of year</b>	<b>\$ (3,052,384)</b>	<b>\$ (1,502,812)</b>
<b>Net loss per share</b>		
Basic and diluted (note 10)	\$ (0.10)	\$ (0.13)
<b>Weighted average number of common shares outstanding</b>		
Basic and diluted (note 10)	16,213,811	8,055,119

See accompanying notes to the consolidated financial statements.

## Consolidated Statements of Cash Flows

Years ended December 31	2010	2009
Cash provided by (used in):		
Operating activities		
Net loss	\$ (1,549,572)	\$ (1,021,496)
Items not affecting cash:		
Depletion, depreciation and accretion	182,243	-
Stock-based compensation	345,098	481,116
Foreign exchange (gain) loss	(14,017)	66,388
	(1,036,248)	(473,992)
Changes in non-cash working capital:		
Accounts receivable	(58,925)	(2,658)
Prepaid expenses and deposits	(33,043)	(2,075)
Accounts payable and accrued liabilities	(36,097)	(106,707)
Deferred revenue	75,264	-
	(1,089,049)	(585,432)
Investing activities		
Additions to petroleum and natural gas properties	(8,238,012)	(862,040)
Restricted cash	3,638,367	(3,586,137)
Changes in non-cash working capital	620,759	223,376
	(3,978,886)	(4,224,801)
Financing activities		
Proceeds from issuance of common shares and warrants	4,240,000	2,821,500
Proceeds from the exercise of warrants	3,405,278	16,250
Share issuance costs	(178,596)	(126,221)
	7,466,682	2,711,529
Foreign exchange gain (loss) on cash held in foreign currencies	14,017	(66,388)
Increase (decrease) in cash and cash equivalents	2,412,764	(2,165,092)
Cash and cash equivalents, beginning of period	740,626	2,905,718
Cash and cash equivalents, end of period	\$ 3,153,390	\$ 740,626
Supplementary information:		
Income taxes received	-	4,394

See accompanying notes to the consolidated financial statements.

## Notes to Consolidated Financial Statements

Years ended December 31, 2010 and 2009

### 1. NATURE OF OPERATIONS

Nextraction Energy Corp. ("Nextraction" or the "Company") was incorporated under the laws of the Province of British Columbia, Canada, and is a public corporation listed on the Toronto Venture Exchange. The Company is engaged in the acquisition, exploration and development of petroleum and natural gas properties in the United States and Canada. During the year ended December 31, 2010, the Company commenced operations from its well on the Company's North Pinedale property.

### 2. BASIS OF PRESENTATION

The consolidated financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These consolidated financial statements include the accounts of Nextraction Energy Corp. and its wholly-owned subsidiary Nextraction Energy (US) Inc. All intercompany transactions have been eliminated.

### 3. SIGNIFICANT ACCOUNTING POLICIES:

#### (a) Use of Estimates

The preparation of consolidated financial statements in accordance with Canadian 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 balance sheet date and the reported amounts of revenue and expenses during the period. Significant areas requiring the use of management estimates relate to the determination of impairment of oil and gas properties, depletion, depreciation and accretion, future income tax assets and liabilities, fair value measurements associated with financial instruments, asset retirement obligations and assumptions used in determining stock-based compensation expense.

The amounts recorded for depletion and depreciation of petroleum properties and the ceiling test calculation are based on estimates of gross proved reserves (as determined by independent engineers), production rates, future costs and other relevant assumptions. The value of the asset retirement obligation is based on the Company's net ownership interest in all wells, and depends on estimates of current market interest rates, inflation rates, future restoration and reclamation expenditure and timelines. By their nature, these estimates are subject to measurement uncertainty and the effects on the consolidated financial statements of changes in such estimates in future years could be significant.

The calculation of income taxes is based on assumptions, which are subject to uncertainty as to timing as well as tax rates at which temporary differences are expected to reverse.

The Black-Scholes option valuation model was developed for the use in estimating the fair value of options, which were fully tradable with no vesting restrictions. This option valuation model requires the input of assumptions including the expected stock price volatility.

The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment with reasonable limits of materiality and within the framework of the significant accounting policies summarized below. Actual results could differ from those estimates.

#### (b) Foreign currency translation

The functional currency of the Company is the Canadian dollar and the Company's US subsidiary is an integrated foreign operation. The Company translates monetary assets and liabilities denominated in foreign currencies at the rates of exchange prevailing at the balance sheet dates. Non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or obligations incurred. Foreign currency revenues and expenses are translated at average rates of exchange during the year. The resulting foreign currency gains or losses are charged to earnings.

#### (c) Cash and cash equivalents

Cash and cash equivalents consists of cash on hand, cash held at banks, and guaranteed investment certificates with maturity dates of three months or less from the date of acquisition and are not restricted in its use.

#### (d) Petroleum and natural gas properties

##### (i) Capitalized costs:

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method, all costs related to the exploration, development and production of petroleum and natural gas reserves are capitalized in a single cost centre. Costs include lease acquisition costs, geological and geophysical costs, costs of drilling productive and non-productive wells, production equipment costs, asset retirement costs and overhead charges related to exploration and development activities.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized unless such a sale would alter the rate of depletion by greater than twenty percent.

### 3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED):

#### (d) Petroleum and natural gas properties (continued)

##### *(ii) Depletion and depreciation:*

Petroleum properties, including estimated costs of future development of proved undeveloped reserves, are depleted and amortized using the unit-of-production method based on estimated gross proven petroleum and natural gas reserves as determined by external experts. For depletion and amortization purposes, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties and seismic costs on undeveloped land are initially excluded from petroleum properties for the purpose of calculating depletion. When proved reserves are assigned, or the property or seismic is considered to be impaired, the cost of the property or seismic or the amount of the impairment is added to costs subject to depletion.

##### *(iii) Ceiling test:*

In applying the full cost method, the Company calculates a ceiling test whereby the carrying amount of property and equipment is compared to the sum of the undiscounted cash flows expected to result from the future production of proved reserves and the cost, less any impairment, of unproved properties. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality differentials. Should the ceiling test result in an excess of carrying amount, the Company would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the cost, less any impairment, of unproved properties. The Company's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying amount would be recorded as a permanent impairment.

#### (e) Interest in joint operations

A substantial portion of the Company's petroleum and natural gas exploration and development activities are conducted jointly with others, and accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

#### (f) Asset retirement obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value is determined through a review of engineering studies, industry guidelines and management's estimate on a site-by-site basis. The fair value of the estimated asset retirement obligations is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on gross proved reserves. The liability amount is increased each reporting period to reflect the passage of time with the corresponding amount charged to earnings as accretion expense. Actual costs incurred upon the settlement of the asset retirement obligation are charged against the asset retirement obligations to the extent of the liability recorded.

#### (g) Revenue recognition

Revenue from the sale of natural gas, crude oil and natural gas liquids are recognized based on volume delivered at contractual delivery points and rates, and when collection is reasonable assured. The cost associated with the delivery, including operating, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

### 3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED):

#### (h) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including derivatives, are recognized on the balance sheet at fair value with the exception of those recognized in certain related party transactions. Subsequent measurement is then based on the financial instrument being classified into one of five categories: held-for-trading, held-to-maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents and restricted cash as loans and receivables, and are measured at fair value, with changes in fair value being recorded in the statement of operations. Accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method. Accounts payable and accrued liabilities are classified as other financial liabilities and are measured at amortized cost using the effective interest method. The Company had no available-for-sale or held to maturity financial instruments as at December 31, 2010 and 2009.

Effective December 31, 2009, the Company adopted the amendments to the CICA Handbook Section 3862, *Financial Instruments - Disclosures*. These amendments require the Company to present information about financial instruments measured at fair value in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices observed in active markets for identical assets or liabilities;  
Level 2 - valuation techniques based on inputs that are quoted prices of similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; inputs other than quoted prices used in a valuation model that are observable for that instrument; and inputs that are derived principally from or corroborated by observable market data by correlation or other means; and  
Level 3 - valuation techniques with significant unobservable market inputs.

The level within which financial asset or liability is classified is determined based on the lowest level of significant input to the fair value measurement. The requirements of this amendment have been included in note 13.

#### (i) Share issue costs

The costs of issuing common shares are applied to reduce the stated value of such shares.

#### (j) Stock based compensation

The Company accounts for stock option agreements using the fair value method. Under this method, compensation expense for stock options granted to employees, officers and directors is measured at fair value at the grant date, estimated using the Black-Scholes valuation model, and expensed over the vesting period of the options granted with a corresponding increase to contributed surplus. Compensation expense for stock-based payments to non-employees is periodically re-measured until counterparty performance is complete. Upon exercise of the stock options, consideration paid by the option holder, together with the amount recognized in contributed surplus, is credited to share capital. The Company does not incorporate a forfeiture rate for stock options that will not vest, but rather accounts for actual forfeitures as they occur.

#### (k) Per share amounts

The calculation of basic loss per share is based on net loss divided by the weighted average number of common shares outstanding during the period.

The treasury stock method of calculating diluted per share amounts is used whereby any proceeds from the exercise of stock options and warrants are assumed to be used to purchase common shares at the average market price during the period. Fully diluted amounts are not presented when the effect of the computations are anti-dilutive due to the losses incurred.

### 3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED):

#### (l) Income taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for the future income tax consequences attributable to difference between the financial statement carrying amounts of the existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment, or substantive enactment, date. Future tax assets are recognized to the extent that they are more likely than not to be realized.

### 4. RECENT PRONOUNCEMENTS:

#### *Convergence with International Reporting Standards*

In February, 2008, the Canadian Accounting Standards Board confirmed that International Financial Reporting Standards (IFRS) will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on and after January 1, 2011. The Company's first mandatory filing under IFRS, which will be the first quarter of 2011, will contain IFRS-compliant information on a comparative basis, as well as reconciliations for that quarter and as at the January 1, 2010 transition date. Although IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in recognition, measurement and disclosure.

### 5. RESTRICTED CASH:

On October 6, 2009, and as later amended on November 11, 2009, the Company entered into a farm-out agreement with a third party to drill an initial test well on the Pinedale Anticline field in Sublette County, Wyoming. Under the terms of the farm-out agreement Nextraction is obligated to fund, through an advance deposit into escrow, 100% of the permitting, drilling and completion expenditures related to the initial test well. As at December 31, 2010 the escrow account balance was \$171,146 (December 31, 2009 - \$3,809,513) of which \$171,146 (2009 - \$212,971) is current to offset accounts payable related to the initial test well and \$Nil (2009 - \$3,596,542) is available for future capital expenditures relating the initial test well.

### 6. PETROLEUM AND NATURAL GAS PROPERTIES:

	Cost	December 31, 2010	
		Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	\$ 9,331,031	\$ 179,322	\$ 9,151,709
	\$ 9,331,031	\$ 179,322	\$ 9,151,709
	Cost	December 31, 2009	
		Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	\$ 1,013,879	\$ -	\$ 1,013,879
	\$ 1,013,879	\$ -	\$ 1,013,879

The Company has included \$6,075,000 for future development costs and excluded \$1,183,240 for undeveloped land and seismic costs from the depletion calculation and ceiling test. During the year ended December 31, 2010, the Company recognized a total of \$13,659 (2009 - \$25,920) of drilling credits as a reduction of petroleum and natural gas properties.

#### *North Pinedale Project:*

During the year ended December 31, 2009, and as later amended on March 22, 2010, the Company entered into a farm-out agreement to drill an initial test well in the Pinedale Anticline field in Sublette County, Wyoming. During the year ended December 31, 2010, the Company drilled and completed the initial test well and by fully funding the completion of the well the Company will receive production revenue equal to 150% of its drilling and completion costs. The joint venture partner has the option to participate in a 26.25% working interest in the initial well subsequent to payout of drilling and completion costs. In addition, the Company has the option to drill and complete a second well under the same terms of the initial test well. For all subsequent wells, the Company will participate as a 25% interest owner.

## 6. PETROLEUM AND NATURAL GAS PROPERTIES (CONTINUED):

### *North Pinedale Project (Continued):*

As of December 31, 2010, the Company has incurred expenditures totaling \$7,615,498 for the Noble 6-24 well, consisting of \$71,958 for well permitting and lease costs, \$436,162 in pre-drilling costs, \$3,490,834 in drilling costs and \$3,616,544 in completion costs.

### *Appalachian Basin Project:*

During the year ended December 31, 2009, and as later amended on May 3, 2010, the Company entered into a farm-out and joint venture agreement to drill and fund five initial test wells, or re-enter and complete 5 existing wells, or a combination thereof, to earn a 95% working interest in each well and a 78.38% net revenue interest. Upon the Company receiving production revenue equal to its drilling and completion costs the joint venture partner will have the option of converting its initial 17.5% net revenue royalty interest in the wells to a 25% working interest. The Company will have the option to fund and complete an additional 25 wells under similar terms as the initial 5 wells, except that the joint venture partner will have the option of converting its initial 17.5% net revenue royalty interest to a 35% working interest. Upon completion of these wells the Company will earn a 47.5% interest in the remaining undrilled lands held by the joint venture partner.

As of December 31, 2010, the Company has incurred expenditures totaling \$1,130,572 on the Appalachian Basin Project of which \$815,341 has been incurred on the five initial test wells.

### *Saturn Seismic and Farm-Out Project:*

During the year ended 2010, the Company entered into a farm-out and joint venture agreement to fund 75% of a 3-D seismic survey program on certain lands in northeastern Montana's Williston Basin. Upon completion of the seismic program the Company has the option to earn a 2 section interest in property leases held by the joint venture partner with the funding and completion of each well drilled. Upon payout of the costs of each respective well the joint venture partner will have the option to back into a 30% working interest on a well by well basis. The Company will have a rolling option to drill and develop the property by commencing a new well within 90 to 120 days of rig release of the previous well until a total of \$10,000,000 has been invested, at which time the Company will earn 50% interest in the remaining property rights not previously earned.

The Company performed a ceiling test calculation as at December 31, 2010 and determined there was no impairment of its petroleum and natural gas properties. The Company's future prices, as adjusted for commodity price differentials and transportation specific to the Company's production (source: GLJ Consultants Ltd. "Reserves and Resource Assessment Evaluation of North Pinedale" report dated effective December 31, 2010), used in the ceiling test calculation are as follows:

	Light oil (C\$/bbl)	Residue Gas <sup>1</sup> (C\$/Mcf)	Exchange rate (US\$/CAN\$)
2011	79.80	4.94	0.98
2012	80.82	5.69	0.98
2013	81.84	6.37	0.98
2014	83.88	6.94	0.98
2015	87.11	7.51	0.98
2016	89.54	7.91	0.98
2017	92.31	8.17	0.98
2018	94.84	8.33	0.98
2019	97.60	8.50	0.98
2020	99.76	8.68	0.98
2021	101.95	8.68	0.98
2022	104.19	9.04	0.98
Thereafter	+ 2.0%/yr	+ 2.0%/year	

<sup>1</sup> The Company's estimate of future prices on residue gas includes forward commodity pricing estimates for both natural gas and natural gas liquids.

## 7. ASSET RETIREMENT OBLIGATIONS:

The Company has estimated the net present value of its total asset retirement obligations at December 31, 2010 to be \$82,061 (December 31, 2009 - \$Nil), based on a total future liability of \$261,713 (December 31, 2009 - \$Nil). These payments are expected to be made ranging from 10 to 25 years into the future. A credit adjusted risk-free discount rate of 6.35% and an inflation rate of 1.9% was used to calculate the present value of the asset retirement obligation.

Years ended December 31	2010	2009
Carrying amount, beginning of period	\$ -	\$ -
Liabilities incurred	79,215	-
Accretion expense	2,920	-
Foreign currency translation	(74)	-
Carrying amount, end of period	\$ 82,061	\$ -

## 8. SHAREHOLDERS' EQUITY:

### (a) Authorized:

Unlimited number of voting common shares.

### (b) Issued and outstanding:

Year ended December 31	2010		2009	
	Number	Amount	Number	Amount
Balance, beginning of year	11,393,513	\$ 5,281,582	7,606,514	\$ 2,788,494
Issued in private placement for cash	4,240,000	4,240,000	3,762,000	2,821,500
Private placement warrant component	-	(426,224)	-	(221,984)
Issued upon exercise of warrants	5,005,813	3,405,279	25,000	16,250
Transfer of fair value on exercise of warrants	-	698,812	-	3,543
Share issue costs	-	(178,597)	-	(126,221)
Share cancelled	-	-	(1)	-
	20,639,326	\$ 13,020,852	11,393,513	\$ 5,281,582

On March 29, 2010, the Company completed a private placement of 4,240,000 units, consisting of one common share and one-half of one common share purchase warrant, at a price of \$1.00 per unit for aggregate gross proceeds to the Company of \$4,240,000. The gross proceeds were allocated to the underlying common shares and warrants on a relative fair value basis. The fair value allocated to the common shares was \$3,813,776 and the fair value allocated to the warrants was \$426,224. Each whole warrant entitles the holder to purchase one additional common share at an exercise price of \$1.25 until March 29, 2011. Share issue costs totaled \$178,597.

On November 19, 2009, the Company completed a private placement of 3,762,000 units, consisting of one common share and one-half of one common share purchase warrant, at a price of \$0.75 per unit for aggregate gross proceeds to the Company of \$2,821,500. The gross proceeds were allocated to the underlying common shares and warrants on a relative fair value basis. The fair value allocated to the common shares was \$2,599,516 and the fair value allocated to the warrants was \$221,984. Each whole warrant entitles the holder to purchase one additional common share at an exercise price of \$0.95 until November 19, 2010. Share issue costs totaled \$126,221.

### (c) Escrow shares:

In connection with the Company's change of business to oil and gas exploration during 2008, under the requirements of the TSX Venture Exchange a total of 993,334 of the Company's shares held by directors and other related parties of the Company were placed in escrow of which 933,334 (2009 - 675,000) have been released as at December 31, 2010. Of the remaining 60,000 escrowed shares, 30,000 will be released on May 5, 2011 and the remainder on November 5, 2011.

## 8. SHAREHOLDERS' EQUITY (CONTINUED):

### (d) Warrants:

	Fair value of warrants	Number of warrants	Weighted average exercise price
Balance as at December 31, 2008	\$ 679,774	4,787,003	\$0.65
Issued in private placement	221,984	1,881,000	\$0.95
Warrants exercised	(3,543)	(25,000)	\$0.65
Balance as at December 31, 2009	898,215	6,643,003	\$0.73
Issued in private placement	426,224	2,120,000	\$1.25
Warrants exercised	(698,812)	(5,005,813)	\$0.68
Warrants expired	(199,403)	(1,637,190)	\$0.90
Balance as at December 31, 2010	\$ 426,224	2,120,000	\$1.25

During the year ended December 31, 2010, the Company issued 2,120,000 warrants associated with the private placement as described above (note 8(b)) with an expiry date of March 29, 2011. Subsequent to year end, these warrants expired unexercised and the fair value of \$426,224 will be transferred into contributed surplus in 2011.

During the year ended December 31, 2010, a total of 5,005,813 warrants (2009 - 25,000) were exercised at an average exercise price of \$0.68 (2009 - \$0.65) for gross proceeds of \$3,405,279 (2009 - \$16,250). The fair value of the warrants exercised was \$698,812 (2009 - \$3,543).

During the year ended December 31, 2010, 261,190 of the \$0.65 warrants and 1,376,000 of the \$0.95 warrants expired on November 5, 2010 and November 19, 2010, respectively. The fair values of these expired warrants of \$37,016 and \$162,387 respectively, were transferred to contributed surplus.

During the year ended December 31, 2009, the Company issued 1,881,000 warrants associated with the private placement as described above (note 8(b)) with an expiry date of November 19, 2010.

The fair values of the warrants issued were estimated using the Black-Scholes pricing model with the following assumptions:

	2010	2009
Expected life	1 year	2 - 5 years
Risk-free interest rate	1.61%	2.38%
Expected volatility	63.28%	75.26%
Expected dividends	-	-

### (e) Stock options:

The Company has a Stock Option Plan (the "Plan") pursuant to which options to purchase common shares may be granted by the Board of Directors to directors, officers, employees and consultants to the Company. In June 2010, the Company amended and restated its stock option plan and the plan now provides for a maximum of 3,308,742 common shares of the Company to be made available for issuance under the Plan.

As at December 31, 2010, 2,110,000 options (2009 - 1,695,000) are issued and outstanding, at an average exercise price of \$0.70 (2009 - \$0.56) and with a weighted-average life of 3.2 years. A total of 1,910,000 of the options granted are vested and exercisable and the remainder vests in periods ranging from 3 months to 2 years. The options generally expire five years from the date of grant.

The following tables summarize information regarding stock options for the years ended December 31, 2010 and 2009:

	Number	Weighted average exercise price
Balance as at December 31, 2008	1,125,000	\$ 0.42
Granted	570,000	0.85
Balance as at December 31, 2009	1,695,000	0.56
Granted	500,000	1.22
Forfeited and cancelled	(85,000)	0.99
Balance as at December 31, 2010	2,110,000	\$ 0.70

## 8. SHAREHOLDERS' EQUITY (CONTINUED):

### (e) Stock options (Continued):

Weighted average exercise price	Options Outstanding		Options Exercisable	
	Number of options	Weighted average remaining contractual life (years)	Number of options	Expiry date
\$ 0.42	1,125,000	2.85	1,125,000	November 5, 2013
\$ 0.85	520,000	4.00	520,000	December 29, 2014
\$ 1.06	20,000	4.14	20,000	February 19, 2015
\$ 1.40	200,000	1.52	50,000	July 6, 2012
\$ 1.25	105,000	4.58	105,000	July 28, 2015
\$ 0.95	140,000	4.92	90,000	December 2, 2015
\$ 0.70	2,110,000	3.24	1,910,000	

### (f) Stock-based compensation

The Company accounts for its stock options granted to directors, officers, employees and consultants using the fair value method using the Black-Scholes option-pricing model. In accordance with the Company's incentive stock plan, these options have an exercise price equal to the fair value of the Company's common shares at the date of grant. The following weighted-average fair value assumptions, for the options granted during the year, are as follows:

Years ended December 31	2010	2009
Fair value per option	\$ 0.36	\$ 0.41
Expected life	2 - 5 years	2 - 5 years
Risk-free interest rate	1.71%	2.38%
Expected volatility	64.06%	75.26%
Expected dividends	-	-

## 9. CONTRIBUTED SURPLUS:

Years ended December 31	2010	2009
Balance, beginning of year	\$ 512,429	\$ 31,313
Stock compensation expense	345,098	481,116
Fair value of expired warrants	199,403	-
	\$ 1,056,930	\$ 512,429

## 10. PER SHARE AMOUNTS:

During the year ended December 31, 2010, there were 16,213,811 (2009 - 8,055,119) weighted average shares outstanding. Exercise of all stock options and share purchase warrants were not included in the computation of diluted loss per share because they were anti-dilutive.

## 11. INCOME TAXES:

Income tax expense (recovery) varies from the amounts that would be computed by applying the basic federal and provincial income tax rates aggregating 28.5% (2009 - 30%) to loss before income taxes as shown in the following table:

Years ended December 31	2010	2009
Loss before income taxes	\$ (1,549,572)	\$ (1,021,496)
Combined corporate tax rate	28.5%	30.0%
Computed expected income tax recovery	(441,628)	(306,449)
Non-deductible stock-based compensation	98,353	144,335
Share issue costs	(50,900)	(37,866)
Previously unrecognized temporary differences	(281,441)	22,658
Change in tax rates	(35,919)	17,141
Change in valuation allowance	705,091	110,901
Other	6,444	49,280
Income tax recovery	\$ -	\$ -

## 11. INCOME TAXES (CONTINUED):

The components of future income tax balances are as follows:

Years ended December 31	2010	2009
Future income tax asset:		
Non-capital loss carry forwards	\$ 2,870,013	\$ 456,706
Tax basis of petroleum & natural gas properties in excess of (less than) carrying amount	(2,182,017)	(17,475)
Share issue costs	62,197	36,847
Other	44,550	11,423
Valuation allowance	(794,743)	(487,501)
Net future taxes	\$ -	\$ -

At December 31, 2010, the Company has non-capital losses of \$8,820,180 (2009 - \$1,780,732) available to be applied against future years' income for tax purposes. If not used, the losses will expire as follows:

December 31, 2014	\$ 1,114
December 31, 2028	381,648
December 31, 2029	978,666
December 31, 2030	7,458,752
	<u>\$ 8,820,180</u>

## 12. RELATED PARTY TRANSACTIONS:

The Company had the following transactions, not disclosed elsewhere in these financial statements, with directors, officers and companies related by virtue of directors in common:

Years ended December 31	2010	2009
Petroleum and natural gas properties:		
Geological consulting	\$ 13,870	\$ 15,198
Expenses:		
Accounting fees	\$ 56,667	\$ -
Administration fees	38,500	18,000
Management and consulting fees	240,157	222,415
Rent	88,640	12,000
Property investigation costs	565	3,271
	<u>\$ 424,529</u>	<u>\$ 255,686</u>

Included in accounts payable and accrued liabilities at December 31, 2010 is \$37,796 (2009 - \$26,079) owing to related companies which is due under normal credit terms.

For the year ended December 31, 2010, the Company paid or accrued \$13,870 (2009 - \$15,198) for engineering, operational and supervisory consulting, \$565 (2009 - \$3,271) for property investigation, \$38,500 (2009 - \$18,000) for administrative fees, \$56,667 (2009 - \$Nil) for accounting fees, \$64,953 (2009 - \$41,000) for management consulting fees and \$88,640 (2009 - \$12,000) for rent to companies related by virtue of common directors. These transactions were measured at fair market rates which is the amount agreed upon by the transacting parties.

For the year ended December 31, 2010, the Company also paid or accrued \$175,204 (2009 - \$181,415) for consulting fees to a company related by virtue of a common officer and director. These transactions were measured at fair market rates which is the amount agreed upon by the transacting parties.

## 13. FINANCIAL INSTRUMENTS:

Management has primary responsibility for monitoring and managing financial instruments risks under direction from the Board of Directors who has the overall responsibility for establishing the Company's risk management framework. The Company's financial instruments recognized on the balance sheet at December 31, 2010 and 2009 consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities. All of the Company's assets and liabilities are valued as Level 1 assets and liabilities, which are based on observable market data. The fair value of these financial instruments approximates their carrying amounts, based on the short term nature of these instruments.

### 13. FINANCIAL INSTRUMENTS (CONTINUED):

*(a) Market risk:*

Market risk is the risk of changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings and the value of financial instruments. The objective of market risk management is to manage and control market risk exposure within acceptable limits, while maximizing returns and meeting shareholder objectives. Market risks are as follows and are largely outside of the control of the Company:

*(i) Interest rate risk:*

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk as its cash and cash equivalents and restricted cash held in escrow earn interest income at variable rates.

*(ii) Foreign currency risk:*

Foreign currency risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates. The Company operates in Canada and the United States and is therefore exposed to foreign currency risk arising from transactions denominated in U.S. dollars. Certain of the Company's cash and cash equivalents and accounts payable and accrued liabilities are held in U.S. dollars. A 1% change in the exchange rate between the Canadian and United States dollar would have an effect on the loss before income taxes for the year ended December 31, 2010 of approximately \$1,597 (2009 - \$35,927). The Company monitors its net exposure to foreign currency fluctuations and adjusts its cash held in U.S. dollars accordingly. The following table lists the Canadian dollar equivalent of financial instruments denominated in U.S. dollars as of December 31, 2010 at the period end exchange rate of CAD\$1.00 equal to US\$1.01 (December 31, 2009 - CAD\$1.00 equal to US\$0.95):

	December 31, 2010	December 31, 2009
Cash	\$ 943,976	\$ 3,862,108
Accounts receivable	36,482	10,540
Accounts payable and accrued liabilities	820,741	279,931

*(iii) Commodity price risk:*

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. As at December 31, 2010, the Company had no fixed price contracts or financial instruments associated with future production.

*(b) Credit risk:*

Credit risk is the risk of financial loss to the Company if a customer fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are concentrated with a limited number of purchasers of commodities and joint interest partners in the oil and gas industry and are subject to normal industry credit risk. Management considers these concentrations of credit risk to be minimal, as the commodity purchasers are major industry participants, and receivables from partners are protected by effective industry standards legal remedies. Receivables related to the sale of the Company's production are normally collected on the 25th day of the month following delivery. The Company places cash and cash equivalents and restricted cash balances with high credit quality financial institutions.

The carrying amounts of cash and cash equivalents, restricted cash and accounts receivable represent the Company's maximum credit exposure. The Company has not experienced any credit loss in the collection of its accounts receivable. The Company has no allowance for doubtful accounts as at December 31, 2010.

### 13. FINANCIAL INSTRUMENTS (CONTINUED):

#### (c) Liquidity risk:

Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation. The Company monitors its capital expenditures and utilizes authorizations for expenditures on both operated and non-operated capital projects. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month.

### 14. MANAGEMENT OF CAPITAL:

The Company's objective when managing its capital is to: maintain a flexible capital structure so as to preserve the ability to meet its financial obligations, and finance its growth, which may include accessing capital markets and credit facilities to fund the drilling of exploration and development wells as well as potential asset or corporate acquisitions.

The Company manages its capital structure and adjusts it as a result of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company considers its capital structure to include shareholders' equity and working capital. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, and/or adjust its capital spending to manage projected debt levels. In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions, and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions. The Company has a certain amount of cash that is restricted for capital purposes as described in note 5. The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated at this time.

There were no changes in the Company's approach to capital management during the year ended December 31, 2010.

### 15. COMMITMENTS :

The Company is obligated under the terms of a gas gathering agreement that allows the operator of a gathering pipeline to be reimbursed for the construction costs (approximately US\$550,000) of the gathering pipeline from future gathering fees paid, with a minimum monthly fee of US\$20,000 until 110% (US\$605,000) of the construction costs have been repaid. During the year ended December 31, 2010, the Company paid US\$120,000 (2009 - \$Nil) in gas gathering fees and the estimated remaining amount is US\$485,000.

Effective July 1, 2008, the Company entered into a three year agreement with an officer and director of the Company, for management consulting services. In the event that the contract is terminated by the Company within the three year period, this officer and director shall be entitled to a 0.5% overriding royalty interest in the oil and gas properties the Company acquired from a company controlled by this officer and director. In addition the Company is obligated to pay to this related company, an additional US\$300,000 cash, or 300,000 common shares of Nextraction or a combination of both, once Nextraction has generated a 15% rate of return from its investment in the first two wells of the Pinedale project. The form of the additional payment is at the option of the officer and director.

As at December 31, 2010, the Company leases office space on a month to month basis and is obligated to give three months' notice to terminate the lease.

#### *Farm-In Agreements*

Under the terms North Pinedale Property Farm-Out Agreements, the Company has the option to earn a greater effective interest in return for the funding of the costs of drilling and completing two wells. The first well, the Noble 6-24, has been drilled and was completed in 2010. Should the Company fail to fund 100% of the costs of the second well the parties will revert back to their original working interest percentages.

## 15. COMMITMENTS (CONTINUED):

### *Farm-In Agreements (Continued)*

Under the terms of the Saturn Seismic and Joint Venture Agreement the Company is required to conduct a seismic program that covers at least 15,000 acres at an estimated net cost to the Company of \$900,000. Within sixty days after completion of the seismic program (but no later than September 15, 2011) the Company is required to spud a test well, and must complete and equip or plug and abandon the well to earn a one contiguous offsetting section of the properties. Failure to drill will result in Nextraction forfeiting all rights to earn any interest on the Farm-Out lands.

## 16. SEGMENTED INFORMATION:

The Company considers that it operates in one reportable segment, being exploration and development of resource property interest. Segmented information relative to this activity on a geographic basis is as follows:

2010	United States	Canada	Total
Revenue	440,237	4,550	444,877
Total assets	9,870,580	2,713,225	12,583,805
Net income (loss)	32,003	(1,581,575)	(1,549,572)
2009	United States	Canada	Total
Revenue (interest income)	250	8,436	8,686
Total assets	4,873,573	706,037	5,579,610
Net loss	5,272	1,016,224	1,021,496

## 17. COMPARATIVE FIGURES:

Certain comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

## 18. SUBSEQUENT EVENTS:

Subsequent to December 31, 2010, the Company granted 120,000 stock options, vesting equally over six and 12 months and expiring in five years, at an exercise price of \$1.00 per share.

On March 10, 2011, the Company completed a non-brokered private placement of 1,620,369 units at a price of \$2.16 per unit for aggregate gross proceeds of \$3,499,999. Each unit consists of one common share of the Company priced at \$1.0005 each and one common share issued on a flow-through basis under the Income Tax Act (Canada) priced at \$1.1595 each. The Company has paid a finder's fee of \$97,843.

On March 15, 2011 the Company and a joint venture partner acquired lands, producing oil wells and related production facilities in a Viking Oil prospect at a cost of \$2,800,000 before closing adjustments on a 50/50 basis. Under the terms of the joint venture agreement, Nextraction has loaned its joint venture partner its share of the acquisition costs and will receive all production revenue until the joint venture partner repays Nextraction for its share of the investment. Nextraction and the joint venture partner will then participate in expenditures and revenues on a 50/50 basis.

On March 24, 2011, the Company completed a brokered private placement on a bought deal basis for 1,157,400 units at a price of \$2.16 per unit for aggregate gross proceeds of \$2,499,984. Each unit consists of one common share of the Company priced at \$1.0005 each and one common share issued on a flow-through basis under the Income Tax Act (Canada) priced at \$1.1595 each. The Company paid underwriter commissions of \$149,999.

## OIL AND GAS DISCLOSURE SUPPLEMENT

- Page 7: Provost Field - An Investigation of Oil Recovery by Water Injection Provost Viking A Pool, dated August 19, 1968, the McDaniels Consultants (1965) Ltd., is a document filed in the public domain with the Alberta Energy Resource Board. McDaniels Consultants (1965) Ltd., acted as an independent appraiser and the Company is unable to determine if McDaniels Consultants (1965) Ltd. was a qualified reserves evaluator or auditor at the time the historical reserve estimates were prepared. The report is relevant to the interests of Nextraction Energy Corp. since a portion of the property acquired in the Provost Field is identified as being part of the Viking pool.
- Page 10: North Pinedale - Reserve calculations were prepared by Management based on publically filed documents and reports. The stated reserves reflect information relating to properties near those owned by Nextraction and are presented for analogous purposes only. These analogous figures do not reflect actual or anticipated reserves from the Nextraction property. Reserve estimates are based on presentations presented at the Wyoming Gas Fair October 2008 and October 2009 and Wyoming Oil and Gas Conservation Commission Docket: 136-2003 dated May 10, 2005 matter of hearing, brought on the commission's own motion to ask all interested parties to show cause and present evidence as to whether or not the Fort Union Formation, the Lance Formation and the Mesaverde Formation (and/or any portions thereof) underlying the subject lands in the Pinedale anticline area and portions of Jonah field are each a separate pool (portions of T29N, R107-108W; T30N, R107-109W; T31N, R108-110W; T32N, R108-110W; T33N, R109-110W; and T34N, R109-110W; Sublette County, Wyoming), and subsequent dockets filed concerning reserves and spacing.
- Liquids-rich gas content information is based on evaluations by Management's review of public production records for wells in the area of Nextraction properties and actual production results of Nextraction's Noble 6-24 well which are also filed with the Wyoming Oil and Gas Conservation Commission, as of search date December 1, 2009. As this information relates to properties in and around Nextraction's North Pinedale property it is relevant to Nextraction in assessing its development program on its property. This analogous information does not reflect actual or anticipated reserves from Nextraction's North Pinedale property.
- Page 11,12: Appalachian Basin - 'Nextraction Announces Potential Of Undiscovered Gas-In-Place Resource Volumes Of Up To 2.5 TCF' (see Company news release dated April 27, 2010). Nextraction's interest in the resources in the properties varies from 50% to 100% and is located in Kentucky and Tennessee. The Chattanooga Shale formation is the primary target of development. The undiscovered resources have been identified in over 70 producing wells in the field as well as in a core well drilled, tested and analyzed by Nextraction. The estimated quantity is 100% identified as "undiscovered resources" (as defined below) and is the estimated resource covering approximately 70,000 acres of property leases. The significant positive factors regarding this undiscovered resource are that the known thickness and rock properties that measure economic variables are in place for commercial production. The significant negative factors regarding the undisclosed resource are that Chattanooga Shale is under-pressured and may not generate significant recovery rates for economic production and natural gas market conditions. "Undiscovered resources" are the quality of petroleum estimated on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered resources is referred to as prospective resources; the remainder is unrecoverable. Undiscovered resources are also referred to as "undiscovered petroleum initially in place". There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Exploration for hydrocarbons is a speculative venture necessarily involving substantial risk. Even where hydrocarbons are discovered, the costs of extracting and delivering the hydrocarbons to market and variations in the market price may render the recovery of any deposit uneconomic. Recovery of any deposits is also subject to uncertainties with respect to the proximity of pipelines and processing facilities, access to the deposits and climatic conditions that may make recovery difficult or impossible.
- Page 12: "Unconventional Gas Services - Chattanooga Shale - Shale Gas", dated June 2010, Client Presentation by [unconventionalgasservices@woodmackenzie.com](mailto:unconventionalgasservices@woodmackenzie.com). The Company is unable to determine if Wood Mackenzie Services was a qualified reserves evaluator or auditor at the time the reserves estimates were prepared. As this information relates to properties in and around Nextraction's Appalachian Basin property it is relevant to Nextraction in assessing extraction from Chattanooga Shale, however this analogous information does not reflect actual or anticipated reserves or production volumes from Nextraction's Appalachian Basin property.

**Directors & Officers**

Mark S. Dolar	President, Chief Executive Officer and Director
R. Michael Jones	Director
Frank Hallam	Director
Eric H. Carlson	Director
Paul B. Trost	Director
Scott D. Badcock	Chief Financial Officer
Kent Edney	Operations Manager and Petroleum Engineer



**Head Office**

Bentall Tower 5  
Suite 328, 550 Burrard Street  
Vancouver, BC  
Canada V6C 2B5  
Phone: 604-630-0300  
Toll Free: 1-888-630-0370  
Fax: 604-484-4710  
Email: [info@nextraction.com](mailto:info@nextraction.com)

**Calgary Office**

Sun Life Plaza West Tower  
Suite 1600, 144 - 4 Ave SW  
Calgary, AB  
Canada T2P 3N4  
Phone: 403-514-8276  
Fax: 403-269-3537

**Registrar and Transfer Agent**

Computershare Investor Services  
3rd Floor, 510 Burrard Street  
Vancouver, BC  
Canada V6C 3B9

**Legal Counsel**

Gowlings Lafleur Henderson LLP  
Suite 2300, 550 Burrard Street  
Vancouver, BC  
Canada V6C 2B5

**Auditors**

KPMG LLP  
777 Dunsmuir Street  
Vancouver, BC  
Canada V7Y 1K3

**Annual General Meeting**

Friday, June 24, 2011  
2:00 PM (local time)  
Suite 328, 550 Burrard Street  
Vancouver, BC  
Canada V6C 2B5

**NE: TSXV**

