Management Discussion and Analysis

The following discussion is an analysis by management of Anterra Energy Inc.'s ("Anterra" or the "Company") operating and financial data for the three months ended June 30, 2011 and prior periods, as well as estimates of future operating and financial performance based on information currently available. It should be read in conjunction with the audited financial statements and notes for Anterra Energy Inc. for the year ended December 31, 2010. The Management Discussion and Analysis ("MD&A") was prepared as of August 26, 2011.

The condensed interim financial statements and comparative information have been prepared in accordance with International Financial Reporting Standard ("IFRS") 1 "First - time Adoption of International Financial Reporting Standards" and with International Accounting Standard 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board. Previously the Company prepared its interim and annual financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Unless otherwise noted, 2010 comparative information has been prepared in accordance with IFRS. Canadian GAAP now comprises IFRS. The adoption of IFRS has not had an impact on the company's operations, strategic decisions and cash flow. The most significant area of impact was the adoption of the IFRS upstream oil and gas accounting principles. Further information on the IFRS impacts is provided in the Accounting Policies and Estimates Section of this MD&A.

Overall Performance Summary

During the second quarter of 2011, there was improvement in both oil and gas prices compared to the previous quarter. The Company was producing an average of 272 boepd in the second quarter of 2011 compared to an average of 275 boepd in the prior quarter 2011. As a result, net oil and gas revenues increased by 1% to $1.60 million in the second quarter of 2011 from $1.58 million in the first quarter of 2011, and by 98% from $0.81 million in the second quarter of 2010.

The Company experienced an increase in gas production due to new well production at Buck Lake. Production from a new well in the second quarter of 2011 brought production back to an average of 272 boepd. Furthermore, the average sales price per boe for the second quarter 2011 improved to $81.08 from $73.86 in the first quarter 2011 and is 33% higher than $60.97 which was recorded in the second quarter of 2010. During the second quarter, the Company reflected positive funds flow from operations primarily because of increased oil and gas production from the new well.

The Company's positive cash flow from operating activities allowed the Company to continue with its development plans. At June 30, 2011, the Company had drawn $3.1 million on its bank facility and had $5.4 million of undrawn credit and a net working capital deficit including the bank overdraft of $3.5 million.

Operating Summary

Production during the second quarter of 2011 was 272 boepd compared to 275 boepd in the first quarter and 156 boepd in the second quarter of 2010. The first horizontal oil well at Buck Lake commenced production in February, 2011. These gains have continued into the second quarter of the year.

In the second quarter of 2011, the Company acquired nine sections of land in Saskatchewan which are prospective for Bakken oil, to bring the Company's total Bakken land holdings to 26 Sections. The Company continues to hold over 51,000 gross acres of land and 31,000 net acres of land in Alberta and Saskatchewan. During the balance of 2011, the Company plans to drill up to two additional horizontal wells in the Cardium. The Company completed a 3-D seismic program over the Bakken lands during the first quarter of 2011. The Company also offers fee based third party midstream processing services and revenues improved by 2% and 80% respectively compared to the first quarter of 2011 and second quarter of 2010.

The following table outlines the operations of the Company for the three months ended June 30, 2011, compared to the same period in 2010 along with the other costs of the Company for the periods.

	Three Months June 30, 2011	**Three Months June 30, 2010**	**Six Months June 30, 2011**	**Six Months June 30, 2010**
Oil and Gas Production				
Revenue	1,966,649	867,372	3,782,462	1,800,171
Royalties	(369,982)	(61,008)	(567,599)	(127,893)
Gross overriding royalties	-	875	-	875
Net revenue	1,596,667	807,239	3,214,863	1,673,153
Operating costs	653,501	606,755	1,064,494	1,370,214
Oil and gas operating margin	943,166	200,484	2,150,369	302,938
Midstream Processing				
Revenue	716,434	397,170	1,396,672	804,463
Operating costs	197,399	182,607	393,364	383,542
Midstream operating margin	519,035	214,563	1,003,308	420,921
Intersegment revenue and cost	(30,911)	(29,765)	(62,579)	(57,793)
Total Net Revenue	2,313,101	1,174,644	4,611,535	2,419,823
Total Operating Costs	850,900	759,597	1,457,858	1,695,963
Total Operating Margin	1,462,201	415,047	3,153,677	723,860
Expenses				
General and administration	495,700	538,472	978,163	1,064,103
Stock compensation	36,265	-	762,016	-
Interest and accretion expense	(11,092)	51,134	41,813	94,744
Depletion and depreciation	395,879	405,579	698,689	800,895
Creditor settlements	-	-	-	-
Total Expenses	**916,752**	**995,185**	**2,480,681**	**1,959,742**
Net Loss Before Tax	**545,449**	**(580,138)**	**672,996**	**(1,235,882)**
Provision For Taxes	**(68,831)**	**(234,171)**	**(242,926)**	**(503,430)**
Net Income (Loss)	**609,280**	**(345,967)**	**915,922**	**(732,452)**
Earnings (loss) per Class A share				
Basic	0.002	(0.001)	0.004	(0.003)
Fully Diluted	0.002	(0.001)	0.004	(0.003)
Weighted Average Number of Class A Shares In Thousands	245,646	244,488	245,662	244,488
Funds Flow From Operations	**972,593**	**(165,159)**	**2,192,964**	**(315,102)**
Funds Flow Per Class A Share	**0.004**	**(0.001)**	**0.009**	**(0.001)**
Cash Flow from operating activities	**1,924,090**	**(602,237)**	**2,648,689**	**(2,085,409)**

Presentation

Funds flow from operations is not a recognized measure under IFRS. However, management believes that funds flow from operations is a useful measure of financial performance as an indication of cash generated from operations of the Company during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period and, further, it is a commonly accepted measure in the industry which is useful for knowledgeable investors for comparison purposes. For the purposes of funds flow from operations calculations, funds flow is defined as "Funds flow from operations" before changes in non-cash operating working capital. Anterra's determination of funds flow from operations may not be comparable to that reported by other companies. Operating margin is not a recognized measure under IFRS; however management believes it is a useful measure of financial performance for assessing the operations of the Company. Operating margin is defined as revenue less operating costs, both of which are IFRS measures.

In this MD&A, the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of 6,000 cubic feet (mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boe's may be misleading particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Quarterly Financial Information

	2nd Quarter 2011 IFRS		1st Quarter 2011 IFRS		4th Quarter 2010 IFRS		3rd Quarter 2010 IFRS
Net Revenue	**$2,313,101**		**$ 2,298,434**		**$ 1,589,256**		**$ 1,313,178**
Oil and gas operating margin	943,166		1,205,604		(519,821)		355,479
Processing operating margin	519,035		485,871		357,290		248,264
Net Income (Loss)	**609,280**		**306,642**		**(1,276,130)**		**(698,265)**
Income (Loss) per share							
Basic	0.002		(0.001)		(0.005)		(0.003)
Fully Diluted	0.002		(0.001)		(0.005)		(0.003)
Weighted Average Number of Shares In Thousands	245,646		245,751		244,488		244,488
Funds Flow From Operations	**972,593**		**1,185,519**		**(832,142)**		**(196,999)**
Funds Flow Per Share	0.004		0.005		(0.003)		(0.001)
Cash flow from operating activities	1,924,590		2,543,052		(1,166,518)		(342,096)

	2nd Quarter 2010 IFRS		1st Quarter 2010 IFRS		4th Quarter 2009 Canadian GAAP		3rd Quarter 2009 Canadian GAAP
Net Revenue	**$ 1,174,644**		**$ 1,245,179**		**$ 1,068,518**		**$ 1,027,786**
Oil and gas operating margin	200,484		102,455		87,303		186,595
Processing operating margin	214,563		206,358		98,923		166,190
Net Income (Loss)	**(345,967)**		**((386,485))**		**(702,770)**		**(396,293)**
Income (Loss) per share							
Basic	(0.001)		(0.001)		(0.011)		(0.009)
Fully Diluted	(0.001)		(0.001)		(0.011)		(0.009)
Weighted Average Number of Shares In Thousands	244,488		219,488		66,411		44,760
Funds Flow From Operations	**(143,606)**		**(231,848)**		**(232,011)**		**(38,211)**
Funds Flow Per Share	(0.001)		(0.001)		(0.004)		(0.001)
Cash flow from operating activities	(580,684)		(1,565,077)		(99,719)		(15,052)

Oil and Gas Production

Production during the second quarter of 2011 increased to an average of 272 boepd from 275 boepd in the first quarter of 2011 and was 74% higher than the second quarter of 2010. Production volumes increased during second quarter of 2011 due to the production from the second well at Buck Lake. The Company's primary focus for 2011 is on the development of non-conventional oil and gas opportunities in the Cardium play at the Breton and Buck Lake areas.

Oil & Gas Production

	Three Months June 30, 2011	Three Months June 30, 2010	Six Months June 30, 2010	Six Months June 30, 2010
Oil (bbl/d)	183	120	196	119
Natural Gas (mcf/d)	337	195	362	211
NGLs (bbl/d)	33	3	18	3
Total (boe/d)	272	126	274	157

Oil & Gas Revenue and Realized Prices

At current commodity price levels of approximately CA$100 for oil and CA$4.22 for gas, revenues in 2011 are expected to increase comparing the 2010 level, due to the increase in production. During the second quarter of 2011, oil prices increased to $101.65 per bbl from $89.77 in 2011 first quarter, while gas prices increased to $4.22 from $3.92 in 2011 first quarter. The average oil price and average gas price for the second quarter were 41% and 22% respectively higher than the prices for the second quarter of 2010. Although commodity prices have decreased recently, the Company anticipates it will continue to generate positive cash flow.

	Three Months June 30, 2011	Three Months June 30, 2010	Six Months June 30, 2011	Six Months June 30, 2010
Oil				
Revenues	$1,671,672	$790,497	$3,354,412	$1,604,399
Prices $/bbl	$101.65	$72.17	$95.32	$74.65
Natural Gas				
Revenues	$111,810	$61,215	$230,578	$161,246
Prices $/mcf	$4.22	$3.45	$4.06	$4.21
NGL's				
Revenues	$183,167	$15,660	$197,472	$34,526
Prices $/bbl	$62.14	$49.71	$61.14	$55.78
Total				
Revenues	$1,966,649	$867,372	$3,782,462	$1,800,171
Price $/bbl	$81.08	$60.96	$77.45	$63.18

Gross Overriding Royalty Income

Two farm-in gas wells drilled at Breton generate gross overriding royalties to the Company until payout. These wells have provided gross overriding royalties of $2,900 for the six months ended June 30, 2011 (2010 – $nil).

Oil and Gas Royalties Expense

Total royalties including crown royalties were $369,982 for the second quarter of 2011 as compared to $197,617 for the first quarter of 2011, and $61,008 for the three months ended June 30, 2010. This represented $15.02 per boe for the second quarter of 2011 as compared to $8.08 per boe for the first quarter of 2011 and $4.29 per boe for the three months ended June 30, 2010. The Company's royalty rates have increased during the quarter with the increase in commodity prices, and production levels.

Oil & Gas Operating Costs

Total oil and gas operating costs for the second quarter of 2011 were $653,501 or $24.47 per boe, including $15,036 for inter-divisional processing charges and $87,247 for well repairs and maintenance. In comparison, operating costs were $409,971 for the first quarter of 2011 or $20.90 per boe, including $16,806 for inter-divisional processing charges and $71,611 for repairs and maintenance. Operating costs for the second quarter of 2010 were $606,755 or $42.65 per boe, including $9,327 for inter-divisional processing charges and $89,542 for repairs and maintenance. These costs have increased due to higher production. The unit operating costs are budgeted to improve in 2011 with the addition of new production from the Company's Cardium horizontal wells. Inter-divisional charges were eliminated in 2011 for consolidation purposes.

Oil & Gas Operating Net Back

The operating net back for the second quarter of 2011 was $41.59 per boe compared to $44.20 per boe for the three months ended March 30, 2011 reflecting the high maintenance costs incurred in both quarters as the Company worked to bring production back on line as well as the legacy impact of reduced production from cost saving measures during 2010. For the second quarter of 2010 the net back was $10.60 per boe. Oil and Gas operating net back is a non-IFRS measure but it is derived from IFRS results and management believes it is commonly used in the industry and for comparison purposes by investors.

	Three Months June 30, 2011	**Three Months June 30, 2010**	**Six Months June 30, 2011**	**Six Months June 30, 2010**
Average realized price ($/boe)	$81.08	$60.96	77.45	63.18
Royalties ($/boe)	15.02	4.29	11.53	4.49
Operating expenses ($/boe)	24.47	42.65	23.01	48.09
Operating net back ($/boe)	$41.59	$ 14.03	42.91	10.60

Processing

Processing revenue for the second quarter of 2011 was $635,401 compared to $699,665 for the first quarter of 2011 and $397,170 for the three months ended June 30, 2010. The Company continued to experience stronger third party volumes during the second quarter of 2011 compared to 2010 and this trend appears to be continuing into the third quarter of 2011.

Processing Operating Costs

Processing operating costs for the second quarter of 2011 were $228,310 (including $30,911 of inter-divisional charges) compared to $182,607 (including $12,378 of inter-divisional charges) for the three months ended March 31, 2011. Inter-divisional charges were eliminated for consolidation purposes.

General and Administrative Expenses

General and administrative expenses for the second quarter of 2011 totaled $495,700 compared to $482,463 for the three months ended March 30, 2011, and $538,472 for the three months ended June 30, 2010.

Interest Expense

Interest expense for the second quarter of 2011 was $74,095 compared to $23,494 in the first quarter of 2011 and $20,181 during the three months ended June 30, 2010.The increase in interest cost reflects the higher drawdown on the Company's credit facility.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense was $395,879 in the second quarter of 2011 compared to $263,212 in the first quarter of 2011 and $405,579 for the second quarter of 2010.

Net Income and Loss

The net income in the second quarter of 2011 was $609,280. It reflected a tax recovery of $63,831, and income before tax of $545,449. This compared to a net income of $306,642, and tax recovery of $179,095 in the first quarter of 2011; and net loss of $345,967, and loss before tax of $580,138, in the second quarter of 2010. The operating margin for the second quarter of 2011 was $1,462,201 compared to $1,691,476 in the first quarter of 2011 and $415,047 in the second quarter of 2010.

During the second quarter, the Company benefited from increases in production and commodity prices. Increased production reflects the capital investment for new well drilling, while overall revenues increased 127% during the quarter comparing to the second quarter of 2010.

Capital Expenditures, Commitments and Contingencies

The Company spent $1,614,175 on capital expenditures during the second quarter, including $269,243 on exploration and evaluation assets and $1,344,932 on property, plant and equipment. The Company has accumulated seven gross sections of Cardium lands and anticipates drilling up to two additional Cardium wells during the balance of 2011. In addition, the Company has now accumulated approximately 26 Sections of Bakken lands in Saskatchewan and the Company has completed a 3-D seismic program over these lands during the first quarter, with drilling of a test well to be completed by the third quarter of 2011.

Liquidity, Capital Resources and Subsequent Events

Funds flow from operations for the second quarter of 2011 totaled a positive $1,924,090 compared to a positive $1,185,519 for the first quarter of 2011 and negative $165,159 for the second quarter of 2010. At June 30, 2011, the Company's net working capital deficit, including the cash position, is approximately $3.5 million, compared to a working capital deficit of $2.5 million at March 31, 2011. At both June 30, 2011 and June 30, 2011, the Company was in compliance with its lender's working capital covenant. In the second quarter of 2011, the Company incurred $1.2 million on drilling and completions for new wells. The Company has plans to drill up to two additional horizontal wells in the Cardium later in the year. In order to exploit its opportunities, the Company will need to obtain additional debt and equity financing as the year progresses.

Bank Debt

At June 30, 2011, the Company had available a $8,500,000 revolving demand loan facility with a Canadian chartered bank. The revolving loan bears interest at prime plus 0.75%, with an effective rate at quarter end of 3.75%. The loan is secured by a general assignment of book debts and a $10,000,000 second floating charge debenture over all assets of the Company. The availability of additional funds under the facility is subject to periodic review with the annual review scheduled for July, 2011. As at June 30, 2011, the Company had $3,126,290 drawn under the facility. The loans are shown as a current liability due to their demand nature despite the lender having not demanded repayment of the loan. At both June 30, 2011 and December 31, 2010, the Company was in compliance with its debt covenants.

Share Capital

At June 30, 2011, there were 246,021,366 Class A Shares and nil Class B Shares outstanding. At June 30, 2011, there were 1,733,331 warrants outstanding. At June 30, 2011, there were 20,350,000 stock options outstanding.

(a) On January 15, 2010, pursuant to an investment agreement with an international investor, the Company closed the final tranche of the investment, whereby the investor acquired 150,000,000 Class A Shares at a price of $0.08 per Class A Share for gross proceeds of $12,000,000. In conjunction with the closing, the Company paid finder's fees to two agents in an aggregate amount of $480,000 and issued an aggregate of 1,599,999 warrants, each warrant entitling the holder to purchase one Class A Share at a price of $0.15 per share exercisable for two years from the date of the closing. Following the closing of the final instalment of this investment, the investor held 77.7% of the outstanding Class A Shares
(b) On July 13, 2010, as part of an arrangement to change executive management and retain the services of certain officers, the Company agreed to issue 600,000 Class A Shares, at a price of $0.10 per share, to two officers of the Company.
(c) On January 27, 2011, the Company issued Class A Common Share of 400,000 at $0.15 per share on the exercise of warrants.
(d) On March 28, 2011, the Company issued Class A Common Share of 263,000 at $0.15 per share on the exercise of warrants.
(e) On April 1, 2011, the Company issued Class A Shares of 133,667 at $0.15 per share on the exercise of warrants.
(f) On May 26, 2011, the Company issued Class A Shares of 136,667 at $0.15 per share on the exercise of warrants.

On July 28, 2011, the Company issued 133,333 Class A Shares at $0.10 per share and 133,333 Class A Shares on a Flow-through basis at $0.10 per share on the exercise of 133,333 broker's warrants.

On July 19, 2011, the Company issued 150,000 Class A Shares at $0.10 per share on the exercise of stock options.

As of the date of this MD&A, the Company has 246,438,032 Class A shares, no Class B shares, 20,200,000 stock options and 1,599,999 warrants outstanding.

The Company has not paid dividends on its common shares to date.

Related Party Transactions

Except as disclosed elsewhere, the Company had the following related party transactions:

During the six month ended June 30, 2011, a legal firm, of which a director is a partner, charged the Company $35,090 (2010 - $21,257) for legal fees and services. There is accounts payable of $10,705 at June 30, 2011.

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

Compensation of key management personnel
The remuneration of directors and other members of key management personnel during the period were as follows:

	Three months		Six months	
	June 30, 2011 $	**June 30, 2010 $**	**June 30, 2011 $**	**June 30, 2010 $**
Short-term employee benefits	83,208	134,875	197,333	168,000
Share-based payment	10,880	15,491	206,880	15,491
	94,088	150,366	404,213	183,491

Outlook

For the balance of 2011, Anterra will continue to focus on the exploration, exploitation and development of its Cardium and Bakken resource projects in Alberta and Saskatchewan. Specifically, the Company intends to continue developing its Cardium project at Buck Lake in Alberta where it has recently drilled two successful horizontal Cardium oil wells on 60% working interest lands. There are potentially 8 -10 additional locations to drill and the Company plans to drill at least two of these development wells this year. At Breton, the Company continues to assess the development potential of this large Belly River oil pool and hopes to drill one horizontal well later this year, with further drilling directly related to the results of the well.

At Abbott in Saskatchewan, the Company has completed the 3-D seismic shoot and interpretation and will be completing the drilling of an exploratory well on its lands in the third quarter of 2011. The Company has 26 sections of 100% lands at Abbott and following a successful exploratory well has many additional locations to drill.

The Company has established a preliminary net capital budget of $10 million to finance its drilling activities during the year. The budget will be funded by undrawn bank lines, cash flow and equity financings.

Changes in Accounting Policies

Explanation of transition to IFRS

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. In February 2008, the AcSB confirmed that Canadian publicly accountable entities will be required to report under IFRS, which will replace Canadian GAAP for years beginning on or after January 1, 2011. Accordingly, the condensed interim financial statements for the six months ended June 30, 2011, including required comparative information, have been prepared in accordance with IFRS 1, First - time Adoption of International Financial Reporting Standards, and with IAS 34, Interim Financial Reporting, as issued by the International Accounting Standards Board ("IASB").

The adoption of IFRS has not had a material impact on the Company's operations, strategic decisions or internal controls. The most significant area of impact was the accounting treatment of full cost oil and gas assets, depletion, flow-through shares, share-based payment transactions and decommissioning liabilities.

IFRS 1 allows first time adopters to IFRS to take advantage of a number of voluntary exemptions from the general principal of retrospective restatement. The Company has taken the following exemptions:

IFRS 3 Business Combinations ("IFRS 3")

The Company has elected to apply the exemption for retrospective application of IFRS 3 to business combinations that took place before the transition date.

IFRS 6 - Exploration for and Evaluation of Mineral Resources ("IFRS 6")

The Company has elected to apply the exemption from full retrospective application of IFRS 6. As such the Company has at January 1, 2010, measured the exploration and evaluation assets at the amount determined under Canadian GAAP and measured the development and production assets by allocating the amount determined under Canadian GAAP to the underlying assets on a pro rata basis using reserve values at that date. As a result of using the IFRS 1 optional exemption, the exploration and evaluation assets and the development and production assets have been subjected to an impairment test.

IAS 23 – Borrowing Costs ("IAS 23")

IAS 23 has not been applied retrospectively. As at the transition date, the Company did not have any qualifying assets.

IAS 37 - Provisions, Contingent Liabilities and Contingent Assets ("IAS 37")

The Company has elected to apply the exemption from full retrospective application of decommissioning liabilities as allowed under IFRS 1. As such, the Company has re-measured the provisions as at January 1, 2010 under IAS 37 and recognized the difference between the amount determined under IAS 37 and the carrying amount of the provisions at January 1, 2010, directly in retained earnings.

IFRIC 4 - Determining whether an Arrangement contains a Lease ("IFRIC 4")

This IFRIC has not been applied retrospectively. The Company made an assessment as to whether an arrangement, existing at the Transition Date, contains a lease on the basis of the facts and circumstances existing at that date. The assessment was made in accordance with the requirements IFRIC 4. The Company did not identify any arrangements containing a lease on the transition date.

A more detailed explanation of the impact of the adoption of IFRS can be found in note 24 to the condensed interim financial statements at June 30, 2011.

Business Risks

Crude oil and natural gas exploration, development, production and processing involve a number of business risks, some of which are beyond the Company's control. These can be categorized as operational, financial and regulatory risks.

Operational risks include finding and developing reserves economically, marketing production and services, product deliverability uncertainties, changing government law and regulation, hiring and retaining skilled employees and contractors and conducting operations in a cost effective and safe manner. The Company continuously monitors and responds to changes in these factors and adheres to all regulations governing its operations. Insurance is also maintained at levels consistent with prudent industry practices to minimize risks, but the Company is not fully insured against all risks, nor are all such risks insurable.

Financial risks include commodity prices, interest rates and the Canadian/United States exchange rate, all of which have considerable impact on the estimates contained herein but are beyond the Company's control. The Company sells all of its production on the spot market and does not currently have a hedge program in place.

The Company relies on access to capital markets for new equity to supplement internally generated cash flow and debt to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury or debt, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. Periodic fluctuations in energy prices may also affect lending policies of the Company's bankers, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the Company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The Company is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

General adverse economic conditions globally, including recession in Canada and a worldwide economic slowdown, recent disruptions to the credit and financial markets in Canada and worldwide and local economic turmoil may adversely affect the value of the Company's business and value of its securities.

Regulatory risks include changes to Canadian federal and provincial laws, which are beyond the Company's control. The Government of Alberta has completed a comprehensive review of the province's oil and natural gas royalty structure.

Forward Looking Statements

This MD&A contains forward looking information related to the Company's planned drilling program, production, revenue, commodity prices, royalties, capital expenditures and commitments, operating costs, general and administrative expenses, funds flow from operations, financing plans, liquidity and capital resources and debt settlement. Forward-looking information is based on expectations and estimates as of the date of this document, and is information that is subject to known and unknown risks and other factors that may cause future actions, conditions or events to differ materially from the anticipated actions, conditions or events expressed or implied by such forward-looking information. Forward-looking information is information that does not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as "believe", "expect", "anticipate", "intend", "plan", "estimate", "should", "could" "may", "objective", "projection", "forecast", "continue", "strategy", "position" or the negative of those terms or other variations of them or comparable terminology.

Further examples of such forward-looking information in this document include but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions, which may prove to be incorrect including: the amounts recorded for depletion, depreciation and accretion, the provision for asset retirement obligations and the ceiling test, which are based on estimates of reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. Stock-based compensation expense is based upon estimates using the Black-Scholes option pricing model.

Risks include, but are not limited to, the availability and costs of financing, general economic conditions and risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the financial health of the Company's joint venture partners; health, safety and environmental risks; and the uncertainty of dealing with government and obtaining regulatory approvals).

At this time, the most significant risk relates to the uncertainty of future oil and gas prices and the current volatility in these markets. Revenues and funds flow from operations will be impacted positively or negatively depending on the ultimate variance to the Company's forecast assumptions. Furthermore, the outcome of commodity price changes are expected to impact the Company's capital spending plans and the ability of joint venture partners and other sources of capital funding to provide financing for the Company's projects.

Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain employees on a cost effective basis, commodity and marketing risk and seasonality. The Company is subject to significant drilling risk and uncertainties including the ability to find oil and gas reserves on an economic basis. The Company is also exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operational risks. Financial risks that Anterra is exposed to include, but are not limited to, access to debt or equity markets and fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate.

It is anticipated that subsequent events and developments may cause a change to the assumptions made by the Company. The Company does not have an intention to update this forward-looking information, except as required by applicable securities laws. This forward-looking information represents the Company's views as of the date of this document and such information should not be relied upon as representing the Company's views as of any date subsequent to the date of this document. The Company has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking information. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current **expectations. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking information.** These factors are not intended to represent a complete list of factors that could affect the Company.

Additional Information

Additional information relating to the Company is available on SEDAR at www.sedar.com and on the Company's website at www.anterraenergy.com.