Management Discussion and Analysis

The following discussion is management's analysis of Anterra Energy Inc.'s ("Anterra" or the "Company") operating and financial data for the nine months ended September 30, 2010 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, 2009. The Management Discussion and Analysis ("MD&A") was prepared as of November 26, 2010.

Overall Performance Summary

During the third quarter of 2010, there was an increase in oil production and a decrease in gas production compared to the first and second quarters, despite having wells shut down for maintenance. There was a decline in gas prices but an increase in oil prices compared to the previous quarter, which resulted in an increase in revenue of 14% to $0.99 million compared to the second quarter at $0.87 million, and an increase of 28% over $0.77 million in the third quarter of 2009. There was an increase in average prices and a decrease in the oil and gas operating costs during the quarter; as a result, the oil and gas operating margin amounted to $0.35 million compared to $0.20 million in the second quarter.

While production in July averaged 186 barrels per day, wells were shut in due to the weather conditions during August and September, which resulted in production averaging 171 barrels per day during the third quarter. Furthermore, the average sale price per barrel for the third quarter 2010 increased to $63.12 from $60.97 in the second quarter of 2010, and was 22% higher than $51.57 in the third quarter of 2009. During the third quarter, the Company generated negative funds flow from operations because of continuing high maintenance costs to re-establish production. Under current conditions, funds flow from operations is expected to remain close to breakeven levels until the Company sees more production from new projects.

At September 30, 2010, the Company had drawn down $1.38 million on its credit facility of $4.5 million, and had a net working capital deficiency including the bank balance of $0.07 million. In the first half of 2010, the Company expended $3.9 million on land positions in Alberta and Saskatchewan. The Company is drilling one horizontal well in the Cardium in November (see Subsequent Events in the Note 16 to the interim financial statements).

Operating Summary

Production during the third quarter of 2010 averaged 171 barrels per day compared to 156 barrels per day in the second quarter of 2010 and was 9% higher than the third quarter of 2009 with 157 barrels per day. The oil production increased during the third quarter. However, gas sales at both Breton and Judy Creek declined during the quarter. During the third quarter of 2010, oil prices averaged $70 and have since recovered to a range from $70 to $80 per barrel, while gas prices dropped to $3.38 per mcf during the quarter. The average oil price and average gas price for the third quarter were 4% higher and 2% lower respectively than the prices for the second quarter of 2010. High maintenance costs in the first quarter of 2010 related to well work overs and site remediation at Breton. These costs continued into the second quarter and, in addition, the Company incurred work over costs at Matziwin and Scots Lake. Overall, the unit oil and gas operating cost declined from $42.65/barrel in the second quarter to $36.07/barrel in the third quarter. The resulting oil and gas operating margin for the third quarter of 2010 was $603,742 compared to $415,047 in the second quarter of 2010 and $352,785 in the third quarter of 2009. During the period, the midstream contribution increased to

$248,000 in the third quarter from $214,000 in the second quarter.

In the first quarter of 2010, the Company acquired five sections of land over the Cardium play in the Breton and Buck Lake area to bring the Company's total Cardium land position to seven sections. In addition, the Company completed the acquisition of twelve sections of land in Saskatchewan which are prospective for Bakken oil, to bring the company's total Bakken land holding to 17 sections. In aggregate, the Company spent approximately $3.9 million on these acquisitions. The Company continues to hold in excess of 51,000 gross acres of land and 31,000 net acres of land in Alberta and Saskatchewan. The Company's primary focus for 2010 is on the development of non-conventional oil and gas opportunities in the Cardium play at Breton and Buck Lake area, and the Company spudded its first Cardium well in November 2010. The timing of up to four additional Cardium wells will depend on the results of the first well and the availability of further funding. The Company is also currently seeking joint venture partners to participate in the follow up program. Anterra plans a 3-D seismic program over the Bakken lands in Saskatchewan and is seeking a partner to participate in this program, which is being delayed until 2011. The drilling of the first well is now scheduled for late 2011, depending on the outcome of the seismic program. The Company also intends to pursue acquisitions in Alberta and Saskatchewan when and as opportunities arise. Anterra also offers fee based third party midstream processing services and, during the quarter throughput and revenues were lower by 3% and higher by 5% respectively compared to the second quarter of 2010. The processing cost is 8% lower than the cost in second quarter.

Abbreviations

ARTC Alberta Royalty Tax Credit
bbls/d barrels per day
barrels barrels of oil equivalent
mbbl thousand barrels
mmbarrel million barrels of oil equivalent
mcf/d thousand cubic feet per day
WTI West Texas Intermediate
bbl barrel
bcf billion cubic feet
barrels per day barrels of oil equivalent per day
mbarrel thousand barrels of oil equivalent
mcf thousand cubic feet
NGLs natural gas liquids
TSX TSX Venture Exchange

Conversion of Units

1.0 bbl = 0.159 cubic meters
1.0 mcf = 28.2 cubic meters
Natural gas is equated to oil on the basis of 6mcf = 1 barrel
6.29 bbls = 1.0 cubic meter
0.035 mcf = 1.0 cubic meter

The following table outlines the operations of the Company for the three months and nine months ended September 30, 2010, compared to the same period in 2009 along with the other costs of the Company for the periods.

	Three Months September 30, 2010		Three Months September 30, 2009		Nine Months September 30, 2010		Nine Months September 30, 2009
Oil and Gas Production							
Revenue	992,665		744,418		2,792,836		2,168,970
Royalties	(70,023)		(34,424)		(197,916)		(101,830)
Gross overriding royalties	107		-		982		-
Net revenue	922,749		709,994		2,595,902		2,067,140
Operating costs	567,270		523,399		1,937,484		1,460,880
Oil and gas operating margin	355,479		186,595		658,418		606,260
Midstream Processing							
Revenue	416,737		334,682		1,221,200		979,487
Operating costs	168,473		168,492		552,015		552,355
Midstream operating margin	248,264		166,190		669,185		427,132
Intersegment revenue and cost	(26,308)		(16,890)		(84,101)		(60,281)
Total Net Revenue	**1,313,178**		**1,027,786**		**3,733,001**		**2,986,346**
Total Operating Costs	709,435		675,001		2,405,398		1,952,954
Total Operating Margin	**603,743**		**352,785**		**1,327,603**		**1,033,392**
Expenses							
General and administration	780,518		567,812		1,844,621		1,237,567
Stock compensation	315,254				315,254		84,373
Creditor settlements			(332,930)		-		(332,930)
Interest	20,223		156,114		55,434		264,786
Depletion, depreciation, accretion	565,671		525,443		1,715,331		1,716,326
Total Expenses	**1,681,666**		**916,439**		**3,930,640**		**2,970,122**
Net Loss Before Tax	**(1,077,923)**		**(563,654)**		**(2,603,037)**		**(1,936,730)**
Provision For Taxes	(239,143)		(167,361)		(668,935)		**(554,492)**
Net Loss	**(838,780)**		(396,293)		**(1,934,102)**		(1,382,238)
Earnings (loss) per Class A share							
Basic	(0.003)		(0.009)		(0.008)		(0.034)
Fully Diluted	(0.003)		(0.009)		(0.008)		(0.034)
Weighted Average Number of Class A Shares In Thousands	244,488		44,760		236,246		40,279
Funds Flow From Operations	**(175,446)**		**(38,211)**		**(572,453)**		**(156,354)**
Funds Flow Per Class A Share	(0.001)		(0.001)		(0.002)		(0.004)

Presentation

Funds flow from operations is not a recognized measure under Canadian generally accepted accounting principles (GAAP). 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 GAAP; 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 GAAP measures.

In this MD&A, the calculation of barrels of oil equivalent (barrel) 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. Barrels may be misleading particularly if used in isolation. A barrel 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

	3rd Quarter 2010	2nd Quarter 2010	1st Quarter 2010	4th Quarter 2009
Net Revenue	**$ 1,313,178**	**$ 1,174,644**	**$ 1,245,179**	**$ 1,068,518**
Oil and gas operating margin	355,479	200,484	102,455	87,303
Processing operating margin	248,264	214,563	206,358	98,923
Net Loss	**(838,781)**	**(543,379)**	**(551,943)**	**(702,770)**
Loss per share				
Basic	(0.003)	(0.002)	(0.003)	(0.011)
Fully Diluted	(0.003)	(0.002)	(0.003)	(0.011)
Weighted Average Number of Shares In Thousands	244,488	244,488	219,488	66,411
Funds Flow From Operations	**(175,446)**	**(165,159)**	**(231,848)**	**(232,011)**
Funds Flow Per Share	(0.001)	(0.001)	(0.001)	(0.004)
Cash flow from operating activities	(129,435)	(602,237)	(1,565,077)	(99,719)

	3rd Quarter 2009	2nd Quarter 2009	1st Quarter 2009	4th Quarter 2008
Net Revenue	**$ 1,027,786**	**$ 1,038,393**	**$ 920,167**	**$ 1,249,398**
Oil and gas operating margin	186,595	305,344	114,321	226,856
Processing operating margin	166,190	131,628	129,314	135,337
Net Income (Loss)	**(396,293)**	**(439,964)**	**(545,981)**	**(1,761,937)**
Income (Loss) per share				
Basic	(0.009)	(0.012)	(0.014)	(0.048)
Fully Diluted	(0.009)	(0.012)	(0.014)	(0.048)
Weighted Average Number of Shares In Thousands	44,760	38,001	38,001	37,050
Funds Flow From Operations	**(38,211)**	**25,315**	**(143,458)**	**(35,010)**
Funds Flow Per Share	(0.001)	0.001	(0.004)	(0.001)
Cash flow from operating activities	(15,052)	183,420	53,039	95,001

Oil & Gas Production

Production during the third quarter of 2010 averaged 171 barrels per day compared to 156 barrels per day in the second quarter of 2010 and was 9% higher than the third quarter of 2009 of 157 barrels per day. In addition, during the quarter, gas sales declined at both Breton and Judy Creek. The Company's primary focus for 2010 is on the development of non-conventional oil and gas opportunities in the Cardium play in the Breton and Buck Lake areas, and the process is well underway for the first Cardium well, which commenced drilling in November 2010. The timing of up to four additional wells will depend on the results of the first well and availability of funding.

Oil & Gas Production

	Three Months September 30, 2010	Three Months September 30, 2009	Nine Months September 30, 2010	Nine Months September 30, 2009
Oil (bbl/d)	141	107	126	116
Natural Gas (mcf/d)	151	284	191	320
NGLs (bbl/d)	5	3	4	3
Total (barrel per day)	171	157	162	172

Oil & Gas Revenue and Realized Prices

The continuing uncertainty of the global economy has resulted in commodity price volatility. At current commodity price levels of approximately $75.00 for oil and $3.50 for gas, revenues in 2010 are expected to remain constant with 2009 levels. During the third quarter of 2010, oil prices have since recovered to a range from $70 to $80, while gas prices decreased below $4.00 during the quarter. The average oil price and average gas price for the third quarter were 4% higher than and 2% lower than the prices for the second quarter of 2010 respectively. Assuming prices hold at current levels, the Company expects to generate breakeven funds flow from existing operational levels, assuming no unforeseen increase to operating expenses. Incremental production from new development activity should lead to positive funds flow from operations as the year progresses.

	Three Months September 30, 2010	Three Months September 30, 2009	Nine Months September 30, 2010	Nine Months September 30, 2009
Oil				
Revenues	$931,261	$652,959	$2,535,661	$1,797,369
Prices $/bbl	$71.90	$66.59	$73.61	$56.72
Natural Gas				
Revenues	$46,992	$79,380	$208,238	$337,695
Prices $/mcf	$3.38	$3.04	$3.99	$3.86
NGL's				
Revenues	$14,411	$12,079	$48,937	$33,906
Prices $/bbl	$31.46	$43.45	$45.42	$41.00
Total				
Revenues	$992,665	$744,418	$2,792,836	$2,168,970
Price $/bbl	$63.12	$51.57	$63.16	$46.06

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 $982 for the nine months ended September 30, 2010, (2009 – $nil).

Oil & Gas Royalties Expense

Total royalties, including crown royalties, were $70,024 for the third quarter of 2010 as compared to $61,008 for the second quarter of 2010 and $34,424 for the three months ended September 30, 2009. This represented $4.45 per barrel for the third quarter of 2010 as compared to $4.29 per barrel for the second quarter of 2010 and $2.38 per barrel for the three months ended September 30, 2009. The Company's royalty rates have increased during the quarter with the increase in the oil production level.

Oil & Gas Operating Costs

Total oil and gas operating costs for the third quarter of 2010 were $567,270 or $36.07 per barrel, including $15,109 for inter-divisional processing charges and $119,661 for well repairs and maintenance. In comparison, operating costs were $606,755 for the second quarter of 2010 or $42.65 per barrel, including $16,191 for inter-divisional processing charges and $138,339 for repairs and maintenance. Operating costs for the third quarter of 2009 were $523,398 or $36.26 per barrel, including $12,594 for inter-divisional processing charges and $43,067 for repairs and maintenance. The high operating and maintenance costs in the first and second quarters of 2010 related to well workovers to bring production back on line and site remediation at Breton. These costs continued into the third quarter. However, in October, the Company saw a considerable improvement as these projects were concluded. Overall, the unit oil and gas operating cost declined from $42.65 per barrel in the second quarter to $36.07 per barrel in the third quarter and, with the reduction in maintenance costs in September, it is expected to decline in the future with increases to 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 2010 for consolidation purposes.

Oil & Gas Operating Net Back

The operating net back for the third quarter of 2010 is $22.60 per barrel compared to $14.03 per barrel for the three months ended June 30, 2010. These numbers reflect the reduction in maintenance costs, which incurred in the second quarter as the Company worked to bring production back on line, reversing the impact of the cost constraint activities in 2009. For the third quarter of 2009 the net back was $12.93 per barrel. The Company incurs high unit operating costs due to the low productivity of most of its wells. Oil and Gas operating net back is a non-GAAP measure but it is derived entirely from GAAP measures and management believes it is commonly used in the industry and for comparison purposes by investors.

		Three Months September 30, 2010	Three Months September 30, 2009	Nine Months September 30, 2010	Nine Months September 30, 2009
Average realized price	($/barrel)	$63.12	$51.57	$63.16	$46.06
Royalties	($/barrel)	4.45	2.38	4.48	2.16
Operating expenses	($/barrel)	36.07	36.26	43.82	31.03
Operating net back	($/barrel)	$22.60	$12.93	14.86	12.87

Processing

Processing revenue for the third quarter of 2010 was $416,737 compared to $397,170 for the second quarter of 2010 and $334,681 for the three months ended September 30, 2009. There was some increase in volumes in the quarter. The Company continued to experience stronger third party volumes during the third quarter of 2010 compared to 2009 and this trend appears likely to continue through the balance of 2010.

Processing Operating Costs

Processing operating costs for the second quarter of 2010 were $168,473 (including $9,836 of inter-divisional charges) compared to $182,607 (including $12,378 of inter-divisional charges) for the three months ended June 30, 2010. In 2010, the Company has been able to lower maintenance charges to a more consistent level after some significant maintenance and plant turnaround costs at the end of 2009. Inter-divisional charges were eliminated for consolidation purposes.

General and Administrative Expenses

General and administrative expenses for the third quarter of 2010 totaled $780,518 and $1,844,621 for the nine months ended September 30, 2010, including the expense of $328,000 to satisfy the obligations under the provisions of employment agreements, compared to $538,472 for the three months ended June 30, 2010, and $567,812 for the three months ended September 30, 2009. The comparable cost for the nine months ended September 30, 2009 was $1,237,567. During the first nine months of 2010, the Company has experienced a higher level of consulting fees and business development costs as the Company has ramped up its resources to prepare for future development plans, compared to 2009 when these costs had been reduced to respond to the downturn in economic conditions. With the development plans reasonably in place, in July the Company determined to restructure some of these costs to lower levels for the balance of the year.

Interest Expense

Interest expense for the third quarter of 2010 was $20,223 compared to $20,181 in the second quarter of 2010 and $156,114 during the three months ended September 30, 2009. The reduction in cost, compared to 2009, is related to paying down the credit facility after the equity investment funds were received in January. The expense for the quarter includes accrued interest of $6,014 on the debentures issued in settlement of the Company's payables and $9,000 for bank renewal fees.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense was $565,671 in the third quarter of 2010 compared to $597,425 in the second quarter of 2010 and $525,443 for the third quarter of 2009.

Net Income and Loss

The net loss in the third quarter of 2010 was $838,781, including stock compensation expense of $315,254. It reflected a tax recovery of $239,143, and a loss before tax of $1,077,924. This compared to a net loss of $543,379, and loss before tax of $741,031, in the second quarter of 2010; and net loss of $396,293, and loss before tax of $563,654, in the third quarter of 2009. The operating margin for the third quarter of 2010 was $603,742 compared to $415,047 in the second quarter of 2010 and $352,785 in the third quarter of 2009.

During the third quarter, the Company has increased production levels and realized a higher price for oil sales, which have increased the revenue by 14% compared to the second quarter. The increase in revenue and decrease in operating costs were more than offset by the G&A expenses, including the expense of $328,000 to satisfy the obligations under the provisions of employment agreements, compared to the second quarter. During this period, the processing contribution has increased quarter to quarter. A marginal improvement in results is expected in the next quarter as consistent production at Breton, Matziwin and Scots Lake occurs and the expected maintenance schedule is reduced.

Capital Expenditures, Commitments and Contingencies

The Company spent $146,603 on capital expenditures during the third quarter, as the Company consolidated its position and made preparations to drill its first well on the Cardium lands in the Breton/Buck Lake area. The Company had previously spent approximately $3.9 million on land acquisitions on Cardium lands at Breton / Buck Lake in Alberta, and on Bakken lands in Saskatchewan in the first quarter.

The Company has now accumulated seven gross sections of Cardium lands and anticipates drilling up to five Cardium wells during 2010 and 2011, with the drilling of the first well in November dependent on the results of the first well and the availability of further funding. In addition, the Company has now accumulated approximately 17 sections on Bakken lands in Saskatchewan and the Company plans a 3-D seismic program over these lands but has delayed this program from the summer to next year due to the environmental assessment, with the drilling of a first well now scheduled for later in 2011. Anterra now believes it has an inventory of over twenty Cardium development drilling locations in Alberta and fifty potential locations in Saskatchewan contingent on results of the 3-D seismic and initial drilling.

The Company has been reassessed by Canada Revenue Agency (“CRA”) for 2004 and 2005 taxation years. The Company has filed a notice of objection respecting the reassessment and, while the outcome is unknown, the Company expects any net changes resulting to the financial statements to be immaterial.

The Company has entered into employment agreements with certain senior management. In addition to defining the terms of employment, the agreement entitled the employees to payments ranging from 6 months to 18 months of compensation for termination without cause or in the event of a change of control. On January 15, 2010 completion of the final installment of the new investment transaction described in the section on Share Capital triggered a change of control. On July 13, 2010, as part of an arrangement to restructure 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 and agreed to pay certain employees $328,000 in aggregate compensation, in order to satisfy the obligations under the provisions of the employment agreements.

Liquidity, Capital Resources and Subsequent Events

Funds flow from operations for the third quarter of 2010 totaled a negative $175,446 compared to a negative $165,159 for the second quarter of 2010 and a negative $38,211 for the third quarter of 2009.

At September 30, 2010, there was $1,376,639 drawn down under the Company’s revolving demand loan facility (see Bank Debt below) and the Company’s net working capital deficit, including the cash position, was $72,180, compared to a working capital deficit of $5.06 million at December 31, 2009. The working capital deficit at September 30, 2010 includes $1.23 million in deposits under the Licensee Liability Rating (“LLR”) requirement with the Energy Resources Conservation Board which has increased by $1.16 million during the first nine months of the year as a result of the impact of the commodity price decline as reflected in the deemed value of the Company’s producing assets when compared to the deemed value of its reclamation liabilities.

In the first three quarters of 2010, the Company has expended $3.9 million on land positions in Alberta and Saskatchewan, and has plans to drill one horizontal well in the Cardium in November. The Company plans to drill up to four more wells depending on the results of the first well and availability of further funding. In order to exploit its opportunities for the year, the Company will need to obtain additional debt and equity financing as the year progresses. The Company is also intending to partially finance the drilling program through joint ventures and is currently seeking partners to participate.

Bank Debt

At September 30, 2010, following the Bank's annual review in May, when the Bank reduced the available amount under the revolving loan from $5,000,000, the Company had available a $4,500,000 revolving demand loan facility with a Canadian chartered bank. The revolving loan bears interest at prime plus 1.25%, an effective rate at quarter end of 4.25%, and the loans are secured by a general assignment of book debts and a $10,000,000 first floating charge debenture over all assets of the Company. In addition, the Company provided additional security during 2009 by issuing fixed charges, mortgages and security interests over certain of the Company's oil and gas assets. As at September 30, 2010, the Company had drawn down $1,376,639 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.

On October 20, 2010, the Company transferred the bank loan to another Canadian chartered bank.

Share Capital

At September 30, 2010, there were 244,088,032 Class A Shares and nil Class B Shares outstanding. At September 30, 2010, there were 2,666,665 warrants outstanding. No additional warrants to purchase Shares have been issued since September 30, 2010. On July 13, 2010, the Company agreed to issue 600,000 Class A Shares, at a price of $0.10 per share, to two officers of the Company, in satisfaction of obligations under their employment agreements.

On July 13, 2010, the Company granted 18,500,000 stock options to directors, officers, employees, and consultants to purchase Class A Shares at an exercise price of $0.10. Of the total options granted, one third vested immediately, with the balance vesting equally on the first and second anniversary of the grant date. Included in these options were 750,000 options granted to consultants providing investor relations services to the Company. The accounting transaction was recorded in November when the process was completed.

The options have been fair valued and the value estimated at $315,254 included in the stock compensation expense. The value was estimated using the Black-Scholes option pricing model with a current share price of $0.08 on July 13, 2010; an exercise price of $0.10 per option; a risk free interest rate of 2.00%; expected volatility of 75%; and a five year average life.

Pursuant to an investment agreement with an international investor dated September 10, 2009, on January 15, 2010, 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 installment of this investment, the investor held 77.7% of the outstanding Class A Shares.

Pursuant to the rules of the TSX Venture Exchange, certain shares of the previous directors, officers and insiders of Resolve (which were exchanged for shares of the Company) were subject to escrow conditions, whereby the Class A Shares were released from escrow over a period of 36 months. Pursuant to these conditions, at December 31, 2009, 555,900 Class A shares remained in escrow; and at September 30, 2010, all Class A Shares had been released.

Related Party Transactions

In addition to the transactions disclosed elsewhere in this MD&A, the Company had the following related party transactions:

(a) At September 30, 2010 and December 31, 2009, the Company has a receivable for $21,399 due from Alliance Success Holding Group Limited ("Alliance"), which owns 78% of the Company's shares at September 30, 2010, for services paid for by the Company on behalf of Alliance, relating to Alliance's investment in the Company.

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

Changes in Accounting Policies (See Note 3 to the interim financial statements)

The CICA issued Handbook Section 1582 "Business Combinations" that replaces the previous business combinations standard. This standard applies prospectively to business combinations on or after January 1, 2011 with earlier application permitted. The Company is currently assessing the impact of the standard. The CICA also issued Handbook Sections 1601 "Consolidated Financial Statements", and 1602 "Non-controlling Interests", which replaces existing guidance under Section 1600 "Consolidated Financial Statements". These standards will be effective for the Company for business combinations occurring on or after January 1, 2011 with early application permitted. The Company is currently assessing the impact of the standard.

During 2009 the Company commenced the process of evaluating and planning the implementation of a comprehensive enterprise wide project to manage the transition to IFRS with reporting to both senior management and the Audit Committee. The project has focused on key impact areas including:

* financial reporting,
* systems and processes,
* communication, and
* training.

Significant accounting differences between our current accounting policies under Canadian GAAP and expected accounting policies under IFRS include the following:

* Under IFRS, depletion and depreciation of property and equipment ("PP&E") will be calculated at a "significant component level" as opposed to the current "entity level" under existing GAAP. The existing full cost pool under Canadian GAAP will be separated into components and depleted individually at the component level. Although depletion will continue to be calculated using the unit-of-production method, under IFRS, the Company has the option to calculate depletion using proven plus probable reserves.

* IFRS differentiates between Exploration and Evaluation ("E&E") assets and Development and Producing ("D&P") assets, whereas under Canadian GAAP they are both considered PP&E. Upon adoption to IFRS, Exploration and Evaluation ("E&E") costs will be separated from PP&E and shown as a separate line item on the balance sheet. E&E costs, to the extent that they are not impaired, are expected are transferred into PP&E when reserves have been assigned to these assets. If reserves have not been established and there are no further plans for development activity, then the E&E expenditures will be reviewed for impairment. Any impairment of E&E assets are charged to income.

* Under IFRS, impairment testing on oil and gas properties will be performed at a lower level than that under current Canadian GAAP. Under IFRS the impairment test compares the carrying value of the oil and gas assets to the greater of the fair value of the assets and the value-in-use of the assets, which is a discounted cash flow measure. Future impairment tests will be required when management determines that indicators of impairment exist. Should impairment losses be recorded in accordance with IFRS, certain of those losses can be reversed in the future, if facts and circumstances change.

* Under IFRS, gains and losses on the disposal of oil and gas assets are recognized in net earnings. The amount of gain or loss is determined by comparing the proceeds from disposal with the corresponding carrying amount.

* Discount rates used in calculating asset retirement obligations ("ARO") has been subject to various interpretations and thus diversity in practice. As a result the IASB is currently reviewing the discount rate issue. Future changes to the standards and interpretations of the guidance could lead to a material change in this provision upon adoption of IFRS.

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. Anterra is currently evaluating how the potential changes may impact the Company's operations.

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 and liquidity, and capital resources. 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 relating to the Company is available on SEDAR at www.sedar.com and on the Company’s website at www.anterraenergy.com.