MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") dated April 28, 2015, of the financial condition and the results of operations of Anterra Energy Inc. ('Anterra" or the "Company") as at and for the and year ended December 31, 2014 should be read in conjunction with the Company's audited financial statements and related notes as at and for the year ended December 31, 2014.

Non-IFRS Measures

This MD&A makes reference to terms commonly used in the petroleum and natural gas industry including funds from operations, funds from operations per share, netback and net debt. Such terms do not have a standard meaning as prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the determination of similar measures for other entities. These measures are identified as non-GAAP measures and are used by management to analyze operating performance and leverage. The Company's method of calculating non-GAAP measures utilized is outlined in conjunction with their presentation within the MD&A. These measures should not be considered an alternative to, or more meaningful, than cash flow from/used in operating activities or net income (loss) as determined in accordance with IFRS.

BOE Presentation

Production volumes and reserves are commonly expressed on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet of gas equal to one barrel of oil, based on an energy equivalency at the burner tip and does not represent a value equivalency at the wellhead. Used in isolation, barrels of oil equivalent may be misleading.

Forward-Looking Information

Certain information in this MD&A constitutes forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. In particular, forward-looking statements include:

- *Statements under "Going Concern" and "Liquidity and Capital Resources" as to ongoing operations.*

Forward-looking statements are not guarantees of future performance and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the assumptions, plans, initiatives or expectations upon which they are based will occur. In addition, forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Such factors include, among others: general economic and business conditions; the price of and demand for oil and natural gas and their effect on the economics of oil and gas exploration; fluctuations in currency and interest rates and their effect on projected profitability of the Company's operations; the ability of the Company to implement its business strategy, including exploration and development plans; the impact of competition and in particular the ability of the Company to maintain its land position in a competitive leasing environment; the availability and cost of seismic, drilling, completions and other equipment; the Company's ability to secure adequate transportation and markets for any oil or gas discovered; drilling and operating hazards and other difficulties inherent in the exploration for and production and sale of oil and natural gas; the availability and cost of financing; the success of any exploration and development undertaken; actions by governmental authorities; and, changes in government regulations and the expenditures required to comply with them (including, but not limited to, the changes in taxes or the royalty or other share of production taken by governmental authorities). Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. Readers are cautioned that the foregoing list of risks, uncertainties and other factors is not exhaustive. Unpredictable or unknown factors not discussed could also have material adverse effects on forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent on other factors, and the Company's course of action would depend on its assessment of the future considering all information then available. All forward-looking statements in this MD&A are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

__Description of Business__

Anterra is engaged in the acquisition, development, optimization and production of crude oil and natural gas in western Canada. The Company is focused on growth through a combination of accretive oil-based acquisitions and the development and optimization of existing and acquired assets.

Going Concern

Crude oil prices weakened significantly during the last months of 2014 negatively impacting the earnings and cash flow for the fourth quarter of 2014. Additionally, during the third quarter of 2014 the Company experienced two major pipeline failures at its Nipisi property. These failures have resulted in the Company incurring spill clean-up and remediation costs of $2.9 million net of insurance recoveries of $0.8 million.

The foregoing together with associated production disruptions were major contributors to the loss reported for the fourth quarter and a working capital deficiency of $5.6 million excluding bank debt of $12.5 million at December 31, 2014. In addition, at December 31, 2014 and as of the date of this MD&A, the Company is in default under its Credit Facility Agreement and the default may continue throughout 2015.

Lower year end commodity prices also had a negative impact on the value of the Company's oil and natural gas reserves and the borrowing base upon which the Company's credit facility is determined. Although proven plus probable reserves at December 31, 2014, as determined by the Company's independent reserve evaluators, increased over year end 2013 reserves, lower commodity prices resulted in a reduction of their Net Present Value as compared to 2013.

Pursuant to a review by the Company's lender, effective March 9, 2015, the Company's $15 million revolving, operating demand loan credit facility was restructured to include a revolving operating demand loan facility in the maximum amount of $10 million and a non-revolving demand loan facility in the maximum amount of $4.8 million. The non-revolving loan facility was repayable as to $200,000 on acceptance of the facilities agreement and thereafter in monthly principal payments of $200,000.

These conditions create a material uncertainty that may cast significant doubt as to the Company's ability to execute on its business strategy and continue as a going concern.

These financial statements have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of obligations in the normal course of business. If this assumption is not appropriate, adjustments to the carrying amounts of assets and liabilities, revenues and expenses and the statement of financial position classifications used in the financial statements may be necessary and such adjustments could be material.

__Operations Summary__

In 2013 Anterra completed two strategic acquisitions: the corporate acquisition of Terrex Energy Inc. in March of 2013 and the Nipisi property acquisition in December of 2013. The full impact of these acquisitions is reflected in the twelve months ended December 31, 2014.

Production and related revenue for the three and twelve months ended December 31, 2014 increased significantly over the comparable periods of 2013 primarily as a result of the Nipisi property acquisition. For the three and twelve month periods ended December 31, 2014, petroleum and natural gas sales volumes averaged 691 boe/d and 670 boe/d respectively as compared to 405 boe/d and 389 boe/d for the comparable periods in 2013. Q4 2014 production increased 16% to 691 boe/d from Q3 2014 production of 598 boe/d. The quarter over quarter production increase was largely the result of interruptions to Q3 production, from plant turnarounds and pipeline failures, being back on-stream. Petroleum and natural gas sales revenue for the year ended December 31, 2014 increased 114% to $20,136,286 from revenue of $9,415,413 in 2013 as a result of the acquisitions. Fourth quarter 2014 revenue totaled $4,063,423 as compared to $2,348,333 for the fourth quarter of 2013. Revenue for Q4 2014 decreased approximately 14% from that of $4,701,942 for Q3 2014 due to lower realized oil prices that more than offset the increase in production.

Oil and gas operating expenses for the three month period and year ended December 31, 2014 also increased over comparable periods in 2013 as a result of increased production from acquisitions. For the year ended December 31, 2014, operating expense totaled $10,788,988 or $44.10/boe compared to $5,851,569 or $41.20/boe in 2013.

Q4 2014 operating costs, excluding spill clean-up and remediation costs, totaled $2,380,982 or $37.46/boe as compared to $1,615,620 or $43.41/boe in the same period last year. Spill clean-up and remediation costs of $2,865,021, net of estimated insurance recoveries, were expensed during the year.

For the year ended December 31, 2014, royalty expense was $5,503,519 or 25% of revenue versus $1,622,853 or 17% of revenue for the same period in 2013. The increase in overall royalty expense was due to higher production, and the increase in royalty rates resulted from higher royalties associated with Nipisi production.

Midstream processing revenue for the year ended December 31, 2014, increased 20% from $3,079,515 in 2013 to $3,696,527 in 2014, primarily as the result of increased throughput from the Breton midstream facility. Midstream operating expenses for three and twelve months ended December 31, 2014 also increased over the comparable periods in 2013 as a result of the increased throughput, higher personnel costs and increased maintenance expenditures. Midstream operating expenses totaled $1,809,075 for the twelve months ended December 31, 2014 as compared to $1,298,301 for 2013.

Funds from operations for the year ended December 31, 2014 totaled $3,277,137 compared to funds from operations of $678,373 for the comparable period in 2013.

Reconciliation of Funds Flow From Operations to Cash Flow From Operating Activities

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	($)	**($)**	($)
Net cash from (used in) operating activities	**2,421,387**	1,290,836	**6,010,368**	(666,451)
Transaction costs	**--**	35,004	**--**	437,821
Unrealized gain on risk management contracts	**259,761**	--	**222,111**	--
Decommissioning expenditures	**203,041**	--	**698,533**	--
Spill clean-up and remediation costs	**1,580,957**	-	**2,865,021**	-
Changes in non-cash working capital	**(3,748,868)**	(1,192,875)	**(6,518,896)**	907,003
Funds flow from operations	**716,278**	132,965	**3,277,137**	678,373

The Company reported a net loss of $16,053,578 for the year ended December 31, 2014; the loss resulted primarily from $2,865,021 of spill clean-up and remediation costs associated with the Nipisi property and an $11,553,164 impairment charge relating to the Breton, Strathmore and other minor properties.

Financial and Operating Results

Production, Revenue and Prices

	Three months ended December 31, **2014**	2013	Year ended December 31, **2014**	2013
Production				
Light crude oil (bbls/d)	**581**	298	**573**	270
Natural gas (mcf/d)	**434**	547	**414**	616
NGLs (bbls/d)	**38**	15	**29**	17
Total production (boe/d)	**691**	405	**670**	389
Total production (boe)	**63,555**	37,221	**244,634**	142,018
Revenue				
Light crude oil ($)	**3,763,221**	2,100,028	**18,839,674**	8,247,527
Natural gas ($)	**139,774**	195,099	**732,821**	843,925
NGLs ($)	**160,428**	53,206	**563,791**	323,961
Gross revenue ($)	**4,063,423**	2,348,333	**20,136,286**	9,415,413
Royalties ($)	**1,141,790**	469,024	**5,053,519**	1,622,853
Operating and transportation expenses ($)	**2,380,982**	1,615,620	**10,788,988**	5,851,569
Spill clean-up and remediation costs ($)	**1,580,957**	-	**2,865,021**	-
Net operating revenue ($)	**(1,040,306)**	263,689	**1,428,758**	1,940,991
Average Realized Prices				
Crude oil ($/bbl)	**70.43**	76.60	**90.15**	83.79
Natural gas ($/mcf)	**3.50**	3.88	**4.85**	3.76
NGLs ($/bbl)	**46.18**	56.23	**53.87**	57.85
Netback				
Total sales price ($/boe)	**63.94**	63.09	**82.31**	66.30
Royalty costs ($/boe)	**17.97**	12.60	**20.66**	11.43
Operating and transportation expenses ($/boe)	**37.46**	43.41	**44.10**	41.20
Operating netback ($/boe)	**8.51**	7.08	**17.55**	13.67
Midstream Processing Operations				
Revenue ($)	**1,029,371**	890,321	**3,696,527**	**3,079,515**
Operating costs ($)	**456,425**	376,935	**1,809,075**	**1,298,301**
Operating netback ($)	**572,946**	513,386	**1,887,452**	**1,781,214**

Petroleum and natural gas sales revenue for the year ended December 31, 2014 increased 114% to $20,136,286 from $9,415,413 in 2013; for the fourth quarter of 2014 revenue totaled $4,063,423 on average daily sales volumes of 691 boe/d compared to revenue of $2,348,333 on sales volumes of 405 boe/d a year ago. The increase in sales volumes was primarily the result of the acquisition of Nipisi in Q4 of 2013.

For the year ended December 31, 2014, revenue increased 114% as a result of a 72% increase in sales volumes and a 24% increase in realized oil and gas prices. For the three months ended December 31, 2014 revenue increased 73% as a result of a 71% increase in sales volumes and 1% increase in realized oil and gas prices.

Crude oil comprised 84% and 86%, respectively of the Company's production for the three and twelve months ended December 31, 2014 as compared to 74% and 69% for the comparable periods in 2013.

For the fourth quarter of 2014, midstream processing revenue totaled $1,029,371 compared to $890,321 a year ago. For the year ended December 31, 2014, revenue increased by 20% from $3,079,515 to $3,696,527. The increase is primarily the result of increased processing revenue from the Breton first phase plant expansion.

Royalties

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	($)	**($)**	($)
Crown royalties	**935,904**	379,447	**4,162,836**	962,468
Freehold royalties	**35,694**	88,602	**216,922**	652,476
Overriding royalties	**170,192**	975	**673,761**	7,909
Total royalties	**1,141,790**	469,024	**5,053,519**	1,622,853
Total royalties ($/boe)	**17.97**	12.60	**20.66**	11.43
Percent of revenue (%)	**28%**	20%	**25%**	17%

Total royalties are a combination of royalties paid on production from Crown lands, royalties paid on production from freehold lands and gross overriding royalties. Crown royalties under the Alberta Royalty Framework are sensitive to both commodity prices and well productivity. As a result royalties and royalty rates will fluctuate with commodity prices and well production.

The overall increase in royalties is the result of the increase in production primarily from the Nipisi acquisition. The decrease in Freehold royalties is a result of declining production from the Company's freehold property at Buck Lake. The year over year increase in overall royalty rates also results primarily from production at Nipisi that attracts an overriding royalty in addition to Crown royalties.

Operating and Transportation Expenses

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	**($)**	**($)**	**($)**
Oil and gas operating expense	**2,148,658**	1,348,698	**9,766,827**	5,067,606
Transportation	**232,324**	266,922	**1,022,161**	783,963
Midstream operating expense	**456,425**	376,935	**1,809,075**	1,298,301
Inter-company eliminations	**(13,622)**	(20,004)	**(53,413)**	(99,786)
Total operating expenses	**2,823,785**	1,972,551	**12,544,650**	7,050,084
Oil and Gas operating and transportation expenses ($/boe)	**37.46**	43.41	**44.10**	41.20

Oil and gas operating and transportation expenses for the three and twelve months ended December 31, 2014 increased substantially over the same periods in 2013 as a result of operating costs associated with increased production from acquisitions. For the twelve months ended December 31, 2014, oil and gas operating and transportation expenses, on a boe of production basis, increased from $41.20 per boe in 2013 to $44.10 per boe in 2014. The cost increase per boe of production is mainly due to higher costs incurred for fuel and power in 2014. Fuel and power costs in 2014 increased to $11.05/boe from $5.81/boe in 2013. During 2014, fuel and power costs comprised 23% of total operating costs as compared to 12% in 2013.

The Company's midstream operating expenses during 2014 increased over 2013 expenses as a result of increased equipment maintenance and personnel costs at the Breton and Suffield area combined with increased midstream throughput.

Operating Netback

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	$/boe	$/boe	$/boe	$/boe
Gross revenue	**63.94**	63.09	**82.31**	66.30
Royalty expenses	**17.97**	12.60	**20.66**	11.43
Operating and transporation expenses	**37.46**	43.41	**44.10**	41.20
Total, $ Per boe	**8.51**	7.08	**17.55**	13.67

Operating netback is defined as revenue excluding realized and unrealized gains on derivative contracts, net of royalties, operating and transportation expenses, determined on a barrel of oil equivalent basis. Anterra's operating netback for the year ended December 31, 2014 increased 28% to $17.55/boe from $13.67/boe in 2013 primarily as a result of a 24% increase in 2014 realized prices over 2013 prices. The Company's operating netback, realized during the fourth quarter of 2014 is relatively consistent with the netback realized in Q4 of 2013, and reflects the decline in oil prices during the quarter and.

General and Administrative ("G&A") Expenses

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	($)	**($)**	($)
Personnel costs	**180,605**	247,111	**937,286**	1,159,816
Professional fees	**160,514**	75,461	**405,856**	334,151
Computer services and subscriptions	**16,067**	31,200	**132,201**	157,794
Investor Relationship	**29,840**	37,503	**138,147**	89,809
Travel and business entertainment	**75,256**	56,430	**174,913**	293,042
Office rent	**57,850**	55,473	**320,401**	221,892
General office expenses	**139,565**	61,821	**489,702**	397,872
Total G&A Expenses	**659,697**	564,999	**2,598,506**	2,654,376
Total, $ Per boe	**10.38**	**15.18**	**10.62**	**18.69**

G&A costs for the twelve months ended December 31 in 2014 remained relatively consistent with 2013. On a per boe of production basis. G&A costs for the twelve months ended December 31, 2014 decreased approximately 43% from $18.69 in 2013 to $10.62 in 2014 as a result of increased production.

Transaction expenses

Transaction expenses relate to professional, consulting and other costs directly related to a transaction. During the year ended December 31, 2013, the Company incurred transaction costs of $437,821 relating to the Nipisi and Terrex transactions.

Exploration and evaluation expense

The Company had no plans for further exploration activities in the Abbott area of Saskatchewan nor had any reserves been assigned to the property as of December 31, 2013. As a result, $4,161,131 of accumulated land, seismic and drilling costs relating to the Abbott property were charged to exploration and evaluation expense in 2013.

Finance Expenses

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	$	$	**$**	$
Interest income on cash on deposit	**(225)**	(291)	**(897)**	(867)
Interest and line of credit fees	**132,120**	19,401	**483,108**	200,323
Interest on debenture	**60,000**	60,000	**240,000**	190,000
Accretion of debenture	**30,326**	30,326	**121,305**	96,033
Accretion of decommissioning obligations	**124,819**	262,950	**553,866**	409,772
Net finance expenses	**347,040**	372,386	**1,397,382**	895,261
Total net finance expenses *($/boe)*	**5.46**	9.98	**5.71**	6.30

For the three and twelve months ended December 31, 2014, interest on bank debt increased to $132,120 and $483,108 respectively from the comparative periods in 2013 due to increased borrowings and an increase in interest rates under the Company's credit facilities.

For the twelve months ended December 31, 2014, accretion of decommissioning liabilities increased 35% from $409,772 to $553,866 compared to the same period in 2013, due to accretion of decommissioning liabilities associated with the Nipisi property.

Depletion and Depreciation ("D&D")

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	$	$	**$**	$
D&D for oil and gas properties	**1,131,810**	749,237	**4,076,584**	2,623,313
D&D for midstream facilities and Other	**29,373**	56,424	**159,023**	172,973
Total D&D	**1,161,183**	805,661	**4,235,607**	2,796,286
Total D&D for oil and gas properties *($/boe)*	**17.71**	20.13	**16.64**	18.47

The provision for depletion and depreciation ("D&D") of property, plant and equipment ("PP&E") is determined on a component basis using the unit-of-production method based on independent estimates of proved and probable reserves and is calculated based on the ratio of production to proved plus probable reserves applied to the cost of the asset. Depreciation of midstream facilities is calculated on a straight-line method and the useful life is 20 years. Depreciation of other non-resource assets is calculated on a straight-line basis at various rates between 20% and 45%.

The overall increase in 2014 D&D costs from 2013 costs results from increased production. The decrease in D&D costs on a boe basis results from the addition of reserves through the Nipisi acquisition at a cost per boe lower than the carrying costs of other reserves.

Share Based Payments

The Company has established a Stock Option Plan that meets with the requirements of the TSX Venture, Exchange. Share based payments reflect the amortization over the vesting period of the fair value of stock options granted, to employees, consultants and directors of the Company.

A summary of the status of the Company's stock option plan as at December 31, 2014 and December 31, 2013 and changes during the periods ended on those dates is presented below.

	Number of options	Weighted average exercise price $
Outstanding at January 1, 2013	19,850,000	0.14
Forfeited	(1,750,000)	0.10
Forfeited	(1,500,000)	0.255
Outstanding at December 31, 2014 and 2013	16,600,000	0.13

The following table summarizes stock options outstanding and exercisable:

Options Exercisable					
Range of exercise prices	Number outstanding at December 31, 2014	Expiry date	Weighted average exercise price	Number exercisable at December 31, 2014	Weighted average remaining contractual life
$0.10	13,100,000	July 13, 2015	$0.10	13,100,000	0.5 years
$0.255	3,500,000	March 26, 2016	$0.255	3,500,000	1.2 years
$0.10 - $0.255	16,600,000		$0.13	16,600,000	0.7 years

Share based payments of $1,752 (2013 - $50,066) were expensed during the year ended December 31, 2014 related to previous granted options. No additional options were granted in 2014 and 2013.

Capital Expenditures

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	**($)**	**($)**	**($)**
Acquisitions	**60,578**	11,825,731	**262,578**	11,621,731
Geological and geophysical	**77,942**	472,342	**225,158**	1,275,516
Midstream facility	**25,362**	103,056	**106,753**	1,380,957
Equipment, workovers, well reactivations and other	**2,858,386**	424,525	**6,352,751**	997,368
Total capital expenditures	**3,022,268**	12,825,654	**6,947,240**	15,275,572
Capital expenditures are categorized as:				
PP&E	**3,022,268**	12,799,056	**6,947,240**	15,274,921
E&E assets	**-**	26,598	**-**	651

The majority of capital expenditures incurred during the three and twelve months periods ended December 31, 2014 relate to activities on the Company's recently acquired property at Nipisi and expenditures at Strathmore relating to the reactivation and expansion of the water flood.

Impairment

At December 31, 2014, due to declines in forward commodity prices, reserve revisions and adjustments to future development costs, the Company tested its oil and natural gas cash generating units ("CGUs") for impairment. As a result, the Company determined that the carrying amount of the CGUs at Breton, Strathmore and its other minor Alberta CGU exceeded their recoverable amount calculated as the fair value less costs to sell. The fair value less costs to sell was determined on a discounted cash flow basis, based on 2014 year-end reserves and commodity prices, using a risk-adjusted discount rate of 12%. The impairment was attributed to PP&E and an impairment loss of $11,553,164 was recorded.

In testing a CGU for impairment, the Company used the commodity price forecast prepared and used by its independent reserve evaluators in the assessment and evaluation of the Company's 2014 year-end reserves. The information presented below has been extracted from the evaluator's commodity price forecast.

Year	Inflation rate	CAD to USD Exchange Rate	Crude oil Edmonton city Gate ($cdn/bbl)	Alberta AECO Average price (cdn/mcf)
2015	0%	0.86	70.95	3.85
2016	2%	0.86	77.10	4.15
2017	2%	0.86	82.25	4.45
2018	2%	0.86	87.60	4.80
2019	2%	0.86	93.15	5.05
2020	2%	0.86	97.55	5.35
2021	2%	0.86	102.15	5.65
2022	2%	0.86	104.20	5.85
2023	2%	0.86	106.25	6.20
2024	2%	0.86	108.40	6.40
2025	2%	0.86	110.55	6.60

A 3% change in the discount rate would result in a $ 4,337,412 change in the impairment amount recognized.

Financial Instruments

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, operating and financial activities. The Company's financial risks are discussed in Note 7 to the Company's financial statements for the year ended December 31, 2014 and are consistent with prior years.

Effective June 1, 2014, the Company entered into a commodity price contract, as outlined below, to mitigate a degree of its exposure to commodity price risk and provide a degree of stability to operating cash flows which enable the Company to fund a portion of its capital program. Additionally effective July 1 2014, the Company entered into two fixed price power contacts also outlined below.

Such contracts are not used for trading or speculative purposes. The Company has not designated the financial derivative contracts as effective accounting hedges although the Company considers them to be an effective economic hedge. As a result, the contracts are recorded at fair value on the statement of financial position, with changes in fair value being recognized as an unrealized gain or loss on the statement of operations.

Commodity price contract

Remaining term	Contract Type	Quantity Contracted	Price Floor	Price Ceiling
Jan 2015 – June 2015	Crude Oil - collar	150 bbls per day	$97.00 / bbl	$112.00/bbl

Power price contracts

Remaining term	Contract Type	Volume	Price
Jan 2015 – Dec 2015	Fixed price	0.2 MW	$52.99/MWh
Jan 2014 – June 2017	Fixed price	1.5 MW	$55.25/MWh

At December 31, 2014, the foregoing derivative contracts were recorded at their combined estimated fair value as a current asset of $222,111 on the statement of financial positon and the Company recognized an unrealized gain of $222,111 and realized gain of $194,512 for the year ended December 31, 2014.

Liquidity and Capital Resources

The Company evaluates its ability to carry on business on a regular basis with key considerations being given to the non-GAAP measures net debt and funds flow from operations. Funds flow from operations represents cash flow generated from operating activities adjusted for expenditures of a non-operational or non-recurring nature including decommissioning activities, transaction costs, spill clean-up and remediation costs and changes in non-cash operating working capital. Funds flow from operations is a key indicator of the Company's ability to meet its current obligations and execute on its planned capital programs. The determination of funds flow from operations is presented on page 3 of the MD&A. Net debt is defined as bank indebtedness plus trade and other payables less accounts receivable and deposits and prepaid expenses. Net debt and changes in net debt is summarized below:

	2014	2013
Net debt, January 1	$ 17,685,841	$ 7,929,584
Funds flow from operations	(3,277,137)	(678,373)
Proceeds from share issue	-	(13,239,418)
Capital expenditures	6,947,240	3,449,842
Decommissioning expenditures	698,533	-
Spill clean-up and remediation costs	2,865,021	
Terrex transaction	-	7,960,655
Nipisi Acquisition	-	11,825,730
Transaction costs	-	437,821
Net debt, December 31	$24,919,498	$17,685,841
Net debt to annualized funds flow	7.6	4.8

The Company considers the ratio of net debt to annualized funds flow to be a key measure of liquidity and the management of capital resources. For the twelve months ended December 31, 2014 the annualized net debt to funds flow ratio was 7.6 to 1 as compared to 4.8 to 1 at December 31, 2013. Net debt at December 31, 2013 reflects the acquisition of the Nipisi property on December 19, 2013 which was funded in part from an $8.3 million draw on the bank credit facility. In addition to capital expenditures exceeding funds flow from operations, the deterioration in the net debt to funds flow ratio from that at December 31, 2013, reflects the impact of spill clean-up and remediation costs and decommissioning expenditures.

At current commodity prices, funds flow from operations will not be sufficient for the Company to execute on its business plan. In addition, the Company is in default under its credit facility. The Company is looking to raise additional capital through the disposition of non-core assets and is exploring the availability of additional equity capital. The Company has curtailed planned capital expenditures until its financial position stabilizes. Please see the discussion under "Going Concern" in this MD&A and Note 2 to the financial statements for the year ended December 31, 2014 for additional information.

Credit Facility

Bank indebtedness is comprised of a revolving, operating, demand loan credit facility bearing interest at the bank prime plus 1.00% (2013 - prime rate 0.75%), with an effective rate at December 31, 2014 of 4.00% (December 31, 2013 – 3.75%). The facility is secured by a first floating charge debenture in the amount of $35 million over all assets of the Company. Under its Credit Facility Agreement, the Company is required to maintain an adjusted working capital ratio, after adding the unused portion of the revolving demand loan facility and excluding outstanding debt under the facility, of not less than 1:1. As at December 31, 2014 the adjusted working capital ratio was 1 to 0.73 and the Company is in default under the Agreement and the default may continue throughout 2015.

Effective March 9, 2015 the Company's $15 million revolving, operating demand loan credit facility was restructured to include a revolving operating demand loan facility in the maximum amount of $10 million and a non-revolving demand loan facility in the maximum amount of $4.8 million. The non-revolving loan facility was repayable as to $200,000 on acceptance of the facilities agreement and thereafter in monthly principal payments of $200,000.

6% Convertible Debenture

In connection with the acquisition of Terrex, the Company and Terrex entered into a settlement agreement with Sandstorm Metals and Energy Ltd. ("Sandstorm"). On March 14, 2013, as part of this settlement, the Company issued a five year, 6% convertible redeemable debenture in the principal amount of $4,000,000 to Sandstorm.

Share Data

As at December 31, 2014 and April 28, 2015, Anterra had 496,871,120 Class A common shares issued and outstanding. Additionally, options, issued pursuant to the Company's stock option plan, for the acquisition of 16.6 million common shares at a weighted average price of $0.13 per share were outstanding; and 4,000,000 share purchase warrants were outstanding. The warrants were issued in conjunction with various equity financings and are exercisable at prices ranging from $0.10 to $0.60 per share and expire at varying times to April 28, 2015.

Sources and (uses) of cash

Sources and (uses) of cash for the three and twelve month periods ended December 31, 2014 and 2013 are summarized below:

	Three months ended December 31,		Year ended December 31,	
	2014	2013	**2014**	2013
	($)	($)	**($)**	($)
Cash – beginning of year	**--**	--	**--**	--
Funds flow from operations	**456,678**	132,965	**3,277,137**	678,372
Unrealized Gain on financial derivative	**-**	-	**(222,111)**	-
Transaction costs	**-**	(35,004)	**-**	(437,821)
Decommissioning expenditure	**(203,041)**	-	**(698,533)**	-
Spill clean-up and remediation costs	**(1,580,957)**	-	**(2,865,021)**	-
Change in non-cash working capital	**4,782,005**	395,942	**8,985,957**	(3,057,969)
Business combination		(11,825,730)	**-**	(11,771,191)
Issue of common shares, net of issue costs	**-**	-	**-**	13,239,418
Advances (repayment of) on bank loan	**(432,417)**	12,331,751	**(1,530,189)**	8,266,535
Cash used to settle Sandstorm	**-**	-	**-**	(3,467,502)
Capital expenditures				
PP&E	**(3,022,268)**	(973,326)	**(6,947,240)**	(3,449,191)
Exploration and evaluation	**-**	(26,598)	**-**	(651)
Cash – end of year	**--**	--	**--**	--

Income taxes

The Company has non-capital losses for income tax purposes totaling approximately $37.9 million. The losses expire between 2023 and 2034. The related tax benefits have only been recognized to the extent there are taxable temporary differences to offset with.

Related Party Transactions

The Company has entered into the following transactions with related parties:

a) LandOcean Energy Services Co., Ltd. ("LandOcean") and Western Union Petro (Canada) Technology Co., Ltd. ("Western Union"), a wholly owned subsidiary of LandOcean.

   LandOcean currently holds approximately 21.7% of the issued and outstanding Class A common shares of Anterra through its subsidiary, LandOcean Resources Investment Canada Co., Ltd. LandOcean has been tasked with (1) assessing the potential of the Company's oil and gas properties and preparing development plans for the properties; and (2) providing assistance to the Company's management in executing such plans. Specific projects, as summarized below, undertaken by LandOcean and Western Union are approved by the independent directors of the Company prior to the commencement of the project. The Company's management monitors and manages the work, and tracks all expenses against a budget approved by the directors for the project.

   i) On April 8, 2013, the Company entered into an agreement ("the Agreement") with LandOcean whereby LandOcean will provide Anterra with long-term technical consulting services including integrated reservoir studies, exploitation evaluations and production planning for existing properties and acquisition projects through to the end of 2014. Pursuant to the Agreement, LandOcean will earn total compensation of $1,949,600 for technical services through to the end of 2014 of which $976,880 has been earned to December 31, 2014. The Company charges technical costs incurred under the Agreement to petroleum and natural gas properties. Additionally, under the terms of the Agreement, $50,000 for travel, communication and management costs, were paid and expensed during 2013. At December 31, 2014, $392,000 was payable to LandOcean in relation to the Agreement.

   ii) During 2014, the Company engaged Western Union, to complete various field projects including the the initial stage of a water flood project at Strathmore, Alberta. During the year total costs of $3,584,962 related to the various projects were incurred of $2,808,105 which remains payable at December 31, 2014

   No work additional to that completed during 2014 is ongoing or anticipated with the above related entities.

b.) During the twelve months ended December 31, 2014, a consulting company, to which an officer of Anterra is related, charged the Company $100,579 (2013 - $93,980) for consulting services. At December 31, 2014, $8,378 was payable in relation to services provided

c.) During the twelve months ended December 31, 2014, a consulting company, to which a director of Anterra is related, charged the Company $23,500 (2013 - $58,300) for management and advisory services.

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 negotiated with third parties.

Subsequent Event

Subsequent to year end, the Company entered into a commodity price contract, on a no-cost collar basis, relating to the sale of 200 bbls of oil per day for the period from June 1, 2015 to December 31, 2015. The contract provides for a floor price of $65.00 per bbl and a ceiling price of $76.00 per bbl.

Off-balance Sheet Arrangements

The Company has not entered into any material off-balance sheet arrangements.

Critical Accounting Estimates

The preparation of financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Actual results may differ materially from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

The Company's assets are aggregated into cash-generating units ("CGUs"), for the purpose of calculating impairment. CGUs are based on an assessment of a unit's ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Judgments are required to assess when impairment indicators exist and impairment testing is required.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Key sources of estimation uncertainty:

The following are the key sources of estimation uncertainties affecting the measurement of balances and transactions in these financial statements.

(i) Decommissioning obligations

The Company estimates decommissioning obligations for oil and gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. This requires assumptions and estimates regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(ii) Income taxes

Tax provisions are based on enacted or substantively enacted legislation. Changes in legislation could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and an assessment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

(iii) Reserves

Estimation of reported recoverable quantities of proved and probable reserves include judgmental assumptions regarding production profiles, future commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows as well as the interpretation of complex geological and geophysical models and data.

The economical geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Anterra's petroleum and natural gas interests are assessed and evaluated at least annually by independent reserve evaluators in accordance with National Instrument 51-101.

(iv) Share-based payments

All equity-settled, share-based awards issued by the Company are recorded at fair value using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the share price, expected volatility, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

(v) Business Combinations

In a business combination, management estimates the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon an estimation of recoverable reserves being acquired.

Changes in Accounting Policy

On January 1, 2014, the corporation adopted IFRIC 21 which provides guidance with respect to recognition of liabilities resulting from government levies. The Company also adopted IAS 32 that clarifies the requirements for offsetting financial assets and liabilities. The adoption of these standards has no impact on the amounts recorded in the financial statements as at December 31, 2014 or on the comparative periods.

During the year ended December 31, 2014 the IASB issued the following standard which is applicable to the Company in future years;

- IFRS 9 “Financial Instruments” replaces IAS 39 “Financial Instruments: Recognition and Measurement” and addressed the classification and measurement of financial assets, effective date of January 1, 2018.

The Company has not completed its evaluation of the effect of adopting IFRS 9 on its financial statements.

Selected Annual Information

Years Ended December 31,	**2014**	2013	2012
(CAD$, except share amounts)	*($)*	*($)*	*($)*
Financial (1)			
Gross revenue	**23,779,400**	12,395,142	7,815,050
Net income (loss)	**(16,053,578)**	(7,102,781)	(813,513)
Per share – basic	**(0.03)**	(0.01)	(0.003)
Per share – diluted	**(0.03)**	(0.01)	(0.003)
Net cash from (used in) operations	**6,010,368**	(666,451)	837,060
Per share – basic	**0.01**	(0.001)	0.003
Per share – diluted	**0.01**	(0.001)	0.003
Capital expenditures	**6,947,240**	3,449,842	4,322,138
Total assets	**68,892,877**	76,869,554	48,035,625
Decommissioning obligations	**22,669,166**	22,152,634	10,673,673
Total non-current liabilities	**29,088,083**	25,642,141	11,872,844
Deferred tax liability	**-**	-	1,199,171
Weighted average shares			
Basic *(#)*	**496,871,120**	392,643,301	246,022,556
Diluted *(#)*	**496,871,120**	392,643,301	246,022,556
Operational			
Production			
Light crude oil *(bbls/d)*	**573**	270	155
Natural gas *(mcf/d)*	**414**	616	351
NGLs *(bbls/d)*	**29**	17	10
Total *(boe/d)*	**670**	389	223
Total *(boe)*	**244,634**	142,018	81,444
Reserves			
Proved plus probable *(mboe)* (2)	**6,031**	5,696	2,414
Lands			
Undeveloped *(net acres)*	**21,790**	26,369	22,442
Wells drilled			
Gross (net) *(#)*	**0(0)**	1 (0)	1 (0.6)

(1) The selected annual information has been prepared in accordance with International Financial Reporting Standards.

(2) Reserves are gross working interest reserves before royalty deductions.

Selected Quarterly Information

Three months ended	**Dec. 31, 2014**	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
	($)	*($)*	*($)*	*($)*
Gross revenue	**5,079,352**	5,504,798	6,598,726	6,596,524
Net income (loss)	**(13,734,171)**	(2,354,633)	(132,443)	167,659
Per share – basic	**(0.03)**	(0.005)	(0.000)	0.000
Per share – diluted	**(0.03)**	(0.005)	(0.000)	0.000
Funds flow from operations [1]	**716,278**	62,272	1,105,934	1,392,653
Per share – basic	**0.001**	0.0002	0.0002	0.0002
Per share – diluted	**0.001**	0.0002	0.0002	0.0002
Capital expenditures	**3,022,268**	2,283,374	896,057	745,541
Impairment expense	**11,553,164**	-	-	-
Total Assets	**68,892,877**	77,656,209	76,361,804	77,067,630
Working capital (deficiency)	**(18,111,393)**	(16,829,510)	(13,198,433)	(13,189,723)
Shareholders' equity	**17,632,799**	31,366,970	33,717,995	33,854,036
Production				
Light crude oil *(bbls/d)*	**581**	515	585	610
NGLs *(bbls/d)*	**434**	341	397	24
Natural gas *(mcf/d)*	**38**	25	27	486
Total *(boe/d)*	**691**	598	679	715
Total (boe)	**63,555**	54,943	61,775	64,362

Three months ended	Dec. 31, 2013	Sep. 30, 2013	Jun 30, 2013	Mar. 31, 2013
Gross revenue	3,238,654	3,509,081	3,139,512	2,527,899
Net income (loss)	(6,284,168)	(584,159)	(1,162,443)	927,989
Per share – basic	(0.01)	(0.001)	(0.003)	0.004
Per share – diluted	(0.01)	(0.001)	(0.003)	0.004
Funds flow from operations	132,966	226,689	(288,799)	607,517
Per share – basic	0.001	0.001	(0.001)	0.001
Per share – diluted	0.001	0.001	(0.001)	0.001
Capital expenditures	12,825,654	1,397,504	1,052,414	63,376
Impairment expense	1,099,100	-	-	-
Total assets	76,869,554	58,716,438	58,298,059	57,568,625
Working capital (deficiency)	(13,685,841)	(958,148)	(6,407,002)	(11,639,857)
Shareholders' equity	33,684,625	39,945,832	34,222,795	28,349,392
Production				
Light crude oil *(bbls/d)*	298	283	290	200
NGLs *(bbls/d)*	15	14	16	22
Natural gas *(mcf/d)*	547	652	726	574
Total *(boe/d)*	405	403	427	314
Total *(boe)*	37,221	37,327	38,853	28,617

(1) Funds flow from operations and funds flow from operations per share are not recognized measures under International Financial Reporting Standards. Refer to the Management's Discussion and Analysis for further discussion.

(2) The selected quarterly information has been prepared in accordance with the accounting principles as contained in the notes to the financial statements for the years ended December 31, 2014 and 2013.

Factors That Have Caused Variations over the Quarters

Factors and trends that have impacted Company's results during the above periods include:

- Anterra's oil and gas revenue is directly impacted by production including the Company's ability to replace production declines through an on-going capital expenditure program or acquisitions. The increase in revenue in 2014 is mainly the result of the Nipisi acquisition in December of 2013.
- Midstream revenue was negatively impacted by scheduled and unscheduled third party shut downs and road bans due to poor weather experienced in northern Alberta.
- Anterra's petroleum and natural gas sales fluctuate from quarter-to-quarter as a result of changes in commodity prices and production volumes.

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.

CORPORATE INFORMATION

Directors

Gary Chang;	Vancouver BC Canada	(2)
Ross O. Drysdale;	Calgary AB Canada	(1)
Gang Fang;	Calgary AB Canada	(2)
Hong Lei;	Beijing P.R. China	
Owen C. Pinnell;	Calgary AB Canada	(1) (3)
Zhen Xiang Huo;	Beijing P.R. China	(3)
Juan Wang	Beijing P.R. China	
Chengfeng Tang	Beijing P.R. China	(1) (2)
Guangzhen Song	Beijing P.R. China	

Notes: (1) Member of the Audit and Reserves Committee
(2) Member of the Environment and Safety Committee
(3) Member of the Compensation and Governance Committee.

Officers

Gang Fang	– Chairman and Chief Executive Officer
Bob D. McCuaig	–Vice President
Norman G. Knecht	– VP Finance and Chief Financial Officer

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Registrar and Transfer Agent
Computershare Trust Company of Canada

Stock Exchange
TSXV Venture Exchange
Trading Symbol: AE.A
OTCQX International
Trading Symbol: ATERF

Auditors
KPMG LLP

Bankers
Canadian Western Bank

Legal Counsel
Norton Rose Fulbright Canada LLP

Securities fillings
www.sedar.com
Information request and other investor relations inquiries can be directed to investor info@anterraenergy.com or by telephone at (403) 215 0860. Additional corporation information can be obtained through Anterra's website at www.anterraenergy.com.