NI 51-101 Form F1

Anterra Energy Inc.

Statement of reserves data

and other oil and gas information

as of December 31, 2014

Prepared by Deloitte

March 23, 2015

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Part 1: Date of statement

Date of statement:	**March 23, 2015**
Effective date:	**December 31, 2014**
Preparation date:	**March 23, 2015**

Anterra Energy Inc.'s (the "Company") oil and gas reserves were evaluated by Deloitte LLP (Deloitte), effective December 31, 2014. Deloitte was engaged by the Company to evaluate proved and proved plus probable reserves: no valuation of possible reserves or resources was undertaken. The Deloitte evaluation was prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook ("COGE Handbook").*

All of the Company's oil and gas reserves are located on-shore, in Canada.

The reserves on the properties described herein are estimates only. By nature, such forecasting of reserves and related economic parameters and analyses are forward-looking statements based on predictions of future events. Actual events or results may differ materially. Furthermore, the estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves.

In certain instances, numbers may not total due to computer-generated rounding.

Part 2: Disclosure of reserves data

Item 2.1 Reserves data (forecast prices and costs)

Item 2.1.1 Breakdown of proved reserves (forecast case)

Please refer to NI 51-101 Forecast Case – Summary of Oil and Gas Reserves in the Appendix.

Item 2.1.2 Net present value of future net revenue (forecast case)

Please refer to NI 51-101 Forecast Case – Summary of Net Present Values of Future Net Revenue in the Appendix.

Item 2.1.3 Additional information concerning future net revenue (forecast case)

Please refer to NI 51-101 Forecast Case – Total Future Net Revenue (Undiscounted), and NI 51-101 Forecast Case – Unit Value of Net Reserves by Production Group in the Appendix.

Item 2.2 Supplemental disclosure of reserves data (constant prices and costs)

Supplemental constant price estimates are not reported.

Item 2.3 Reserves disclosure varies with accounting

The Company has no subsidiaries and is not a subsidiary of another company.

Item 2.4 Future net revenue disclosure varies with accounting

The Company has no subsidiaries and is not a subsidiary of another company.

Part 3: Pricing assumptions

Item 3.1 Constant prices used in estimates

Supplemental constant price estimates are not reported.

Item 3.2 Forecast prices used in estimates

Forecast oil and gas prices are laid out in the Deloitte Price Forecast December 31, 2014 Table (see Appendix). All prices are stated in Canadian dollars unless otherwise indicated. Adjustments for oil differential and gas heating values are applied to these prices, as appropriate for each entity. Capital and operating costs are inflated.

Part 4: Reconciliation of changes in reserves

Item 4.1 Reserves reconciliation

Please refer to NI 51-101 Forecast Case - Reserves Reconciliation Summary in the Appendix.

Part 5: Additional information relating to reserves data

Item 5.1 Undeveloped reserves

	Oil		Natural Gas		NGLs	
	First attributed WI Mbbl	Cumulative WI Mbbl	First attributed WI MMcf	Cumulative WI MMcf	First attributed WI Mbbl	Cumulative WI Mbbl
Proved undeveloped						
*Prior to 2012	1,070	448	1,337	968	29	61
2012	-	197	-	247	-	20
2013	200	845	166	754	8	15
2014	65	601	24	462	6	21
Probable undeveloped						
**Prior to 2012	697	1,133	1,217	1,406	73	73
2012	-	523	-	343	-	13
2013	716	1,973	93	1,150	4	15
2014	309	2,165	116	776	21	31

* Cumulative volumes were not reported prior to 2010.
** Probable undeveloped reserves were not reported prior to 2010.

Undeveloped reserves were assigned within seven properties: Breton, Matziwin, Minnehik-Buck Lake, Nipisi, Sakwatamau, Strathmore, Two Creek – Jurassic A, and Two Creek – Jurassic B.

Breton

Two new undeveloped locations were assigned reserves this year.

Reserves were assigned to four horizontal Belly River wells that are to be drilled into the Norbuck Basal Belly River B Pool Unit and one horizontal Belly River well located in the southwest just outside of the Unit boundary. Each of the locations were assigned 90 Mbbl of probable reserves based on the successful 02/10-25-048-05W5/0 well drilled in the Basal Belly River H pool. The 02/10-25 well is located immediately beside the 00/10-25-048-05W5/0 oil well which has produced over 313 Mbbl of oil to date and is the largest well in the pool. Given that seven wells in the Norbuck Basal Belly River B Pool Unit have produced greater than 313 Mbbl it would be reasonable to assume that a horizontal location drilled in the Unit could perform as well or better than one drilled in the Belly River H pool. Proved reserves were not assigned at this time due to the fact that there has not yet been a horizontal well drilled by the Company into this pool. The Company has confirmed the estimated on-stream dates forecast.

Reserves that were previously assigned to the two vertical well locations, LC/15-23-047-04W5/A and LC11-24-047-04W5/A, have been removed. Based on the current pricing situation and with the knowledge of the Company's plans to exploit this property using short horizontal locations and not vertical wells, the locations are no longer forecast to be drilled.

A review of the location, 02/16-35-047-04W4W5/0, indicates that the well could be drained by the offsetting producers 00/16-35-047-04W5/0 and 00/10-35-047-04W5/0. The two suspended oil wells have produced a combined oil production of approximately 1,500 Mbbl from the northeast quarter of section 35. With the high water cuts from the wells at the time of their suspension, up to 99 percent, and the assigned probable horizontal location to the northeast, Deloitte advises that no reserves be assigned until this location is drilled and proved productive.

Matziwin

No new locations were assigned reserves this year.

The Company plans to drill a short leg horizontal well at HZ/01-16-023-14W4/A to increase Pekisko recovery in section sixteen. The Company has also planned to drill an offsetting location at HZ/03-15-023-14W4/A. Proved undeveloped and proved plus probable reserves were assigned primarily by analogy to the 02/04-15-023-14W4/0 well. Deloitte confirmed estimated on-stream dates with the Company.

Minnehik-Buck Lake

No new locations were assigned reserves this year.

There are three horizontal Cardium locations accounted for in this property, with proved locations assigned in section 17-045-05W5. A type well generated from existing vertical and horizontal Cardium oil producers was used as the basis of assigning reserves. These new locations are considered as infills, based on the estimated areal extent of the existing wells. Currently, spacing for the Cardium is limited to four wells per section; however operators in the area, such as Sinopec Daylight Energy to the north, have started downspacing to six or eight wells per section. Deloitte has assigned reserves assuming the Company would get the same approval for downspacing. Sinopec Daylight has also been experimenting with increasing the length of the wellbores of their Cardium horizontal wells. The Company has completed the 01-17 and the 08-17 wells with oil fractures, and the 09-17 was completed with a slick-water fracture.

These infill locations were assigned reserves after a review of the original oil-in-place for section 17-045-05W5. The production to date and the assigned reserves were used to estimate the remaining oil-in-place. The remaining reserves were assigned to the two horizontal infill locations after confirming the recovery factor from the gross production and reserves assigned and compared to the pool ticket. One additional location to the north of the 00/09-17 well has been forecast with the knowledge of higher GOR’s in the north of the section as reflected in the 09-17 well. The profile for this northern location in the section reflects the lower production rates and higher gas volumes, as seen in the 09-17 well, therefore resulting in assigned reserves being closer to the 09-17 well. The Company no longer plans to drill the previously assigned Cardium locations in section 08-045-05W5.

Nipisi

Seven new undeveloped locations were assigned reserves this year.

Over the next several years the Company also plans to drill several wells in this property in order to access volumes not fully swept by the waterflood. Based on an analysis of the waterflood in this area, Deloitte expects that there are some oil volumes remaining in the pool that have not been accounted for within the reserves assigned to existing wells. A total of seven locations have been assigned reserves based on a review of the geology and the performance of offsetting wells. Two locations, LC/02-29-078-08W5/0 and LC/15-29-078-08W5/0, has been assigned proved undeveloped reserves due to the lower water-cuts (less than 95 percent) of the surrounding wells and the lack of offsetting water injection. The remaining five locations have only been assigned probable reserves due to the uncertainty in where the injected water has migrated and where the oil-water contact now lies and a concern that initial water-cuts will possibly be too high for the wells to be economic.

Sakwatamau

No new locations were assigned reserves this year.

The Company has identified two horizontal drilling locations in the Belloy Formation in the north part of the pool. These locations are proposed to the north of the existing defined pool boundary. Probable undeveloped reserves have been assigned to both locations based on volumetric analysis and a review of the previously produced wells in the pool. Proved reserves were not assigned due to the lack of certainty regarding the oil water contact and the effect of areal extent of these locations. Additionally, there has not been a horizontal well drilled in this area targeting the Belloy Formation to date.

Strathmore

No new locations were assigned reserves this year.

Assigned probable undeveloped reserves for the drilling of the LC/14-07-022-25W5/A and LC/07-18-22-25W5/A locations as part of the Lower Mannville B Pool are estimated by Deloitte to be drilled, completed, and producing in 2017. The estimated reserves, initial rate, and segment profiles were assigned based on a review of the immediate offsetting wells and the expected production from a revitalized waterflood in place. Deloitte also consulted document provided by the Company, submitted to them by LandOcean Energy Services Co. Ltd., dated March 2014. The document took an in depth analysis of the potential development plans for the pool, and was titled “Improved Water Flooding Plan for Lower Mannville B of Strathmore”. The Company has indicated that they plan to implement the development plans outlined in the report and will continue to do so in the future. The direction from the report, is to make full use of existing wells through perfecting injection patterns to achieve bidirectional flooding for more oil wells, by adjusting the injections, attaining water cut control, and increasing reservoir pressure. Proved undeveloped reserves were not assigned because of the uncertainty that the Company will drill these locations in the near future.

Two Creek – Jurassic A

No new locations were assigned reserves this year.

An assignment of probable undeveloped reserves to this group includes the re-alignment of the waterflood, including the reactivation of two non-producing wells and a water injection well drilled at 00/05-17-065-15W5/0. The forecast producing rates and incremental reserves were based on simulation data provided by Terrex and the performance of the pool to date. Based on confirmation from the Company, Deloitte has forecast water injection to commence in mid-2016.

The Company has identified two horizontal drilling locations, the H1/10-08-065-15W5/A and the H2/12-08-065-15W5/A wells. Proved undeveloped reserves were assigned to the H1/10-08-065-15W5/A oil location and probable undeveloped reserves were assigned to the H2/12-08-065-15W5/A oil location. Reserves are based on volumetric analysis from geological parameters estimated from offset well logs by Deloitte. A drainage area of 80 acres and a recovery factor of 20 percent was based on the expected recovery of a waterflood in this pool and the offset production of the horizontal wells in the pool. The initial producing rate and forecast production trend were based on the 00/14-08-065-15W5/00, 102/02-17-065-15W5/00, and 100/06-17-065-15W5/00 wells producing from the pool. Based on confirmation from the Company, Deloitte has forecast the two locations to come on-stream in 2017.

Two Creek – Jurassic B

No new locations were assigned reserves this year.

Probable undeveloped reserves have been assigned based on a waterflood development plan proposed by the Company. As identified by the Company at last year's evaluation, the pressure in the Jurassic B Pool has been significantly depleted to approximately 13 percent of the original pressure, through the production of oil and water, but predominantly from the large volumes of gas produced. The Company identified both a gas cap and downdip water leg, each largely influencing the pool production. According to the plan proposed previously by Terrex, a reservoir re-pressurization to 40 percent of the original would be required in order to successfully develop the waterflood. Deloitte has estimated that this would require suspending production for approximately one year during injection, through three injector entities as identified by the Company. Injection would occur in the southern portion of the pool, near the migrated water-oil contact estimate. Two additional producers are also expected to be reactivated after this year of injection is complete.

Terrex previously identified the Killam North – Upper Mannville F2F pool as an analogous waterflood scenario. It should be noted that while both pools have seen pressure depletion, the Killam pool is not a direct analog. The Killam pool contains: a heavier oil (24 API) with less expected solution gas, a higher porosity, lower initial water saturation, and is approximately five times the size by volume of oil initially-in-place. The Killam pool pressure was depleted from an original six MPa to under one MPa before the waterflood was implemented, and according to public data, the pool has an estimated five percent incremental recovery factor due to the enhanced oil recovery from the waterflood. That incremental recovery factor is considered reasonable, and has been applied in the Two Creek B pool. This represents a total estimated ultimate recovery of 1.0 MMbbl on the total proved plus probable case.

Item 5.2 Significant factors or uncertainties

Reserve estimates are subject to change with such factors as updated production data, well performance and operational issues, ongoing development activities, price forecasts, and other economic conditions.

Item 5.3 Future development costs

	Undiscounted future costs net (M$)		Discounted (10%) future costs net (M$)	
Year	Proved	Proved + probable	Proved	Proved + probable
2015	7,964.7	9,489.7	7,523.0	8,992.7
2016	5,129.6	22,349.8	4,523.8	19,461.2
2017	4,993.9	15,241.9	4,012.0	12,069.0
2018				
2019				
2020+				
Total	18,088.2	47,081.4	16,058.8	40,522.9

Forecast capital expenditures will be funded by forecast cash flow, development lines of credit and additional equity.

Part 6: Other oil and gas information

Item 6.1 Oil and gas properties and wells

Item 6.1.1 Major properties

Breton, Alberta

The Breton property is located near the town of Breton, Alberta approximately 50 miles southwest of Edmonton, Alberta in Townships 47 and 48, Ranges 3 and 4 W5M. The property contains two producing oil wells, one producing oil Unit containing six wells, and seven drilling locations. The Company holds a working interest of 100 percent in the majority of their wells, as well as two royalty interest only wells. Production is from the Belly River Formation.

The Breton property consists of six producing oil wells which are in the Norbuck Basal Belly River B Pool Unit, two producing Non-Unit oil wells, and six oil well locations, five of which are horizontal wells. There are also three producing oil wells and two producing gas wells to which no reserves were assigned as they are producing below the economic limit. In addition, there are several service wells which are used to dispose of water and other produced fluids. The two Non-Unit producing wells in the property have been assigned proved developed producing reserves, based on decline analysis with consideration towards well performance.

All other wells in the property were either uneconomic or have not produced for a reasonable amount of time in which it was assumed they would not come back on-stream. No reserves have been assigned to these entities.

Nipisi, Alberta

The Nipisi property is located approximately 40 miles northwest of Slave Lake, Alberta in Townships 78 and 79, Ranges 8 and 9 W5M. The Company acquired the property from Pengrowth Energy Corp. effective December 18, 2013 and holds working interests ranging from 22.5 to 100 percent in 17 oil wells producing from the Gilwood Formation. The Company is the main operator in the property.

Proved developed producing reserves have been assigned to 17 producing entities based on decline analysis with consideration towards performance history of the wells and the area. Based on received operating statements, gas has been conserved on all of the wells in the property. Gas-oil ratios have been estimated based on the performance of the wells. The wells included in this property are located primarily to the west of the Nipisi Gilwood Unit 1. The Gilwood A pool was first produced from in 1965, and water injection was implemented in 1969. The western flank of the pool, where these wells produce from, was first brought on-stream in the early 1980s.

The Company has indicated that they plan to reactivate and install new pumps in five wells which are currently not producing. These reactivations coincide with plans to resume water injection on two wells: 00/10-08-079-08W5/0 and 00/12-17-079-08W5/0. Proved developed non-producing reserves have been assigned to these wells assuming production will return to the rates seen prior to shut-in. It is expected that the reactivation of the water injectors will provide pressure support and result in similar decline rates in these wells. Based on the capital required to reactivate these wells and their expected remaining volumes, two of these planned reactivation wells were found to be uneconomic and therefore have not had any reserves assigned.

The Company also plans to install new pumps on four wells that are currently producing. A review of wells in the pool which have undergone pump changes in the past show that these pumps generally result in a doubling of the prior oil production rate. Proved developed non-producing reserves have been assigned to these four wells based on this increase in rate and a slightly steeper decline rate than seen prior to the pump installation.

All other entities in the property are either suspended, abandoned, or water injection wells and are not producing oil volumes. No reserves have been assigned to these entities.

Strathmore, Alberta

The Strathmore property is located 40 miles southeast of Calgary, Alberta in Townships 21 to 23, Ranges 25 to 26 W4M. The Company has 100 percent working interest in the Strathmore property which contains 29 non-producing wells and the oil producing Lower Mannville B Pool group. The Lower Manville B Pool group consists of six producing oil wells and 35 non-producing oil wells. The wells in this property are producing from the Ellerslie Formation. The Company is the operator of this property.

The producing wells in the Lower Mannville B Pool have been evaluated as a group. There have been six to nine producing wells in the group over the past two years, and more than 30 non-producing oil wells. Proved developed producing and proved plus probable developed producing reserves have not been assigned due to the high operating costs, lower recent production volumes, and low oil prices.

Proved developed reserves have been forecast based on the reactivations of the following wells: 00/12-31-021-25W4, 00/13-31-021-25W4, 00/03-06-022-25W4, 00/05-06-022-25W4, 00/14-06-022-25W4, 00/04-07-022-25W4, 00/02-18-022-25W4, 02/10-18-022-25W4, 00/11-18-022-25W4, and 00/05-19-022-25W4. The timing and capital for the reactivations have been scheduled for the first and third quarter of 2015. As part of the reactivation, the Company will be installing electric submersible pumps to increase fluid output from the wells. It is assumed that the workovers will increase overall productivity in the pool. The Company has also undertaken a program to convert wells to injectors and increase injection rates in the pool, expecting overall fluid production to increase, maintaining the watercuts exhibited over the past several years.

Item 6.1.2 Gross and net oil and gas wells

Country/Province	Oil		Gas		Non-producing		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	50.0	46.1	-	-	175.0	164.6	225.0	210.7
Saskatchewan	1.0	0.5	-	-	7.0	3.3	8.0	3.8
Total	51.0	46.6	-	-	182.0	167.9	233	214.5

The Company does not have any additional wells that were not evaluated by Deloitte.

Item 6.2 Properties with no attributed reserves

The Company has 4,547 total hectares (3,410 ha net) of land in Abbott, Saskatchewan where no reserves have been assigned. The Company farmed-out a 25% interest in the lands, the proceeds from which were used to drill a second exploration test well. The well was drilled, logged, and abandoned.

Item 6.3 Forward contracts

The Company has an oil volume hedge with Nexen for 150 bbls of crude per day from June 1, 2014 through May 31, 2015 on a zero cost collar basis with a floor of $97.00 Canadian per bbl and a ceiling of $112 Canadian per bbl.

Item 6.4 Additional information concerning abandonment and reclamation costs

No. of net wells

Included in evaluation	214.5
Not included in evaluation	0.0

Property	Gross cost of abandonment and reclamation
Breton	$65,000/well
Frontier	$50,000/well
Judy Creek	$90,000/well
Matziwin	$50,000/well
Minnehik-Buck Lake	$65,000/well
Nipisi	$70,000/well
Sakwatamau	$75,000/well
Scots Lake	$50,000/well
Shadow	$90,000/well
Strathmore	$70,000/well
Two Creek – Jurassic A	$80,000/well
Two Creek – Jurassic B	$80,000/well

The abandonment costs are based on area averages taken from the Alberta Energy Regulator (AER) Directive 011 called the “Alberta Regional Well Abandonment Cost Tables”. Reclamation costs are taken from the AER Directive 011 section called “Alberta Regional Well Reclamation Cost Table”.

Forecast abandonment costs	Proved		Proved plus probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
	M$	M$	M$	M$
Next 3 fiscal years	2,295.4	1,874.6	2,295.4	1,874.6
Following years	15,709.9	7,055.3	17,897.5	6,947.2
Total	**18,005.3**	**8,929.9**	**20,192.9**	**8,821.9**

Item 6.5 Tax Horizon

The Company is expected to begin paying income tax in 2022 based on proved plus probable cash flow economics.

Item 6.6 Costs incurred

	$
Proved property acquisition	206,579
Land acquisition (unproved)	-
Exploration	-
Development	6,740,661
Total	6,947,240

Item 6.7 Exploration and development activities

The Company did no exploration and development drilling in 2014.

Item 6.8 Production estimates

Forecast production working interest January 1, 2015 - December 31, 2015		Proved	Proved + probable
Breton			
	Oil (Mbbl)	19.2	26.5
	Gas (MMcf)	10.9	13.7
	NGL (Mbbl)	0.1	0.1
Nipisi			
	Oil (Mbbl)	122.6	124.1
	Gas (MMcf)	37.2	36.8
	NGL (Mbbl)	9.2	9.1
Strathmore			
	Oil (Mbbl)	24.4	24.4
	Gas (MMcf)	133.3	133.3
	NGL (Mbbl)	0.8	0.8
Remaining properties			
	Oil (Mbbl)	50.3	50.8
	Gas (MMcf)	36.3	37.5
	NGL (Mbbl)	1.6	1.6
Total			
	Oil (Mbbl)	216.6	225.9
	Gas (MMcf)	217.7	221.4
	NGL (Mbbl)	11.6	11.6

Item 6.9 Production history

Total Company	Q12014	Q2 2014	Q3 2014	Q4 2014
Volumes				
oil, bbl	54,903	53,256	47,391	53,430
gas, Mcf	43,728	36,161	31,341	39,904
natural gas liquids, bbl	2,171	2,492	2,328	3,474
Boe	64,362	61,775	54,943	63,555
Production				
oil, bopd	610	585	515	581
gas, Mcf/d	486	397	341	434
natural gas liquids, bopd	24	27	25	38
Boe/d	715	679	597	691
Price				
oil, $/bbl	96.28	100.13	94.07	70.43
gas, $/Mcf	6.32	5.06	4.27	3.50
natural gas liquids, $/bbl	70.66	56.01	47.42	46.18
Total, $/Boe	88.80	91.55	85.58	63.94
Operating expenses, royalties, and netback averages, $/Boe				
royalties paid	19.71	23.59	20.91	18.55
operating cost	40.78	44.49	54.95	37.53
netback	21.92	15.60	2.43	1.30

Reserve definitions

Reserves are classified in accordance with the following definitions which meet the standards established by National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities and found in Appendix 1 to Companion Policy 51-101 CP, Part 2 Definition of Reserves.

Reserve categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and are disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and production status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

Developed Reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Use of Barrels of Oil Equivalent (Boe)

Disclosure provided herein in respect of Boe units may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf of natural gas to 1 bbl of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Abbreviations

Certain terms and abbreviations used in this document are defined below:

"bbl"	barrel of oil or NGL;
"bcf"	billion cubic feet of natural gas;
"bpd"	barrel of oil or NGL per day;
"Boe"	barrel of oil equivalent determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel;
"Boe/d"	barrel of oil equivalent per day;
"Mbbl"	thousand barrels;
"MBoe"	thousand barrels of oil equivalent;
"Mcf"	thousand cubic feet of natural gas;
"Mcfe"	Mcf of gas equivalent determined by converting a volume of oil or NGL to Mcf using the ratio of 0.1667 barrels to 1 Mcf;
"Mcf/d"	thousand cubic feet of natural gas per day;
"MMcf"	million cubic feet of natural gas;
"MMcf/d"	million cubic feet of natural gas per day;
"NGLs"	natural gas liquids;
"$US"	United States dollar;
"$Cdn"	Canadian dollar.

Conversion

In this document measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions.

To convert from:	To:	Multiply by:
Mcf	cubic metres	28.174
Cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Appendix

NI 51-101 Forecast – Oil and Gas Reserves Summary
NI 51-101 Forecast – Summary of Net Present Values of Future Net Revenue
NI 51-101 Forecast – Total Future Net Revenue
NI 51-101 Forecast – Unit Value of Net Reserves by Production Group
NI 51-101 Forecast – Reconciliation of Company Gross Reserves
Deloitte Price Forecast December 31, 2014

Anterra Energy Inc.
NI 51-101 FORECAST CASE
OIL AND GAS RESERVES SUMMARY
Deloitte December 31, 2014 Forecast Pricing

Effective: December 31, 2014 Canada

VOLUMES IN IMPERIAL UNITS

	Oil						Natural gas											
	Light, medium and shale		Heavy		Bitumen		Solution		Associated and non-associated		Coalbed methane		Natural gas liquids		Sulphur		Total Boe	
Category	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mlt	Co. Share Gross Mlt	WI Gross MBoe	Co. Share Net MBoe
PDP	990.6	842.5	340.1	292.0	0.0	0.0	536.8	427.9	0.0	0.0	0.0	0.0	61.7	39.2	0.0	0.0	1,481.9	1,245.1
PDNP	584.3	515.8	10.2	8.9	0.0	0.0	779.2	747.2	0.0	0.0	0.0	0.0	16.9	12.3	0.0	0.0	741.2	661.4
PUD	497.3	411.7	103.3	86.5	0.0	0.0	461.9	357.3	0.0	0.0	0.0	0.0	21.3	13.6	0.0	0.0	698.8	571.3
TP	2,072.1	1,770.0	453.5	387.4	0.0	0.0	1,777.9	1,532.4	0.0	0.0	0.0	0.0	99.9	65.0	0.0	0.0	2,921.9	2,477.8
PB	2,309.2	1,907.3	534.5	433.5	0.0	0.0	1,211.6	1,048.3	0.0	0.0	0.0	0.0	63.1	42.5	0.0	0.0	3,108.8	2,558.0
P+P	4,381.4	3,677.3	988.1	820.9	0.0	0.0	2,989.4	2,580.6	0.0	0.0	0.0	0.0	163.0	107.5	0.0	0.0	6,030.7	5,035.8

VOLUMES IN METRIC UNITS

	Oil						Natural gas											
	Light, medium and shale		Heavy		Bitumen		Solution		Associated and non-associated		Coalbed methane		Natural gas liquids		Sulphur		Total Boe	
Category	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3t	Co. Share Gross E3t	WI Gross E3m3e	Co. Share Net E3m3e
PDP	157.4	133.9	54.0	46.4	0.0	0.0	15.1	12.1	0.0	0.0	0.0	0.0	9.8	6.2	0.0	0.0	235.5	197.9
PDNP	92.8	82.0	1.6	1.4	0.0	0.0	22.0	21.1	0.0	0.0	0.0	0.0	2.7	2.0	0.0	0.0	117.8	105.1
PUD	79.0	65.4	16.4	13.7	0.0	0.0	13.0	10.1	0.0	0.0	0.0	0.0	3.4	2.2	0.0	0.0	111.0	90.8
TP	329.3	281.3	72.1	61.6	0.0	0.0	50.1	43.2	0.0	0.0	0.0	0.0	15.9	10.3	0.0	0.0	464.3	393.7
PB	367.0	303.1	84.9	68.9	0.0	0.0	34.1	29.5	0.0	0.0	0.0	0.0	10.0	6.7	0.0	0.0	494.0	406.5
P+P	696.2	584.4	157.0	130.4	0.0	0.0	84.2	72.7	0.0	0.0	0.0	0.0	25.9	17.1	0.0	0.0	958.3	800.2

Anterra Energy Inc.
NI 51-101 FORECAST CASE
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE – WITH CORPORATE TAX POOLS
Deloitte December 31, 2014 Forecast Pricing

Effective: December 31, 2014 Canada

	Before Income Taxes					After Income Taxes					Unit Value Before Income Tax Discounted at 10%
Reserves category	0% M$	5% M$	10% M$	15% M$	20% M$	0% M$	5% M$	10% M$	15% M$	20% M$	$/Boe
PDP	36,115.1	27,083.3	22,364.6	19,350.4	17,208.9	36,115.1	27,083.3	22,364.6	19,350.4	17,208.9	17.96
PDNP	14,411.0	8,768.3	5,529.0	3,482.9	2,096.4	14,299.1	8,756.9	5,527.7	3,482.7	2,096.3	8.36
PUD	19,098.2	8,059.3	3,178.8	725.0	(632.1)	14,306.2	6,199.8	2,383.5	57.6	(812.5)	5.56
TP	69,624.2	43,910.9	31,072.3	23,558.3	18,673.2	64,720.3	42,040.0	30,275.8	23,190.8	18,492.8	12.54
PB	86,544.3	44,523.1	26,397.8	16,387.8	10,138.1	64,891.9	33,211.7	19,416.3	11,717.6	6,864.2	10.32
P+P	156,168.5	88,433.9	57,470.1	39,946.1	28,811.2	129,612.2	75,251.6	49,692.1	34,908.4	25,357.0	11.41

Values may not add due to rounding
Unit Value calculation based on Net Boe reserves.

Anterra Energy Inc.
NI 51-101 FORECAST CASE
TOTAL FUTURE NET REVENUE – WITH CORPORATE TAX POOLS
Deloitte December 31, 2014 Forecast Pricing

Effective: December 31, 2014 Canada

Category	Revenue*	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Tax Expenses	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
PDP	136,503.0	19,186.7	63,942.4	0.0	17,258.8	36,115.1	0.0	36,115.1
PDNP	58,034.7	7,044.4	29,799.3	6,780.0	0.0	14,411.0	111.9	14,299.1
PUD	67,064.3	11,573.0	24,338.4	11,308.2	746.5	19,098.2	4,792.0	14,306.2
TP	261,602.1	37,804.1	118,080.2	18,088.2	18,005.3	69,624.2	4,903.9	64,720.3
PB	301,708.0	53,913.3	130,069.6	28,993.2	2,187.5	86,544.3	21,652.4	64,891.9
P+P	563,310.0	91,717.4	248,149.8	47,081.4	20,192.9	156,168.5	26,556.3	129,612.2

*Revenue includes product revenue and other income from facilities, wells and corporate if specified.

Anterra Energy Inc.
NI 51-101 FORECAST CASE
UNIT VALUE OF NET RESERVES BY PRODUCTION GROUP
Deloitte December 31, 2014 Forecast Pricing

Effective: December 31, 2014 Canada

	Reserves					
	Oil	**Gas**	**NGL**	**Boe**	**NPV**	**Unit Value**
	Net	Net	Net	Net	10%	$/Primary
	Mbbl	MMcf	Mbbl	MBoe	M$	Product
Light & Medium Crude Oil						M$/Mbbl
Proved developed producing	842.5	427.9	39.2	953.0	19,394.1	23.02
Proved developed non-producing	515.8	747.2	12.3	652.6	5,463.6	10.59
Proved undeveloped	411.7	357.3	13.6	484.8	3,019.4	7.33
Proved	1,770.0	1,532.4	65.0	2,090.4	27,877.2	15.75
Probable	1,907.3	1,048.3	42.5	2,124.5	23,536.1	12.34
Proved plus probable	3,677.3	2,580.6	107.5	4,214.9	51,413.2	13.98
Heavy Oil						M$/Mbbl
Proved developed producing	292.0	0.0	0.0	292.0	2,970.5	10.17
Proved developed non-producing	8.9	0.0	0.0	8.9	65.3	7.38
Proved undeveloped	86.5	0.0	0.0	86.5	159.4	1.84
Proved	387.4	0.0	0.0	387.4	3,195.2	8.25
Probable	433.5	0.0	0.0	433.5	2,861.7	6.60
Proved plus probable	820.9	0.0	0.0	820.9	6,056.9	7.38
Total						M$/MBoe
Proved developed producing	1,134.6	427.9	39.2	1,245.1	22,364.6	17.96
Proved developed non-producing	524.6	747.2	12.3	661.4	5,529.0	8.36
Proved undeveloped	498.2	357.3	13.6	571.3	3,178.8	5.56
Proved	2,157.3	1,532.4	65.0	2,477.8	31,072.3	12.54
Probable	2,340.8	1,048.3	42.5	2,558.0	26,397.8	10.32
Proved plus probable	4,498.2	2,580.6	107.5	5,035.8	57,470.1	11.41

Anterra Energy Inc.
NI 51-101 FORECAST CASE
RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT

Opening Case: Deloitte December 31, 2013 Forecast Pricing
Closing Case: Deloitte December 31, 2014 Forecast Pricing

Effective: December 31, 2014

Canada

	Light & Medium Oil			Heavy Oil			Associated & Non-Associated Gas			Natural Gas Liquids		
	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable
	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Opening balance	2,003.1	1,972.3	3,975.4	493.0	533.6	1,026.6	1,786.6	1,646.0	3,432.6	79.6	42.2	121.8
Production	-162.7	0.0	-162.7	-36.7	0.0	-36.7	-102.9	0.0	-102.9	-9.6	0.0	-9.6
Technical revisions	25.8	61.9	87.6	-4.4	2.5	-1.9	-47.7	-518.2	-516.7	13.5	-1.7	11.5
Extensions & improved recovery	260.7	348.8	609.5	0.0	0.0	0.0	72.1	127.3	199.4	17.5	22.7	40.2
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-54.7	-73.7	-128.5	1.7	-1.6	0.1	-25.6	-43.6	-23.0	-1.1	-0.2	-0.9
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing balance	2,072.1	2,309.2	4,381.4	453.5	534.5	988.1	1,777.9	1,211.6	2,989.4	99.9	63.1	163.0

Deloitte Resource Evaluation & Advisory
Canadian Domestic Forecast
Base Case Forecast Effective December 31 2014

					Crude Oil Pricing							Natural Gas Liquids Pricing Edmonton Par Prices				Natural Gas Pricing						Sulphur
		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	WTI at Cushing Oklahoma US$/bbl Real	WTI at Cushing Oklahoma US$/bbl Current	Edmonton City Gate C$/bbl Real	Edmonton City Gate C$/bbl Current	WCS 20.5 Deg. API Hardisty C$/bbl Current	Bow River 25 Deg. API Hardisty C$/bbl Current	Heavy Oil 12 Deg. API Hardisty C$/bbl Current	Ethane C$/bbl Current	Propane C$/bbl Current	Butane C$/bbl Current	Pentanes + Condensate C$/bbl Current	Alberta Reference Average Price C$/mcf Current	Alberta AECO Average Price C$/mcf Real	Alberta AECO Average Price C$/mcf Current	B.C. Direct Stn. 2 Sales C$/mcf Current	NYMEX US$/Mcf Real	NYMEX US$/Mcf Current	Alberta Plant Gate C$/lt Current
H	2004	1.8%	1.8%	0.770	$49.68	$41.40	$63.50	$52.91	$36.14	$37.98	$30.40	$19.05	$35.16	$44.02	$55.47	$6.31	$7.86	$6.55	$6.53	$7.08	$5.90	$40.71
i	2005	2.2%	2.2%	0.826	$66.64	$56.56	$81.63	$69.29	$44.60	$45.62	$33.70	$23.78	$43.19	$51.88	$74.72	$8.30	$10.32	$8.76	$8.22	$10.38	$8.81	$40.99
s	2006	2.0%	2.0%	0.882	$76.04	$66.02	$84.40	$73.28	$51.22	$51.90	$39.53	$19.83	$44.07	$58.16	$78.18	$6.56	$7.53	$6.54	$6.58	$7.77	$6.75	$19.53
t	2007	2.1%	2.1%	0.935	$81.62	$72.32	$86.96	$77.05	$52.90	$53.87	$39.76	$18.42	$49.75	$59.35	$81.64	$6.20	$7.28	$6.45	$6.40	$7.88	$6.98	$38.02
o	2008	2.4%	2.4%	0.943	$109.97	$99.57	$113.54	$102.80	$82.95	$83.90	$73.08	$22.59	$56.96	$83.54	$109.82	$7.88	$9.01	$8.16	$8.20	$9.79	$8.86	$303.83
r	2009	0.3%	0.3%	0.880	$66.47	$61.65	$71.27	$66.10	$58.66	$59.80	$54.40	$11.61	$34.62	$56.21	$69.52	$3.85	$4.27	$3.96	$4.17	$4.26	$3.95	($5.08)
i	2010	1.8%	1.8%	0.971	$85.34	$79.40	$83.62	$77.80	$67.22	$68.18	$60.62	$11.53	$45.19	$68.79	$84.06	$3.76	$4.31	$4.01	$4.01	$4.72	$4.39	$56.94
c	2011	2.9%	2.9%	1.012	$100.18	$94.88	$100.88	$95.54	$77.12	$78.42	$69.60	$10.30	$52.41	$86.98	$105.29	$3.46	$3.83	$3.63	$3.34	$4.22	$4.00	$101.60
a	2012	1.5%	1.5%	1.001	$96.47	$94.11	$88.74	$86.57	$73.10	$74.41	$64.07	$6.73	$30.80	$75.47	$99.71	$2.25	$2.45	$2.39	$2.29	$2.82	$2.75	$126.81
l	2013	0.9%	0.9%	0.972	$98.84	$97.91	$94.25	$93.36	$74.97	$76.29	$65.49	$8.68	$38.54	$77.44	$103.57	$2.98	$3.20	$3.17	$3.08	$3.77	$3.73	$62.17
2	12 Mths H	2.0%	2.0%	0.907	$93.90	$93.90	$95.95	$95.95	$81.53	$81.99	$73.73	$12.61	$40.80	$57.94	$101.82	$4.26	$4.56	$4.56	$4.39	$4.41	$4.41	$77.67
0	0 Mths F	0.0%	0.0%	0.860	$67.00	$67.00	$70.95	$70.95	$55.45	$56.45	$46.95	$10.80	$28.40	$46.10	$70.95	$3.65	$3.85	$3.85	$3.75	$3.70	$3.70	$75.00
1																						
4	Avg.	N/A	N/A	0.907	$93.90	$93.90	$95.95	$95.95	$81.53	$81.99	$73.73	$12.61	$40.80	$57.94	$101.82	$4.26	$4.56	$4.56	$4.39	$4.41	$4.41	$77.67
F	2015	0.0%	0.0%	0.860	$67.00	$67.00	$70.95	$70.95	$55.45	$56.45	$46.95	$10.80	$28.40	$46.10	$70.95	$3.65	$3.85	$3.85	$3.75	$3.70	$3.70	$75.00
o	2016	2.0%	2.0%	0.860	$70.00	$71.40	$75.60	$77.10	$61.30	$62.30	$52.65	$11.60	$30.85	$50.15	$77.10	$3.95	$4.05	$4.15	$4.05	$3.90	$4.00	$76.50
r	2017	2.0%	2.0%	0.860	$72.00	$74.90	$79.05	$82.25	$66.10	$67.15	$57.25	$12.55	$32.90	$53.50	$82.25	$4.25	$4.30	$4.45	$4.35	$4.10	$4.25	$78.05
e	2018	2.0%	2.0%	0.860	$74.00	$78.55	$82.55	$87.60	$71.15	$72.20	$62.15	$13.35	$35.00	$56.95	$87.60	$4.55	$4.50	$4.80	$4.65	$4.25	$4.50	$79.60
c	2019	2.0%	2.0%	0.860	$76.00	$82.25	$86.05	$93.15	$76.35	$77.45	$67.15	$14.05	$37.25	$60.55	$93.15	$4.80	$4.65	$5.05	$4.95	$4.40	$4.75	$81.20
a	2020	2.0%	2.0%	0.860	$78.00	$86.10	$88.35	$97.55	$80.45	$81.55	$71.05	$15.00	$39.05	$63.45	$97.55	$5.15	$4.85	$5.35	$5.25	$4.55	$5.00	$82.80
s	2021	2.0%	2.0%	0.860	$80.00	$90.10	$90.70	$102.15	$84.70	$85.80	$75.10	$15.75	$40.90	$66.40	$102.15	$5.40	$5.00	$5.65	$5.50	$4.70	$5.30	$84.45
t	2022	2.0%	2.0%	0.860	$80.00	$91.90	$90.70	$104.20	$86.40	$87.55	$76.60	$16.45	$41.70	$67.70	$104.20	$5.65	$5.10	$5.85	$5.75	$4.80	$5.50	$86.15
	2023	2.0%	2.0%	0.860	$80.00	$93.75	$90.70	$106.25	$88.10	$89.30	$78.15	$17.40	$42.55	$69.05	$106.25	$6.00	$5.30	$6.20	$6.10	$4.95	$5.80	$87.85
	2024	2.0%	2.0%	0.860	$80.00	$95.60	$90.70	$108.40	$89.85	$91.05	$79.70	$17.95	$43.40	$70.45	$108.40	$6.15	$5.35	$6.40	$6.25	$5.00	$6.00	$89.65
	2025	2.0%	2.0%	0.860	$80.00	$97.50	$90.70	$110.55	$91.65	$92.90	$81.30	$18.40	$44.25	$71.85	$110.55	$6.35	$5.40	$6.60	$6.45	$5.05	$6.15	$91.40
	2026	2.0%	2.0%	0.860	$80.00	$99.45	$90.70	$112.75	$93.50	$94.75	$82.95	$19.15	$45.15	$73.30	$112.75	$6.60	$5.50	$6.85	$6.70	$5.15	$6.40	$93.25
	2027	2.0%	2.0%	0.860	$80.00	$101.45	$90.70	$115.05	$95.35	$96.65	$84.60	$20.05	$46.05	$74.75	$115.05	$6.90	$5.65	$7.15	$7.05	$5.25	$6.65	$95.10
	2028	2.0%	2.0%	0.860	$80.00	$103.50	$90.70	$117.35	$97.30	$98.55	$86.30	$20.45	$46.95	$76.25	$117.35	$7.05	$5.65	$7.30	$7.20	$5.25	$6.80	$97.00
	2029	2.0%	2.0%	0.860	$80.00	$105.55	$90.70	$119.70	$99.20	$100.55	$88.00	$20.85	$47.90	$77.80	$119.70	$7.20	$5.65	$7.45	$7.30	$5.25	$6.95	$98.95
	2030	2.0%	2.0%	0.860	$80.00	$107.65	$90.70	$122.05	$101.20	$102.55	$89.75	$21.25	$48.85	$79.35	$122.05	$7.35	$5.65	$7.60	$7.45	$5.25	$7.05	$100.95
	2031	2.0%	2.0%	0.860	$80.00	$109.80	$90.70	$124.50	$103.25	$104.60	$91.55	$21.70	$49.85	$80.95	$124.50	$7.50	$5.65	$7.75	$7.60	$5.25	$7.20	$102.95
	2032	2.0%	2.0%	0.860	$80.00	$112.00	$90.70	$127.00	$105.30	$106.70	$93.40	$22.10	$50.85	$82.55	$127.00	$7.65	$5.65	$7.90	$7.75	$5.25	$7.35	$105.00
	2033	2.0%	2.0%	0.860	$80.00	$114.25	$90.70	$129.55	$107.40	$108.85	$95.25	$22.55	$51.85	$84.20	$129.55	$7.80	$5.65	$8.05	$7.95	$5.25	$7.50	$107.10
	2034	2.0%	2.0%	0.860	$80.00	$116.55	$90.70	$132.15	$109.55	$111.00	$97.15	$23.00	$52.90	$85.90	$132.15	$7.95	$5.65	$8.25	$8.10	$5.25	$7.65	$109.25
	2034+	2.0%	2.0%	0.860	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	0.0%	2.0%	2.0%

Notes:
- All prices are in Canadian dollars except WTI and NYMEX gas which are in U.S. dollars
- Edmonton city gate prices based on historical light oil par prices posted by the government of Alberta and Net Energy differential futures (40 Deg. API < 0.5% Sulphur)
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point
- 1 Mcf is equivalent to 1 mmbtu
- Real prices listed in 2014 dollars with no escalation considered
- Alberta gas prices, except AECO, include an average cost of service to the plant gate