ANTERRA ENERGY INC.

FORM 51-101F1

STATEMENT OF RESERVES DATA
AND
OTHER OIL AND GAS INFORMATION

The following statement of Reserves Data
And Other Oil and Gas Information is
Dated with an effective date of December 31, 2009.

Anterra Energy Inc.

Statement of Reserves Data and Future Net Revenue

The following Statement of Reserves Data and Other Oil and Gas Information, dated April 19, 2010, is presented with an effective date of December 31, 2009 as evaluated by AJM Petroleum Consultants in their report dated March 25, 2010. The pricing used in the forecast price evaluations is set forth in the notes to the tables.

All evaluations of future revenue are after the deduction of future income tax expenses, (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs, but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of Anterra's reserves. There is no assurance that the forecast price and cost assumptions contained in the AJM Petroleum Consultants Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the AJM Petroleum Consultants Report. The recovery and reserves estimates on Anterra's properties described herein are estimates only. The actual reserves on Anterra's properties may be greater or less than those calculated.

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

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS[9]

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mmcf)	Net[1] (mmcf)	Gross[1] (mbbl)	Net[1] (mbbl)
Proved								
Developed Producing[2][6]	384	349	23	21	873	685	10	6
Developed Non-Producing[2][7]	42	39	2	2	8	7	-	-
Undeveloped	262	210	-	-	166	144	2	2
Total Proved[2]	688	598	25	23	1,047	836	12	8
Probable [3]	332	249	15	14	396	306	4	2
Total Proved plus Probable[2][3]	1,020	847	40	37	1,443	1,142	16	10

NET PRESENT VALUES OF FUTURE NET REVENUES
BASED ON FORECAST PRICES AND COSTS[9]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**0% (M$)**	**5% (M$)**	**10% (M$$**	**15% (M$)**	**20% (M$)**
Proved										
Developed Producing[2][6]	28,546	16,777	12,147	9,711	8,196	24,031	14,780	11,029	9,000	7,707
Developed Non-Producing[2][7]	1,862	1,349	1,047	852	719	1,396	1,022	803	663	568
Undeveloped	21,928	10,574	6,108	3,885	2,601	16,458	7,887	4,498	2,801	1,815
Total Proved[2]	52,336	28,700	19,302	14,448	11,516	41,885	23,689	16,330	12,464	10,090
Probable [3]	33,009	11,571	5,602	3,387	2,361	24,752	8,683	4,212	2,555	1,789
Total Proved Plus Probable[2][3]	85,345	40,271	24,904	17,835	13,877	66,637	32,372	20,542	15,019	11,879

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS[9]

	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Developed Producing	62,055	6,306	25,199	-	2,004	28,546	4,516	24,030
Developed non-producing	4,783	398	2,508	15	-	1,862	465	1,397
Undeveloped	35,357	6,966	4,152	2,220	91	21,928	5,470	16,458
Total Proved[2]	102,195	13,670	31,859	2,235	2,095	52,336	10,451	41,885
Total Proved Plus Probable[2][3]	160,280	27,931	42,690	2,235	2,080	85,344	18,707	66,637

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS[9]

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/ year) ($/boe)
Total Proved[2]	Light and medium crude oil (including solution gas and other by-products)	17,708	26.97
	Heavy Oil (including solution gas and other by-products)	274	11.81
	Gas (including by-products but excluding solution gas from oil wells)	1,320	14.99
Total Proved Plus Probable[2([3]	Light and medium crude oil (including solution gas and other by-products)	22,611	24.30
	Heavy Oil (including solution gas and other by-products)	587	15.22
	Gas (including by-products but excluding solution gas from oil wells)	1,706	14.68

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS [9]

The following table sets forth a reconciliation of the changes in Anterra's light and medium crude oil, heavy oil and associated and non-associated gas (combined) reserves as at December 31, 2009 against such reserves as at December 31, 2008 based on the forecast price and cost assumptions set forth in note 9:

	Light and Medium Oil			**Heavy Oil**			**Associated and Non-Associated Gas**		
	Gross Proved (mbbl)	Gross Probable[11] (mbbl)	Gross Proved Plus Probable (mbbl)	Gross Proved[12] (mbbl)	Gross Probable[11,12] (mbbl)	Gross Proved Plus Probable (mbbl)	Gross Proved (mmcf)	Gross Probable[11] (mmcf)	Gross Proved Plus Probable (mmcf)
At December 31, 2009	736	385	1,121	25	14	39	1,309	516	1,825
Extensions	(15)	(33)	(48)	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	6	(18)	(12)	6	0	6	(50)	(104)	(154)
Discoveries	-	-	-	-	-	-	-	-	-
Recompletion							-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(5)	(3)	(8)	(1)	2	1	(94)	(16)	(110)
Production	(34)	-	(34)	(6)	-	(6)	(118)	-	(118)
At December 31, 2009	688	331	1,019	25	15	40	1,047	396	1,443

Notes:

1. "Gross Reserves" are Anterra's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of Anterra. "Net Reserves" are Anterra's working interest (operating or non-operating) share after deduction of royalty obligations, plus Anterra's royalty interests in reserves.
2. "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.
3. "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.
4. "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.
5. "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 (e.g. when compared to the cost of drilling a well) to put the reserves on production.
6. "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.
7. "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.
8. "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.
9. The pricing assumptions used in the AJM Petroleum Consultants Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. AJM Petroleum Consultants is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Light and Medium Crude Oil			Natural Gas	Natural Gas Liquids	Inflation Rate	Exchange Rate
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40^0 API ($Cdn/bbl)**	**Cromer Medium 29.3^0 API ($Cdn/bbl)**	**AECO Gas Price Average ($Cdn/bbl)**	**Edmonton Propane ($Cdn/bbl)]**	**%**	**$US/$Cdn**
2010	75.00	77.55	65.05	5.80	42.65	0%	.95
2011	81.60	84.45	71.45	6.70	46.45	2%	.95
2012	85.85	88.90	75.40	7.05	48.90	2%	.95
2013	90.20	93.45	79.45	7.45	51.40	2%	.95
2014	97.40	101.05	86.05	7.55	55.60	2%	.95
2015	104.90	108.85	93.85	7.75	59.85	2%	.95
2016	112.60	116.95	101.95	7.90	64.30	2%	.95
2017	114.85	119.30	104.30	8.25	65.60	2%	.95
2018	117.15	121.70	106.70	8.55	66.95	2%	.95
2019	119.50	124.10	109.10	8.85	68.25	2%	.95
2020	121.90	126.60	111.60	9.15	69.65	2%	.95
Thereafter	2%/Year	2%/Year	2%/Year	2%/Year	2%/Year	2%	.95

The weighted average prices received by the Company in 2009 were $60.35/bbl for oil, $3.97/mcf for gas, and $43.98/bbl for natural gas liquids.

10. Company actual before income taxes, excluding G&A.
11. Includes changes due to revised production estimates and timing, abandonment costs and all other adjustments.
12. 25.1Mbbl of Gross Proved oil reserves and 14.0 Mbbl of Gross Probable oil reserves have been reclassified from medium to heavy oil and these transfers have been made within the opening balance.

Significant Factors or Uncertainties

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

In particular, in the current economic conditions there is consequential uncertainty on whether the economic assumptions used in this report will be realised and whether internally generated cash flow and available financing opportunities will be sufficient to fund estimated future development costs. In recent months an improvement in general economic conditions has been apparent, however uncertain economic conditions continue globally, with slow growth in Canada, continuing worldwide economic slowdown, disruptions to the credit and financial markets in Canada and worldwide and local economic turmoil, which may adversely affect the economic assumptions, the value of the Company's business and value of its securities.

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

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

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

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

Regulatory risks include changes to Canadian federal and provincial laws, which are beyond the Company's control. The Government of Alberta has completed another comprehensive review of the province's oil and natural gas royalty structure. Anterra is currently evaluating how the potential changes may impact the Company's operations.

Undeveloped Reserves

The following table discloses for each product type the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years.

	Light and Medium Oil		**Heavy Oil**		**Natural Gas**		**Natural Gas Liquids**	
	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mmcf)	Net[1] (mmcf)	Gross[1] (mbbl)	Net[1] (mbbl)
Proved Undeveloped Reserves[8]								
2009	262	210	-	-	166	144	2	2
2008	283	247	-	-	163	136	-	-
2007	299	276	-	-	575	494	-	-

Anterra plans to pursue the development of these reserves within the next two years. There are no probable undeveloped reserves.

Future Development Costs

The AJM Petroleum Consultants report includes proved and probable reserves which require the expenditure of additional capital. These future development costs are estimated at $2,235,000 for proved reserves and $2,235,000 for proved and probable reserves, with the costs being incurred in 2010. Funding for these costs will be from funds flow from operations, by farming out certain projects to third parties and, in addition, the Company may raise additional capital or dispose of non-core assets.

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which Anterra held a working interest as at December 31, 2009. (Gross wells are defined as the total number of wells in which Anterra has an interest, while net wells are the number of wells obtained by aggregating Anterra's working interest in each of its gross wells):

	Oil		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Alberta				
Producing	22.0	21.1	7.0	3.6
Non-producing	34.0	32.7	12.0	9.9
Service	19.0	18.8	-	-
Saskatchewan				
Producing	7.0	3.3	-	-
Non-producing	1.0	0.5	-	-
Service	-	-	-	-

Costs Incurred

The following table summarizes the capital expenditures made by Anterra in Canada on oil and natural gas properties for the year ended December 31, 2009.

	(M$)
Property acquisition costs - unproved	90
Exploration expenditures	1,220
Development expenditures	207

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Anterra completed during its 2009 financial year. (Gross wells are defined as the total number of wells in which Anterra has an interest, while net wells are the number of wells obtained by aggregating Anterra's working interest in each of its gross wells):

	Exploratory Wells		Development Wells	
Canada	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	1	1	1	0.45
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	1	1	1	0.45

During most of 2009, in response to the economic conditions, the Company restricted Company funded capital expenditures on exploration and development activities. However, in December, the Company drilled and abandoned an exploratory horizontal well into the lower Shaunavon prospect in S.W. Saskatchewan. Also, in December, through a farmout agreement, an infill horizontal well was drilled on the Company's Matziwin property and this well is now on production. Under the terms of the agreement the partner funded 100% of the drilling, completion and tie-in costs to earn a 60% interest in the well for the first nine months and 55% thereafter. The focus for 2010 will be on the development of the Company's resource play at Breton – Buck Lake, where the Company has acquired 7 sections of land with Cardium prospectivity.

Forward Contracts

The Company does not have any forward contracts at the end of December 31, 2009.

Abandonment and Reclamation Costs

The Company bases its estimates for the costs of abandonment and reclamation of surface leases, wells and facilities on previous experience of management with similar well sites and facility locations. As at December 31, 2009, management expected to incur such costs on 98 net wells and facilities. The total of such costs for financial statement purposes was estimated at $4,843,000 (undiscounted) and $2,110,747 (discounted at 9%). Future net revenue figures set forth in this Statement include abandonment liabilities only for wells assigned reserves. These costs were estimated at $2,095,000 (undiscounted) and $962,000 (discounted at 10%). Abandonment and reclamation costs of $2,748,000 (undiscounted) are not considered in the future net revenue figures. Within the next three financial years, it is expected such costs will total approximately $200,000 (undiscounted).

Tax Horizon

The Company did not pay income taxes in 2009 and, based on available tax pools, does not expect to pay taxes in 2010, but could pay tax in 2011 depending on revenues and on the assumption that no new significant expenditures are made on oil and gas property and tangible equipment in the year that are not renounced as flow through expenditures.

Production Estimates

The following table sets forth the net volume of the Company's production estimated for the year ended December 31, 2010 as evaluated by AJM Petroleum Consultants , which is reflected in the estimate of future net revenues in the forecast prices and costs case disclosed in the tables contained under "Disclosure of Reserves Data":

Reserves Category	**Light and Medium Oil (mbbl)**	**Heavy Oil (mbbl)**	**Natural Gas (mmcf)**	**Natural Gas Liquids (mbbl)**
Proved				
Breton	32.3	-	119.0	1.5
Matziwin	9.1	-	-	-
Frontier	3.8	-	-	-
Judy Creek	-	-	20.2	-
Scots Lake	3.6	-	-	-
Other Properties	-	-	-	-
Total Canada	48.8	-	139.2	1.5
Proved plus Probable				
Breton	33.4	-	120.9	1.5
Matziwin	10.2	-	-	-
Frontier	4.2	-	-	-
Judy Creek	-	-	21.2	-
Scots Lake	4.0	-	2.2	-
Other Properties	-	-	-	-
Total Canada	51.8	-	144.3	1.5

Production History

Total Production

	Three Months Ended March 31, 2009	**Three Months Ended June 30, 2009**	**Three Months Ended September 30, 2009**	**Three Months Ended December 31, 2009**
Oil (mbbl)	11	11	10	9
Natural Gas (mmcf)	34	27	26	23
Natural Gas Liquids (mbbl)	0.3	0.3	0.3	0.3

Daily Production

	Three Months Ended March 31, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2009	Three Months Ended December 31, 2009
Oil (bbl/d)	117	125	107	98
Natural Gas (mcf/d)	380	298	284	247
NGLs (bbl/d)	3	3	3	3
Total (boe/d)	184	177	157	142

Oil and Gas Operating Net Back per Unit of Volume, including Realized Price, Royalties, and Operating Expenses

	Three Months Ended March 31, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2009	Three Months Ended December 31, 2009
Average realized price ($/boe)	$38.76	$48.62	$51.57	$59.15
Royalties ($/boe)	$2.49	$1.63	$2.38	$4.41
Operating expenses ($/boe)	$29.36	$28.05	$36.26	$47.83
Operating net back ($/boe)	$6.92	$18.94	$12.93	$6.91

APPENDIX 1

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Anterra Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Audit and Reserves Committee of the board of directors of the Company has:

(a) Reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) Met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) Reviewed the reserves data with management and the independent qualified reserves evaluator.

The Audit and Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit and Reserves Committee: approved (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information; (b) the filing of the Form 51-101F2 of the independent qualified reserves evaluator on the reserves data; and (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

Signed *("Owen C. Pinnell")*
Owen C. Pinnell, Chairman and CEO

Signed *("Giles Parker")*
Giles Parker, VP, Finance and CFO

Signed *("J.Ronald Woods")*
James H. Coleman, Director

Signed *("Ross O. Drysdale")*
Ross O. Drysdale, Director

Dated: April 19, 2010