NATIONAL INSTRUMENT 51-101

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Year Ended December 31, 2010

Dated May 2, 2011

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This Statement of Reserves Data and Other Oil and Gas Information (the "**Statement**") of Manitok Energy Inc. ("**Manitok**" or the "**Corporation**") is dated March 30, 2011 and is effective December 31, 2010. The preparation date of the information regarding reserves and future net revenues in the Statement and of the independent engineering evaluation of the Corporation's reserves (the "**Sproule Report**") prepared by Sproule Associates Limited ("**Sproule**"), an independently qualified reserves evaluator and auditor of Calgary, Alberta, was January to March, 2011.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value.

Oil and Natural Gas Reserves

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the estimated present worth of future net cash flows associated with Manitok's reserves as evaluated by Sproule. The reserves are based on forecast price assumptions. The information in respect of the reserves was derived from the Sproule Report, which report was prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 *Standard of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the COGE Handbook.

The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than the Sproule Report due to rounding. The values in the Sproule Report do not include the value of undeveloped land holdings nor the tangible value of Manitok's interest in any associated plant and wellsite facilities. The cash flow forecasts account for well abandonment costs. **It should not be assumed that the present values of estimated future net cash flows shown below are representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. Actual crude oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein.**

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

All of the reserves held by Manitok as at December 31, 2010 are located in Canada and, specifically, in the province of Alberta. In this Statement, references to "dollars" and "$" are expressed in Canadian dollars, unless otherwise stated.

The following table summarizes Sproule's estimates of Manitok's oil and natural gas reserves at December 31, 2010, using the Sproule forecast of prices and costs.

Summary of Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2010

	Light/Medium Oil		Heavy Oil		Natural Gas[1]		NGLs		Total	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Proved										
Developed Producing	-	-	190.5	172.0	1,269	1,108	0.2	0.1	402.2	356.8
Developed Non-Producing	-	-	40.0	38.7	300	277	1.6	1.1	91.6	86.0
Undeveloped	-	-	165.0	152.8	-	-	-	-	165.0	152.8
Total Proved	**-**	**-**	**395.5**	**363.4**	**1,569**	**1,385**	**1.8**	**1.3**	**658.8**	**595.5**
Probable	-	-	133.4	118.6	629	549	1.7	1.2	239.9	211.3
Total Proved Plus Probable	**-**	**-**	**528.9**	**482.0**	**2,197**	**1,935**	**3.5**	**2.4**	**898.7**	**806.8**

Notes:
(1) Estimates of reserves of natural gas include both associated and non-associated gas.
(2) Columns may not add due to rounding of individual items.

The following table is a summary of Manitok's present values of future net revenues associated with such reserves at December 31, 2010, using the Sproule forecast of prices and costs, before and after deducting future income tax expense, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

Net Present Values of Future Net Revenues
Forecast Prices and Costs
As at December 31, 2010

	Before Income Taxes Discounted At (% /year)					After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%
Reserves Category	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	($/boe)
Proved											
Developed Producing	10,357	9,170	8,248	7,513	6,916	10,357	9,170	8,248	7,513	6,916	23.12
Developed Non-Producing	2,092	1,447	1,041	776	597	2,092	1,447	1,041	776	597	12.10
Undeveloped	2,651	2,017	1,511	1,101	767	2,651	2,017	1,511	1,101	767	9.89
Total Proved	**15,100**	**12,635**	**10,799**	**9,390**	**8,280**	**15,100**	**12,635**	**10,799**	**9,390**	**8,280**	**18.13**
Probable	7,064	5,223	3,995	3,141	2,525	6,228	4,676	3,627	2,887	2,347	18.90
Total Proved Plus Probable	**22,164**	**17,858**	**14,795**	**12,531**	**10,805**	**21,328**	**17,311**	**14,427**	**12,278**	**10,626**	**18.33**

Note:
(1) Columns may not add due to rounding of individual items.

The following table provides a breakdown of various elements of Manitok's future net revenue attributable to proved reserves and proved plus probable reserves estimated using forecast prices and costs and calculated without discount.

Total Future Net Revenue
(Undiscounted)
Forecast Prices and Costs
As at December 31, 2010

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Develop-ment Costs ($000s)	Well Abandonment Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Taxes ($000s)	Future Net Revenue After Income Taxes ($000s)
Proved	38,384	3,306	14,683	4,432	861	**15,100**	-	**15,100**
Proved Plus Probable	52,750	4,866	19,638	5,152	929	**22,164**	836	**21,328**

The following table details by production group Manitok's net present value of future net revenues (before deducting future income tax expenses), estimated using forecast prices and costs and calculated using a discount rate of 10%.

Net Present Value of Future Net Revenues By Production Group
Forecast Prices And Costs
As at December 31, 2010

Reserves Category	Production Group	Future Net Revenue Before Income Taxes[3] (discounted at 10%/year)	
		($000s)	($/boe)
Proved	Light and Medium Oil[1]	-	-
	Heavy Oil[1]	8,076	22.22
	Natural Gas[2]	2,724	11.73
	Total	10,800	
Proved Plus Probable	Light and Medium Oil[1]	-	-
	Heavy Oil[1]	10,780	22.36
	Natural Gas[2]	4,015	12.36
	Total	14,795	

Notes:
(1) Includes solution gas and other by-products.
(2) Includes by-products but excludes solution gas.
(3) Other revenue and costs of Manitok not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Manitok's net reserves.
(4) Columns may not add due to rounding of individual items.

Pricing Assumptions

The following table details the reference prices as at December 31, 2010 in the Sproule Report for evaluating the net present values of future net revenues from reserves relating to Manitok's reserves disclosed above. The forecast cost and price assumptions used were determined by Sproule using information available from numerous governmental agencies, industry publications, oil refineries, natural gas marketers and industry trends. These forecast price assumptions are subject to many uncertainties that exist in both domestic and international petroleum industries.

Summary of Pricing and Inflation Rate Assumptions as at December 31, 2010
Forecast Prices and Costs

	OIL			NATURAL GAS	NATURAL GAS LIQUIDS				
Year	**WTI Cushing Oklahoma 40° API ($US/bbl)**	**Edmonton Par Price 40° API ($/bbl)**	**Hardisty Heavy 12° API ($/bbl)**	**Alberta AECO-C Spot ($/mmbtu)**	**Edmonton Pentanes+ ($/bbl)**	**Edmonton Butane ($/bbl)**	**Edmonton Propane ($/bbl)**	**Ethane Plantgate ($/bbl)**	**Exchange Rate ($US/$Cdn)**
Forecast									
2011	88.40	93.08	74.46	4.04	95.32	62.44	55.20	11.21	0.932
2012	89.14	93.85	75.08	4.66	96.11	62.95	55.66	12.91	0.932
2013	88.77	93.43	72.87	4.99	95.68	62.67	55.41	13.83	0.932
2014	88.88	93.54	71.09	6.58	95.79	62.75	55.47	18.22	0.932
2015	90.22	94.95	72.16	6.69	97.24	63.69	56.31	18.53	0.932
2016	91.57	96.38	73.25	6.80	98.71	64.65	57.16	18.83	0.932
2017	92.94	97.84	74.36	6.91	100.20	65.63	58.02	19.15	0.932
2018	94.34	99.32	75.48	7.02	101.71	66.62	58.90	19.46	0.932
2019	95.75	100.81	76.62	7.14	103.25	67.63	59.79	19.79	0.932
2020	97.19	102.34	77.78	7.26	104.81	68.65	60.69	20.11	0.932
Thereafter	Escalated at a rate of 1.5%								

Note:

(1) Weighted average historical prices of Manitok's reserves for the six-month period ended December 31, 2010 were $3.69/mcf for natural gas and $59.27/bbl for crude oil and NGLs. Transportation expense has been included in the realized price to align with pricing assumptions contained in the Sproule Report.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of Manitok's gross proved reserves, gross probable reserves and gross proved plus probable reserves as at December 31, 2010 against such reserves as at June 30, 2010 based on forecast price and cost assumptions.

	Light and Medium Oil			Heavy Oil		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
June 30, 2010	2.9	9.2	12.1	252.5	180.2	432.7
Extensions and Improved Recovery	-	-	-	74.9	45.0	119.9
Technical Revisions	(1.4)	(9.2)	(10.6)	83.2	(91.8)	(8.6)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions(1)	(1.5)	-	(1.5)	-	-	-
Economic Factors	-	-	-	-	-	-
Production(2)	-	-	-	(15.1)	-	(15.1)
December 31, 2010	**-**	**-**	**-**	**395.5**	**133.4**	**528.9**

	Natural Gas Liquids			Natural Gas		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved Plus Probable (Mmcf)**
June 30, 2010	8.3	22.0	30.3	1,688	839	2,527
Extensions and Improved Recovery	-	-	-	-	-	-
Technical Revisions	(2.8)	(3.3)	(6.1)	12	(84)	(72)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions(1)	(3.4)	(17.0)	(20.4)	(26)	(126)	(152)
Economic Factors	-	-	-	-	-	-
Production(2)	(0.3)	-	(0.3)	(105)	-	(105)
December 31, 2010	**1.8**	**1.7**	**3.5**	**1,569**	**629**	**2,198**

	Total		
Factors	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
June 30, 2010	545.0	351.2	896.3
Extensions and Improved Recovery	74.9	45.0	119.9
Technical Revisions	81.0	(118.3)	(37.3)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions(1)	(9.2)	(38.0)	(47.2)
Economic Factors	-	-	-
Production(2)	(32.9)	-	(32.9)
December 31, 2010	**658.8**	**239.9**	**898.7**

Notes:

(1) On August 4, 2010, the Corporation sold a non-core asset for approximately $1.8 million.

(2) Represents production from July 1, 2010 to December 31, 2010.

Undeveloped Reserves

The following table sets forth, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the periods indicated.

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (Mmcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
Year[(1)]	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end
Prior	-	-	-	170	90	333	-	-	15	226
June 30/09	-	-	170	170	333	187	-	2	226	203
June 30/10	-	-	170	171	187	185	2	2	203	204
Dec 31/10	-	-	171	165	185	-	2	-	204	165

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding financial year.

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (Mmcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
Year[(1)]	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end	First Attributed[(1)]	Total at Year-end
Prior	-	17	238	147	339	416	-	23	295	256
June 30/09	17	9	147	147	416	348	23	41	256	255
June 30/10	9	8	147	147	348	315	41	19	255	226
Dec 31/10	8	-	147	71	315	-	19	-	226	71

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding financial year.

The proved and probable undeveloped reserves attributable to Manitok's reserves have been estimated by Sproule in the Sproule Report in accordance with the procedures and standards contained in the COGE Handbook and consistent with NI 51-101. As at December 31, 2010, total proved plus probable undeveloped reserves were 236 Mbbl.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserves estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The reserves estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

The evaluated oil and natural gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and natural gas producing company.

Future Development Costs

The following table sets forth the future development costs deducted in the estimation of the future net revenue attributable to the Corporation's reserves estimated in the Sproule Report.

	Forecast Prices and Costs	
Calendar Year	**Proved ($000s)**	**Proved Plus Probable ($000s)**
2011	4,250	4,970
2012	-	-
2013	-	-
2014	-	-
2015	-	-
Remainder	182	182
Total Undiscounted	4,432	5,152
Total Discounted at 10% per year	4,081	4,744

Manitok expects to fund the additional future development costs with its current cash position from recent equity financings and internally generated cash flow from operations.

Principal Properties

Information relating to Manitok's principal properties is set out below.

Swimming Area, Alberta

The Swimming property is located approximately 80 kilometres west of Lloydminster, Alberta. This property was acquired in 2005 as part of Manitok Exploration Inc.'s initial transaction with Provident Energy Trust ("**Provident**"). In December 2010, it was producing approximately 150 bbls/d of heavy (11° - 13° API) oil from the Cummings, GP and Sparky formations. Manitok holds a 100% interest in all three producing wells which were drilled by Manitok Exploration Inc. in 2007 and the five producing wells drilled by Manitok in August and September of 2010. Manitok has obtained down spacing for the producing acreage providing an opportunity for 20 new drills utilizing multi-well surface drilling pads. Manitok has 3D seismic over the development area allowing it to better identify the most prospective locations and prioritize the drilling schedule. In addition, Manitok has a 100% interest in an additional 10 sections (6,400 acres) of undeveloped land in Swimming with no pending expiries. In addition to the development potential, this property provides Manitok with a stable oil production base and leverage to the price of oil.

Hairy Hill/Mannville Area, Alberta

This property is located in east-central Alberta, approximately 100 kilometres east of Edmonton, Alberta. In December 2010, it was producing approximately 65 boe/d (net) of lean natural gas from the Viking and Mannville formation. The Hairy Hill portion of this property was acquired through a farm-in in 2006. Manitok Exploration Inc. drilled four farm-in wells to earn its interest; three on freehold lands and one on Crown lands. In addition, Manitok Exploration Inc. purchased shallow Crown rights to complement deeper rights earned. Manitok's interest in all three producing wells in Hairy Hill is 100%. The natural gas produced is delivered into a third party operated system.

The Mannville area interests were acquired in 2005 under Manitok Exploration Inc.'s initial transaction with Provident. These are Crown leases in which Manitok has interests varying from 25 to 50 percent and included one (0.5 net) producing natural gas well and four (1.3 net) shut-in natural gas wells.. One

(0.5 net) Sparky gas well was drilled by Manitok Exploration Inc. in June of 2006. Manitok has a 5% interest in the Mannville North Gas Gathering System and a 5.74% interest in the Mannvillle North Gas Compression Facility.

The Manitok Hairy Hill/Mannville properties provide stable sweet natural gas production with low operating costs.

Coleman Area, Alberta

The Coleman property is located in the Foothills Belt of Alberta, approximately 30 kilometres north of Coleman, Alberta. This property was purchased in 2007 and consists of two Rundle C natural gas wells. In December 2010 these wells were producing approximately 30 to 40 boe/d (net) of dry slightly sour natural gas. Manitok has a 50% interest in these wells operated by Devon Energy Corporation ("**Devon**"), which wells produce into the Devon gathering system and are processed at the Devon Coleman gas plant. The availability of open Crown acreage in this area will allow Manitok to pursue posting and purchasing of Crown lands to provide further exploration and development opportunities in this core area.

Natural gas production from the two wells in this area has been stable since it was acquired in 2007 and the reserves have a long life of 25 plus years. As the existing wellbores are not draining the structure effectively, there is potential to significantly increase recovery of the reserves in place through lower risk exploitation operations.

Producing and Non-Producing Wells

The following table sets forth Manitok's producing and non-producing wells at December 31, 2010, all of which are located in Alberta. The stated interests are subject to land-owners and other royalties, where applicable, in addition to the customary Crown royalties and mineral taxes.

	Producing Crude Oil Wells		Non-producing Crude Oil Wells		Producing Natural Gas Wells		Non-producing Natural Gas Wells		Total Wells	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	8	8.0	4	4.0	7	5.0	7	4.3	26	21.3

Notes:
(1) "Gross" refers to all oil and gas wells in which Manitok has a working interest.
(2) "Net" refers to the aggregate of the percentage working interests of Manitok in the gross wells, before the deduction of any royalty interests.

For additional information respecting Manitok's important properties, plants, installations and facilities and the reserves attributed to each property and production information included therein, see "Principal Properties" above.

Properties with No Attributed Reserves

The undeveloped land holdings attributable to Manitok's reserves, as at December 31, 2010, consisted of approximately 84,620 gross (81,020 net) acres of land. All of such lands are located in Alberta.

A third party evaluation of Manitok's undeveloped land holdings has not been undertaken. The simple average working interest in undeveloped lands of Manitok as at December 31, 2010 was 95.7%.

As at December 31, 2010, approximately 3,200 gross (1,920 net) acres of Manitok's land holdings expire in 2011.

Forward Contracts

Manitok may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. During the financial year ended December 31, 2010, Manitok had not entered into financial or physical hedges in respect of commodity prices, foreign exchange contracts or other similar forward sales contracts.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which are expected to be incurred in connection with Manitok's reserves for the periods indicated. The amounts disclosed are based on forecast prices and costs for total proved plus probable reserves.

	Abandonment and Reclamation Costs Undiscounted ($000s)	**Abandonment and Reclamation Costs Discounted at 10% ($000s)**
Total as at December 31, 2010	2,431	1,100
Anticipated to be paid in 2011	120	109
Anticipated to be paid in 2012	-	-
Anticipated to be paid in 2013	79	59
Total anticipated costs in next three years	199	168

The portion of abandonment and reclamation costs not deducted as abandonment and reclamation costs in estimating future net revenue is $1.5 million ($0.7 million discounted at 10%). Salvage value recoveries on wells and facilities have not been determined and as such have been excluded from future net revenues. Manitok's abandonment and reclamation costs were estimated by management and employees of Manitok based on their experience in the industry.

As at December 31, 2010, Manitok is expected to incur reclamation and abandonment costs in respect of 21.3 wells (net).

Tax Horizon

Manitok has available for deduction against future taxable income non-capital losses of approximately $8.1 million. The majority of these losses, if not utilized, will expire commencing in 2024. Subject to certain restrictions, Manitok also has resource expenditures available to reduce taxable income in future years. Manitok will need to pay income taxes in future years when its income exceeds the resource expenditures and losses carry forward available at that time.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) incurred by Manitok for the six month period ended December 31, 2010.

Expenditures	**Six Month Period Ended December 31, 2010 ($000s)**
Acquisition costs-Unproved properties	1,823.0
Acquisition costs-Proved properties	-
Exploration costs[1]	2,367.8
Development costs[2]	2,891.2
Property dispositions	(2,202.8)
Total	**4,879.2**

Note:
(1) Geological and geophysical capital expenditures and drilling and re-completion costs for exploration wells.
(2) Development and facilities capital expenditures.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells drilled during the six month period ended December 31, 2010.

	Exploratory Wells		**Development Wells**	
	Gross[1]	**Net[2]**	**Gross[1]**	**Net[2]**
Oil	1	1.0	4	4.0
Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	**1**	**1.0**	**4**	**4.0**

Notes:
(1) "Gross" means the total number of wells comprising the Corporation's reserves.
(2) "Net" means the number of wells obtained by aggregating the working interest in each of the gross wells comprising the Corporation's reserves.

For details on the Corporation's important current and likely exploration and development activities during 2011, see "Principal Properties".

Production History

The following table sets forth certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback in respect of Manitok's reserves for the periods indicated.

	Six Month Period Ended December 31, 2010	Three Month Period Ended December 31, 2010
Average Daily Production[1]		
Crude Oil (bbl/d)[2]	84.1	97.7
Natural Gas (mcf/d)[3]	568.8	604.0
Combined (boe/d)	178.9	198.4
Average Realized Sales Price[1]		
Crude Oil ($/bbl)[2]	59.27	62.05
Natural Gas ($/mcf)[3]	3.69	3.64
Combined ($/boe)	39.59	41.63
Royalties[4]		
Crude Oil ($/bbl)[2]	(6.80)	(6.13)
Natural Gas ($/mcf)[3]	(0.27)	(0.22)
Combined ($/boe)	(4.05)	(3.70)
Operating Expenses[5][6]		
Crude Oil ($/bbl)[2]	(22.29)	(24.38)
Natural Gas ($/mcf)[3]	(3.17)	(2.39)
Combined ($/boe)	(20.60)	(19.29)
Transportation and Marketing Expenses		
Crude Oil ($/bbl)	(2.34)	(2.20)
Natural Gas ($/mcf)	(0.21)	(0.18)
Combined ($/boe)	(1.77)	(1.65)
Operating Netback[7]		
Crude Oil ($/bbl)[2]	27.84	29.33
Natural Gas ($/mcf)[3]	0.04	0.85
Combined ($/boe)	13.17	16.99

Notes:

(1) Before deduction of royalties.

(2) Crude Oil includes heavy oil and NGLs, as NGLs on their own are considered immaterial. The amounts attributed to light oil are negligible.

(3) Natural Gas includes associated and non-associated gas and all other marketable gas.

(4) Quarterly royalty amounts are based on estimates and are subject to periodic adjustments. These adjustments can cause significant variations when applied to low production volumes and are expressed on a per barrel basis.

(5) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and NGLs production.

(6) Where multiple product types are attributable to a single well, the operating expenses attributable to that well are allocated based on the proportionate production of each product. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(7) Netbacks are calculated by subtracting royalties, operating costs and transportation expenses from revenues.

The following table indicates the net average daily production volumes from Manitok's important fields for the six month financial period ended December 31, 2010.

Area	Natural Gas (mcf/d)	Light Oil (bbls/d)	Heavy Oil (bbls/d)	NGLs (bbls/d)	Total (boe/d)
Coleman	172.5	-	-	0.2	29.0
Hairy Hill/Mannville	392.2	-	-	-	65.4
Swimming	-	-	82.3	-	82.3
Other	4.0	0.1	-	1.5	2.2
Total	**568.7**	**0.1**	**82.3**	1.7	**178.9**

Production for six month financial period ended December 31, 2010 was 53.0% natural gas, 0.1% light oil, 46.0% heavy oil and 1.0% NGLs.

Production Estimates

The following table sets out the estimated volume of Manitok's company interest production (working interest plus royalty interest, before royalties) for the six month financial period ended December 31, 2011 as reflected in the estimates of future net revenue disclosed herein.

	2011 Estimated Average Daily Production – Forecast Dollar Pricing				
Reserves Category	**Natural Gas (mcf/d)**	**Light Oil (bbls/d)**	**Heavy Oil (bbls/d)**	**NGLs (bbls/d)**	**Total (boe/d)**
Proved producing					
Coleman	209	-	-	-	34.8
Hairy Hill/Mannville	409	-	-	-	68.2
Swimming	-	-	153	-	153.0
Other properties	-	-	-	-	-
Total proved producing	**618**	**-**	**153**	**-**	**256.0**
Proved					
Coleman	209	-	-	-	34.8
Hairy Hill/Mannville	409	-	-	-	68.2
Swimming	-	-	185	-	185.0
Other properties	113	-	-	-	18.8
Total proved	**731**	**-**	**185**	**-**	**306.8**
Proved plus probable					
Coleman	209	-	-	-	34.8
Hairy Hill/Mannville	449	-	-	-	74.8
Swimming	-	-	193	-	193.0
Other properties	118	-	-	-	19.7
Total proved plus probable	**776**	**-**	**193**	**-**	**322.3**

Marketing

Crude oil, natural gas and NGLs will be priced based on daily spot prices adjusted for quality and transportation. See "Forward Contracts".

ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	mcf	thousand cubic feet
bbls	barrels	mcf/d	thousand cubic feet per day
bbls/d	barrels per day	Mmcf	million cubic feet
Mbbl	thousand barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	mmbtu	million British Thermal Units
boe/d	barrel of oil equivalent per day	GJ	Gigajoule

Other

boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 bbl of crude oil for 6 mcf of natural gas. *Disclosure provided herein in respect of boes 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.*

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

In the tables set forth in this Statement, unless otherwise indicated, the following definitions and other notes are applicable.

1. "**Gross**" means:

   (a) in relation to the Corporation's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

   (b) in relation to wells, the total number of wells in which the Corporation has an interest; and

   (c) in relation to properties, the total area of properties in which the Corporation has an interest.

2. "**Net**" means:

   (a) in relation to the Corporation's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

   (b) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

   (c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

3. Definitions of Reserves:

Reserves 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 shall be disclosed.

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

(a) **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.

(b) **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.

(c) **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:

(a) **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.

(i) **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.

(ii) **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.

(b) **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.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserve entities" (which refers to the lowest level at which reserves calculations are performed) and to "reported reserves" (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. Future Income Tax Expense

Future income tax expenses are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

5. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

8. "**Exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

9. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection

(natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented do not represent fair market value.

12. The forecast price and cost assumptions assume the continuance of current laws and regulations.

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Manitok Energy Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Manitok Energy Inc., as at December 31, 2010, prepared January to March 2011	Canada	-	$14,795	-	$14,795

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed, but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
March 30, 2011

(signed) *"Paul B. Jung"*

Paul B. Jung, P. Eng.
Senior Petroleum Engineer and Associate

(signed) *"Alec Kovaltchouk"*

Alec Kovaltchouk, P. Geol.
Manager, Geoscience and Associate

(signed) *"Harry J. Helwerda"*

Harry J. Helwerda, P. Eng., FEC
Executive Vice-President and Director

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings are ascribed in National Instrument 51-101 have the same meanings herein.

Management of Manitok 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, 2010, 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 is presented in the Statement of Reserves Data and Other Oil and Gas Information of the Company effective as of December 31, 2010.

The 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 and auditor to report without reservation; and

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

The Reserves Committee 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 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 Form 51-101F2 which is the report 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 judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Massimo M. Geremia*"
Massimo M. Geremia
President and Chief Executive Officer

(signed) "*Robert G. Dion*"
Robert G. Dion
Vice President, Finance and Chief Financial Officer

(signed) "*Cameron G. Vouri*"
Cameron G. Vouri
Director

(signed) "*Bruno P. Geremia*"
Bruno P. Geremia
Director

Dated: May 2, 2011