Butte Energy Inc.

The "Reporting Issuer" or the "Company"

FORM 51-101F1
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

For the Fiscal Year Ended December 31, 2014

This is the form referred to in item 1 of section 2.1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Terms for which a meaning is given in NI 51-101 have the same meaning in this Form 51-101F1.

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ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
MSTB	1,000 stock tank barrels
Bbls/d	barrels per day
NGLs	natural gas liquids
STB	stock tank barrels of oil
STB/d	stock tank barrels of oil per day

Natural Gas

Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
Mscf/d	thousand standard cubic feet per day
MMscf/d	million standard cubic feet per day
MMBTU	million British Thermal Units
Bscf	billion standard cubic feet
GJ	gigajoule

Other

AECO	Niska Gas Storage's natural gas storage facility located at Suffield, Alberta.
BIT	Before Income Tax
AIT	After Income Tax
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mscf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
$M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

1. The date of this Statement is April 29, 2015

2. The effective date of the information provided in this Statement is as of the Company's most recently completed fiscal year ended December 31, 2014.

3. The date of preparation of this Statement is April 7, 2015.

PART 2 DISCLOSURE OF RESERVES DATA

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Butte Energy Inc. (the "Company") as evaluated by Chapman Petroleum Engineering Ltd. ("Chapman") as at December 31, 2014 and dated March 11, 2015 (the "Chapman Report"). Chapman is an independent qualified reserves evaluator and auditor.

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 the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Chapman Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Chapman Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

All monetary values presented in this document are expressed in terms of Canadian dollars.

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	Company Reserves[1]							
	Light and Medium Oil		Heavy Oil		Natural Gas[9]		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing[2][6]	2	1	-	-	-	-	-	-
Developed Non-Producing[2][7]	-	-	-	-	-	-	-	-
Undeveloped[2][8]	-	-	-	-	-	-	-	-
TOTAL PROVED[2]	**2**	**1**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PROBABLE[3]	368	276	-	-	-	-	-	-
TOTAL PROVED + PROBABLE[2][3]	**370**	**277**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL POSSIBLE[4]	201	145	-	-	-	-	-	-
TOTAL PROVED + PROBABLE + POSSIBLE	**571**	**422**	**-**	**-**	**-**	**-**	**-**	**-**

SUMMARY OF NET PRESENT VALUES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	Net Present Values of Future Net Revenue									
	Before Income Tax Discounted at					After Income Tax Discounted at				
	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.
Reserves Category	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
PROVED										
Developed Producing(2)(6)	14	14	14	13	13	14	14	14	13	13
Developed Non-Producing(2)(7)	-	-	-	-	-	-	-	-	-	-
Undeveloped(2)(8)	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED(2)	**14**	**14**	**14**	**13**	**13**	**14**	**14**	**14**	**13**	**13**
TOTAL PROBABLE(3)	6,651	5,379	4,387	3,605	2,978	6,651	5,379	4,387	3,605	2,978
TOTAL PROVED + PROBABLE(2)(3)	**6,665**	**5,393**	**4,401**	**3,618**	**2,991**	**6,665**	**5,393**	**4,401**	**3,618**	**2,991**
TOTAL POSSIBLE(4)	5,643	4,343	3,400	2,700	2,173	5,643	4,343	3,400	2,700	2,173
TOTAL PROVED + PROBABLE + POSSIBLE	**12,308**	**9,736**	**7,801**	**6,318**	**5,164**	**12,308**	**9,736**	**7,801**	**6,318**	**5,164**

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	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)**
Total Proved(2)	112	25	73	-	-	14	-	14
Total Proved Plus Probable(2)(3)	32,814	8,402	13,000	4,335	412	6,665	-	6,665
Total Proved Plus Probable Plus Possible(4)	51,723	13,708	18,971	6,203	532	12,309	-	12,309

FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($M)
Total Proved[2]	Light and Medium Oil (including solution gas and other by-products)	14
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but not solution gas)	-
Total Proved Plus Probable[2][3]	Light and Medium Oil (including solution gas and other by-products)	4,401
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but not solution gas)	-
Total Proved Plus Probable Plus Possible[4]	Light and Medium Oil (including solution gas and other by-products)	7,801
	Heavy Oil (including solution gas and other by-products)	-
	Natural Gas (including by-products but not solution gas)	-

OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	Reserves						Net Present	Unit Values
	Oil		Gas[9]		NGL		Value (BIT)	@ 10%/yr
Reserve Group by Category	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl	10% M$	
Light and Medium Oil								
Proved								
Developed Producing	2	1	-	-	-	-	14	14
Developed Non-Producing	-	-	-	-	-	-	-	N/A
Undeveloped	-	-	-	-	-	-	-	N/A
Total Proved	**2**	**1**	**-**	**-**	**-**	**-**	**14**	**14**
Probable	368	276	-	-	-	-	4,387	16
Proved Plus Probable	**370**	**277**	**-**	**-**	**-**	**-**	**4,401**	**16**
Possible	201	145	-	-	-	-	3 400	23
Proved + Probable + Possible	**571**	**422**	**-**	**-**	**-**	**-**	**7,801**	**18**

Notes:

1. "Gross Reserves" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company'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. Includes associated, non-associated and solution gas where applicable.

PART 3 PRICING ASSUMPTIONS

The following table detail the benchmark reference prices for the regions in which the Company operated, as at December 31, 2014 reflected in the reserves data disclosed above under "Part 2 - Disclosure of Reserves Data". The forecast price assumptions assume the continuance of current laws and regulations and take into account inflation with respect to future operating and capital costs. There will be adjustments to the field prices from the benchmarks below.

CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES
January 1, 2015

Date	WTI [1] $US/STB	Brent Spot (ICE) [2] $US/STB	AB Synthetic Crude Price [3] $CDN/STB	Western Canada Select [4] $CDN/STB	Exchange Rate $US/$CDN
HISTORICAL PRICES					
2004	41.51	38.26	52.89	37.52	0.77
2005	56.64	54.57	69.16	43.25	0.83
2006	66.05	65.16	72.88	50.40	0.88
2007	72.34	72.44	75.57	53.17	0.94
2008	99.67	96.94	102.98	83.88	0.94
2009	61.95	61.74	76.77	53.04	0.88
2010	79.48	79.61	80.56	66.58	0.97
2011	94.88	111.26	102.45	77.43	1.01
2012	94.05	111.63	92.56	71.70	1.00
2013	97.98	108.56	100.17	75.76	0.97
2014	93.12	99.43	101.07	82.07	0.91
CONSTANT PRICES (The average of the first-day-of-the-month price for the preceding 12 months-SEC)					
	94.35	101.25	102.83	83.33	0.91
FORECAST PRICES					
2015	65.00	69.55	72.86	59.02	0.88
2016	75.00	80.25	84.23	68.22	0.88
2017	81.00	86.67	91.05	73.75	0.88
2018	85.00	90.95	95.59	77.43	0.88
2019	90.00	96.30	101.27	82.03	0.88
2020	94.00	100.58	105.82	85.71	0.88
2021	96.00	102.72	108.09	87.55	0.88
2022	96.00	102.72	108.09	87.55	0.88
2023	97.92	104.77	110.27	89.32	0.88
2024	99.88	106.87	112.50	91.12	0.88
2025	101.88	109.01	114.77	92.96	0.88
2026	103.91	111.19	117.08	94.84	0.88
2027	105.99	113.41	119.45	96.75	0.88
2028	108.11	115.68	121.85	98.70	0.88
2029	110.27	117.99	124.31	100.69	0.88
2030	112.48	120.35	126.82	102.72	0.88
Constant thereafter					

Notes: [1] West Texas Intermediate quality (D2/S2) crude (40API) landed in Cushing, Oklahoma.
[2] The Brent Spot price is estimated based on historic data.
[3] Equivalent price for Light Sweet Crude (D2/S2) & Synthetic Crude (34API) landed in Edmonton.
[4] Western Canada Select (20.5API), spot price for B.C., Alberta, Saskatchewan and Manitoba.

The Company's weighted average prices received this fiscal year is $68.00/STB for oil.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at December 31, 2014 against such reserves as at December 31, 2013 based on the forecast price and cost assumptions.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2014

	Light and Medium Oil					**Heavy Oil**					**Associated and Non-Associated Gas**				
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (MMscf)	Gross Probable (MMscf)	Gross Proved Plus Probable (MMscf)	Gross Possible (MMscf)	Gross Proved Plus Probable Plus Possible (MMscf)
At December 31, 2013	**-**	**223**	**223**	**201**	**424**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Production (Sales)	(1)	-	(1)	-	(1)	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	3	145	148	-	148	-	-	-	-	-	-	-	-	-	-
At December 31, 2014	**2**	**368**	**370**	**201**	**571**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in aggregate before that time.

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (Mmscf)**	**Natural Gas Liquids (Mbbl)**
Aggregate prior to 2012	-	-	-	-
2012	33	-	-	-
2013	(33)	-	-	-
2014	-	-	-	-

The following table sets forth the volumes of probable undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in aggregate before that time.

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (Mmscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2012	-	-	-	-
2012	313	-	-	-
2013	(90)	-	-	-
2014	145	-	-	-

The following table sets forth the volumes of possible undeveloped reserves that were first attributed for each of the Company's product types for the most recent three financial years and in aggregate before such time.

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (Mmscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2012	-	-	-	-
2012	-	-	-	-
2013	201	-	-	-
2014	-	-	-	-

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developing those undeveloped reserves.

Probable Undeveloped Reserves

The Company's proved undeveloped reserves are assigned to one directional drilling location and two horizontal drilling locations within a mapped and partially developed oil pool. These reserves are to be developed in 2015 and 2016.

Possible Undeveloped Reserves

The Company's possible undeveloped reserves are assigned to one horizontal drilling location where reservoir properties are less well known than in the probable case. These reserves are to be developed in 2017 anticipating that the two probable horizontal locations are successful.

Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. Chapman Petroleum Engineering Ltd., an independent engineering firm, evaluates all of the Company's reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted.

Although every reasonable effort has been made by the Company to ensure that reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rates; industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks the Company faces in this market. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward looking statements and accordingly, no assurance can be given that any events anticipated by the forward looking statements will transpire or occur, if any of them do, what benefits the Company can derive from. The reader is cautioned not to place undue reliance on this forward looking information.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which are deducted in the estimation of the future net revenues of the proved and probable reserves.

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	**Total Proved plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)**
2015	-	1,000
2016	-	3,335
2017	-	-
2018	-	-
2019	-	-
Total for five years	-	4,335
Remainder	-	-
Total for all years	-	4,335

The Company has been successful in raising its required capital through equity financings and plans to continue to do so for the development costs specified above. There is no assurance that the Company will be able to raise funds on terms acceptable to it or at all, which could result in the Company restricting or terminating its capital expenditure program. The effect of the costs of the expected funding would have no impact on the revenues or reserves currently reported.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The following table sets forth the number of acres associated with reserves at December 31, 2014.

Oil and Gas Properties Associated with Reserves
As of December 31, 2014

		Acreage					
		Developed		Undeveloped		Total	
Properties	Location	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Chigwell	Alberta	160	160	-	-	160	160

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2014.

Oil and Gas Wells Associated with Reserves
As of December 31, 2014

	Oil		Natural Gas	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Chigwell				
Producing	1.0	1.0	-	-
Non-producing	-	-	-	-

[1] Total number of wells in which the Company has a working interest.
[2] Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

At the fiscal year ended December 31, 2014, all of the Company's oil and gas properties were located in Central Alberta, Canada. As at December 31, 2014, the Company held 19,669 gross (16,066 net) acres. For 2014 and 2013, the Company did not drill any new wells. For 2012 the Company drilled 4 gross (4 net) wells of which one is producing, one is shut-in and two were dry and abandoned. For 2011, there were 3 gross (3 net) non-producing oil wells and for both 2010 and 2009 there were 1 gross (1 net) non-producing oil wells.

Item 6.2 Properties with No Attributed Reserves

The Company's working interests at December 31, 2014 in the prospect areas of its oil and gas properties is detailed in the table below including the corresponding gross and net acreage of each area, of which 9,966 gross and net acres is expected to expire in 2015 in the Willingdon area.

Prospect Area	Operator	Current Working Interest	Gross Acres	Net Acres	Current Status or Work Commitment
Chigwell	Butte Energy	100%	418	418	Providing available financing, the Company is planning to drill three wells in 2015 and implement an enhanced oil recovery scheme for total expected costs of approximately $4,300,000.
Duvernay	Butte Energy	51%	7,209	3,686	The Company has no plans to drill additional wells in this area in 2015.
Morinville	Butte Energy	100%	634	634	The Company should receive the reclamation certificate in 2015.
Sholdice	Butte Energy	100%	640	640	The Sholdice 12-10-020-22 W4M well, is standing cased and sitting suspended. The expectation is abandonment will occur in 2015.
Willingdon Leduc	Butte Energy	99%	11,246	11,166	Drilled the 02-26-055-15 W4M well, which is standing cased and sitting suspended as a possible disposal well awaiting further evaluation of the prospect area. There is no further drilling commitment at December 31, 2014.

Item 6.2.1 Significant Factors or Uncertainties Affecting Properties with No Attributed Reserves

Significant economic factors or significant uncertainties that affect the activities on properties with no attributed reserves include:

1. Exploration and Reserve Risk

   Exploration, appraisal and development of oil and gas reserves are speculative and involve a significant degree of risk. There can be no assurances that exploration or appraisal of the properties in which the subsidiaries hold rights will be successful.

2. Market Risk

   In the event of successful development of oil and gas reserves, the marketing of the Company's prospective production of oil and gas from such reserves shall be dependent on market fluctuations and the availability of processing and refining facilities and transportation infrastructure, including roads, pipelines and pipeline capacity at economic tariff rates which Company may have limited or no control.

Item 6.3 Forward Contracts

The Company is not a party to any active agreements relating to the transportation or marketing of oil gas. The Company entered into a transportation arrangement with respect to the St. Albert prospect, but the well was abandoned prior to December 31, 2011.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

The estimated abandonment and restoration costs used by Chapman are based on the AER Directive 11, which details the typical costs of abandonment and reclamation by well type in each specific geographic region. The Company expects to have costs relating to 5 net wells, including the location to be drilled. All costs have been included in the Chapman report.

FUTURE ABANDONMENT AND RESTORATION COSTS

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Estimated Using Forecast Prices and Costs (10% Discounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Estimated Using Forecast Prices and Costs (10% Discounted) ($M)
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
Total for three years	-	-	-	-
Remainder	-	-	412	180
Total for all years	-	-	412	180

The Company's abandonment and reclamation costs for surface leases, wells, facilities and pipelines are related to 1 gross (1 net) well the Company has drilled in 2012 at Chigwell in Central Alberta.

The Company has internally determined, based on previous experience that the abandonment and reclamation costs for the one well will cost the Company, net of estimated salvage value, $50,000 or $51,000 discounted at 10 percent.

The abandonment of the Sholdice well will occur in 2015. The Company expects the abandonment costs to total approximately $100,000 in the next three years.

Item 6.5 Tax Horizon

The Company does not expect to become taxable under the proved plus probable plus possible cash flows forecast in this report.

Item 6.6 Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties during the year ended December 31, 2014.

	Costs Incurred ($)
Property Acquisitions Costs – Proved properties	-
Property Acquisition Costs – Unproved properties	33,511
Exploration costs	105,136
Development costs	200,023
	338,670

Item 6.7 Exploration and Development Activities

The following table summarizes the Company's drilling activity and results for the year ended December 31, 2014.

	Exploratory Wells		**Development Wells**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Oil Wells	-	-	-	-
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
	-	-	-	-

(1) Total number of wells in which the Company has a working interest.
(2) Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

During 2014, the Company did not drill any new wells nor develop any additional reserves. The Company could drill as many as five development locations on its Chigwell property on Section 35 42-26 W4 in Central Alberta targeting the Viking formation. This section sits immediately adjacent to an EOR (Enhanced Oil Recovery) scheme operated by a third party. The Company's commitment is to drill an additional three wells. The agreement with the mineral owner provides for extensions to compensate for delays in regulatory process and approval.

Item 6.8 Production Estimates

The following table sets forth the volume of production estimated by Chapman for 2015 (12 months).

TOTAL PROVED RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Chigwell, Alberta	2	-	-	-
Total for all areas	2	-	-	-

TOTAL PROVED PLUS PROBABLE RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Chigwell, Alberta	6	-	-	-
Total for all areas	6	-	-	-

The values above are the Company's gross working interest before the deduction of royalties payable to others.

Item 6.9 Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year.

	Quarter 4	Quarter 3	Quarter 2	Quarter 1
Average Daily Production				
Light and Medium Oil (Bbl/d)	14	5	9	12
Natural Gas (Mscf/d)	-	28	74	107
Average Net Prices Received				
Light and Medium Oil ($/Bbl)	68.00	79.79	85.96	90.95
Natural Gas ($/Mscf)	-	6.28	4.22	4.15
Royalties				
Light and Medium Oil ($/Bbl)	14.57	3.87	2.80	2.03
Natural Gas ($/Mscf)	-	.10	.14	.18
Production Costs				
Light and Medium Oil ($/Bbl)	49.23	87.52	35.42	24.99
Natural Gas ($/Mscf)	-	15.63	5.71	4.20
Netback Received				
Light and Medium Oil ($/Bbl)	4.20	(11.60)	47.74	63.93
Natural Gas ($/Mscf)	-	(9.45)	(1.63)	(0.23)