PrairieSky Royalty Ltd.

Management's Discussion and Analysis

(Prepared in accordance with IFRS)

For the period ended September 30, 2014

(Prepared in Canadian Dollars)

Management’s Discussion and Analysis

This Management’s Discussion and Analysis (“MD&A”) for PrairieSky Royalty Ltd. (“PrairieSky” or the “Company”) should be read with the unaudited Interim Condensed Financial Statements for the period ended September 30, 2014 (“Interim Condensed Financial Statements”) and its audited financial statements as at December 31, 2013 and for the period from incorporation on November 27, 2013 to December 31, 2013. This MD&A was prepared and is dated November 3, 2014.

The Interim Condensed Financial Statements and comparative information have been prepared in Canadian dollars and in accordance with International Accounting Standard (“IAS”) 34, “Interim Financial Reporting” issued by the International Accounting Standards Board (“IASB”). PrairieSky receives royalty income on production; as such, the production volumes are equivalent on a gross and net basis.

Certain measures in this document do not have any standardized meaning as prescribed by International Financial Reporting Standards (“IFRS”) and, therefore, are considered non-GAAP measures. Non-GAAP measures are commonly used in the oil and gas industry and by PrairieSky to provide potential investors with additional information regarding the Company’s liquidity and its ability to generate funds to conduct its business. Non-GAAP measures include Operating Cash Flow, Netback, Funds from Operations, Adjusted Net Earnings and Comprehensive Income per share basic and diluted and Adjusted Funds from Operations per Share basic and diluted. Further information can be found in the Non-GAAP Measures section of this MD&A, including a reconciliation of Cash from Operating Activities to Funds from Operations; and a reconciliation of Adjusted Net Earnings and Comprehensive Income Per Share basic and diluted and Adjusted Funds from Operations Per Share basic and diluted.

The following volumetric measures may be abbreviated throughout this MD&A: barrel (“bbl”) per day (“bbls/d”); barrel of oil equivalent (“BOE”) per day (“BOE/d”); thousand cubic feet (“Mcf”); and million cubic feet (“MMcf”) per day (“MMcf/d”). BOE is an industry measurement to summarize the amount of energy equivalent found in a barrel of crude. See the discussion on energy conversions in the Advisory section of this MD&A for explanation.

Readers should also read the Advisory section located at the end of this MD&A, which provides information on Forward-Looking Statements, Natural Gas, Oil and Natural Gas Liquids (“NGL”) conversions and currency and references to PrairieSky.

BUSINESS OVERVIEW

HISTORY

The Company was incorporated under the *Business Corporations Act (Alberta)* under the name 1786071 Alberta Ltd. on November 27, 2013. On April 11, 2014, the Company filed articles of amendment to change its name to “PrairieSky Royalty Ltd.”. The Company had no significant operating activity from the date of incorporation until May 27, 2014, when it acquired a royalty business (the “Acquisition”) from Encana Corporation (“Encana”), with assets comprised of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, natural gas liquids and certain other mineral rights located predominantly in central and southern Alberta (the “Fee Lands”); (ii) lessor interests in and to leases that are currently issued in respect of certain Fee Lands (“Lessor Interests”); (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments (“GORR Interests”) on lands located predominantly in Alberta (“GORR Lands”); (iv) an irrevocable, perpetual licence to certain proprietary seismic data of Encana; and (v) certain other related assets as set forth in the Purchase and Sale Agreement between the Company and Encana (collectively, the “Acquired Business”). In this MD&A the Fee Lands, the Lessor Interests, the GORR Lands, and assets or interests acquired subsequent to the Acquisition are collectively referred to as the “Royalty Assets”.

On May 29, 2014, PrairieSky completed an initial public offering (“IPO”) whereby Encana sold 52.0 million common shares of the Company (“Common Shares”) and the Common Shares were listed and posted for trading on the Toronto Stock Exchange (“TSX”). On June 3, 2014, the Company announced that in connection with the IPO the over-allotment option granted to the underwriters to purchase up to an additional 7.8 million common shares from Encana at the offering price had been exercised in full. Following completion of the IPO and exercise of the over-allotment option, Encana owned 70.2 million Common Shares, representing 54% of the issued and outstanding Common Shares.

On September 26, 2014, PrairieSky and Encana announced the completion of a secondary offering of 70.2 million Common Shares at a price of $36.50 per share, for aggregate gross proceeds to Encana of approximately $2.6 billion. The Company did not receive any of the proceeds from this secondary offering. Following the closing of the secondary offering, Encana no longer holds any interest in PrairieSky.

PRAIRIESKY ROYALTY

PrairieSky is focused on encouraging third parties to actively develop the Royalty Assets, while strategically seeking additional petroleum and natural gas royalty assets that provide PrairieSky with medium-term to long-term value enhancement potential. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas, rather, third party development of the Royalty Assets provides the Company with royalty revenues as petroleum and natural gas are produced from such properties. PrairieSky carries on business in the provinces of Alberta, Saskatchewan and British Columbia.

PrairieSky’s asset base includes a geologically and geographically diverse portfolio of Fee Lands predominately located in Alberta that encompasses approximately 5.2 million acres with petroleum and/or natural gas rights and an additional 1.1 million acres in coal only titles.

PrairieSky’s operations include royalty income earned through crude oil, NGL and natural gas produced on the Royalty Assets. The Company’s royalty revenues are derived from the Lessor Interests that are leased out by the Company and upon which lessees pay lessor royalties and GORR Interests on GORR Lands leased by third parties.

Petroleum and natural gas royalty structures are typically linked directly to production volumes and price. Therefore the Company’s net earnings can be significantly impacted by fluctuations in commodity prices and production volumes. Production volumes can be influenced by various factors, including the extent of exploration and development activity by third parties on the Royalty Assets, the timing and amount of capital expenditures, and the expertise and financial resources of third party lessees. Commodity pricing is influenced by market supply and demand as well as other factors such as weather, quality of product and access to markets. The Company is able to mitigate some of these risks to the extent that there are a multitude of third parties actively exploring and developing the Royalty Assets and the production of natural gas, crude oil, and NGL is diversified.

Natural gas pricing within the North American market is typically impacted by seasonality and weather conditions. Natural gas is a seasonal fuel with demand generally being higher during the winter and summer and lower in the spring and fall. Crude oil prices are generally determined by global supply and demand factors and these variances do not have seasonal predictability. Production conditions on the Fee Lands are susceptible to diverse weather patterns experienced in western Canada and can impact operations. Natural gas and NGL pricing is also impacted by industrial demand and North American natural gas inventories. As such, PrairieSky's royalty revenue will be directly impacted as third party lessees experience these conditions.

Costs incurred by the Company are primarily freehold mineral taxes and lease administration expenses. Lease administration expenses include such items as land title management, contract administration, technical evaluation, negotiations and compliance costs to secure both mineral rights and ensure accurate royalty revenue payments. Costs and associated risks typical of oil and gas upstream development such as drilling, production equipment and land restoration are not incurred by PrairieSky. These costs are the responsibility of the third parties conducting operations on the Royalty Assets.

Management's discussion and analysis for this reporting period focuses on the commencement of operations on May 27, 2014 to the period ending September 30, 2014.

PRAIRIESKY'S STRATEGIC OBJECTIVES

The Company's objective is to generate significant cash flow and growth for shareholders through indirect oil and gas investment at a relatively low risk and low cost to the Company. The Company seeks to achieve this objective by (i) focusing on organic growth of the royalty revenue from the Fee Lands; (ii) proactively monitoring and managing the portfolio of Royalty Assets to ensure third party adherence to lease terms and contractual provisions (including offset well obligations); and (iii) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders. The Company intends to pay out the majority of the cash flow as dividends to shareholders over time.

RESULTS OVERVIEW

HIGHLIGHTS

On May 27, 2014, the Company commenced active operations following the completion of the Acquisition; prior to this date, the Company did not have significant assets, liabilities, or operations.

In the three months ended September 30, 2014, PrairieSky reported:

- Funds from Operations of $68.7 million and Net Earnings of $57.5 million.
- Average crude oil production volumes of 6,599 bbls/d, average NGL production volumes of 1,493 bbls/d and average natural gas production volumes of 44.1 MMcf/d.
- Average realized crude oil prices of $88.36 per bbl. Average realized NGL prices of $71.34 per bbl and average realized natural gas prices of $3.75 per Mcf.

During the period from May 27, 2014 to September 30, 2014, PrairieSky reported:

- Funds from Operations of $99.7 million and Net Earnings of $81.4 million.
- Average crude oil production volumes of 6,690 bbls/d, average NGL production volumes of 1,517 bbls/d and average natural gas production volumes of 43.8 MMcf/d.
- Average realized crude oil prices of $91.30 per bbl. Average realized NGL prices of $69.01 per bbl and average realized natural gas prices of $3.95 per Mcf.
- Cash and cash equivalents of $56.9 million.
- Working capital of $75.2 million.

Significant developments for the Company during the period from May 27, 2014 to September 30, 2014 included the following:

- Acquired royalty interests from a third party oil and gas producer effective July 31, 2014 for a cash purchase price of $9.0 million.
- Completed the secondary offering of 70.2 million common shares of PrairieSky on September 26, 2014, at an offering price of $36.50 per common share, for aggregate gross proceeds to Encana of approximately $2.6 billion. The Company did not receive any of the proceeds of the secondary offering. Following the closing of the secondary offering, Encana no longer holds any interest in PrairieSky.

FINANCIAL RESULTS AND QUARTERLY PRICES

($ millions, unless otherwise noted)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Revenues	**$ 87.7**	**$ 124.9**
Funds from Operations[1]	**68.7**	**99.7**
Per Share – basic[2]	**0.53**	**1.68**
Per Share – diluted[2]	**0.53**	**1.67**
Adjusted Per Share – basic and diluted[1]	**0.53**	**0.77**
Net Earnings and Comprehensive Income	**57.5**	**81.4**
Per Share – basic and diluted[2]	**0.44**	**1.37**
Adjusted Per Share – basic and diluted[1]	**0.44**	**0.63**
Dividends[3]	**41.3**	**55.0**
Per Share	**0.3174**	**0.4232**
Production Volumes		
Natural Gas (MMcf/d)	**44.1**	**43.8**
Crude Oil (bbls/d)	**6,599**	**6,690**
NGL (bbls/d)	**1,493**	**1,517**
Total (BOE/d)[4]	**15,448**	**15,507**
Realized Pricing[5]		
Natural Gas ($/Mcf)	**$ 3.75**	**$ 3.95**
Crude Oil ($/bbl)	**88.36**	**91.30**
NGL ($/bbl)	**71.34**	**69.01**
Total ($/BOE)[4]	**$ 55.67**	**$ 57.55**
Natural Gas Price Benchmarks		
AECO ($/Mcf)	**$ 4.22**	**$ 4.45**
Oil Price Benchmarks		
West Texas Intermediate (WTI) (US$/bbl)	**97.44**	**100.21**
Edmonton Light Sweet ($/bbl)	**98.11**	**101.32**

(1) A Non-GAAP measure, which is defined under the Non-GAAP Measures section in this MD&A.
(2) Net Earnings and Comprehensive Income and Funds from Operations per common share are calculated using the weighted average number of Common Shares outstanding from January 1, 2014 to September 30, 2014 after giving effect to stock options.
(3) A dividend of $0.1058 per Common Share was declared on September 8, 2014. The dividend was paid on October 15, 2014 to shareholders of record as at September 30, 2014.
(4) See "Conversions of Natural Gas to BOE".
(5) Excludes pricing due to Royalty Compliance Revenue, defined under the Pricing section in this MD&A.

In the three months ended September 30, 2014

- Funds from Operations were $68.7 million and Operating Cash Flow was $74.5 million.
- Average crude oil and NGL production volumes were 6,599 bbls/d and 1,493 bbls/d, respectively.
- Average realized crude oil and NGL prices were $88.36 per bbl and $71.34 per bbl, respectively.
- Average realized natural gas prices were $3.75 per Mcf during the period and average natural gas production volumes were 44.1 MMcf/d.
- Current income tax was $14.0 million.
- Depletion, Depreciation, and Amortization ("DD&A") was $8.7 million.
- Administrative expense was $5.7 million.

- Freehold mineral taxes expense was $3.3 million.
- Net Earnings were $57.5 million.

For the period May 27, 2014 to September 30, 2014

- Funds from Operations were $99.7 million and Operating Cash Flow was $104.9 million.
- Average crude oil and NGL production volumes were 6,690 bbls/d and 1,517 bbls/d, respectively.
- Average realized crude oil and NGL prices were $91.30 per bbl and $69.01 per bbl, respectively.
- Average realized natural gas prices were $3.95 per Mcf during the period and average natural gas production volumes were 43.8 MMcf/d.
- Current income tax was $18.2 million.
- DD&A was $12.4 million.
- Administrative expense was $8.4 million.
- Freehold mineral taxes expense was $4.4 million.
- Net Earnings were $81.4 million.

PRODUCTION

PRODUCTION VOLUMES

(average daily)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Natural Gas (MMcf/d)	**44.1**	**43.8**
Crude Oil (bbls/d)	**6,599**	**6,690**
NGL (bbls/d)	**1,493**	**1,517**
Total Production (BOE/d)	**15,448**	**15,507**

In the three months ended September 30, 2014

Royalty revenues of $83.5 million were received from approximately 17,000 producing wells and approximately 230 industry payors. Average crude oil production volumes were 6,599 bbls/d, average NGL production volumes were 1,493 bbls/d and average natural gas production volumes were 44.1 MMcf/d.

PrairieSky's crude oil, NGL and natural gas production volumes are primarily marketed with lessees' production.

For the period May 27, 2014 to September 30, 2014

Royalty revenues of $117.7 million were received from approximately 17,000 producing wells and approximately 230 industry payors. Average crude oil production volumes were 6,690 bbls/d, average NGL production volumes were 1,517 bbls/d and average natural gas production volumes were 43.8 MMcf/d.

Production volumes are impacted by prior period production adjustments, third party development activities and natural declines. Although no prior period information is presented, the Company's compliance program continues to ensure receipt of revenues and production volumes from operating activities on the Royalty Assets prior to completion of the IPO.

FINANCIAL RESULTS

REVENUES

Revenues by Product ($ millions)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Crude Oil	$ 53.8	$ 77.7
Natural Gas	20.0	26.8
NGL	9.7	13.2
	83.5	117.7
Other Revenues	4.2	7.2
Total Revenues	$ 87.7	$ 124.9

Revenues by Royalty Classification ($ millions)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Fee Lands	$ 81.3	$ 114.9
GORR Interests	2.2	2.8
	83.5	117.7
Other Revenues	4.2	7.2
Total Revenues	$ 87.7	$ 124.9

The Company's operations include royalty revenues earned from crude oil, NGL and natural gas produced on the Fee Lands and the GORR Lands. Royalty rates vary from approximately 1% to 40%. The average royalty rate for the three months ended September 30, 2014 and period from May 27, 2014 to September 30, 2014 was approximately 8% for each period presented. In the three months ended September 30, 2014, revenues from the Lessor Interests were $81.3 million or 97% of total royalty revenues and GORR Interests were $2.2 million or 3% of total royalty revenues. In the period from May 27, 2014 to September 30, 2014, revenues from the Lessor Interests were $114.9 million or 98% of total royalty revenues and GORR Interests were $2.8 million or 2% of total royalty revenues.

Other revenues include lease rental income from leases that are currently issued in respect of certain Fee Lands, nonperformance fees and revenues from sulphur.

As the Company receives royalty revenue from third parties, production is not hedged, and the Company does not currently intend to enter into any commodity price hedges.

Finance Items ($ millions)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Finance Income	$ (0.3)	$ (0.3)
Finance Expense	0.1	0.2
Net Finance Items	$ (0.2)	$ (0.1)

Finance income includes interest on funds on deposit, short term investments and accounts receivable. Finance expense includes Acquisition closing transaction costs, credit facility set-up and maintenance fees.

PRICING

Realized Pricing	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Natural Gas ($/Mcf)[2]	**$ 3.75**	**$ 3.95**
Crude Oil ($/bbl)[2]	**88.36**	**91.30**
NGL ($/bbl)[2]	**71.34**	**69.01**
Total ($/BOE)[1][2]	**$ 55.67**	**$ 57.55**

(1) See "Conversions of Natural Gas to BOE".
(2) Excludes Royalty Compliance Revenue

Compliance Pricing by Product	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Natural Gas ($/Mcf)	**$ 1.19**	**$ 0.87**
Crude Oil ($/bbl)	**0.22**	**0.11**
NGL ($/bbl)	**(0.40)**	**(0.19)**
Total ($/BOE)[1]	**$ 3.14**	**$ 2.24**

(1) See "Conversions of Natural Gas to BOE".

Royalty Compliance Revenue is the revenue received as a result of the extensive process of identifying, analyzing, resolving and collecting corrected payments from royalty payors. The Company collected $7.4 million in Compliance Revenues for the three months ended September 30, 2014 and $7.7 million for the period from May 27, 2014 to September 30, 2014.

CAPITAL

During the three month period ended September 30, 2014 and the period from May 27, 2014 to September 30, 2014, the Company completed acquisitions with an aggregate cost of $11.5 million which were primarily comprised of 34,080 acres of royalty assets that are complementary to the existing Company assets.

From the above, 33,440 acres relates to the acquisition referred to in Note 10 of the Interim Condensed Financial Statements for the period ended September 30, 2014. From the date of acquisition to September 30, 2014, approximately $0.3 million of revenue was recognized as net income. If this business combination had been effective upon commencement of active operations on May 27, 2014, management estimates that revenues for the three months ended September 30, 2014 and period from May 27, 2014 to September 30, 2014 would have been $0.4 million and $0.6 million respectively.

From the date of acquisition to September 30, 2014, approximately $0.2 million of revenue was recognized as net income related to 640 acres of the royalty assets mentioned above. If this acquisition had been effective upon commencement of active operations on May 27, 2014, management estimates that revenues for the three months ended September 30, 2014 and period from May 27, 2014 to September 30, 2014 would have been $0.3 million and $0.4 million respectively.

OPERATING RESULTS

	For the three months ended September 30, 2014		For the period May 27, 2014 to September 30, 2014	
	Operating Cash Flow[1] ($ millions)	Total Netback[1] ($/BOE)	Operating Cash Flow[1] ($ millions)	Total Netback[1] ($/BOE)
Revenues[2]	$ 83.5	$ 58.80	$ 117.7	$ 59.79
Administrative Expenses	5.7	4.05	8.4	4.28
Freehold Mineral Taxes	3.3	2.28	4.4	2.22
Operating Cash Flow/Netback	$ 74.5	$ 52.47	$ 104.9	$ 53.29

	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Production Volumes (BOE/d)[3]	15,448	15,507

(1) Non-GAAP measure. See “Non-GAAP Measures” in this MD&A.
(2) Excludes the impact of Other Revenues.
(3) See “Conversions of Natural Gas to BOE”

For the three months ended September 30, 2014

Operating Cash Flow was $74.5 million and was impacted by:

- Average total realized price of $58.80 per BOE on production;
- Average total production volumes of 15,448 BOE/d;
- Production revenue of $83.5 million; and
- Freehold mineral tax of $3.3 million.

For the period May 27, 2014 to September 30, 2014

Operating Cash Flow was $104.9 million and was impacted by:

- Average total realized price of $59.79 per BOE on production;
- Average total production volumes of 15,507 BOE/d;
- Production revenue of $117.7 million; and
- Freehold mineral tax of $4.4 million.

Freehold mineral tax is levied on an annual basis on the value of oil and natural gas production from non-Crown lands. Throughout the year it is impacted by production estimates and prices. For the third quarter of 2014 and for the period from May 27, 2014 to September 30, 2014, freehold mineral taxes were an average of 4% of revenues.

ADMINISTRATIVE

($ millions)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Salaries and Benefits	$ 3.4	$ 4.5
Share-Based Compensation	0.8	2.0
Office Expense	0.7	1.0
Public Company Expense	0.3	0.3
Information Technology and Other	0.5	0.6
Total Administrative Expense	$ 5.7	$ 8.4

	For the three months ended September 30, 2014				For the period May 27, 2014 to September 30, 2014			
	($ millions)		($/BOE)[1]		($ millions)		($/BOE)[1]	
Administrative – cash	$	4.9	$	3.47	$	6.4	$	3.24
Administrative – non-cash		0.8		0.58		2.0		1.04
Total Administrative Expense	$	5.7	$	4.05	$	8.4	$	4.28

(1) See "Conversions of Natural Gas to BOE".

Of the total share-based compensation for the period from May 27, 2014 to September 30, 2014, the Company expensed $0.7 million, related to the Company's Deferred Share Unit ("DSU") plan. All Directors elected to receive their annual Board and Committee retainers and fees in the form of DSUs. The remaining $1.3 million for the period from May 27, 2014 to September 30, 2014 share-based compensation expense relates to the Company's other employee share-based plans. The share-based cash-settled plans' expenses were determined based on the difference between the grant price and the closing share price at September 30, 2014. For further explanation refer to Note 17 of the Interim Condensed Financial Statements.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions)	Three months ended September 30, 2014		For the period May 27, 2014 to September 30, 2014	
Depreciation, Depletion and Amortization	$	8.7	$	12.4

The Company calculates DD&A relative to total proved and probable reserves. DD&A was calculated based on production for the period from May 27, 2014 to September 30, 2014 following completion of the Acquisition.

On May 27, 2014 the Company began depleting crude oil, NGL and natural gas properties using the unit-of-production method over proved plus probable reserves on a prospective basis. For the period from May 27, 2014 to September 30, 2014, the Company recorded $3.1 million lower depletion expense than it would have using proved reserves. Based on the reserves at the date of the change in estimate, the effect reduced depletion by $1.64 per BOE.

INCOME TAX

($ millions)	Three months ended September 30, 2014		For the period May 27, 2014 to September 30, 2014	
Current Tax Expense	$	14.0	$	18.2
Deferred Tax Expense (Recovery)		(1.3)		0.2
Income Tax Expense	$	12.7	$	18.4

The Company's interim income tax expense is determined using the estimated annual effective income tax rate applied to year-to-date net earnings before tax.

For the period from May 27, 2014 to September 30, 2014, the Company's effective tax rate was approximately 18.4%. The effective tax rate in any period is a function of total income tax to the amount of net earnings before income tax for the period. The Company's effective tax rate differs from the Canadian statutory tax rate of 25% primarily as a result of the reversal of the initial difference between the carrying value of net assets transferred and the tax pools acquired on May 27, 2014 for which no deferred tax asset was recognized and partially offset by non-deductible employee-related expenses.

Under the terms of the Acquisition, the Company acquired tax pools of approximately $500 million relating to the Royalty Assets. Under IFRS, deferred income tax liabilities and assets are not recognized for temporary differences arising on the initial recognition of an asset or liability in a transaction which is not a business combination and, at the time of transaction, affects neither accounting net earnings nor taxable earnings. For further explanation refer to Note 8 of the Interim Condensed Financial Statements.

Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. Management believes that the tax provision for the Company is adequate.

COMMON CONTROL TRANSACTION

($ millions)	As at May 27, 2014
Exploration and Evaluation Assets	$ 6.8
Property, Plant and Equipment, net	181.2
Other Assets	16.5
Goodwill	57.8
Net Working Capital	37.7
Carrying Value of Net Assets Acquired:	$ 300.0

The Company commenced active operations on May 27, 2014 following the completion of the Acquisition. The Company was a wholly owned subsidiary and controlled by Encana prior to closing the IPO, and immediately subsequent to closing remained controlled by Encana. Consequently, the entity was under common control at the time of the Acquisition. The Acquisition has been accounted for using the predecessor values from the date of transaction method, whereby the Acquired Business is transferred to the Company based on the historical carrying value carved out of Encana. The table above summarizes the carrying value of the net assets transferred as of May 27, 2014.

The difference between the Common Share consideration of $555.7 million and the carrying value of the Acquired Business of $300.0 million is recognized as a Reserve from Common Control in Shareholders' Equity, as follows:

($ millions)	
Common Shares	$ 555.7
Carrying Value of Net Assets Transferred	(300.0)
Reserve from Common Control	$ 255.7

The amounts reported above are management's estimates using information available at the time of preparation of the financial statements. In accordance with the terms of the Purchase and Sale Agreement in respect of the Acquisition ("PSA"), the transaction is subject to closing adjustments which will be settled within 180 days of closing of the Acquisition. Any closing adjustments will result in an adjustment to the carrying amounts of assets and liabilities reported above.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Net Cash From (Used In)		
Operating Activities	**$ 77.2**	**$ 104.0**
Investing Activities	**(6.2)**	**(5.7)**
Financing Activities	**(41.3)**	**(41.5)**
Increase (Decrease) in Cash and Cash Equivalents	**29.7**	**56.8**
Cash and Cash Equivalents, End of Period	**$ 56.9**	**$ 56.9**

OPERATING ACTIVITIES

Net cash from operating activities in the third quarter of 2014 was $77.2 million. For the third quarter of 2014, the net change in other assets and liabilities was an increase of $0.8 million and the net change in non-cash working capital was an increase of $12.2 million.

Net cash from operating activities for the period from May 27, 2014 to September 30, 2014 was $104.0 million. For the period May 27, 2014 to September 30, 2014, the net change in other assets and liabilities was an increase of $1.1 million and the net change in non-cash working capital was an increase of $8.3 million.

The Company had working capital of $75.2 million as at September 30, 2014. Accounts receivable and accrued revenues consist primarily of trade receivable and accrued revenues related to lease and royalty payments from third parties. Accounts payable and accrued liabilities consist primarily of freehold mineral tax, amounts due related to the Acquisition on May 27, 2014, share-based compensation and salary related accruals. At September 30, 2014, working capital included cash and cash equivalents of $56.9 million.

INVESTING ACTIVITIES

For the third quarter, investing activities were $6.2 million comprised of $9.9 million primarily from the acquisition of 33,440 acres of royalty assets offset by $3.7 million of proceeds from lease issuance bonuses related to leases issued for certain Fee lands.

For the period from May 27, 2014 to September 30, 2014, investing activities were $5.7 million comprised primarily of $9.9 million from the acquisition of 33,440 acres of royalty assets offset by $4.2 million of proceeds from lease issuance bonuses related to certain Fee Lands.

FINANCING ACTIVITIES

For the third quarter and period from May 27, 2014 to September 30, 2014, financing activities were $41.3 million and $41.5 million respectively, which resulted from dividends to shareholders.

Credit Facility

PrairieSky has in place an unsecured $75 million extendible revolving credit facility (the “Revolving Facility”), with a permitted increase to $125 million (subject to certain conditions), and an unsecured $25 million extendible operating credit facility (the “Operating Facility”, and together with the Revolving Facility, the “Credit Facility”). The Credit Facility has a three-year term and, subject to certain requirements, may be extendible annually. The Credit Facility is fully revolving up to maturity and may be extended or accelerated pursuant to the Credit Facility’s terms and conditions. Maintenance costs for the period from May 27, 2014 to September 30, 2014 were $0.1 million.

Outstanding Share Data

As at September 30, 2014 and November 3, 2014, PrairieSky had 130.0 million Common Shares outstanding and 0.5 million outstanding stock options.

Common Shares

On incorporation, the Company issued 100 Common Shares to Encana at a subscription price and stated capital of $100 per Common Share. In connection with an internal reorganization involving the Company and Encana that was completed effective December 13, 2013, the Company issued an additional 25.0 million Common Shares with a nominal stated capital to Encana for non-cash consideration, and subsequently paid certain cash dividends and dividends in-kind to Encana.

Share Consolidation

On January 31, 2014, the Company amended its articles to effect a consolidation of its Common Shares, pursuant to which one new Common Share was issued for every 4,166.6833 outstanding Common Shares.

Initial Public Offering

On May 22, 2014, a final prospectus was filed qualifying the distribution of 52.0 million Common Shares which were sold by Encana pursuant to the terms of an underwriting agreement dated May 22, 2014 at a price of $28.00 per Common Share which closed on May 29, 2014. On June 3, 2014, the underwriters exercised the over-allotment option resulting in an additional 7.8 million Common Shares being sold by Encana at a price of $28.00 per Common Share. The Company did not receive any proceeds from the IPO nor was it responsible for any fees or expenses of the IPO.

On May 29, 2014, the Company and Encana entered into, among other agreements: (i) a Governance Agreement, which governed various aspects of the relationship; and (ii) an Investor Liquidity Agreement, which provided Encana or its transferee the ability to require the Company, among other things, to file future prospectuses in respect of the distribution of all or a portion of the Common Shares held by Encana or its transferee. The Governance Agreement and the Liquidity Agreement terminated, in accordance with their terms, on completion of the secondary offering on September 26, 2014.

Acquisition of Royalty Business

On May 22, 2014, the Company and Encana entered into the PSA for the acquisition of the Acquired Business from Encana, pursuant to which Encana received 129.994 million Common Shares as consideration. Under the PSA, the legal stated capital maintained by the Company for the Common Shares issued to Encana was $555.7 million. As part of the Acquisition, the Company and Encana entered into: (i) a Seismic Licence Agreement for which Encana granted the Seismic Licence to the Company; and (ii) Lease Issuance and Administration Agreements pursuant to which the Company issued leases to document Encana's retention of a working interest in respect of certain Fee Lands purchased in the Acquisition and pursuant to which, the Company receives royalties from Encana.

Secondary Offering

On September 26, 2014, PrairieSky and Encana announced the completion of the secondary offering of 70.2 million Common Shares at a price of $36.50 per Common Share, for aggregate gross proceeds to Encana of approximately $2.6 billion. The Company did not receive any of the proceeds of the secondary offering. Following the closing of the secondary offering, Encana no longer holds any interest in PrairieSky.

Dividends

PrairieSky currently pays a monthly dividend to shareholders at the discretion of the Board of Directors. Dividend payments were $41.3 million or $0.3174 per share for the third quarter of 2014 and for the period from May 27, 2014 to September 30, 2014. On September 8, 2014, the Board declared a dividend of $0.1058 per Common Share paid on October 15, 2014 to shareholders of record as at September 30, 2014. On October 20, 2014, the Board declared a dividend of $0.1058 per common share payable on November 17, 2014 to shareholders of record as at October 31, 2014.

Capital Structure

The Company's objective when managing its capital structure is to maintain financial flexibility in order to distribute cash to shareholders in the form of dividends after consideration of the Company's financial requirements for its business and future growth opportunities.

The Company's capital structure is comprised of shareholders' equity and working capital. The Company's capital structure is managed by taking into account operating activities, dividends paid to shareholders, taxes, available Credit Facility, share issuance costs and other factors. The Company's operating results and capital structure is impacted by the level of development activity by third parties on the Royalty Assets and the resultant royalty revenues, level of costs incurred by the Company and commodity prices.

Stewardship of the Company's capital structure is managed through its financial and operating forecast process. The forecast of the Company's future cash flows is based on estimates of production, crude oil, natural gas and NGL prices, freehold mineral tax expense, general and administrative expense and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, production expectations and other factors that in the Company's view would impact cash flow.

COMMITMENTS AND CONTINGENCIES

CONTRACTUAL COMMITMENTS

($ millions)	Expected Future Payments					
(undiscounted)	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Information technology	$ 0.1	$ 0.1	$ -	$ -	$ -	$ 0.2
Office lease	0.2	0.8	0.3	-	-	1.3
Commitments	$ 0.3	$ 0.9	$ 0.3	$ -	$ -	$ 1.5

The table above outlines the Company's contractual obligations at September 30, 2014.

CONTINGENCIES

In the normal course of operations, the Company may become party to litigation. For the period May 27, 2014 to September 30, 2014, there are no known claims as determined by the Company that are subject to accrual or disclosure.

TRANSACTIONS WITH RELATED PARTIES

Following the closing of a secondary offering on September 26, 2014, the Company and Encana are no longer related parties.

Concurrently with completion of the Acquisition and before closing of the IPO, the Company and Encana entered into a number of agreements, including: (i) Lease Issuance and Administration Agreements pursuant to which the Company issued leases to document Encana's retention of a working interest in respect of certain Fee Lands purchased in the Acquisition and pursuant to which, the Company will receive royalties from Encana; (ii) a Transition Services Agreement pursuant to which Encana will provide or arrange for the provision of certain day-to-day administrative services required by the Company, until December 31, 2014, subject to earlier termination in certain circumstances. These transactions were in the normal course of operations and were measured at the exchange amount. Certain Directors of the Company are common Directors with those of Encana.

The Company has the following related party transactions with Encana:

	Three months ended September 30, 2014	**For the period May 27, 2014 to September 30, 2014**
Royalties and lease rentals revenues	**$ 8.2**	**$ 14.3**
Office lease rental	**0.2**	**0.3**
	$ 8.0	**$ 14.0**

Amount recognized on the Statement of Earnings and Comprehensive Income include:

	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Revenues	$ 8.2	$ 14.3
Administrative	0.2	0.3
	$ 8.0	$ 14.0

Amounts recognized on the Balance Sheet include:

	As at September 30, 2014	As at December 31, 2013
Accounts receivable and accrued revenues	$ 5.2	$ -
Prepaid expense	0.1	-
Accounts payable and accrued liabilities	(2.1)	-
Dividend payable	(7.4)	-
	$ (4.2)	$ -

RISK MANAGEMENT

The Royalty Assets expose the Company to some of the same industry risks and conditions faced by all oil and gas companies. The most significant are those that directly impact production volumes and commodity pricing and include the following:

OPERATING RISK

- Fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil, NGLs and natural gas;
- Access to pipelines or other transportation methods for bringing crude oil, NGLs and natural gas to market;
- Variations in currency exchange rates relative to commodity prices;
- Risk associated with fluctuations in accruals due to reliance on historical production information and delays of actual production receipts obtained from lessees and matching to government reporting databases;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. The reserves will deplete over time through continued production and the Company, industry partners and royalty payors may not be able to replace these reserves on an economic basis;
- Industry activity levels and intense competition for land, goods and services, and qualified personnel;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Risk associated with volatility in global financial markets;
- Risk associated with the Credit Facility, including compliance with the agreements and related covenants;
- Operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- Changes in government regulations, taxation, and royalties; and
- Safety and environmental risks.

The Company employs the following strategies to mitigate these risks, including:

- Not undertaking any direct development or operational activities associated with production;
- A compliance program to collect corrected royalties on production from the Royalty Assets in accordance with the terms of the various leases and agreements;
- Maintaining a focus on controlling costs to maximize profitability;
- A conservative approach to debt as demonstrated by the absence of any current debt issuance or use of the Credit Facility; and
- An active contract management strategy to ensure appropriate allocation of risk and adherence to all terms and conditions by counterparties.

FINANCIAL RISKS

The Company is exposed to financial risks arising from its financial liabilities. Financial risks include market risk (commodity prices and interest rates), credit risk and liquidity risks.

Commodity Price Risk

Commodity price risk is the risk the Company will encounter with fluctuations in the fair value of future cash flows from changes in commodity prices. Commodity prices for crude oil, NGL and natural gas are influenced by macroeconomic events that dictate the levels of supply and demand.

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

The Company maintains a compliance program to ensure royalties are paid correctly on production from the Royalty Assets in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken.

A substantial portion of the Company's accounts receivable are from leases and other agreements with oil and gas industry operators and are subject to normal industry credit risks. However, the Company's leasing arrangements typically provide for termination of the lease in the event of non-payment of royalties which would result in a return of the oil and gas rights to the Company. In addition, the Company has the ability to take its royalty share of production in-kind, thereby further mitigating credit risk.

As at September 30, 2014, the Company had one counterparty whose accounts receivable individually accounted for more than 10% of the total accounts receivable balance. The maximum credit risk exposure associated with accounts receivable and accrued revenues is the total carrying value. For the period presented, the Company does not have an allowance for doubtful accounts nor provides for any doubtful accounts as there is negligible history of default.

Liquidity Risk

Liquidity risk arises from the inability to meet general funding needs, in part due to accounts receivable from lessees typically being settled in the following months, and to manage the assets, liabilities, and capital structure of the Company. Liquidity risk is the risk that the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company has access to funding alternatives through the Credit Facility. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due.

The Company's sources of liquidity include cash and cash equivalents, working capital funds and Operating and Revolving Facilities. The primary use of funds are dividends, freehold mineral taxes, administrative expenses and cash taxes.

ENVIRONMENTAL REGULATION AND RISK

The oil and gas industry is subject to environmental regulations pursuant to provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of regulatory authorities. Liability for abandonment and reclamation costs on the Royalty Assets rests with the third party lessees.

Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company's operations and financial condition.

ACCOUNTING POLICIES AND ESTIMATES

CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates through the application of the Company's accounting policies and practices, which have a significant impact on the financial results. A summary of PrairieSky's significant accounting policies can be found in Note 3 to the Interim Condensed Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining PrairieSky's financial results.

Reserve Estimates, Depletion and Impairments

Reserve estimates can have a significant impact on net earnings, as they are a key input to DD&A calculations and impairment tests. Costs accumulated within each area are depleted using the unit-of-production method based on proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves. A downward revision in reserves estimates could result in the recognition of a higher DD&A charge to net earnings.

PrairieSky's Property, Plant and Equipment relating to crude oil, NGLs and natural gas plus other mineral rights and exploration and evaluation costs, are aggregated into cash generating units ("CGUs") based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net earnings. The recoverable amount of the CGU is the greater of its fair value less costs of disposal and its value in use. Fair value less costs of disposal may be determined using after-tax discounted future net cash flows of proved and probable reserves using forecast prices and costs. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from continued use of the CGU. A downward revision in reserves estimates could result in the recognition of impairments charged to net earnings. Upon assessment of the Royalty Assets, the Company has one CGU.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net earnings.

All of PrairieSky's oil and gas reserves and resources are evaluated and reported on by independent qualified reserves evaluators ("IQRE"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and future costs, all of which are subject to numerous uncertainties and various interpretations. Accordingly the impact of changes in reserves estimates on the Company's financial statements could be material.

Oil and Gas Revenue Accruals and Royalty Interests

PrairieSky follows the accrual method of accounting, making estimates in the financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. The Company has no operational control over the Fee Lands and as a result, the Company uses historical production information to estimate revenue accruals. These accrual estimates are expected to be revised, based on the receipt of actual production results.

Share-Based Compensation

The Company's share-based compensation plans include a Stock Option Plan, Restricted Share Unit ("RSU") Plan, Performance Share Unit ("PSU") Plan, and a Deferred Share Unit ("DSU") Plan. Obligations for payments of cash or common shares under the Company's long term incentive plans are accrued over the vesting period using fair values. Judgments include which valuation model is most appropriate for the grant of the award to estimate its fair value. Estimates and assumptions are then used in the valuation model to determine the fair value.

For the equity-settled Stock Option Plan, fair values are determined at the grant date and are recognized over the vesting period as compensation costs with a corresponding credit to Shareholder's Equity. The Company uses the Black-Scholes option pricing model which requires that management make assumptions for the expected life of the option, the anticipated volatility of the share price over the life of the option, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. The assumptions used by the Company are discussed in Note 16 to the Interim Condensed Financial Statements.

For the cash-settled RSU, PSU and DSU Plans, fair values are determined at each reporting date and changes are recognized as compensation costs with a corresponding change in liabilities. The fair value of RSUs and PSUs at grant date are estimated based on the volume weighted average trading price on the TSX for five trading days prior to one business day prior to the date of grant, except for the initial grant which was based on the IPO price. Judgment is also required to estimate the number of RSUs that will ultimately vest.

PSUs, RSUs and DSUs are accounted for as liability instruments and are remeasured at fair value based on the market value of the Common Shares at each reporting date.

Goodwill

Upon acquisition, goodwill is attributed to the applicable CGU that is expected to benefit from the business combination's synergies. This represents the lowest level that goodwill is monitored for internal management purposes. Subsequent measurement of goodwill is at cost less any accumulated impairments.

Goodwill is assessed for impairment at least annually. If the goodwill carrying amount for the CGU exceeds the recoverable amount of the CGU, the associated goodwill is written down with an impairment recognized in net earnings. The recoverable amounts are determined annually based on the greater of fair value less costs of disposal or value in use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows for the CGU. Discounted future net cash flows are based on forecast commodity prices and costs over the expected economic life of the proved and probable reserves and discounted using market-based rates. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the CGU. Goodwill impairments are not reversed.

The Company's reserves are evaluated annually by the Company's IQRE. The cash flows used in determining the recoverable amount are based on information contained in the IQRE reports and management's assumptions provided therein.

Income Taxes

Income tax is recognized in net earnings except for items directly related to Shareholders' Equity, where the associated income tax is also directly recognized. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted or substantively enacted at the end of the reporting period.

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability.

Deferred income tax is calculated using the enacted or substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. The effect of a change in the enacted or substantively enacted tax rates is recognized in net earnings or in Shareholders' Equity depending on the item to which the adjustment relates.

Deferred income tax liabilities and assets are not recognized for temporary differences arising on:

- the initial recognition of goodwill; or
- the initial recognition of an asset or liability in a transaction which is not a business combination and, at the time of the transaction, affects neither accounting net earnings nor taxable earnings.

Deferred income tax assets are recognized to the extent future recovery is probable. Deferred income tax assets are reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the asset to be recovered.

Related to the Acquisition under common control, the Company qualifies for the initial recognition exemption under IAS 12 "Income Taxes" and a deferred tax asset will not be recognized related to the excess of the tax pools acquired relative to the carrying value of the net assets transferred. The unrecognized deferred income tax asset is being amortized based on the net tax pool and DD&A claims calculated for the period.

Income tax expense for an interim period is based on an estimated average annual effective income tax rate.

RECENT ACCOUNTING PRONOUNCEMENTS

New Pronouncements Adopted

On January 1, 2014, the Company adopted the following accounting standards updates issued by the International Accounting Standards Board ("IASB"), which have not had a material impact on the Interim Condensed Financial Statements:

- IAS 32, “Financial Instruments: Presentation” was amended to clarify requirements for offsetting financial instruments in the balance sheet. The amendment requires that the right to offset must be available on the current date and cannot be contingent on a future event. The standard has been applied retrospectively.
- International Financial Reporting Interpretations Committee 21, "Levies" provides guidance for accounting for levies that fall under the scope of IAS 37, Provisions, Contingent Liabilities and Contingent Assets. The interpretation requires that obligations arising from levies imposed through legislation by governments are recognized when the triggering event or activity specified in the legislation occurs. The standard has been applied retrospectively.

New Standards Issued Not Yet Adopted

On December 16, 2011, the IASB issued IFRS 9, “Financial Instruments”, which replaces IAS 39, “Financial Instruments: Recognition and Measurement”. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The classification and measurement requirements will be applied retrospectively upon adoption of the standard. In November 2013, IFRS 9 and IFRS 7 “Financial Instruments: Disclosures”, were amended to include a new hedge accounting model that better reflects risk management activities in the financial statements of entities that elect to apply hedge accounting. This amendment to IFRS 9 also removes the previous mandatory effective date of January 1, 2015. The new effective date of IFRS 9 will be determined when the impairment phase of the project is completed. These new standards and amendments are not expected to have a material impact on the Company’s Financial Statements.

On May 12, 2014, the IASB issued “Clarification of Acceptable Methods of Depreciation and Amortization” which amends IAS 16 “Property, Plant and Equipment” and IAS 38 “Intangible Assets”. The amendments to IAS 16 clarify that use of revenue-based methods to calculate the depreciation of property, plant and equipment are not appropriate as revenue also includes factors other than the consumption of the economic benefits derived from the asset. The amendments to IAS 38 state that revenue is not an appropriate basis for amortization of intangible assets, except in limited circumstances. These amendments will apply prospectively, effective January 1, 2016 and early application is permitted. The amendment is not expected to have a material impact on the Company’s Financial Statements.

On May 28, 2014, the IASB issued IFRS 15, “Revenue from Contracts with Customers” which is the result of the joint project with Financial Accounting Standards Board. The new standard replaces the two main recognition standards IAS 18, “Revenue” and IAS 11, “Construction Contracts”. The new standard provides a five step model framework as a core principal upon which an entity recognizes revenue and becomes effective January 1, 2017. The Company is currently assessing the potential impact of the standard on the Company’s Financial Statements.

CHANGE IN ACCOUNTING ESTIMATE

On May 27, 2014, the Company began depleting crude oil, NGL and natural gas properties using the unit-of-production method over their proved plus probable reserves on a prospective basis. The previous policy was to deplete using the unit-of production method over the proved reserves. The change in estimate was made as proved plus probable reserves better reflects the estimated remaining service life of the related assets. For the period from May 27, 2014 to September 30, 2014, the Company recorded $3.1 million lower depletion expense than it would have recorded using proved reserves. Based on the reserves at the date of change in estimate, the effect reduced depletion by $1.64 per BOE. It is not practical for the Company to estimate the effect on depletion expense for future periods.

NON-GAAP MEASURES

Certain measures in this MD&A do not have any standardized meaning as prescribed by IFRS and therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures are commonly used in the oil and gas industry and by the Company to provide potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include Operating Cash Flow, Netback, Funds from Operations, Adjusted Net Earnings and Comprehensive Income Per Share basic and diluted and Adjusted Funds from Operations Per Share basic and diluted. Management's use of these measures is discussed further below.

"Operating Cash Flow" represents the cash margin for product sold. Operating Cash Flow is calculated as revenues excluding other revenues, less freehold mineral taxes and administrative expenses. Operating Cash Flow provides a consistent measure of the cash generating performance for product sold to assess the comparability of the underlying performance between years.

"Netback" represents the cash margin for product sold on a BOE basis. Netback is calculated using Operating Cash Flow, excluding other revenues, on a per BOE basis. Netback is used to assess the ability to provide cash generating performance per unit of product sold. Netback measures are commonly used in the oil and gas industry to assess performance comparability. Refer to the Operating Results table in this MD&A document for the summary of this reporting period's netback calculations.

FUNDS FROM OPERATIONS

Funds from Operations is defined as cash from operating activities, including, net change in non-cash working capital, lease issuance bonuses and financing costs. Funds from Operations is utilized by management to evaluate the ability of the Company to generate cash from operations. This is considered a measure of operating performance as it demonstrates the Company's ability to fund capital expenditures, and meet the intention of the Company to distribute the majority of its cash flow on an ongoing basis to shareholders as dividends. Such a measure provides a useful tool of the Company's operations on an ongoing basis by eliminating certain non-cash charges. Below is a reconciliation of Funds from Operations to Cash From (Used in) Operating Activities, which is the most comparable IFRS measure.

($ millions)	**Three months ended September 30, 2014**	**For the period May 27, 2014 to September 30, 2014**
Cash From (Used in) Operating Activities	**$ 77.2**	**$ 104.0**
Add back (deduct):		
Net Change in Non-cash Working Capital	**(12.2)**	**(8.3)**
Lease Issuance Bonus	**3.7**	**4.2**
Financing Costs	**-**	**(0.2)**
Funds From Operations	**$ 68.7**	**$ 99.7**

ADJUSTED PER COMMON SHARE CALCULATIONS – BASIC AND DILUTED

Adjusted Per Share calculations provide a better measure of the Company's performance given the fact that the Company was in existence since January 1, 2014, but only commenced operations on May 27, 2014. Adjusted Basic Common Shares outstanding reflect the shares issued and outstanding as at September 30, 2014 which were 130.0 million and Adjusted Diluted Common Shares outstanding reflect the impact of stock options. Below is a computation of Adjusted Net Earnings and Comprehensive Income Per Common Share basic; Adjusted Net Earnings and Comprehensive Income Per Common Share diluted; Adjusted Funds from Operations Per Common Share basic; Adjusted Funds from Operations Per Common Share diluted. Calculation of Net Earnings Per Common Share is disclosed in Note 16 of the Interim Condensed Financial Statements.

Adjusted Net Earnings and Comprehensive Income Per Common Share

The following table presents the computation of Adjusted Net Earnings and Comprehensive Income per Common Share:

	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Net Earnings and Comprehensive Income	$ 57.5	$ 81.4
Number of Common Shares:		
Common Shares outstanding – basic	130.0	130.0
Effect of dilutive securities	0.1	0.1
Common Shares outstanding – diluted	130.1	130.1
Adjusted Net Earnings and Comprehensive Income per Common Share		
Basic(1) and Diluted(2)	$ 0.44	$ 0.63

(1) Adjusted Net Earnings and Comprehensive Income per Common Share is calculated using the number of PrairieSky common shares outstanding as at September 30, 2014.

(2) Adjusted Net Earnings and Comprehensive Income per Common Share is calculated using the number of PrairieSky common shares outstanding as at September 30, 2014, giving effect to stock options.

Adjusted Funds from Operations Per Common Share

The following table presents the computation of Adjusted Funds from Operations per Common Share:

	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Funds from Operations	$ 68.7	$ 99.7
Number of Common Shares:		
Common Shares outstanding – basic	130.0	130.0
Effect of dilutive securities	0.1	0.1
Common Shares outstanding – diluted	130.1	130.1
Adjusted Funds from Operations per Common Share		
Basic(1) and Diluted(2)	$ 0.53	$ 0.77

(1) Adjusted Funds from Operations per Common Share is calculated using the number of PrairieSky common shares outstanding as at September 30, 2014.

(2) Adjusted Funds from Operations per Common Share is calculated using the number of PrairieSky common shares outstanding as at September 30, 2014, giving effect to stock options.

FUNDS FROM OPERATIONS PER COMMON SHARE CALCULATIONS – BASIC AND DILUTED

Funds from Operations Per Common Share

The following table presents the computation of Funds from Operations per Common Share:

	Three months ended September 30, 2014	For the period May 27, 2014 to September 30, 2014
Funds from Operations	$ 68.7	$ 99.7
Number of Common Shares:		
Common Shares outstanding – basic	130.0	59.5
Effect of dilutive securities	0.1	0.1
Common Shares outstanding – diluted	130.1	59.6
Funds from Operations per Common Share		
Basic(1)	$ 0.53	$ 1.68
Diluted(2)	$ 0.53	$ 1.67

(1) Funds from Operations per Common Share is calculated using the weighted average number of Common Shares outstanding from January 1, 2014 to September 30, 2014.

(2) Funds from Operations per Common Share is calculated using the weighted average number of Common Shares outstanding from January 1, 2014 to September 30, 2014, giving effect to stock options

ADVISORY

FORWARD-LOOKING STATEMENTS

This MD&A includes certain statements regarding PrairieSky's future plans and operations as at September 30, 2014, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. Forward-looking statements contained in this MD&A include our expectations with respect to the following:

- commodity prices including supply and demand factors relating to crude oil, natural gas and natural gas liquids;
- expected future commitments and payments related thereto;
- the potential impact of the final statement of adjustments to be performed in accordance with the PSA with Encana;
- PrairieSky's business and growth strategy and anticipated sources of future income;
- industry drilling, development and licensing activity on the Royalty Assets, our exposure in emerging opportunities, and the potential impact of thereof on production and reserves;
- possible revisions to accrued estimates based on receipt of actual results;
- expected impacts of accounting standards, including those announced but not yet adopted;
- expected impacts including production and cash flow from acquisitions;
- the expectation that there will be no operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with development of the Royalty Assets**;**
- estimated general and administrative expenses;
- the ability to mitigate the risks of fluctuations in commodity prices and production volumes;
- average production and contribution from the Royalty Assets; and
- amounts and rates of income taxes and timing of payment thereof.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, lack of pipeline capacity, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. In addition, PrairieSky is subject to numerous risks and uncertainties in relation to the Acquisition. These risks and uncertainties include risks relating to the potential for disputes to arise with Encana, and limited ability to recover indemnification from Encana under the PSA and other certain agreements. The foregoing and other risks are described in more detail in PrairieSky's final prospectus dated May 22, 2014 and in this MD&A under the heading "Risk Management".

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things; the ability of the lessees and working interest owners on the Royalty Assets to maintain or increase production and reserves from these properties; the ability and willingness of the lessees and working interest owners on the Royalty Assets to comply with, and PrairieSky to enforce, lease terms and contractual provisions, as applicable, in order to receive payments; the ability of the lessees or working interest owners on the Royalty Assets to operate in a safe, efficient and effective manner; the timely receipt of any required regulatory approvals by lessees or working interest owners on the Royalty Assets; the willingness and financial capability of the lessees and working interest owners to continue to develop and invest additional capital in the Royalty Assets; the ability of the lessees and working interest owners on the Royalty Assets to obtain financing on acceptable terms to fund capital expenditures; field production rates, decline rates and the well performance and characteristics of the Royalty Assets; the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Assets through acquisitions and third party development; the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage; the ability of the operators of the properties in which PrairieSky has a royalty interest in, to successfully market their respective petroleum and natural gas products or, for royalty payments taken-in-kind by PrairieSky, if any, the ability of PrairieSky or a third party marketer to successfully market PrairieSky's in-kind petroleum and natural gas products; surface rights access being granted to third parties on PrairieSky's properties; the benefits of the seismic data anticipated to be used by PrairieSky and sub-licensed to lessees on the PrairieSky's properties; the level of costs and expenses to be incurred by PrairieSky, including with respect to interest, general and administrative expenses and income tax expenses; the ability of PrairieSky to obtain and retain qualified staff and services in a timely and cost efficient manner; the absence of any material litigation or claims against PrairieSky; the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which PrairieSky has an interest in oil and natural gas properties; and future crude oil, natural gas and NGL prices and currency, exchange and interest rates.

Readers are cautioned that the assumptions used in the preparation of such forward looking information and statements, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive.

Any forward-looking statement is made only as of the date of this MD&A, and PrairieSky undertakes no obligation to update or revise any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for PrairieSky to predict all of these factors or to assess in advance the impact of each such factor on PrairieSky's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statements.

The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

You are further cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net income, as further information becomes available and as the economic environment changes.

CONVERSIONS OF NATURAL GAS TO BOE

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (BOE). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 BOE ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the BOE ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

CURRENCY AND REFERENCES TO PRAIRIESKY

All information included in this MD&A, and the Interim Condensed Financial Statements is shown on a Canadian dollar basis. All proceeds from divestitures are provided on a before-tax basis.

For convenience, references in this document to the “Company”, “we”, “us”, “our”, and “its” may, where applicable, refer only to PrairieSky.

ADDITIONAL INFORMATION

Additional information about PrairieSky, including unaudited Interim Condensed Financial Statements and notes thereto, and PrairieSky’s final prospectus dated May 22, 2014, is available on SEDAR at www.sedar.com or PrairieSky’s website at www.prairiesky.com.