MANAGEMENT'S DISCUSSION AND ANALYSIS AND INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at September 30, 2016 and for the three and nine months ended September 30, 2016 and 2015

CONTENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") should be read in conjunction with Tourmaline's unaudited interim condensed consolidated financial statements and related notes as at and for the three and nine months ended September 30, 2016 and the consolidated financial statements for the year ended December 31, 2015. The consolidated financial statements and the MD&A can be found at www.sedar.com. This MD&A is dated November 14, 2016.

The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("IFRS") and sometimes referred to in this MD&A as Generally Accepted Accounting Principles ("GAAP") as issued by the International Accounting Standards Board. All dollar amounts are expressed in Canadian currency, unless otherwise noted.

Certain financial measures referred to in this MD&A are not prescribed by IFRS. See "Non-GAAP Financial Measures" for information regarding the following non-GAAP financial measures used in this MD&A: "cash flow", "operating netback", "working capital (adjusted for the fair value of financial instruments)", "net debt", "adjusted EBITDA", "senior debt", "total debt", and "total capitalization".

Additional information relating to Tourmaline can be found at www.sedar.com.

Forward-Looking Statements - Certain information regarding Tourmaline set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. Such statements represent Tourmaline's internal projections, forecasts, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital investment or expenditures, anticipated future debt, expenses, production, cash flow and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Tourmaline believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies.

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to: the size of, and future net revenues and cash flow from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; the focus of and timing of capital expenditures; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; the performance characteristics of the Company's crude oil, NGL and natural gas properties; crude oil, NGL and natural gas production levels and product mix; Tourmaline's future operating and financial results; capital investment programs; supply and demand for crude oil, NGL and natural gas; future royalty rates; drilling, development and completion plans and the results therefrom; future land expiries; dispositions and joint venture arrangements; amount of operating, transportation and general and administrative expenses; treatment under governmental regulatory regimes and tax laws; and estimated tax pool balances. In addition, 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.

These forward-looking statements are subject to numerous risks and uncertainties, most of which are beyond the Company’s control, including the impact of general economic conditions; volatility and uncertainty in market prices for crude oil, NGL and natural gas; industry conditions; currency fluctuation; imprecision of reserve estimates; liabilities inherent in crude oil, NGL and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition; the lack of availability of qualified personnel or management and skilled labour; changes in income tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, any of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; the receipt of applicable regulatory or third-party approvals; and the other risks considered under "Risk Factors" in Tourmaline’s most recent annual information form available at www.sedar.com.

With respect to forward-looking statements contained in this MD&A, Tourmaline has made assumptions regarding: future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment and services; effects of regulation by governmental and regulatory agencies; and future operating costs.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide readers with a more complete perspective on Tourmaline’s future operations and such information may not be appropriate for other purposes. Tourmaline’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. Readers are cautioned that the foregoing lists of factors are not exhaustive.

These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Boe Conversions - Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

PRODUCTION

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	**2015**	**Change**	**2016**	**2015**	**Change**
Natural gas *(mcf/d)*	**895,256**	786,910	14%	**969,089**	767,587	26%
Oil *(bbl/d)*	**11,826**	10,669	11%	**12,642**	10,630	19%
NGL *(bbl/d)*	**8,312**	8,477	(2)%	**9,453**	7,348	29%
Oil equivalent *(boe/d)*	**169,347**	150,297	13%	**183,610**	145,909	26%
Natural gas %	**88%**	87%		**88%**	88%	

Production for the three months ended September 30, 2016 averaged 169,347 boe/d compared to 150,297 boe/d for the same quarter of 2015. Although, 2016 third quarter production is 13% higher than the same quarter of the prior year, it was negatively impacted by a combination of weather-related activity delays, third-party plant turnarounds, NGL volume reductions due to a fire at the Pembina Saturn 2 facility, and continued firm service transportation cutbacks in Alberta and B.C.

For the nine months ended September 30, 2016, production increased 26% to 183,610 boe/d from 145,909 boe/d for the same period of 2015. The increase in natural gas production is related to the Company's successful exploration and production program, as well as corporate and property acquisitions over the past year. The growth in oil and NGL production is the result of increased drilling in the Spirit River/Peace River High Charlie Lake oil plays, incremental liquids recovered in the Wild River area via deep-cut processing, and strong condensate recoveries from new wells commencing production as the liquids-rich Montney Turbidite is developed in northeast British Columbia. Approximately 95% of the growth in production volumes since the third quarter of 2015 can be attributed to wells brought on stream from the Company's exploration and production program, with the remainder of the change being from corporate and property acquisitions (net of dispositions).

Full-year average production guidance for 2016 is unchanged from 190,000-195,000 boe/d as disclosed in the Company's June 30, 2016 MD&A.

REVENUE

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Revenue from:						
Natural gas	**$ 210,562**	$ 209,059	1%	**$ 517,606**	$ 594,004	(13)%
Oil and NGL	**72,562**	58,151	25%	**205,056**	187,985	9%
Realized gains from:						
Natural gas	**19,848**	22,714	(13)%	**86,875**	107,047	(19)%
Oil and NGL	**1,508**	22,720	(93)%	**21,174**	43,607	(51)%
Total revenue from natural gas, oil and NGL sales	**$ 304,480**	$ 312,644	(3)%	**$ 830,711**	$ 932,643	(11)%

Revenue for the three months ended September 30, 2016 decreased 3% to $304.5 million from $312.6 million for the same quarter of 2015. Revenue for the nine month period ended September 30, 2016 decreased 11% from $932.6 million in 2015 to $830.7 million in 2016. Lower revenue in the current period is consistent with the significant decrease in realized commodity prices and lower realized gains on energy marketing and risk management activities, partially offset by higher production volumes. Revenue includes all petroleum, natural gas and NGL sales and the realized gain on financial instruments.

TOURMALINE REALIZED PRICES:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	**2016**	2015	Change
Natural gas *($/mcf)*	**$ 2.80**	$ 3.20	(13)%	**$ 2.28**	$ 3.35	(32)%
Oil *($/bbl)*	**$ 54.97**	$ 74.06	(26)%	**$ 54.59**	$ 69.57	(22)%
NGL *($/bbl)*	**$ 18.66**	$ 10.48	78%	**$ 14.33**	$ 14.81	(3)%
Oil equivalent *($/boe)*	**$ 19.54**	$ 22.61	(14)%	**$ 16.51**	$ 23.41	(29)%

BENCHMARK OIL AND GAS PRICES:

	Three Months Ended September 30,		
	2016	2015	Change
Natural gas			
NYMEX Henry Hub *(USD$/mcf)*	**$ 2.79**	$ 2.74	2%
PG&E Malin (USD$/mmbtu)	**$ 2.67**	$ 2.69	(1)%
AECO *(CAD$/mcf)*	**$ 2.38**	$ 2.91	(18)%
West Coast Station 2 (CAD$/mcf)	**$ 1.83**	$ 1.72	6%
ATP 5A Day Ahead Index (CAD$/GJ) (1)	**$ 2.41**	$ –	–%
Oil			
NYMEX *(USD$/bbl)*	**$ 44.94**	$ 46.48	(3)%
Edmonton Par *(CAD$/bbl)*	**$ 54.34**	$ 55.37	(2)%

(1) ATP 5A Day Ahead Index prices commenced December 1, 2015.

RECONCILIATION OF INDEX PRICES TO TOURMALINE'S REALIZED GAS PRICES:

	Three Months Ended September 30,		
($/mcf)	**2016**	2015	Change
Weighted average index natural gas prices	**$ 2.38**	$ 2.69	(12)%
Heat/quality differential	**0.18**	0.20	(10)%
Realized gain	**0.24**	0.31	(23)%
Tourmaline realized natural gas price	**$ 2.80**	$ 3.20	(13)%
Premium to index pricing due to higher heat content	**8%**	7%	

CURRENCY – EXCHANGE RATES:

	Three Months Ended September 30,		
	2016	2015	Change
CAD$/USD$ (1)	**$ 0.7668**	$ 0.7643	–%

(1) Average rates for the period.

The realized average natural gas price for the three and nine months ended September 30, 2016 was $2.80/mcf and $2.28/mcf, respectively, which is 13% and 32% lower than the same periods of the prior year. The lower natural gas price reflects lower index prices experienced during the quarter which was partially offset by realized gains on commodity contracts. In the third quarter of 2016, the Company began transporting natural gas on the TransCanada GTN pipeline and selling it in Malin, Oregon in the United States. As a result, the Company's realized price on natural gas has increased due to the premium received at Malin compared to selling at AECO.

The realized price for the third quarter of 2016, included a gain on commodity contracts of $19.8 million (nine months ended September 30, 2016 - $86.9 million) compared to a gain of $22.7 million for the same period of the prior year (nine months ended September 30, 2015 - $107.0 million). The gains on commodity contracts include realized gains on natural gas sold at Malin which received a significant premium over AECO index prices. Realized gains on commodity contracts for the three and nine months ended September 30, 2016 have decreased compared to the same period of the prior year primarily due to a lower premium received on commodity contracts in 2016. Realized prices exclude the effect of unrealized gains or losses on commodity contracts. Once these gains and losses are realized they are included in the per-unit amounts.

Realized oil prices decreased by 26% and 22% for the three and nine months ended September 30, 2016, respectively. The realized price for the third quarter of 2016 included a gain on commodity contracts of $1.5 million (nine months ended September 30, 2016 - $21.2 million) compared to a gain of $22.7 million gain on commodity contracts in the third quarter of 2015 (nine months ended September 30, 2015 - $43.6 million). The decrease in gains on commodity contracts is related to 2015 having a significantly higher portion of oil volume hedged as these contracts were unwound in Q4 2015.

NGL prices increased 78% from $10.48/bbl to $18.66/bbl, when compared to the same quarter of 2015. The increase in NGL prices is related to a decrease in the proportion of ethane in the NGL mix, due to the fire at Pembina's Saturn 2 facility, which is priced lower than other NGLs. Additionally, there has been a recovery in the price of propane during 2016 which was significantly discounted in 2015 due to oversupply in the market.

ROYALTIES

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(000s)	**2016**	**2015**	**2016**	**2015**
Natural gas	**$ 3,518**	$ 7,687	**$ 6,498**	$ 16,253
Oil and NGL	**8,467**	7,068	**20,607**	19,033
Total royalties	**$ 11,985**	$ 14,755	**$ 27,105**	$ 35,286
Royalties as a percentage of revenue	**4.2%**	5.5%	**3.8%**	4.5%

For the quarter ended September 30, 2016, the average effective royalty rate was 4.2% compared to 5.5% for the same quarter of 2015. For the nine month period ended September 30, 2016, the average effective royalty rate decreased from 4.5% in 2015 to 3.8% in 2016. The decrease in royalty rates can be attributed to lower commodity prices received during the period. Royalty rates are impacted by changes in commodity prices whereby the actual royalty rate decreases when prices decrease. The Company also receives gas cost allowance from the Crown, which further reduces royalties, to account for expenses incurred to process and transport the Crown's portion of natural gas production.

The Company also continues to benefit from the New Well Royalty Reduction Program and the Natural Gas Deep Drilling Program in Alberta, as well as the Deep Royalty Credit Program in British Columbia.

On January 29, 2016, the Alberta Government (the "Government") released a new Royalty Regime effective January 1, 2017. The new regime will apply to wells drilled after the effective date, whereby all other wells will follow the old framework for a further 10 years. On April 21, 2016, the Government provided further details and calibration on the Modernized Royalty Framework ("MRF"). On July 11, 2016, the Government further announced two new royalty programs: the Enhanced Hydrocarbon Recovery Program ("EHRP") and the Emerging Resources Program ("ERP").

The EHRP will begin January 1, 2017 and will replace the existing Enhanced Oil Recovery Program. It will help to promote incremental production through enhanced recovery methods. The ERP is also effective January 1, 2017, and will encourage industry to access new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. Detailed program and application guidelines are expected in the next few months.

On July 12, 2016, the Government announced that new wells spud before January 1, 2017 may elect to opt-in early to the MRF, if they meet certain criteria. Accordingly, wells spud before July 13, 2016 will continue to operate under the previous royalty framework until December 31, 2026. Wells spud during the early election period (July 13, 2016 to December 31, 2016) that did not elect to opt-in early to the MRF or did not meet the criteria will continue to operate under the previous royalty framework until December 31, 2026.

On September 29, 2016, the Government announced that wells re-entered on or after January 1, 2017 will be subject to the MRF. A drilling and completion cost allowance will be calculated on the incremental activity and the royalty will be calculated based on production from all legs according to the MRF rules.

At this time, the Company does not anticipate opting-in early to the MRF. Based on the details provided thus far, we believe that the MRF is generally consistent with the initial goal of incentivising the use of technology to improve productivity and rewards producers deploying the most competitive operating practices. As additional information is provided, the Company will continue to monitor the expected overall impact starting in 2017.

The Company expects its royalty rate for 2016 to be approximately 5%, consistent with the previous Company guidance contained in the Company's June 30, 2016 MD&A. The royalty rate is sensitive to commodity prices, and as such, an increase in commodity prices will increase the actual rate.

OTHER INCOME

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Other income	**$ 6,124**	$ 7,941	(23)%	**$ 19,774**	$ 22,322	(11)%

Other income decreased from $7.9 million in the third quarter of 2015 to $6.1 million for the same quarter of 2016. For the nine month period ended September 30, 2016, other income decreased from $22.3 million in 2015 to $19.8 million in 2016. The decrease in other income is due to lower processing fees received in 2016 as the Company is now processing less third-party volumes at its owned-and-operated gas processing facilities. As the Company's production increases, third-party volumes processed at those facilities is reduced. Conversely, if the Company's production is temporarily reduced in a certain area, processing income from third parties could increase for a short period of time.

OPERATING EXPENSES

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s) except per unit amounts	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Operating expenses	**$ 50,754**	$ 62,299	(19)%	**$ 174,274**	$ 176,637	(1)%
Per boe	**$ 3.26**	$ 4.51	(28)%	**$ 3.46**	$ 4.43	(22)%

Operating expenses include all periodic lease and field-level expenses and exclude income recoveries from processing third-party volumes. For the third quarter of 2016, total operating expenses were $50.8 million compared to $62.3 million in 2015, a decrease of 19% over a production base increase of 13% for the same period. Operating costs for the nine months ended September 30, 2016 were $174.3 million, compared to $176.6 million for the same period of 2015, reflecting a 1% decrease in total costs over a 26% increase in production.

On a per boe basis, the costs decreased from $4.51/boe for the third quarter of 2015 to $3.26/boe in the third quarter of 2016. For the nine months ended September 30, 2016, operating costs were $3.46/boe, down from $4.43/boe in the prior year. Operating expenses in 2016 have decreased significantly due to lower power costs, lower water trucking costs as a result of capital investments in water management infrastructure and a decline in contractor costs. Furthermore, the Company's investments in processing facilities in 2014 and 2015 have reduced the volume of gas flowing to third-party facilities, also contributing to the reduction in operating expenses on a per boe basis. Along with a commitment to continue to drive down the overall cost structure, the Company is also realizing increased operational efficiencies in all three core areas along with fixed costs being distributed over a significantly higher production base.

The Company's full year 2016 average operating cost target is now being reduced to $3.60/boe, which is a $0.15/boe decrease from the previous guidance of $3.75/boe included in the Company's June 30, 2016 MD&A. Although, additional deep cut processing was curtailed in the third quarter due to a fire at the Pembina Saturn 2 facility, the Company does expect an increase in operating expenses per boe during the fourth quarter of 2016 due to additional volumes, bearing higher operating expenses, flowing through the facility. Actual costs per boe can change, however, depending on a number of factors, including the Company's actual production levels.

TRANSPORTATION

(000s) except per unit amounts	Three Months Ended September 30, 2016	2015	Change	Nine Months Ended September 30, 2016	2015	Change
Natural gas transportation	**$ 34,223**	$ 19,947	72%	**$ 85,752**	$ 59,231	45%
Oil and NGL transportation	**9,775**	7,437	31%	**26,657**	23,279	15%
Total transportation	**$ 43,998**	$ 27,384	61%	**$ 112,409**	$ 82,510	36%
Per boe	**$ 2.82**	$ 1.98	42%	**$ 2.23**	$ 2.07	8%

For the third quarter of 2016, total transportation expenses were $44.0 million compared to $27.4 million in 2015. Transportation costs for the nine months ended September 30, 2016 were $112.4 million, compared to $82.5 million for the same period of 2015, reflecting increased costs related to higher production volumes.

On a per boe basis, the costs increased to $2.82/boe for the third quarter of 2016 (nine months ended September 30, 2016 - $2.23/boe) from $1.98/boe in the third quarter of 2015 (nine months ended September 30, 2015 - $2.07/boe). The per-unit increase in costs in 2016 is primarily due to the Company beginning to transport natural gas to Malin in the third quarter of 2016. The increased distance resulted in higher per boe transportation costs. Additionally, during the quarter, the Company incurred higher unutilized transportation fees on firm transportation agreements for natural gas due to the production constraints experienced. As production increases, these unutilized charges will be reduced.

GENERAL & ADMINISTRATIVE EXPENSES ("G&A")

(000s) except per unit amounts	Three Months Ended September 30, 2016	2015	Change	Nine Months Ended September 30, 2016	2015	Change
G&A expenses	**$ 14,549**	$ 15,934	(9)%	**$ 44,212**	$ 44,261	−%
Administrative and capital recovery	**(1,093)**	(2,511)	(56)%	**(3,055)**	(7,286)	(58)%
Capitalized G&A	**(5,763)**	(5,741)	−%	**(17,918)**	(17,062)	5%
Total G&A expenses	**$ 7,693**	$ 7,682	−%	**$ 23,239**	$ 19,913	17%
Per boe	**$ 0.49**	$ 0.56	(13)%	**$ 0.46**	$ 0.50	(8)%

G&A expenses for the third quarter of 2016 were $7.7 million, consistent with the same quarter of the prior year. G&A expenses for the nine month period ended September 30, 2016 were $23.2 million compared to $19.9 million for the same period of 2015. The decrease in administrative and capital recoveries in 2016 compared to 2015 can be attributed to lower recoveries received from partners due to a reduction in the Company's capital exploration and production activities.

For the three and nine months ended September 30, 2016, G&A expenses were $0.49/boe and $0.46/boe, down from $0.56/boe and $0.50/boe, respectively, in the prior year. The cost per boe decrease reflects Tourmaline's growing production base which continues to increase at a faster rate than total G&A costs.

G&A costs for 2016 are expected to average approximately $0.50/boe which is unchanged from the initial guidance released March 7, 2016.

SHARE-BASED PAYMENTS

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s) except per unit amounts	**2016**	**2015**	**2016**	**2015**
Share-based payments	**$ 10,546**	$ 15,170	**$ 35,160**	$ 48,018
Capitalized share-based payments	**(5,273)**	(7,585)	**(17,580)**	(24,009)
Total share-based payments	**$ 5,273**	$ 7,585	**$ 17,580**	$ 24,009
Per boe	**$ 0.34**	$ 0.55	**$ 0.35**	$ 0.60

The Company uses the fair value method for the determination of non-cash related share-based payments expense. During the third quarter of 2016, 415,000 stock options were granted to employees, officers, directors and key consultants at a weighted-average exercise price of $36.22 and 805,147 options were exercised, resulting in $23.4 million of cash proceeds. No stock options were forfeited for the three months ended September 30, 2016.

The Company recognized $5.3 million of share-based payments expense in the third quarter of 2016 compared to $7.6 million in the third quarter of 2015. Capitalized share-based payments for the third quarter of 2016 were $5.3 million compared to $7.6 million for the same period of the prior year.

For the nine months ended September 30, 2016, share-based payment expense totalled $17.6 million and a further $17.6 million in share-based payments were capitalized (nine months ended September 30, 2015 - $24.0 million and $24.0 million, respectively).

Share-based payments are lower in 2016 compared to the same period of 2015 which reflects higher per option values being expensed in 2015 compared to 2016 due to the graded vesting of the options.

DEPLETION, DEPRECIATION AND AMORTIZATION (“DD&A”)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s) except per unit amounts	**2016**	**2015**	**2016**	**2015**
Total depletion, depreciation and amortization	**$ 159,861**	$ 174,772	**$ 509,186**	$ 520,105
Less mineral lease expiries	**(7,731)**	(12,960)	**(14,611)**	(49,394)
Depletion, depreciation and amortization	**$ 152,130**	$ 161,812	**$ 494,575**	$ 470,711
Per boe	**$ 9.76**	$ 11.70	**$ 9.83**	$ 11.82

DD&A expense, excluding mineral lease expiries, was $152.1 million for the third quarter of 2016 compared to $161.8 million for the same period of 2015. For the nine month period ended September 30, 2016, DD&A expense (excluding mineral lease expiries) was $494.6 compared to $470.7 million in the same period of 2015.

The per-unit DD&A rate (excluding the impact of mineral lease expiries) was $9.76/boe for the third quarter of 2016 compared to the rate of $11.70/boe for the same quarter of 2015. The per-unit DD&A rate (excluding the impact of mineral lease expiries) was $9.83/boe for the nine month period ended September 30, 2016 compared to the rate of $11.82/boe in the same period of the prior year.

The decrease in per boe depletion in 2016 can be attributed to lower future development costs per well as drilling and completion costs have decreased over the past year thereby adding a higher proportion of reserves with lower associated future development costs, resulting in a lower depletion rate.

Mineral lease expiries for the three months ended September 30, 2016 were $7.7 million, compared to expiries in the same quarter of the prior year of $13.0 million. For the nine months ended September 30, 2016, expiries were $14.6 million compared to $49.4 million for the same period in 2015. The Company prioritizes drilling on what it believes to be the most cost-efficient and productive acreage, and with an extensive land base, the Company has chosen not to continue some of the expiring sections of land. The Company explores a number of alternatives (including swaps, farm-outs and dispositions) to realize the value from these sections before they expire.

FINANCE EXPENSES

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Interest expense	**$ 9,985**	$ 9,498	5%	**$ 30,734**	$ 27,482	12%
Accretion expense	**775**	788	(2)%	**2,278**	2,038	12%
Foreign exchange (gain) on U.S. denominated debt	**(18,494)**	–	(100)%	**(64,748)**	–	(100)%
Realized loss on cross-currency swaps	**18,494**	–	100%	**64,748**	–	100%
Realized loss on interest rate swaps	**671**	777	(14)%	**2,414**	2,052	18%
Transaction costs on corporate and property acquisitions	**–**	923	(100)%	**214**	1,948	(89)%
Total finance expenses	**$ 11,431**	$ 11,986	(5)%	**$ 35,640**	$ 33,520	6%

Finance expenses for the three and nine months ended September 30, 2016 totaled $11.4 million and $35.6 million compared to $12.0 million and $33.5 million, respectively, for the same periods of 2015. The finance expenses in the first nine months of 2016 compared 2015 include increased interest expense attributed to a higher average bank debt outstanding, partially offset by a lower average effective interest rate. The average bank debt outstanding and the average effective interest rate on the debt for the nine months ended September 30, 2016 was $1,436.1 million and 2.52%, respectively (nine months ended September 30, 2015 – $1,203.6 million and 2.69%, respectively).

For the nine months ended September 30, 2016, the Company drew from the credit facility and term loan in U.S. dollars, as permitted under the credit facility and term loan, which when repaid created a foreign exchange gain. Concurrent with the draw of U.S. dollar denominated borrowings, the Company entered into cross-currency swaps to manage the foreign currency risk resulting from holding U.S. dollar denominated borrowings. The Company fixed the Canadian dollar amount for purposes of principal and interest repayment resulting in a loss on cross-currency swaps equivalent to the realized foreign exchange gain. These transactions allow the Company to take advantage of the interest rate spread between CDOR and LIBOR (for U.S. borrowings) without taking on foreign exchange risk.

DEFERRED INCOME TAXES (RECOVERY)

For the three months ended September 30, 2016, the provision for deferred income tax expense was $11.8 million compared to a deferred income tax expense of $14.0 million for the same period of 2015. For the nine months ended September 30, 2016, the provision for deferred income tax recovery was $25.0 million compared to deferred income tax expense of $65.2 million for the same period in 2015. The recovery is primarily due to the pre-tax loss recorded for the nine months ended September 30, 2016 compared to pre-tax income in 2015. The deferred income tax expense in 2015 reflects an increase in the Alberta corporate tax rate from 10% to 12% which was introduced by the Government in June 2015.

CASH FLOW FROM OPERATING ACTIVITIES, CASH FLOW AND NET EARNINGS (LOSS)

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s) except per unit amounts	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Cash flow from operating activities	**$ 185,067**	$ 261,398	(29)%	**$ 504,767**	$ 606,796	(17)%
Per share (1)	**$ 0.79**	$ 1.19	(34)%	**$ 2.20**	$ 2.85	(23)%
Cash flow (2)	**$ 185,531**	$ 197,100	(6)%	**$ 479,259**	$ 607,869	(21)%
Per share (1)(2)	**$ 0.79**	$ 0.90	(12)%	**$ 2.09**	$ 2.86	(27)%
Net earnings (loss)	**$ 24,738**	$ 28,489	(13)%	**$ (91,592)**	$ 45,451	(302)%
Per share (1)	**$ 0.10**	$ 0.13	(23)%	**$ (0.40)**	$ 0.21	(290)%
Operating netback per boe (2)	**$ 12.69**	$ 15.06	(16)%	**$ 10.28**	$ 16.02	(36)%

(1) Per share amounts have been calculated using the weighted average number of diluted common shares except the net earnings (loss) per share amounts in periods which Tourmaline has reported a net loss. In these periods, the weighted average number of basic common shares has been used as there is an anti-dilutive impact on per-share calculations. For the nine months ended September 30, 2016, the weighted average number of common shares – diluted would be 229,783,855 excluding the anti-dilutive impact.

(2) See "Non-GAAP Financial Measures".

Cash flow for the three months ended September 30, 2016 was $185.5 million or $0.79 per diluted share compared to $197.1 million or $0.90 per diluted share for the same period of 2015. Cash flow for the nine months ended September 30, 2016 was $479.3 million or $2.09 per diluted share compared to $607.9 million or $2.86 per diluted share for the same period of 2015.

The Company had after-tax net earnings for the three months ended September 30, 2016 of $24.7 million or $0.10 per diluted share compared to after-tax net earnings of $28.5 million or $0.13 per diluted share for the same period of 2015. For the nine month period ended September 30, 2016, the after-tax net loss was $91.6 million or $0.40 per share compared to after-tax net earnings of $45.5 million or $0.21 per diluted share for the first nine months of 2015.

The decrease in both cash flow and after-tax net earnings (loss) in 2016 reflects significantly lower realized oil and natural gas prices, partially offset by an increase in production over 2015. Net (loss) for the nine months ended September 30, 2016 has also been significantly impacted by unrealized losses on financial instruments of $76.0 million, compared to unrealized gains of $11.2 million from the same period of the prior year. These unrealized losses are primarily related to future calls, written by the Company, on oil and natural gas that are currently above strip pricing. By entering into these future calls, the Company has been able to realize a higher premium on physical commodity contracts in the current year.

CAPITAL EXPENDITURES

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s)	**2016**	**2015**	**2016**	**2015**
Land and seismic	**$ 5,537**	$ 8,477	**$ 13,793**	$ 37,376
Drilling and completions	**125,708**	290,153	**290,153**	676,420
Facilities	**49,313**	122,866	**158,169**	392,528
Property acquisitions	**37,634**	955	**225,449**	91,341
Property dispositions	**–**	(6,144)	**(18,000)**	(6,663)
Other	**6,256**	6,322	**18,751**	19,638
Total cash capital expenditures	**$ 224,448**	$ 422,629	**$ 688,315**	$ 1,210,640

During the third quarter of 2016, expenditures on exploration and production were $180.6 million compared to $421.5 million for the same quarter of 2015. Total cash expenditures including acquisitions, net of dispositions, were $224.4 million compared to $422.6 million for the same period of 2015. During the nine month period ended September 30, 2016, the Company invested $688.3 million of cash consideration, net of dispositions, compared to $1,210.6 million for the same period in 2015.

The drilling and completion costs of $290.2 million for the first nine months of 2016 include 156.32 net wells drilled and completed compared to $676.4 million spent on 252.15 net wells drilled and completed in 2015. The significantly lower costs per well reflect the Company's continuous improvement of operating practices, combined with reduced drilling and completion service costs.

Facilities expenditures in 2016 include work on the new Brazeau Gas Plant commissioned in the first quarter of 2016, and progress payments on the new Doe Gas Plant, Mulligan marketing terminal, and Sundown Gas Plant expansion, all of which are expected to be commissioned in early 2017.

The following table summarizes the drill, complete and tie-in activities for the periods:

	Nine Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	Gross	**Net**	**Gross**	**Net**
Drilled	**96**	**84.21**	159	133.68
Completed (1)	**85**	**72.11**	138	118.47
Tied-in (1)	**13**	**10.10**	61	49.54

(1) A multi-well pad is included as a single completion and tie-in.

Exploration and production capital expenditures in 2016 are now forecast to be $825.0 million (including the acquisition and divestiture activity in the first quarter of 2016) which is $50.0 million higher than the previous guidance of $775.0 million disclosed in the Company's MD&A dated August 3, 2016. The Company expects drilling and completions costs of approximately $425.0 million, facilities expenditures (including equipment, pipelines and tie-ins) of $220.0 million, as well as, land and seismic expenditures of $15.0 million. The capital budget is closely monitored and will continue to be adjusted as required depending on cash flow available.

Acquisitions and Dispositions

2016

On January 29, 2016, the Company acquired assets in the Minehead-Edson-Ansell area of the Alberta Deep Basin for cash consideration of $183.0 million, before customary adjustments. The acquisition resulted in an increase in Property, Plant and Equipment ("PP&E") of approximately $179.2 million, an increase in Exploration and Evaluation ("E&E") assets of $4.8 million, and the assumption of $1.0 million in decommissioning liabilities. The assets acquired included land interests, production, reserves and facilities in the area.

On March 1, 2016, the Company sold non-core assets for cash consideration of $18.0 million, before customary adjustments.

2015

On April 1, 2015, the Company acquired Perpetual Energy Inc.'s ("Perpetual") interests in the West Edson area of the Alberta Deep Basin with the issuance of 6,750,000 Tourmaline shares at a price of $38.32 per share for total consideration of $258.7 million. The acquisition resulted in an increase in Property, Plant and Equipment ("PP&E") of approximately $226.9 million and an increase in Exploration and Evaluation ("E&E") assets of $34.2 million. The interests included Perpetual's land interests, production, reserves and facilities that were jointly-owned with Tourmaline.

On July 20, 2015, the Company acquired all of the issued and outstanding shares of Bergen Resources Inc. ("Bergen"). As consideration, the Company issued 725,000 common shares at a price of $33.90 per share for total consideration of $24.6 million. Total transaction costs incurred by the Company of $0.2 million associated with this acquisition were expensed in the consolidated statement of income and comprehensive income. The acquisition resulted in an increase in PP&E of approximately $26.8 million and E&E assets of $2.1 million. The acquisition of Bergen consolidated the Company's working interest in a core area of the Peace River High.

On August 14, 2015, the Company acquired all of the issued and outstanding shares of Mapan Energy Ltd. ("Mapan"). As consideration, the Company issued 2,718,026 common shares at a price of $32.98 per share for total consideration of $89.6 million. The acquisition resulted in an increase in PP&E of approximately $58.5 million. Total transaction costs incurred by the Company of $1.1 million associated with this acquisition were expensed in the consolidated statement of income and comprehensive income. The acquisition of Mapan provides for an increase in lands and production in the Alberta Deep Basin, one of the Company's core areas.

LIQUIDITY AND CAPITAL RESOURCES

On April 5, 2016, the Company issued 10,387,500 common shares at a price of $27.11 per share for total gross proceeds of $281.6 million (net proceeds - $269.9 million). The proceeds were used to temporarily reduce bank debt which were subsequently redrawn, to fund the Company's 2016 exploration and development program.

On May 17, 2016, the Company issued 1,320,000 flow-through common shares at a price of $35.50 per share, for total consideration of $46.9 million. The proceeds were used to temporarily reduce bank debt and then to fund the Company's 2016 exploration and development program.

The Company has a covenant-based, unsecured, bank credit facility in place with a syndicate of bankers in the amount of $1,800.0 million. In June 2016, the Company extended the term of the facility from three to four years resulting in a maturity of June 2020. In addition, the maximum ratio of senior debt to adjusted EBITDA was increased from 3.0 to 3.75 times and the maximum ratio of senior debt to total capitalization has increased from 0.5 to 0.55 times, respectively. The maturity date may, at the request of the Company and with consent of the lenders, be extended on an annual basis. The credit facility includes an expansion feature ("accordion") which allows the Company, upon approval from the lenders, to increase the facility amount by up to $500.0 million by adding a new financial institution or by increasing the commitment of its existing lenders. With the exception of the increase in length of term and the changes to the financial covenants, the debt was renewed under the same terms and conditions as those outlined in note 9 of the Company's consolidated financial statements for the year ended December 31, 2015. The Company also has a $50.0 million operating revolver, resulting in total bank credit facility capacity of $1,850.0 million. The facility can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus applicable margins, which range from 0.50% to 3.90% depending on the type of borrowing and the Company's senior debt to adjusted EBITDA ratio.

The Company also has a $250.0 million term loan with a Canadian Chartered Bank. The term loan can be drawn in either Canadian or U.S. funds and bears interest at the bank's prime lending rate, banker's acceptance rates or LIBOR (for U.S. borrowings), plus 220 basis points with a maturity of November 2020. The maturity date may, at the request of the Company and with consent of the lender, be extended on an annual basis. The covenants for the term loan are the same as those under the Company's current credit facility and the term loan will rank equally with the obligation under the Company's credit facility.

The Company's aggregate borrowing base capacity is $2.1 billion.

As at September 30, 2016, the Company had negative working capital of $148.4 million, after adjusting for the fair value of financial instruments (the unadjusted working capital deficiency was $162.3 million) (December 31, 2015 – $283.8 million and $247.4 million, respectively). As at September 30, 2016, the Company had $248.8 million in long-term debt outstanding and $992.2 million drawn against the revolving credit facility for total bank debt of $1,241.0 million (net of prepaid interest and debt issue costs) (December 31, 2015 - $1,266.6 million). Net debt at September 30, 2016 was $1,389.4 million compared to $1,550.4 million at December 31, 2015. The significant reduction in net debt can primarily be attributed to the April and May financings partially offset by property acquisitions during the first half of 2016. As at September 30, 2016, the Company is in compliance with all debt covenant calculations.

For 2016, management has continued to match the capital budget to cash flow and as such management believes the Company has sufficient resources to fund the remainder of its 2016 exploration and development programs. For the first nine months of 2016, E&P spending, excluding acquisitions and divestitures, was $462.1 million slightly lower than cash flow for the same period of $479.3 million. As at September 30, 2016, the Company had $840.5 million in unutilized borrowing capacity. The 2016 exploration and development program continues to be diligently monitored and adjusted as necessary depending on commodity prices in order to remain consistent with cash flow. Management is dedicated to keeping a strong balance sheet, which has proven to be very important, especially in times of depressed commodity prices.

SHARES AND STOCK OPTIONS OUTSTANDING

As at November 14, 2016, the Company has 235,988,606 common shares outstanding, 18,260,365 stock options granted and outstanding. The Company has also reserved 10,023,101 common shares, subject to closing adjustments, to be issued upon the closing of the acquisition of assets from Shell Canada Energy ("Shell Canada") and 21,758,700 subscription receipts to be converted to 21,758,700 common shares upon the closing of the acquisition of assets from Shell Canada. Further details on the acquisition have been included in note 13 of the Company's unaudited interim condensed consolidated financial statements as at and for the three and nine months ended September 30, 2016.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

In the normal course of business, the Company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

PAYMENTS DUE BY YEAR

(000s)	**1 Year**	**2-3 Years**	**4-5 Years**	**>5 Years**	**Total**
Firm transportation and processing agreements	203,070	448,643	405,350	1,073,103	2,130,166
Capital commitments (1)	308,828	603,364	258,364	28,835	1,199,391
Credit facility (2)	–	–	1,096,968	–	1,096,968
Term debt (3)	7,711	15,422	258,828	–	281,961
Flow-through share commitments	7,128	46,860	–	–	53,988
Operating leases	5,593	10,950	2,704	–	19,247
	$ 532,330	$ 1,125,239	$ 2,022,214	$1,101,938	$ 4,781,721

(1) Includes drilling commitments, and capital spending commitments under the joint arrangement in the Spirit River complex of $300.0 million per year until 2019. The capital spending commitment under the joint arrangement can be deferred to future periods in the event of an economic downturn, and as agreed upon by both parties. Since December 31, 2015, an economic downturn event, as defined in the joint arrangement in the Spirit River complex has existed and as such capital spending for 2016 may be reduced and extended to future years.

(2) Includes interest expense at an annual rate of 2.59% being the rate applicable to outstanding debt on the credit facility at September 30, 2016.

(3) Includes interest expense at an annual rate of 3.09% being the fixed rate on the term debt at September 30, 2016.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease arrangements, all of which are reflected in the commitments and contractual obligations table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities. The Company's financial risks are discussed in note 5 of the Company's audited consolidated financial statements for the year ended December 31, 2015.

As at September 30, 2016, the Company has entered into certain financial derivative contracts in order to manage commodity price and interest rate risk. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, even though the Company considers all commodity contracts to be effective economic hedges. Such financial derivative contracts are recorded on the consolidated statement of financial position at fair value, with changes in the fair value being recognized as an unrealized gain or loss on the consolidated statement of income and comprehensive income. The contracts that the Company has in place at September 30, 2016 are summarized and disclosed in note 3 of the Company's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2016 and 2015.

The Company has entered into physical delivery sales contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the consolidated financial statements. Physical contracts in place at September 30, 2016 have been summarized and disclosed in note 3 of the Company's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2016 and 2015.

Financial derivative and physical delivery contracts entered into subsequent to September 30, 2016 are detailed in note 3 of the Company's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2016 and 2015.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates. The Company's use of estimates and judgments in preparing the interim condensed consolidated financial statements is discussed in note 1 of the consolidated financial statements for the year ended December 31, 2015.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109. The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by National Instrument 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

There were no changes in the Company's DC&P or ICFR during the period beginning on July 1, 2016 and ending on September 30, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

The Company uses the guidelines as set in the Committee of Sponsoring Organizations of the Treadway Commission 2013 Internal Control-Integrated Framework.

BUSINESS RISKS AND UNCERTAINTIES

Tourmaline monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Tourmaline maintains a level of liability, property and business interruption insurance which is believed to be adequate for Tourmaline's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

See "Forward-Looking Statements" in this MD&A and "Risk Factors" in Tourmaline's most recent annual information form for additional information regarding the risks to which Tourmaline and its business and operations are subject.

IMPACT OF ENVIRONMENTAL REGULATIONS

The oil and gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. 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 and the imposition of material fines and penalties.

The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of the Company's business more expensive or prevent the Company from conducting its business as currently conducted. Tourmaline focuses on conducting transparent, safe and responsible operations in the communities in which its people live and work.

NON-GAAP FINANCIAL MEASURES

This MD&A or documents referred to in this MD&A make reference to the terms "cash flow", "operating netback", "working capital (adjusted for the fair value of financial instruments)", "net debt", "adjusted EBITDA", "senior debt", "total debt", and "total capitalization" which are not recognized measures under GAAP, and do not have a standardized meaning prescribed by GAAP. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the terms "cash flow", "operating netback", "working capital (adjusted for the fair value of financial instruments)" and "net debt", for its own performance measures and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the non-GAAP measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of the Company's performance. The terms "adjusted EBITDA", "senior debt", "total debt", and "total capitalization" are not used by management in measuring performance but are used in the financial covenants under the Company's credit facility. Under the Company's credit facility "adjusted EBITDA" means generally net income or loss, excluding extraordinary items, plus interest expense and income taxes and adjusted for non-cash items and gains or losses on dispositions, "senior debt" means the sum of drawn amounts on the credit facility, the term loan and outstanding letters of credit less cash and cash equivalents and excluding debt issue costs ("bank debt"), "total debt" means generally the sum of "senior debt" plus subordinated debt, Tourmaline currently does not have any subordinated debt, and "total capitalization" means generally the sum of the Company's shareholders' equity and all other indebtedness of the Company including bank debt, all determined on a consolidated basis in accordance with GAAP.

Cash Flow

A summary of the reconciliation of cash flow from operating activities (per the statements of cash flow), to cash flow, is set forth below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s)	**2016**	**2015**	**2016**	**2015**
Cash flow from operating activities (per GAAP)	**$ 185,067**	$ 261,398	**$ 504,767**	$ 606,796
Change in non-cash working capital	**464**	(64,298)	**(25,508)**	1,073
Cash flow	**$ 185,531**	$ 197,100	**$ 479,259**	$ 607,869

Operating Netback

Operating netback is calculated on a per boe basis and is defined as revenue (excluding processing income) less royalties, transportation costs and operating expenses, as shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/boe)	**2016**	**2015**	**2016**	**2015**
Revenue, excluding processing income	**$ 19.54**	$ 22.61	**$ 16.51**	$ 23.41
Royalties	**(0.77)**	(1.07)	**(0.54)**	(0.89)
Transportation costs	**(2.82)**	(1.98)	**(2.23)**	(2.07)
Operating expenses	**(3.26)**	(4.51)	**(3.46)**	(4.43)
Operating netback [(1)]	**$ 12.69**	$ 15.06	**$ 10.28**	$ 16.02

(1) May not add due to rounding.

Working Capital (Adjusted for the Fair Value of Financial Instruments)

A summary of the reconciliation of working capital to working capital (adjusted for the fair value of financial instruments) is set forth below:

(000s)	As at September 30, 2016	As at December 31, 2015
Working capital (deficit)	**$ (162,280)**	$ (247,391)
Fair value of financial instruments – short-term (net)	**13,849**	(36,392)
Working capital (deficit) (adjusted for the fair value of financial instruments)	**$ (148,431)**	$ (283,783)

Net Debt

A summary of the reconciliation of net debt is set forth below:

(000s)	As at September 30, 2016	As at December 31, 2015
Bank debt	**$ (1,240,970)**	$(1,266,604)
Working capital (deficit)	**(162,280)**	(247,391)
Fair value of financial instruments – short-term (net)	**13,849**	(36,392)
Net debt	**$ (1,389,401)**	$(1,550,387)

SELECTED QUARTERLY INFORMATION

	2016			2015				2014
($000s, unless otherwise noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
PRODUCTION								
Natural gas *(mcf)*	**82,363,542**	89,091,644	94,075,078	85,328,135	72,395,759	69,606,629	67,548,751	63,719,524
Oil and NGL*(bbls)*	**1,852,618**	2,060,260	2,141,099	2,302,708	1,761,403	1,469,591	1,677,123	1,426,951
Oil equivalent *(boe)*	**15,579,875**	16,908,867	17,820,279	16,524,064	13,827,363	13,070,696	12,935,248	12,046,872
Natural gas *(mcf/d)*	**895,256**	979,029	1,033,792	927,480	786,910	764,908	750,542	692,604
Oil and NGL *(bbls/d)*	**20,138**	22,640	23,529	25,030	19,146	16,149	18,635	15,510
Oil equivalent *(boe/d)*	**169,347**	185,812	195,828	179,610	150,297	143,634	143,725	130,944
FINANCIAL								
Total revenue from natural gas, oil and NGL sales, net of royalties	**292,495**	238,572	272,539	353,478	297,889	293,752	305,716	316,722
Cash flow from operating activities	**185,067**	143,392	176,308	228,959	261,398	151,028	194,370	201,188
Cash flow (1)	**185,531**	134,298	159,430	242,351	197,100	203,029	207,740	233,238
Per diluted share	**0.79**	0.58	0.72	1.10	0.90	0.95	1.01	1.14
Net earnings (loss)	**24,738**	(77,940)	(38,390)	34,636	28,489	(5,197)	22,159	265,210
Per basic share	**0.11**	(0.34)	(0.17)	0.16	0.13	(0.02)	0.11	1.31
Per diluted share	**0.10**	(0.34)	(0.17)	0.16	0.13	(0.02)	0.11	1.29
Total assets	**7,790,816**	7,694,141	7,844,728	7,640,671	7,471,042	7,071,801	6,801,583	6,622,303
Working capital (deficit)	**(162,280)**	(60,567)	(201,588)	(247,391)	(297,698)	(70,156)	(195,907)	(189,928)
Working capital (deficit)(adjusted for the fair value of financial instruments) (1)	**(148,431)**	(43,755)	(227,133)	(283,783)	(339,177)	(86,090)	(232,572)	(223,655)
Cash capital expenditures	**224,448**	49,010	414,857	325,499	422,629	290,629	497,382	152,135
Total outstanding shares *(000s)*	**234,966**	234,161	221,484	221,336	220,813	216,378	204,284	203,162
PER UNIT								
Natural *gas ($/mcf)*	**2.80**	1.87	2.20	2.99	3.20	3.17	3.69	4.09
Oil and NGL *($/bbl)*	**39.98**	38.94	33.60	47.65	45.91	53.34	43.13	55.91
Revenue *($/boe)*	**19.54**	14.61	15.66	22.08	22.61	22.85	24.84	28.25
Operating netback *($/boe)* (1)	**12.69**	8.63	9.71	15.22	15.06	16.37	16.70	20.23

(1) See Non-GAAP Financial Measures.

The oil and gas exploration and production industry is cyclical. The Company's financial position, results of operations and cash flows are principally impacted by production levels and commodity prices, particularly natural gas prices.

On an annual basis, the Company has had continued production growth over the last two years. The Company's average annual production has increased from 112,929 boe per day in 2014 to 154,403 boe per day in 2015 and

183,610 boe per day in the first nine months of 2016. The production growth can be attributed primarily to the Company's exploration and development activities, and from acquisitions of producing properties.

The Company's cash flow was $929.0 million in 2014, $850.2 million in 2015, and 2016 forecast cash flow is $760.8 million. The decrease in cash flow year-over-year continues to reflect the significant declines in commodity prices over the same periods. Commodity price fluctuations can indirectly impact expected production by changing the amount of funds available to reinvest in exploration, development and acquisition activities in the future. Changes in commodity prices impact revenue and cash flow available for exploration, and also the economics of potential capital projects as low commodity prices can potentially reduce the quantities of reserves that are commercially recoverable. The Company's capital program is dependent on cash flow generated from operations and access to capital markets.