CALGARY, Nov. 14, 2016 /CNW/ - Tourmaline Oil Corp. (TSX:TOU) ("Tourmaline" or the "Company") is pleased to announce strong financial and operating results for the third quarter of 2016.

HIGHLIGHTS

- Third quarter 2016 earnings of $24.7 million, underscoring the profitability of Tourmaline's three core resource plays.
- Third quarter 2016 cash flow(1) of $185.5 million, a 38% increase from second quarter of 2016.
- Record low operating costs of $3.26/boe in Q3 2016, a continuation of the quarterly trend of operating cost reduction and a 25% reduction from the full-year 2015 operating costs per boe.
- All-in cash costs of $7.25/boe (operating, transportation, general and administration and financing) in Q3 2016, down 4.1% from the full-year 2015 average.
- A realized natural gas price of $2.80/mcf, or $0.42 higher than the average AECO price of $2.38/mcf, continues to underscore the Company's emphasis on selling natural gas into multiple stronger markets throughout North America coupled with prudent financial hedging practices.
- Continued balance sheet strength highlighted by net debt(2) of $1.39 billion is driven primarily by a continued emphasis on managing E&P capital spending within available cash flow.
- On October 20, 2016, Tourmaline announced a strategic asset acquisition in the Alberta Deep Basin and NEBC Montney Complex (Gundy area assets) from Shell Canada for $1.369 billion, subject to closing adjustments. Upon closing, Tourmaline will acquire current production of approximately 24,850 boepd, estimated 2P reserves of 473.5 mmboe, a combined evaluated future drilling inventory of 2,147 locations, and a substantial increase in key midstream infrastructure.
- The Board of Directors has approved a $1.35 billion 2017 capital program, pro forma the Shell Canada acquisition.

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(1) "Cash flow" is defined as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Financial Measures" below and in the attached Management's Discussion and Analysis.

(2) "Net debt" is defined as long-term debt plus working capital (adjusted for the fair value of financial instruments). See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

FINANCIAL RESULTS AND CAPITAL PROGRAM

Third quarter 2016 cash flow of $185.5 million was 38% higher than Q2 2016 cash flow due to continued strong cost performance and higher than anticipated realized commodity pricing. Operating costs in Q3 2016 were $3.26/boe, the lowest in Company history. Third quarter earnings were $24.7 million; Tourmaline is profitable on a full-cycle basis in these low natural gas price environments due to continued emphasis and progress on both capital and cash cost control. The Company has also achieved the 15% 2H 2016 drill-and-complete capital cost reduction targets in all three core operated areas. This allows for the drilling of approximately 20 incremental new wells within the same capital budget for the 2017 EP capital program. Tourmaline plans to operate a 17-rig program in 2017, pro forma the Shell Canada acquisition, up from 12 rigs previously, and still execute a cash flow budget for the year. Third quarter EP capital spending was $180.6 million, compared to cash flow of $185.5 million and the Company plans on maintaining Q4 EP capital spending in line with forecast Q4 cash flow.

Tourmaline completed two modest acquisitions in the third quarter of 2016 - at Obed in the Deep Basin and at Dawson in NEBC, for a total of $37.6 million. These acquisitions added approximately 1,250 boepd, 7.5 mmboe of 2P reserves (Company estimate), and 112 future locations. Both assets will be tied into Tourmaline infrastructure. The Obed property is joint with Shell Canada and Tourmaline will subsequently acquire the balance of the property with the closing of the Shell Canada transaction at the end of November. With expansion of the operated rig fleet to 14 rigs during the fourth quarter of 2016, Tourmaline now expects E&P capital spending of $825.0 million for full year 2016.

The Tourmaline Board of Directors has approved a 2017 EP capital budget of $1.35 billion pro forma the Shell Canada transaction, including the drilling of 300 wells (gross), completion of the Doe BC 2-11 gas plant, completion of the Spirit River 3-10 gas plant expansion, compressor expansion at the Wild River 14-20 gas plant and construction of the new Sundown pipeline lateral. Approximately 45 of the 300 planned wells in 2017 will be on the Shell Canada assets.

Tourmaline continues to maintain a very strong balance sheet and a low debt to cash flow ratio. The Company is expecting debt to cash flow of approximately 1.0 times in 2017 pro forma the Shell Canada transaction and the $1.35 billion capital program. The 2017 capital program is less than anticipated 2017 cash flow of $1.44 billion.

PRODUCTION OUTLOOK

Tourmaline expects to achieve the 2016 exit production target of 210,000-215,000 boepd in late November. The Company is now expecting full-year 2017 average production of 225,000 boepd, up from 215,000 boepd previously, not including the Shell Canada transaction.

Pro forma the Shell Canada transaction, Tourmaline is expecting average production between 250,000 and 260,000 boepd in 2017, representing year-over-year growth of over 30%. The Company is expecting a further 20-25% growth in production in 2018.

A combination of weather-related activity delays, third party plant turnarounds, NGL volume reductions due to a fire-related curtailment at a third party deep cut facility, and continued firm service cutbacks in Alberta and BC led to Q3 2016 production levels of 169,347 boepd, approximately 8% lower than Q2 2016. The Company is still on track to achieve full-year average production of 190,000-195,000 boepd, yielding approximately 25% year-over-year growth.

As previously disclosed, the Company has over 100 new wells coming on-production in the second half of the year; almost all of these wells will now start-up in the fourth quarter. The Company has brought over 30,000 boepd of new production on-production to date in the fourth quarter.

EP UPDATE

- Tourmaline is currently operating 14 drilling rigs with nine in the Alberta Deep Basin, two in NEBC and three on the Peace River High.
- The Company plans to bring approximately 100 wells on-production between September and December - 42 of those wells have been started up since mid-September.
- The 4-13-83-8 W6 Upper Charlie Lake well at Earring-Mulligan has averaged 658 bpd of 31 API oil and 0.7 mmcfpd of natural gas over the first 42 days of production (768 boepd).
- The Spirit River 6-1-78-7 W6 Upper Charlie Lake well has averaged 865 bbls/day oil and 1.8 mmcfpd of natural gas over the first 22 days of production.
- The first Lower Charlie Lake step-out to the two December 2015 discoveries averaged 1,379 bpd of 35 API oil and 2.1 mmcfpd of sweet gas (1,730 boepd) over the first 30 days of production. Cumulative oil production to date is 50,204 bbls. The Company expects to have five additional Lower Charlie Lake horizontals on-production during the fourth quarter as the Company continues to delineate this new pool.
- The Company continues to drive down drill-and-complete capital costs in all three core operated areas with the second half 2016 EP program. Average drill-and-complete costs for the NEBC Montney horizontals are $2.75 million over the last 12 wells (30 stages). Average drill-and-complete costs for the Peace River High Charlie Lake oil complex horizontals are $2.4 million over the last 12 wells vs a target of $2.7 million (27 stages). Average drill-and-complete costs for the Alberta Deep Basin Cretaceous horizontals are $3.67 million over the last 20 wells vs a target of $4.4 million (22-24 stages).
- The Company's most recent Montney Turbidite well at Doe is flowing 692 bbls/day of 61.3° API condensate and 3.2 mmcfpd of natural gas on the second day of in-line production testing.
- The Company's most recent Wilrich horizontal well at Minehead in the Alberta Deep Basin is producing 36 mmcfpd at a flowing casing pressure of 25.3 MPa on the seventh day of in-line production testing.

CORPORATE SUMMARY – THIRD QUARTER 2016

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
OPERATIONS						
Production						
Natural gas (mcf/d)	895,256	786,910	14%	969,089	767,587	26%
Crude oil and NGL (bbl/d)	20,138	19,146	5%	22,095	17,978	23%
Oil equivalent (boe/d)	169,347	150,297	13%	183,610	145,909	26%
Product prices(1)						
Natural gas ($/mcf)	$ 2.80	$ 3.20	(13)%	$ 2.28	$ 3.35	(32)%
Crude oil and NGL ($/bbl)	$ 39.98	$ 45.91	(13)%	$ 37.37	$ 47.19	(21)%
Operating expenses ($/boe)	$ 3.26	$ 4.51	(28)%	$ 3.46	$ 4.43	(22)%
Transportation costs ($/boe)	$ 2.82	$ 1.98	42%	$ 2.23	$ 2.07	8%
Operating netback ($/boe)(3)	$ 12.69	$ 15.06	(16)%	$ 10.28	$ 16.02	(36)%
Cash general and administrative expenses ($/boe)(2)	$ 0.49	$ 0.56	(13)%	$ 0.46	$ 0.50	(8)%
FINANCIAL ($000, except share and per share)						
Revenue	304,480	312,644	(3)%	830,711	932,643	(11)%
Royalties	11,985	14,755	(19)%	27,105	35,286	(23)%
Cash flow(3)	185,531	197,100	(6)%	479,259	607,869	(21)%
Cash flow per share (diluted)(3)(4)	$ 0.79	$ 0.90	(12)%	$ 2.09	$ 2.86	(27)%
Net earnings (loss)	24,738	28,489	(13)%	(91,592)	45,451	(302)%
Net earnings (loss) per share (diluted)(4)	$ 0.10	$ 0.13	(23)%	$ (0.40)	$ 0.21	(290)%
Capital expenditures (net of dispositions)	224,448	422,629	(47)%	688,315	1,210,640	(43)%
Weighted average shares outstanding						
(diluted)				229,507,106	212,561,337	8%
Net debt(3)				(1,389,401)	(1,484,095)	(6)%

(1) Product prices include realized gains and losses on financial instrument contracts.

(2) Excluding interest and financing charges.

(3) See "Non-GAAP Financial Measures" in the attached Management's Discussion and Analysis.

(4) 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.

Conference Call Tomorrow at 8:00 a.m. MST (10:00 a.m. EST)

Tourmaline will host a conference call tomorrow, November 15, 2016 starting at 8:00 a.m. MST (10:00 a.m. EST). To participate, please dial 1-888-231-8191 (toll-free in North America), or local dial-in 647-427-7450, a few minutes prior to the conference call.

Conference ID number is 91127771.

Reader Advisories

CURRENCY

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION

This press release contains forward-looking information within the meaning of applicable securities laws. The use of any of the words "forecast", "expect", "guidance", "target", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information. More particularly and without limitation, this press release contains forward-looking information concerning Tourmaline's plans and other aspects of its anticipated future operations, management focus, objectives, strategies, financial, operating and production results and business opportunities, including anticipated potential benefits of and opportunities associated with the Deep Basin Assets and the Montney Assets, the closing and timing of closing of the Shell Canada acquisition, the use of proceeds of the associated equity financings, anticipated petroleum and natural gas production for various periods, drilling inventory or locations, cash flow levels, capital spending, cost reduction initiatives, projected operating and drilling costs, projected operating netbacks, the timing for facility expansions and facility start-up dates, as well as Tourmaline's future drilling prospects and plans, business strategy, future development and growth opportunities, prospects and asset base. The forward-looking information is based on certain key expectations and assumptions made by Tourmaline, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve volumes; operating costs the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the state of the economy and the exploration and production business; the availability and cost of financing, labour and services; ability to market crude oil, natural gas and NGL successfully; and the completion of the Shell Canada acquisition on the terms and timing contemplated.

Statements relating to "reserves" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Although Tourmaline believes that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Tourmaline can give no assurances that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature it involves inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, production, revenues, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions including the Shell Canada acquisition; ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; and changes in legislation, including but not limited to tax laws, royalties and environmental regulations. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect Tourmaline, or its operations or financial results, are included in the Company's most recently filed Management's Discussion and Analysis (See "Forward-Looking Statements" therein), Annual Information Form (See "Risk Factors" and "Forward-Looking Statements" therein) and other reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or Tourmaline's website (www.tourmalineoil.com).

The forward-looking information contained in this press release is made as of the date hereof and Tourmaline undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless expressly required by applicable securities laws.

BOE CONVERSIONS

Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

RESERVES DATA

This news release contains references to estimates of gross 2P reserves attributed to the assets located in the Alberta Deep Basin (the "Deep Basin Assets"), the NEBC Montney Complex (the "the Montney Assets") and at Obed in the Alberta Deep Basin and Dawson in NEBC (the "Additional Deep Basin and NEBC Assets"). Gross reserves are the total working interest reserves before the deduction of any royalties and including any royalty interests receivable. The reserve estimates are based on, in the case of the Montney Assets, a report prepared by GLJ Petroleum Consultants Ltd. effective June 30, 2016 (the "GLJ Montney Report"), in the case of the Deep Basin Assets, a Tourmaline internal evaluation prepared by a qualified reserves evaluator in accordance with National Instrument 51-101 and the COGE Handbook effective October 1, 2016 (the "Internal Deep Basin Evaluation") and in the case of the Additional Deep Basin and NEBC Assets, a Tourmaline internal evaluation prepared by a qualified reserves evaluator in accordance with National Instrument 51-101 and the COGE Handbook effective June 1, 2016 (the "Internal Additional Assets Evaluation"). Such reserve estimates are subject to the same limitations discussed above under "Forward?Looking Information".

"2P reserves" means proved plus probable reserves. "Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.

This news release contains certain oil and gas metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate the Company's performance however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the Company's performance in previous periods and therefore such metrics should not be unduly relied upon.

FINANCIAL OUTLOOK

Also included in this news release are estimates of Tourmaline's cash flow, operating netbacks and pro forma operating netbacks, capital expenditures, and other assumptions disclosed in this news release and including Tourmaline's estimated 2017 average production of 225,000 boepd (250,000-260,000 boepd based on a pro forma basis) and 2018 estimated increase of average production of 20-25%, on a pro forma basis, and commodity price assumptions for natural gas (AECO - $3.06/mcf for 2017 and 2018), and crude oil (WTI (US) - $60.00/bbl for 2017 and 2018) and an exchange rate assumption of $0.80 (US/CAD) for 2017 and 2018. To the extent that such estimate constitutes a financial outlook, they were approved by management of Tourmaline on the date hereof and are included to provide readers with an understanding of Tourmaline's anticipated cash flow, operating netbacks and anticipated future business operations, including the anticipated effect of the Acquisition on the Company's business operations based on the capital expenditure, production and other assumptions described herein and readers are cautioned that the information may not be appropriate for other purposes. Tourmaline disclaims any intention or obligation to update or revise any future-oriented financial information or financial outlook information contained in this news release, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

NON-GAAP FINANCIAL MEASURES

This press release includes references to financial measures commonly used in the oil and gas industry, "cash flow", and "operating netbacks", which do not have a standardized meaning prescribed by International Financial Reporting Standards ("GAAP"). Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. "Cash flow" is defined as cash flow from operations adjusted for non-cash working capital. "Operating netbacks" are calculated on a per-boe basis and are defined as revenue (excluding processing income) less royalties, transportation costs and operating expenses. Management uses the terms "cash flow" and "operating netbacks" for its own performance measures and to provide shareholders and potential investors with a measurement of the Company's efficiency. Readers 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.

ESTIMATED DRILLING INVENTORY

This press release discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 2,259 undrilled locations disclosed in this presentation, 115 are proved undeveloped locations, 363 are probable undeveloped locations, and 1,781 are unbooked. Proved undeveloped locations and probable undeveloped locations are booked and derived from the GLJ Montney Report, the Internal Deep Basin Evaluation and the Internal Additional Assets Evaluation and account for drilling locations that have associated proved and/or probable reserves, as applicable.

Unbooked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

PRODUCTION TESTS

Any references in this release to initial production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue to produce and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

CERTAIN DEFINITIONS:

bbl	barrel
bbls/day	barrels per day
bbl/mmcf	barrels per million cubic feet
bcf	billion cubic feet
bpd or bbl/d	barrels per day
boe	barrel of oil equivalent
boepd or boe/d	barrel of oil equivalent per day
bopd or bbl/d	barrel of oil, condensate or liquids per day
FCP	final circulating pressure
gj	gigajoule
gjs/d	gigajoules per day
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd or mcf/d	thousand cubic feet per day
mcfe	thousand cubic feet equivalent
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmbtu/d	million British thermal units per day
mmcf	million cubic feet
mmcfpd or mmcf/d	million cubic feet per day
MPa	megapascal
mstboe	thousand stock tank barrels of oil equivalent
NGL	natural gas liquids

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s) except per unit amounts	2016	2015	Change	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")

	Three Months Ended September 30,			Nine Months Ended September 30,		
(000s) except per unit amounts	2016	2015	Change	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

$

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.

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(000s) (unaudited)	September 30, 2016	December 31, 2015
Assets		
Current assets:		
Accounts receivable	$ 137,226	$ 175,624
Prepaid expenses and deposits	12,759	14,769
Fair value of financial instruments (note 3)	1,223	39,677
Total current assets	151,208	230,070
Long-term asset	6,196	6,688
Fair value of financial instruments (note 3)	116	?
Exploration and evaluation assets (note 4)	644,129	620,142
Property, plant and equipment (note 5)	6,989,167	6,783,771
Total Assets	$ 7,790,816	$ 7,640,671
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 298,416	$ 474,176
Fair value of financial instruments (note 3)	15,072	3,285
Total current liabilities	313,488	477,461
Bank debt (note 7)	1,240,970	1,266,604
Fair value of financial instruments (note 3)	35,561	9,701
Deferred premium on flow-through shares (note 9)	10,661	5,982
Decommissioning obligations (note 6)	190,008	163,459
Deferred taxes	461,625	485,888
Shareholders' equity:		
Share capital (note 9)	4,650,801	4,266,234
Non-controlling interest (note 8)	27,155	28,431
Contributed surplus	187,186	171,958
Retained earnings	673,361	764,953
Total shareholders' equity	5,538,503	5,231,576
Total Liabilities and Shareholders' Equity	$ 7,790,816	$ 7,640,671

Commitments (note 12).

Subsequent events (notes 3 and 13).

See accompanying notes to the interim condensed consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s) except per-share amounts (unaudited)	2016	2015	2016	2015
Revenue:				
Oil and natural gas sales	$ 283,124	$ 267,210	$ 722,662	$ 781,990
Royalties	(11,985)	(14,755)	(27,105)	(35,286)
Net revenue from oil and natural gas sales	271,139	252,455	695,557	746,704
Realized gain on financial instruments	21,356	45,434	108,049	150,653
Unrealized gain (loss) on financial instruments (note 3)	16,728	27,874	(75,985)	11,196
Other income	6,124	7,941	19,774	22,322
Total net revenue	315,347	333,704	747,395	930,875
Expenses:				
Operating	50,754	62,299	174,274	176,637
Transportation	43,998	27,384	112,409	82,510
General and administration	7,693	7,682	23,239	19,913
Share-based payments (note 11)	5,273	7,585	17,580	24,009
(Gain) on divestitures	?	?	(7,074)	(35,232)
Depletion, depreciation and amortization	159,861	174,772	509,186	520,105
Total expenses	267,579	279,722	829,614	787,942
Income (loss) from operations	47,768	53,982	(82,219)	142,933
Finance expenses	11,431	11,986	35,640	33,520
Income (loss) before taxes	36,337	41,996	(117,859)	109,413
Deferred taxes (recovery)	11,793	13,969	(24,991)	65,232
Net income (loss) and comprehensive income (loss) before non-controlling interest	24,544	28,027	(92,868)	44,181
Net income (loss) and comprehensive income (loss)				
attributable to:				
Shareholders of the Company	24,738	28,489	(91,592)	45,451
Non-controlling interest (note 8)	(194)	(462)	(1,276)	(1,270)
	$ 24,544	$ 28,027	$ (92,868)	$ 44,181
Net income (loss) per share attributable to common shareholders (note 10)				
Basic	$ 0.11	$ 0.13	$ (0.40)	$ 0.22
Diluted	$ 0.10	$ 0.13	$ (0.40)	$ 0.21

See accompanying notes to the interim condensed consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s) (unaudited)	Share Capital	Contributed Surplus	Retained Earnings	Non-Controlling Interest	Total Equity
Balance at December 31, 2015	$ 4,266,234	$ 171,958	$ 764,953	$ 28,431	$ 5,231,576
Issue of common shares (note 9)	319,423	-	-	-	319,423
Share issue costs, net of tax (note 9)	(10,009)	-	-	-	(10,009)
Share-based payments	-	17,580	-	-	17,580
Capitalized share-based payments	-	17,580	-	-	17,580
Options exercised (note 9)	75,153	(19,932)	-	-	55,221
Loss attributable to common shareholders	-	-	(91,592)	-	(91,592)
Loss attributable to non-controlling interest	-	-	-	(1,276)	(1,276)
Balance at September 30, 2016	$ 4,650,801	$ 187,186	$ 673,361	$ 27,155	$ 5,538,503

(000s) (unaudited)	Share Capital	Contributed Surplus	Retained Earnings	Non-Controlling Interest	Total Equity
Balance at December 31, 2014	$ 3,615,378	$ 124,325	$ 684,866	$ 30,006	$ 4,454,575
Issue of common shares (note 9)	221,108	-	-	-	221,108
Issue of common shares on acquisitions (note 9)	372,878	-	-	-	372,878
Share issue costs, net of tax	(6,562)	-	-	-	(6,562)
Share-based payments	-	24,009	-	-	24,009
Capitalized share-based payments	-	24,009	-	-	24,009
Options exercised (note 9)	49,968	(13,717)	-	-	36,251
Income attributable to common shareholders	-	-	45,451	-	45,451
Loss attributable to non-controlling interest	-	-	-	(1,270)	(1,270)
Balance at September 30, 2015	$ 4,252,770	$ 158,626	$730,317	$ 28,736	$ 5,170,449

See accompanying notes to the interim condensed consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(000s) (unaudited)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Cash provided by (used in):				
Operations:				
Net income (loss)	$ 24,738	$ 28,489	$ (91,592)	$ 45,451
Items not involving cash:				
Depletion, depreciation and amortization	159,861	174,772	509,186	520,105
Accretion	775	788	2,278	2,038
Share-based payments	5,273	7,585	17,580	24,009
Deferred taxes (recovery)	11,793	13,969	(24,991)	65,232
Unrealized (gain) loss on financial instruments	(16,728)	(27,874)	75,985	(11,196)
(Gain) on divestitures	-	-	(7,074)	(35,232)
Amortization on long-term asset	166	-	492	-
Non-controlling interest	(194)	(462)	(1,276)	(1,270)
Decommissioning expenditures	(153)	(167)	(1,329)	(1,268)
Changes in non-cash operating working capital	(464)	64,298	25,508	(1,073)
Total cash flow from operating activities	185,067	261,398	504,767	606,796
Financing:				
Issue of common shares	23,365	18,210	383,684	263,676
Share issue costs	-	(3)	(13,642)	(9,386)
Increase/(decrease) in bank debt	(89,124)	(38,785)	(25,634)	239,808
Total cash flow from/(used in) financing activities	(65,759)	(20,578)	344,408	494,098
Investing:				
Exploration and evaluation	(24,026)	(38,785)	(38,030)	(106,834)
Property, plant and equipment	(162,788)	(389,033)	(442,836)	(1,019,128)
Property acquisitions	(37,634)	(955)	(225,449)	(91,341)
Proceeds from divestitures	-	6,144	18,000	6,663
Net repayment of long-term obligation	-	(671)	-	(2,402)
Changes in non-cash investing working capital	105,140	182,480	(160,860)	(150,904)
Total cash flow used in investing activities	(119,308)	(240,820)	(849,175)	(1,363,946)
Changes in cash	-	-	-	(263,052)
Cash, beginning of period	-	-	-	263,052
Cash, end of period	$ -	$ -	$ -	$ -

Cash is defined as cash and cash equivalents.

See accompanying notes to the interim condensed consolidated financial statements.

NOTES TO THE INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

AS AT SEPTEMBER 30, 2016 AND FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016 AND 2015

(tabular amounts in thousands of dollars, unless otherwise noted) (unaudited)

Corporate Information:

Tourmaline Oil Corp. (the "Company") was incorporated under the laws of the Province of Alberta on July 21, 2008. The Company is engaged in the acquisition, exploration, development and production of petroleum and natural gas properties. These unaudited interim condensed consolidated financial statements reflect only the Company's proportionate interest in such activities.

The Company's registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada T2P 1G1.

1. BASIS OF PREPARATION

These unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting". These unaudited interim condensed consolidated financial statements do not include all of the information and disclosure required in the annual financial statements and should be read in conjunction with the Company's consolidated financial statements for the year ended December 31, 2015.

The accounting policies and significant accounting judgments, estimates, and assumptions used in these unaudited interim condensed consolidated financial statements are consistent with those described in Notes 1 and 2 of the Company's consolidated financial statements for the year ended December 31, 2015, except as noted below.

On January 1, 2016, the Company adopted the amendments made to IFRS 11 – Joint Arrangements, which provided new guidance on the accounting for the acquisition of an interest in a joint operation that constitutes a business. There was no impact on the Company as a result of adopting the amended standard.

The unaudited interim condensed consolidated financial statements were authorized for issue by the Board of Directors on November 14, 2016.

2. DETERMINATION OF FAIR VALUE

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Tourmaline classifies the fair value of transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The fair value of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities approximate their carrying amounts due to their short term nature. Bank debt bears interest at a floating market rate with applicable variable margins, and accordingly the fair market value approximates the carrying amount. The Company's financial instruments have been assessed on the fair value hierarchy described above and classified as Level 2.

3. 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 consistent with those discussed in note 5 of the Company's 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, foreign exchange 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 and interest rate contracts to be effective economic hedges. As a result, all such contracts are recorded on the condensed interim consolidated statement of financial position at fair value, with changes in the fair value being recognized as an unrealized gain or loss on the condensed interim consolidated statement of income (loss) and comprehensive income (loss).

The Company has the following financial derivative commodity contracts in place as at September 30, 2016 (1):

(000s)		2016	2017	2018	2019	2020	Fair Value
Gas							
Financial swaps	mmbtu/d	101,957	15,068	4,932	–	–	$ 548
	USD$/mmbtu	$ 3.02	$ 3.11	$ 3.11			
NYMEX call options							
(writer) (2)	mmbtu/d	–	110,000	110,000	90,000	20,000	$ (25,031)
	USD$/mmbtu		$ 3.77	$ 3.77	$ 3.94	$ 3.75	
Oil							
Financial swaps	bbls/d	3,500	3,000	–	–	–	$ (2,222)
	USD$/bbl	$ 49.28	$ 49.63				
Financial call							
swaptions (3)	bbls/d	400	4,000	2,125	–	–	$ (12,646)
	USD$/bbl	$ 80.10	$ 62.45	$ 52.18			
Total Fair Value							$ (39,351)

(1) The volumes and prices reported are the weighted-average volumes and prices for the period.

(2) These are European calls whereby the counterparty can exercise the option monthly on a particular day to purchase NYMEX at a specified price.

(3) These are European and Asian swaptions whereby the Company provides the option to extend an oil swap into the period subsequent to the call date, or retroactively fix the price on the volumes under the contract.

The Company has entered into the following financial derivative commodity contracts subsequent to September 30, 2016:

Type of Contract	Quantity	Time Period	Contract Price
Gas Financial swaps	30,000 mmbtu/d	November 2016	USD$3.23/mmbtu
Gas Financial swaps	20,000 mmbtu/d	December 2016	USD$3.47/mmbtu
Gas Financial swaps	10,000 mmbtu/d	April 2017 – December 2017	USD$3.19/mmbtu

The Company has the following interest rate swap arrangements:

(000s)					
Term	Type (Floating to Fixed)	Amount	Company Fixed Interest Rate	Counter Party Floating Rate Index	Fair Value
Apr 5, 2016 – Apr 5, 2019	Swap	$ 50,000	0.867%	Floating Rate	$ 1
Nov 28, 2014 – Nov 28, 2019	Swap	$ 250,000	2.065%	Floating Rate	$ (9,322)
Jun 6, 2016 – Jun 6, 2020	Swap	$ 50,000	1.025%	Floating Rate	$ (276)
Apr 5, 2016 – Apr 5, 2021	Swap	$ 50,000	0.988%	Floating Rate	$ (205)
Jun 13, 2016 – Jun 13, 2021	Swap	$ 25,000	0.973%	Floating Rate	$ (85)
Aug 31, 2016 – Aug 31, 2021	Swap	$ 25,000	0.958%	Floating Rate	$ (61)
Sep 30, 2016 – Sep 28, 2021	Swap	$ 25,000	0.900%	Floating Rate	$ 17
Nov 28, 2019 – Nov 28, 2022	Swap	$ 50,000	1.025%	Floating Rate	$ (12)
Total Fair Value					$ (9,943)

The following table provides a summary of the unrealized gains (losses) on financial instruments recorded in the interim condensed consolidated statements of income (loss) and comprehensive income (loss) for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000s)	2016	2015	2016	2015
Unrealized gain/(loss) on financial instruments				
– commodity contracts	$ 15,689	$ 29,063	$ (76,420)	$ 17,922
Unrealized gain/(loss) on financial instruments				
– interest rate swaps	1,039	(1,189)	435	(6,726)
Total unrealized gain/(loss) on financial instruments	$ 16,728	$ 27,874	$ (75,985)	$ 11,196

In addition to the financial commodity contracts discussed above, 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 interim condensed consolidated financial statements.

The Company has the following physical contracts in place at September 30, 2016 [(1)(7)]:

		2016	2017	2018	2019	2020
Gas						
Fixed price – AECO	mcf/d	289,308	58,114	–	–	–
	CAD$/mcf	$ 2.38	$ 2.47	–	–	–
Basis differentials (2)(3)	mmbtu/d	171,087	76,678	57,500	57,500	57,500
	USD$/mmbtu	$ (0.53)	$ (0.61)	$ (0.62)	$ (0.62)	$ (0.62)
Basis differentials – Stn 2 (4)	mcf/d	52,151	45,463	47,928	19,482	17,811
	CAD$/mcf	$ (0.33)	$ (0.24)	$ (0.22)	$ (0.10)	$ (0.12)
AECO monthly calls /	mcf/d	10,430	75,857	71,116	–	–
call swaptions (5)	CAD$/mcf	$ 5.56	$ 4.60	$ 4.25	–	–
Oil						
Fixed differential (6)	bbls/d	2,328	962	–	–	–
	USD$/bbl	$ (6.78)	$ (6.84)	–	–	–

(1) The volumes and prices reported are the weighted-average volumes and prices for the period.

(2) Tourmaline also has 39.3 mmcf/d of NYMEX-AECO basis differentials at $(0.67) from 2021-2024.

(3) Tourmaline also has 10,000 mmbtu/d SoCal – AECO basis differential at $(0.73) until October 2016.

(4) Tourmaline also has 9,482 mcf/d of Stn 2. basis differentials at $(0.26) for 2021.

(5) These are monthly calls for 2016 and in 2017 are European Swaptions, whereby the Company provides the option to extend a gas swap into the period subsequent to the call date or increase the volumes under contract. In 2018, there is a combination of monthly calls and European Swaptions.

(6) Tourmaline sells physical crude at a fixed differential to NYMEX.

(7) Tourmaline also has entered into deals to sell 30,000 mmbtu/d at Chicago GDD pricing less transportation costs from April 2015 to October 2020; 20,000 mmbtu/d at Chicago GDD pricing less transportation costs from April 2015 to March 2020; and 20,000 mmbtu/d at Ventura GDD pricing less transportation costs from April 2015 to October 2020.

The Company has entered into the following physical contracts subsequent to September 30, 2016:

Type of Contract	Quantity	Time Period	Contract Price
Gas Fixed Price – AECO	25,000 GJs/d	April 2017 – October 2017	CAD$2.87/GJ
Gas Fixed Price – AECO	20,000 GJs/d	April 2017 – December 2017	CAD$2.85/GJ
Gas Basis Differentials	20,000 mmbtu/d	January 2018 – December 2024	USD($0.69)/mmbtu

4. EXPLORATION AND EVALUATION ASSETS

(000s)	
As at December 31, 2015	$ 620,142
Capital expenditures	38,030
Transfers to property, plant and equipment (note 5)	(14,909)
Acquisitions	16,220
Divestitures	(743)
Expired mineral leases	(14,611)
As at September 30, 2016	$ 644,129

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven and probable reserves, as well as undeveloped land. Additions represent the Company's share of costs on E&E assets during the period.

Impairment Assessment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At September 30, 2016 and December 31, 2015, the Company determined that no indicators of impairment existed on its E&E assets; therefore, impairment tests were not performed.

5. PROPERTY, PLANT AND EQUIPMENT

Cost

(000s)	
As at December 31, 2015	$ 8,685,985
Capital expenditures	460,416
Transfers from exploration and evaluation (note 4)	14,909
Change in decommissioning liabilities (note 6)	24,576
Acquisitions	219,702
Divestitures	(19,918)
As at September 30, 2016	$ 9,385,670

Accumulated Depletion, Depreciation and Amortization

(000s)	
As at December 31, 2015	$ 1,902,214
Depletion, depreciation and amortization	494,575
Divestitures	(286)
As at September 30, 2016	$ 2,396,503

Net Book Value

(000s)	
As at December 31, 2015	$ 6,783,771
As at September 30, 2016	$ 6,989,167

Future development costs of $4,890.7 million were included in the depletion calculation at September 30, 2016 (December 31, 2015 – $4,523.1 million).

Capitalization of G&A and Share-Based Payments

A total of $17.9 million in G&A expenditures have been capitalized and included in E&E and PP&E assets at September 30, 2016 (December 31, 2015 – $22.9 million). Also included in E&E and PP&E are non-cash share-based payments of $17.6 million (December 31, 2015 - $30.8 million).

Impairment Assessment

In accordance with IFRS, an impairment test is performed on a Cash Generating Unit ("CGU") if the Company identifies an indicator of impairment. At September 30, 2016, the Company determined that there were no indicators of impairment on any of the Company's CGUs; therefore, an impairment test was not performed.

For the year ended December 31, 2015, the Company identified indicators of impairment on all of its CGUs due to the decline in current and forward commodity prices for oil and natural gas and performed impairment tests accordingly. The Company determined that there was no impairment to PP&E at December 31, 2015.

Business Combinations

Minehead-Edson-Ansell

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 lands, production, reserves and facilities in a core area of the Alberta Deep Basin.

Results from operations are included in the Company's unaudited interim condensed consolidated financial statements from the closing date of the transaction. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	Minehead-Edson-Ansell	
Fair value of net assets acquired:		
Property, plant and equipment	$	179,230
Exploration and evaluation		4,753
Decommissioning obligations		(983)
Total	$	183,000
Consideration:		
Cash	$	183,000

Perpetual Energy Inc.

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 land, production, reserves and processing capacity along with allowing the Company to leverage operational synergies created from having full ownership of the assets.

Results from operations are included in the Company's unaudited interim condensed consolidated financial statements from the closing date of the transaction. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	Perpetual Energy Inc.	
Fair value of net assets acquired:		
Property, plant and equipment	$	226,943
Exploration and evaluation		34,160
Decommissioning obligations		(2,443)
Total	$	258,660
Consideration:		
Common shares issued	$	258,660

Corporate Acquisitions

Bergen Resources Inc.

On July 20, 2015, the Company acquired all of the issued and outstanding shares of Bergen Resources Inc. ("Bergen"). As consideration, the Company issued of 725,000 Tourmaline 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 interim condensed consolidated statement of income (loss) and comprehensive income (loss). The acquisition resulted in an increase in Property, Plant and Equipment ("PP&E") of approximately $26.8 million and Exploration and Evaluation ("E&E") assets of $2.1 million along with net debt of $8.4 million. Results from operations for Bergen are included in the Company's unaudited interim consolidated financial statements from the closing date of the transaction. The acquisition of Bergen consolidated the Company's working interest in a core area of the Peace River High.

Mapan Energy Ltd.

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

Results from operations for Mapan are included in the Company's unaudited interim condensed consolidated financial statements from the closing date of the transaction. The acquisition has been accounted for using the purchase method based on fair values as follows:

(000s)	Mapan Energy Ltd.
Fair value of net assets acquired:	
Cash	$ 11,011
Working capital	4,000
Property, plant and equipment	58,471
Fair value of financial instruments	(122)
Decommissioning obligations	(3,157)
Deferred income tax asset	19,437
Total	$ 89,640
Consideration:	
Common shares issued	$ 89,640

Acquisitions and Dispositions of Oil and Natural Gas Properties

For the nine months ended September 30, 2016, the Company completed property cash acquisitions for total cash consideration of $42.5 million excluding the Minehead-Edson-Ansell acquisition (December 31, 2015 - $92.0 million). There were also $8.0 million in acquisitions involving non-cash consideration (December 31, 2015 - $73.4 million). The Company also assumed $1.4 million in decommissioning liabilities in addition to the Minehead-Edson-Ansell acquisition (December 31, 2015 - $3.0 million).

On March 1, 2016, the Company sold non-core assets for cash consideration of $18.0 million, before customary adjustments. The net book value of the oil and natural gas properties disposed was equal to the cash consideration received.

6. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $241.0 million (December 31, 2015 – $224.5 million), with some abandonments expected to commence in 2021. A risk-free rate of 1.72% (December 31, 2015 – 2.15%) and an inflation rate of 1.8% (December 31, 2015 – 1.8%) were used to calculate the decommissioning obligations. The downward adjustment during the year in the risk-free rate used to calculate decommissioning obligations resulted in the majority of the increase in future estimated cash outlays.

(000s)	As at September 30, 2016	As at December 31, 2015
Balance, beginning of period	$ 163,459	$ 114,038
Obligation incurred	7,972	16,780
Obligation incurred on corporate acquisitions	?	3,516
Obligation incurred on property acquisitions	2,430	5,484
Obligation divested	(1,406)	(270)
Obligation settled	(1,329)	(1,613)
Accretion expense	2,278	2,854
Change in estimate	16,604	22,670
Balance, end of period	$ 190,008	$ 163,459

7. BANK DEBT

The Company has a covenant-based, unsecured, revolving credit facility in place with a syndicate of banks in the amount of $1,800.0 million. In addition, the Company has a $50.0 million operating revolver, resulting in total bank credit facility capacity of $1,850.0 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. 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 credit 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.

As at September 30, 2016, the Company had $248.8 million in long-term debt outstanding and $992.2 million drawn against the bank 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). In addition, Tourmaline has outstanding letters of credit of $18.5 million (December 31, 2015 - $13.4 million), which reduce the credit available on the facility. The effective interest rate for the nine months ended September 30, 2016 was 2.52% (nine months ended September 30, 2015 – 2.69%). As at September 30, 2016, the Company is in compliance with all debt covenants.

8. NON-CONTROLLING INTEREST

The Company owns 90.6 percent of Exshaw Oil Corp., a private company engaged in oil and gas exploration in Canada. A reconciliation of the non-controlling interest is provided below:

(000s)	As at September 30, 2016	As at December 31, 2015
Balance, beginning of period	$ 28,431	$ 30,006
Share of subsidiary's net loss for the period	(1,276)	(1,575)
Balance, end of period	$ 27,155	$ 28,431

9. SHARE CAPITAL

(a) Authorized

Unlimited number of Common Shares without par value.

Unlimited number of non-voting Preferred Shares, issuable in series.

(b) Common Shares Issued

	As at September 30, 2016		As at December 31, 2015	
(000s) except share amounts	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of period	221,335,925	$ 4,266,234	203,162,112	$ 3,615,378
For cash on public offering of common shares (1)(4)	10,387,500	281,605	4,947,500	195,425
For cash on public offering of flow-through common shares (2)(3)(5)	1,320,000	37,818	1,122,700	38,403
Issued on corporate and property acquisitions (note 5)	-	-	10,193,026	372,878
For cash on exercise of stock options	1,922,480	55,221	1,910,587	37,159
Contributed surplus on exercise of stock options	-	19,932	-	14,051
Share issue costs	-	(13,642)	-	(10,066)
Tax effect of share issue costs	-	3,633	-	3,006
Balance, end of period	234,965,905	$ 4,650,801	221,335,925	$ 4,266,234

(1) On April 5, 2016, the Company issued 10.388 million common shares at a price of $27.11 for total gross proceeds of $281.6 million. A total of 37,500 common shares were purchased by insiders.

(2) On May 17, 2016, the Company issued 1.320 million flow-through shares at a price of $35.50 per share for total gross proceeds of $46.9 million. The implied premium on the flow-through common shares was determined to be $9.0 million or $6.85 per share. As at September 30, 2016, the Company is committed to spend the full amount on qualified exploration expenditures by December 31, 2017. The expenditures will be renounced to investors with an effective date of December 31, 2016.

(3) On March 12, 2015, the Company issued 0.64 million flow-through shares at a price of $50.00 per share for total gross proceeds of $32.0 million. The implied premium on flow-through common shares was determined to be $6.3 million or $9.87 per share. As at September 30, 2016, the Company had spent the full committed amount. The expenditures were renounced to investors with an effective renunciation date of December 31, 2015.

(4) On June 23, 2015, the Company issued 4.948 million common shares at a price of $39.50 for total gross proceeds of $195.4 million. A total of 54,000 common shares were purchased by insiders.

(5) On November 25, 2015, the Company issued 0.48 million flow-through shares at a price of $34.10 per share for total gross proceeds of $16.5 million. The implied premium on flow-through common shares was determined to be $3.7 million or $7.75 per share. As at September 30, 2016, the Company is committed to spend $7.1 million on qualified exploration expenditures by December 31, 2016. The expenditures were renounced to investors with an effective renunciation date of December 31, 2015.

10. EARNINGS PER SHARE

Basic earnings-per-share attributed to common shareholders was calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net earnings (loss) for the period (000s)	$ 24,738	$ 28,489	$ (91,592)	$ 45,451
Weighted average number of common				
shares – basic	234,600,727	218,745,913	229,507,106	211,389,015
Earnings (loss) per share – basic	$ 0.11	$ 0.13	$ (0.40)	$ 0.22

Diluted earnings-per-share attributed to common shareholders was calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net earnings (loss) for the period (000s)	$ 24,738	$ 28,489	$ (91,592)	$ 45,451
Weighted average number of common				
shares – diluted	235,627,273	219,376,160	229,507,106	212,561,337
Earnings (loss) per share – fully diluted	$ 0.10	$ 0.13	$ (0.40)	$ 0.21

There were 11,637,666 and 18,282,566 options excluded from the weighted-average share calculations for the three and nine month periods ended September 30, 2016 because they were anti-dilutive (three and nine months ended September 30, 2015 – 11,098,666 and 11,083,666 options).

11. SHARE-BASED PAYMENTS

The Company has a rolling stock option plan. Under the employee stock option plan, the Company may grant options to its employees up to 23,496,591 shares of common stock, which represents 10% of the current outstanding common shares. The exercise price of each option equals the volume-weighted average market price for the five days preceding the issue date of the Company's stock on the date of grant and the option's maximum term is five years. Options are granted throughout the year and vest 1/3 on each of the first, second and third anniversaries from the date of grant.

	Nine Months Ended September 30,			
	2016		2015	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Stock options outstanding,				
beginning of period	19,746,414	$ 36.50	17,046,500	$ 36.44
Granted	620,300	33.74	1,359,500	37.40
Exercised	(1,922,480)	28.72	(1,870,253)	19.38
Forfeited	(161,668)	38.94	(33,333)	39.17
Stock options outstanding,				
end of period	18,282,566	$ 37.20	16,502,414	$ 38.45

The weighted average trading price of the Company's common shares was $30.29 during the nine months ended September 30, 2016 (nine months ended September 30, 2015 – $36.94).

The following table summarizes stock options outstanding and exercisable at September 30, 2016:

Range of Exercise Price	Number Outstanding at Period End	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at Period End	Weighted Average Exercise Price
$20.79 - $29.26	4,958,401	2.92	26.32	1,636,101	26.03
$30.24 - $39.57	4,245,165	2.54	34.86	2,674,832	33.89
$40.18 - $48.99	7,429,000	2.44	42.11	4,522,667	41.74
$51.47 - $56.76	1,650,000	2.77	53.85	1,100,000	53.85
	18,282,566	2.62	37.20	9,933,600	38.38

The fair value of options granted during the nine month period ended September 30, 2016 was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

	September 30,	
	2016	2015
Fair value of options granted (weighted average)	$ 9.65	$ 10.93
Risk-free interest rate	1.89%	2.29%
Estimated hold period prior to exercise	4 years	4 years
Expected volatility	33%	33%
Forfeiture rate	2%	2%
Dividend per share	$ 0.00	$ 0.00

12. COMMITMENTS

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.

13. SUBSEQUENT EVENTS

On October 20, 2016, the Company issued 0.9 million flow-through shares at a price of $44.50 per share for total gross proceeds of $39.6 million. The implied premium on the flow-through common shares was determined to be $7.7 million or $8.63 per share. The Company is committed to spend the full amount on qualified exploration expenditures by December 31, 2017.

On October 20, 2016, the Company entered into an agreement with Shell Canada Energy ("Shell Canada") to acquire strategic assets located in the Alberta Deep Basin and the Northeast BC Montney complex for total consideration of $1,368.8 million, before customary adjustments, including cash consideration of $1,000.0 million and the remainder in Tourmaline common shares. The acquisition of assets is expected to close on or about November 30, 2016.

On November 10, 2016, in connection with the acquisition of assets from Shell Canada, the Company issued 2.9 million subscription receipts of Tourmaline at a price of $34.75 per subscription receipt for gross proceeds of $100.0 million. The subscription receipts were issued through a prospectus offering which also contains an over-allotment option to issue an additional 0.4 million subscription receipts. The over-allotment option was exercised in full resulting in gross proceeds of $115.0 million.

On November 10, 2016, the Company, also completed a private placement where 18.3 million subscription receipts were issued at a price of $34.75 per subscription receipt for gross proceeds of $635.0 million. In conjunction with the private placement, certain officers, directors, and employees of Tourmaline participated through a non-brokered offering and 175,000 subscription receipts were issued at a price of $34.75 per subscription receipt for gross proceeds of $6.1 million.

The gross proceeds from the prospectus offering, private placement and non-brokered offering will be held in escrow pending the completion of the asset acquisition from Shell Canada at which time the net proceeds will be released from escrow to Tourmaline and each subscription receipt will be automatically exchanged for one common share of Tourmaline for no additional consideration.

ABOUT TOURMALINE OIL CORP.

Tourmaline is a Canadian senior crude oil and natural gas exploration and production company focused on long-term growth through an aggressive exploration, development, production and acquisition program in the Western Canadian Sedimentary Basin.

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