CALGARY, Feb. 22, 2017 /CNW/ - Tourmaline Oil Corp. (TSX:TOU) ("Tourmaline" or the "Company") enjoyed another record year of material, profitable reserve additions with ever-improving efficiencies.

HIGHLIGHTS

- Proved plus probable reserves ("2P") increased to 1,746.8 mmboe during 2016, a 58% increase over 2015 reserves of 1,108.3 mmboe and a 64% increase (34% per diluted share) before taking into account annual production of 68.0 mmboe. Total proved ("TP") reserves increased 44% and proved developed producing ("PDP") reserves increased 60% over 2015 before taking into account annual production of 68.0 mmboe.
- 2016 2P reserve net present value (PV10 before tax) increase of $4.46 billion over 2015; the estimated 2P reserve NAV(1) (PV10 before tax) at year-end 2016 was $47.11 per diluted share.
- Tourmaline now has 2P reserves of 8.93 TCF of natural gas and 258.4 mmbbls of oil, condensate and natural gas liquids at December 31, 2016.
- 2P reserve replacement(2) of 10.4 times for 2016 based on 2P reserve additions of 706.5 mmboe before taking into account 2016 annual production.
- 2016 2P finding, development and acquisition ("FD&A") costs of $5.94/boe including changes in future development capital ("FDC"), 2016 TP FD&A costs of $9.21/boe including FDC and 2016 PDP FD&A costs of $14.69/boe.
- In 2016, Tourmaline's E&P capital program of approximately $730.7 million generated over 75,000 boe/d of new production resulting in capital efficiency of approximately $9,500 boe/d, an improvement of 39% over 2015 E&P capital efficiency of approximately $15,500 boe/d.
- After eight years, Tourmaline now has 1.75 billion boe of independently recognized 2P reserves at year-end 2016, essentially all of which will be serviced by Company-owned infrastructure. The Company has also produced 230.6 mmboe during the first eight years of operation.
- 2016 2P recycle ratio of 1.8 times based on 2P FD&A of $5.94/boe (including FDC) and 2016 estimated cash flow(3) of $10.77/boe. Q4 2016 estimated cash flow was $14.31/boe as gas prices recovered significantly.
- 2016 full-year average production of 185,672 boepd was 20% higher than 2015 average production of 154,403 boepd (10% per diluted share).
- Current daily Company production is approximately 235,000 boepd.
- The Company has only 1,819 gross locations recognized in the 2016 reserve report of a well-defined future development drilling inventory of 14,713 gross locations. The infrastructure skeleton, which is now complete in all three core areas, is in general reach of all of the future locations.

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(1) 2P Reserve NAV per share is calculated as 2P NPV10 reserve value divided by total diluted shares outstanding at December 31, 2016.
(2) Reserve replacement is calculated by dividing the annual 2P reserve additions by annual production.
(3) See Non-GAAP Financial Measures.

RESERVE REPORT OVERVIEW

Record Reserve Additions in 2016

The Company increased 2P reserves by 64% in 2016 to 1.75 billion boe (34% per diluted share), total proved reserves by 44% to 858.9 mmboe and PDP reserves by 60% to 351.9 mmboe, prior to annual 2016 production of 68.0 mmboe. The net 2016 2P addition of 638.5 mmboe in a single year is a Company record as was the total proved reserve addition of 214.9 mmboe. This was driven in part by the Shell Canada ("Shell") acquisition that was completed in November 2016. The acquisition was weighted to 2P reserves (PDP - 51.0 mmboe, TP - 121.6 mmboe, 2P - 483.9 mmboe) due primarily to the undeveloped nature of the Gundy BC Montney assets. Tourmaline is executing a three-year development plan that will convert the majority of the 2P reserve base at Gundy to proved reserves.

Historical Reserve Growth and Value Creation

Tourmaline consistently achieves top decile annual reserve growth. Three-year total reserve growth is 224% for 2P reserves (135% per diluted share), 224% for total proved reserves (135% per diluted share) and 323% for PDP reserves (207% per diluted share), before taking into account three-year total production of 165.5 mmboe. 2P reserve net present value increased by $4.46 billion in 2016 to $12.71 billion (PV10 before tax). Proved plus probable reserve NAV (PV10 before tax) at year-end 2016 is now $47.11 per diluted share, an increase of 26% from 2015.

Historical Reserve Category Conversion

Over the past eight years, Tourmaline has consistently and systematically converted 2P reserves to proven reserves and PDP reserves. The 2P reserves to proved reserves conversion occurs over approximately two years and the 2P reserves to PDP reserves occurs over approximately four years. Of the 140 wells rig-released by the Company in 2016, 88 of those wells were conversions of existing undeveloped locations. Similarly in 2015, 93 of the 181 wells rig-released were conversions from the undeveloped reserve category. PDP reserves grew by 60% in 2016 prior to annual 2016 production of 68.0 mmboe, despite 41 fewer wells drilled during the year. Tourmaline estimates further Q1 2017 PDP reserve additions of 52.0 mmboe as approximately 70-75 wells (gross) will be tied-in during the quarter. FDC for 2P reserves in the 2016 report of $6.4 billion represents under four years of forecast future cash flow. For 2016, 2P FDC increased by $1.9 billion, which includes $2.2 billion attributable to the Deep Basin and Gundy assets acquired from Shell Canada partially offset by a decrease of 2P FDC of $518.6 million reflecting significant decreases in capital costs.

Balance as at December 31,	2016	2015	2014	2013	2012	2011	5 Year Total Reserve Growth (%)
Reserves (Mboe)							
Proved Producing	351,931	263,227	177,811	122,327	91,952	67,312	423%
Total Proved	858,932	644,059	472,296	316,462	249,210	149,049	476%
Proved plus Probable	1,746,822	1,108,279	855,793	590,099	438,038	270,069	547%

Reserve Replacement

Proved plus probable reserves were replaced by 1,040% in 2016, a record for the Company, before taking into account 2016 annual production of 68.0 mmboe. Total proved reserves were replaced by 416% in 2016 and PDP reserves were replaced by 231%, before production. The three-year 2P reserve replacement ratio is 799%, before taking into account three-year production. Total proved reserve life is a conservative 9.3 years, consistent with anticipated 2017 production range of 240,000 - 260,000 boepd.

Reserve Addition Costs, Recycle Ratios

The 2P FD&A costs (including FDC) were $5.94/boe in 2016 and total proved reserve FD&A costs (including FDC) were $9.21/boe yielding annual recycle ratios of 1.8 times for 2P and 1.2 times for TP, respectively. Excluding acquisitions and divestitures ("A&D"), PDP finding and development ("F&D") costs (including FDC) were $8.59/boe in 2016 yielding a PDP recycle ratio of 1.3 times. Three-year average 2P FD&A costs (including FDC) are now $6.96/boe as the Company continues to systematically improve these metrics over time. E&P capital efficiency in 2016, excluding A&D, was approximately $9,500 boepd.

Technical Revisions

Proved plus probable technical revisions in 2016 relating to reserve bookings in previous years were 10.7 mmboe. This is the fifth consecutive year in which the Company has realized positive technical revisions to pre-existing reports. This is primarily driven by continued improvements in well performance in all three core areas.

Gas, Oil, Condensate and Liquids Reserves

Tourmaline now has a 2P natural gas reserve base of 8.93 TCF, one of the largest in Canada. The Company has approximately 12% of the existing well defined future drilling inventory recognized in the 2016 report (1,819 gross locations booked of a total inventory of 14,713 locations). All three core areas are largely de-risked from a subsurface standpoint with over 200 horizontal wells drilled in each of the three core areas to date. This significant, independently recognized reserve base is anticipated to double in approximately 5 years assuming a drilling pace comparable to 2017. The current Company-operated infrastructure skeleton is in general reach of all the locations in the 2016 reserve report.

Oil, condensate and NGL reserves are 258.4 mmboe at year-end 2016, a 202% increase over the past 3 years. With expected total liquid production in excess of 40,000 bpd in 2017, Tourmaline is now a top ten Canadian liquids producer, as well as the second largest producer of Canadian natural gas (current daily gas production of between 1.2 and 1.3 bcf/day).

PRODUCTION UPDATE

- Current daily production is approximately 235,000 boepd.
- The Company expects average Q1 2017 production of between 230,000 and 235,000 boepd.

- Anticipated average annual production guidance for 2017 of 240,000-260,000 boepd, including over 40,000 bpd of oil, condensate and NGL production. The Company has increased the production range to better account for unscheduled firm service reductions throughout the year.
- The Doe 2-11 gas plant remains on schedule for a late March/early April start-up, adding an additional 12,500 boepd of total production including 3,000-3,500 bpd of condensate.
- Tourmaline has added approximately 3,000 boepd to the Shell Deep Basin assets since acquiring them in November 2016 through existing well and plant optimization activities. Drilling operations have now commenced on two pads on the Shell Deep Basin acreage.
- An incremental 6,000-7,000 bpd of light oil production from the Peace River High Charlie Lake complex is also expected to come on-stream during the first quarter, some of which was deferred from Q4 2016.
- In total, the Company expects to bring 75-80 new wells on-stream during the first quarter of 2017.
- 2016 average production was 185,672 boepd, approximately 2% less than annual guidance, with Q4 2016 average production of 191,814 boepd. Q4 production was negatively impacted by firm service interruptions on all three major pipeline systems as well as weather related delays during the first half of the fourth quarter. These restrictions postponed certain tie-ins into Q1 2017. Facility capital deferrals (pipeline loops, in-field compression) made in the first half of 2016 led to some in-field production bottlenecks in Q4 2016 given the extremely high deliverability of a number of the new wells. These pipeline looping and compression projects are being completed in Q1 2017, eliminating these bottlenecks.
- 2016 annual production growth was 20% over 2015, amongst the best in the sector.

EP UPDATE

- Tourmaline is currently operating 17 drilling rigs with 11 of the rigs in the Alberta Deep Basin, 3 rigs in the NEBC Montney gas-condensate complexes and 3 rigs on the Peace River High.
- The Company continues to deliver some of the strongest wells historically in all three core areas at continuing record low drill and complete capital costs.
- The Minehead 16-15-49-19W5M Notikewin horizontal well in the Alberta Deep Basin averaged 29.7 mmcfpd over the first 60 days on-stream with 2.20 bcf of cumulative gas production to date.
- The Kakwa 12-35-61-6W6M Falher C horizontal well in the Alberta Deep Basin averaged 20.5 mmcfpd over the first 50 days on-stream, with 27,531 bbls of condensate produced to date (26 bbls/mmcf, 249 bbls/day).
- The Minehead 15-25-50-20W5M Falher C horizontal in the Alberta Deep Basin has averaged 11.3 mmcfpd over the first 60 days of production.
- The Ansel 15-31-50-19W5M Wilrich horizontal in the Alberta Deep Basin has averaged 13.4 mmcfpd over the first 60 days of production.
- The C12-21-80-15W6M Upper Montney horizontal well in Sunrise-Dawson BC averaged 1,461 boepd over the first 60 days of production (8.0 mmcfpd of gas and 128 bbls/day of condensate and liquids). The B12-21-80-15W6M Middle Montney horizontal averaged 1,398 boepd over the first 60 days of production (6.9 mmcfpd of gas and 248 bbls/day of condensate and liquids). The A13-21-80-15W6M Lower Montney Turbidite horizontal averaged 775 boepd over the first 60 days of production (1.84 mmcfpd of gas and 469 bbls/day of condensate and liquids). All three wells were brought on-stream during November and are restricted to flowing up tubing. Tourmaline's previous operational practice was to flow NEBC Montney wells unrestricted up casing for the first few months of production and run tubing at a later date. The new field practice saves approximately $200,000 in per pad costs, but reduces IP 30 and IP 90 production rates.
- The Spirit River 16-14-77-8W6M Lower Charlie Lake well averaged 1,158 boepd (841 bpd oil and 1.9 mmcfpd of gas) over the first 90 days of production. The well has produced 80,330 bbls of oil after 103 days of production. The Company is bringing another 5 Lower Charlie Lake wells on-stream in the first quarter.
- The Mulligan 4-13-83-8W6M Upper Charlie Lake well has averaged 798 boepd (631 bpd oil and 1.0 mmcfpd of gas) over the first 90 days of production and has now produced 63,257 bbls of oil after 102 days of production. The Company has 4 additional multi-well pads to bring on-stream at Mulligan during the first quarter.
- Development of the Gundy BC Montney property has commenced with the first rig already drilling. A second rig will arrive in mid-summer and the Company expects to have 75 wells drilled, completed and tied into the 200 mmcfpd facility that the Company is planning for the second half of 2018.

2016/2017 CAPITAL PROGRAM

- 2016 EP capital spending was $730.7 million, consistent with full-year cash flow.
- The 2017 EP capital program of $1.3 billion includes a 17-rig drilling program that will deliver 35% annual production growth for less than anticipated 2017 cash flow of $1.4 billion ($3.15/mcf AECO 2017 forecast natural gas price).
- The Company expects an exit 2017 debt-to-cash flow of approximately 1.0 times.

MARKETING AND HEDGING

- For 2017, Tourmaline has approximately 265 mmcfpd hedged at a weighted average fixed price of $3.11/mcf (AECO) and an additional 134 mmcfpd of basis differential at a weighted average of $0.62 Cdn/mcf.
- In addition, for 2017, 235 mmcfpd is sold to export markets attracting prices similar to the prevailing U.S. NYMEX prices. The export component is scheduled to grow to 340 mmcfpd by exit 2018.
- 520 mmcfpd of Tourmaline's 2017 forecast gas production is exposed to short-term AECO prices, 120 mmcfpd is priced at Station 2, and 40 mmcfpd is priced at Sumas, BC.

2016 RESERVE SUMMARY

The following tables summarize the Company's gross reserves defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves. Company net reserves are defined as the working net carried, and royalty interest reserves after deduction of all applicable burdens.

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves and

Net Present Values of Future Net Revenue

as of December 31, 2016

Forecast Prices and Costs[(1)]

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas[(2)]		Natural (
Reserves Category	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Compar (Mbbls)
Proved Developed Producing	8,259	6,836	1,333,542	1,229,132	505,572	471,239	37,141
Proved Developed Non-Producing	425	364	71,567	65,260	73,281	69,321	3,414
Proved Undeveloped	18,213	15,244	1,560,004	1,444,218	852,666	789,754	58,695
Total Proved Reserves	26,898	22,444	2,965,113	2,738,610	1,431,519	1,330,315	99,250
Total Probable Reserves	27,447	22,647	2,004,129	1,802,306	2,529,840	2,247,300	104,777
Total Proved Plus Probable Reserves	54,344	45,092	4,969,243	4,540,916	3,961,358	3,577,615	204,027

	Net Present Values Of Future Net Revenue ($000s)							
	Before Future Income Taxes Discounted at (%/year)					After Future Income Taxes Discoun (%/year)		
Reserves Category	0	5	10	15	20	0	5	10
Proved Developed Producing	6,007,635	4,785,453	3,962,143	3,398,090	2,993,090	6,007,635	4,785,453	3,962,143
Proved Developed Non-Producing	537,122	404,308	323,230	269,716	232,093	537,122	404,308	323,230
Proved Undeveloped	7,030,367	4,626,831	3,248,018	2,386,932	1,811,983	5,203,885	3,452,904	2,436,399
Total Proved Reserves	13,575,124	9,816,592	7,533,390	6,054,737	5,037,165	11,748,642	8,642,665	6,721,772
Total Probable Reserves	16,506,314	8,619,703	5,172,017	3,411,853	2,403,437	12,142,663	6,262,189	3,695,293
Total Proved Plus Probable Reserves	30,081,438	18,436,295	12,705,407	9,466,590	7,440,602	23,891,305	14,904,855	10,417,064

Notes:

(1) Tables may not add due to rounding.

(2) Shale Natural Gas is required to be presented separately from Conventional Natural Gas as its own product type pursuant to National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). While the Tourmaline Montney reserves do not strictly fit the definition of "shale gas" as defined in NI 51-101 because the natural gas is not "primarily adsorbed" as stated within the definition, the Montney reserves have been included as shale gas for purposes of this disclosure. Prior to the Company's December 31, 2015 reserve report, Montney gas was classified as product type "Natural Gas".

(3) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the Company which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

Total Future Net Revenue ($000s)

(Undiscounted)

as of December 31, 2016

Forecast Prices and Costs[1]

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment
Proved Producing	9,959,761	919,608	2,842,234	-	190,284
Proved Developed Non-Producing	802,207	72,607	142,404	40,781	9,293
Proved Undeveloped	13,965,981	1,218,611	2,649,199	2,947,285	120,520
Total Proved	24,727,950	2,210,825	5,633,837	2,988,066	320,097
Total Probable	31,464,890	3,805,153	7,492,904	3,429,046	231,473
Total Proved Plus Probable	56,192,840	6,015,978	13,126,742	6,417,111	551,571

Note:

(1) Table may not add due to rounding.

(2) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

Summary of Pricing and Inflation Rate Assumptions

Forecast Prices and Costs (1)

Crude Oil and Natural Gas Liquids Pricing

			NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma		Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton	Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Inflation(2) %	CAD/USD Exchange Rate $US/$Cdn(3)	Constant 2017 $ $US/Bbl	Then Current $US/ Bbl	Then Current $Cdn/Bbl	Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus $Cdn/Bbl
2017	0.7	0.7600	55.00	55.00	68.24	11.16	24.82	47.01	70.95
2018	2.0	0.7900	59.71	60.90	73.16	10.26	26.16	52.53	75.40
2019	2.0	0.8167	62.93	65.47	76.25	10.61	27.70	54.57	78.72
2020	2.0	0.8333	65.14	69.13	79.37	11.90	29.10	57.49	81.52
2021	2.0	0.8500	67.63	73.21	82.56	12.58	30.61	60.83	84.77
2022	2.0	0.8500	68.10	75.19	84.85	12.96	31.80	62.55	87.17
2023	2.0	0.8500	68.54	77.19	87.15	13.41	33.01	64.24	89.44
2024	2.0	0.8500	68.97	79.23	89.50	13.82	34.26	66.00	91.86
2025	2.0	0.8500	69.37	81.28	91.89	14.07	35.54	67.74	94.67
2026	2.0	0.8500	69.78	83.39	94.01	14.40	36.73	69.31	96.73
2027	2.0	0.8500	69.75	85.03	95.85	14.72	37.82	70.69	98.66
2028	2.0	0.8500	69.75	86.73	97.78	15.04	38.59	72.10	100.62
2029	2.0	0.8500	69.77	88.48	99.74	15.29	39.36	73.56	102.65
2030	2.0	0.8500	69.77	90.26	101.76	15.61	40.14	75.03	104.73
2031	2.0	0.8500	69.77	92.06	103.78	15.94	40.97	76.53	106.81
2032	2.0	0.8500	69.77	+2.0%/yr	+2.0/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Year	Natural Gas and Sulphur Pricing									
	Henry Hub Nymex Near Month Contract		Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/NIT Spot Then Current $Cdn/ MMbtu	Alberta Plant Gate Spot				British Columbia	
	Constant 2017 $ $US/ MMbtu	Then Current $US/MMbtu			Constant 2017 $ $Cdn/ MMbtu	Then Current $Cdn/MMbtu	ARP $Cdn/ MMbtu	Sumas Spot $US/ MMbtu	Westcoast Station 2 $Cdn/MMbtu	Spot P Gate $Cdn/M
2017	3.50	3.50	3.55	3.43	3.20	3.20	3.20	3.02	3.00	2.84
2018	3.24	3.30	3.35	3.17	2.88	2.94	2.94	2.87	2.78	2.62
2019	3.29	3.42	3.47	3.26	2.91	3.03	3.03	3.01	2.94	2.78
2020	3.53	3.75	3.80	3.67	3.23	3.43	3.43	3.44	3.35	3.18
2021	3.66	3.96	4.01	3.86	3.34	3.62	3.62	3.71	3.54	3.37
2022	3.69	4.07	4.12	3.97	3.38	3.73	3.73	3.82	3.65	3.48
2023	3.73	4.20	4.25	4.11	3.42	3.86	3.86	3.95	3.76	3.59
2024	3.74	4.30	4.35	4.23	3.46	3.98	3.98	4.05	3.88	3.71
2025	3.73	4.37	4.42	4.31	3.46	4.05	4.05	4.12	3.96	3.79
2026	3.73	4.46	4.51	4.41	3.47	4.15	4.15	4.21	4.06	3.89
2027	3.73	4.55	4.60	4.51	3.48	4.24	4.24	4.31	4.16	3.98
2028	3.74	4.65	4.70	4.60	3.48	4.33	4.33	4.40	4.24	4.07
2029	3.73	4.73	4.78	4.68	3.48	4.41	4.41	4.47	4.32	4.14
2030	3.73	4.82	4.87	4.77	3.48	4.50	4.50	4.56	4.41	4.23
2031	3.73	4.92	4.97	4.87	3.48	4.59	4.59	4.66	4.51	4.32
2032	3.73	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.48	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/

Notes:

(1) Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Reserve Report and Deloitte in the Deloitte Reserve Report, were an average of forecast prices and costs published by GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd. effective January 1, 2017 (each of which is available on their respective websites at www.gljpc.com, www.sproule.com and www.mcdan.com).

(2) Inflation rates used for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

RESERVES PERFORMANCE RATIOS

The following tables highlight Tourmaline's reserves, F&D and FD&A costs as well as the associated recycle ratios.

Reserves, Capital Expenditures and Cash Flow[1][2]

As at December 31,	2016	2015	2014
Reserves (Mboe)			
Proved Producing	351,931	263,227	177,811
Total Proved	858,932	644,059	472,296
Proved Plus Probable	1,746,822	1,108,279	855,793
Capital Expenditures ($ millions)			
Exploration and Development[3]	756	1,451	2,031
Net Acquisitions (Dispositions)	1,545	451	(250)
Total Capital Expenditures	2,301	1,902	1,782
Cash Flow ($/boe)			
Cash Flow	10.77	15.09	22.54
Cash Flow - Three Year Average	15.17	18.47	19.93

Notes:

(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 Company's most recently filed Management's Discussion and Analysis for further discussion.

(2) 2016 Financial numbers are unaudited.

(3) Includes capitalized G&A of $25 million, $26 million and $21 million for 2016, 2015 and 2014 respectively.

Finding and Development Costs

Finding and Development Costs, Excluding FDC	2016	2015	2014	2014-2016 Avg.
Total Proved				
Reserve Additions (MMboe)	126.4	187.1	190.1	
F&D Costs ($/boe)	5.98	7.76	10.68	8.42
F&D Recycle Ratio(1)	1.8	1.9	2.1	1.8
Total Proved Plus Probable				
Reserve Additions (MMboe)	158.7	260.2	300.7	
F&D Costs ($/boe)	4.76	5.58	6.75	5.89
F&D Recycle Ratio(1)	2.3	2.7	3.3	2.6

Finding and Development Costs, Including FDC	2016	2015	2014	2014-2016 Avg.
Total Proved				
Change in FDC ($ millions)	(239.9)	(42.7)	935.8	
Reserve Additions (MMboe)	126.4	187.1	190.1	
F&D Costs ($/boe)	4.08	7.53	15.61	9.71
F&D Recycle Ratio(1)	2.6	2.0	1.4	1.6
Total Proved Plus Probable				
Change in FDC ($ millions)	(518.6)	(190.5)	1,430.3	
Reserve Additions (MMboe)	158.7	260.2	300.7	
F&D Costs ($/boe)	1.49	4.84	11.51	6.89
F&D Recycle Ratio(1)	7.2	3.1	2.0	2.2

Finding, Development and Acquisition Costs

Finding, Development and Acquisition Costs, Excluding FDC	2016	2015	2014	2014-2016 Avg.
Total Proved				
Reserve Additions (MMboe)	282.8	228.1	197.1	
FD&A Costs ($/boe)	8.14	8.34	9.04	8.45
FD&A Recycle Ratio[(1)]	1.3	1.8	2.5	1.8
Total Proved Plus Probable				
Reserve Additions (MMboe)	706.5	308.9	306.9	
FD&A Costs ($/boe)	3.26	6.16	5.80	4.53
FD&A Recycle Ratio[(1)]	3.3	2.5	3.9	3.4

Finding, Development and Acquisition Costs, Including FDC	2016	2015	2014	2014-2016 Avg.
Total Proved				
Change in FDC ($ millions)	304.0	21.7	919.3	
Reserve Additions (MMboe)	282.8	228.1	197.1	
FD&A Costs ($/boe)	9.21	8.43	13.71	10.21
FD&A Recycle Ratio[(1)]	1.1	1.8	1.6	1.5
Total Proved Plus Probable				
Change in FDC ($ millions)	1,894.0	(84.1)	1,410.8	
Reserve Additions (MMboe)	706.5	308.9	306.9	
FD&A Costs ($/boe)	5.94	5.89	10.40	6.96
FD&A Recycle Ratio[(1)]	1.8	2.6	2.2	2.2

Note:

[(1)] The recycle ratio is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

INVESTOR RELATIONS ACTIVITIES

Tourmaline is scheduled to press release full-year 2016 financial results after the close of markets on March 7, 2017. A conference call discussing these results will be held at 7:30 a.m. Mountain Time on MaRch 8, 2017.

Reader Advisories

CURRENCY

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

RESERVES DATA

The reserves data set forth above is based upon the reports of GLJ Petroleum Consultants Ltd. ("GLJ") and Deloitte LLP, each dated effective December 31, 2016, which have been consolidated into one report by GLJ and adjusted to apply certain of GLJ's assumptions and methodologies and pricing and cost assumptions. The consolidated report includes 100% of the reserves and future net revenue attributable to the properties of Exshaw Oil Corp., a subsidiary of the Company, without reduction to reflect the 9.4% third-party minority interest in Exshaw. The price forecast used in the reserve evaluations is an average of the January 1, 2017 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd., each of which is available on their respective websites, www.gljpc.com, www.sproule.com and www.mcdan.com, and will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this news release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2016, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2017.

UNAUDITED FINANCIAL INFORMATION

Certain financial and operating results included in this news release such as FD&A costs, F&D costs, recycle ratio, cash flow, capital expenditures, operating costs and production information are based on unaudited estimated results. These estimated results are subject to change upon completion of the audited financial statements for the year ended December 31, 2016, and changes could be material. Tourmaline anticipates filing its audited financial statements and related management's discussion and analysis for the year ended December 31, 2016 on SEDAR on or before March 31, 2017.

Per share information is based on the total common shares outstanding, after accounting for outstanding Company options, at year-end 2016 and 2015, respectively.

BOE EQUIVALENCY

In this news release, production and reserves information may be presented on a "barrel of oil equivalent" or "BOE" basis. 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. In addition, 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 conversion on a 6:1 basis may be misleading as an indication of value.

INITIAL PRODUCTION (IP) RATES

Any references in this news release to IP rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production 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.

INDUSTRY METRICS

This news release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this news release. These metrics are "reserve replacement", "F&D" costs, "FD&A" costs, "recycle ratio", "F&D recycle ratio", and "FD&A recycle ratio". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time, however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods.

"F&D" costs are calculated by dividing the sum of the total capital expenditures for the year (in dollars) by the change in reserves within the applicable reserves category (in boe). F&D costs, including FDC, includes all capital expenditures in the year as well as the change in FDC required to bring the reserves within the specified reserves category on production.

"FD&A costs" are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in boe). FD&A costs, including FDC, includes all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in FDC required to bring the reserves within the specified reserves category on production.

The Company uses F&D and FD&A as a measure of the efficiency of its overall capital program including the effect of acquisitions and dispositions. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

FINANCIAL OUTLOOK

Also included in this news release are estimates of Tourmaline's 2017 cash flow and debt to cash flow level, which is based on, among other things, the various assumptions as to production levels, capital expenditures, and other assumptions disclosed in this news release and including Tourmaline's estimated 2017 average production of 240,000 to 260,000 boepd and commodity price assumptions for natural gas (AECO - $3.15/mcf for 2017), and crude oil (WTI (US) - $60/bbl for 2017) and an exchange rate assumption of $0.77 (US/CAD) for 2017. To the extent such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Tourmaline on February 22, 2017 and is included to provide readers with an understanding of Tourmaline's anticipated cash flow 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.

FORWARD-LOOKING INFORMATION

This news release contains forward-looking information within the meaning of applicable securities laws. The use of any of the words "forecast", "expect", "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 news 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 petroleum and natural gas production for various periods, drilling inventory or locations, cash flow and debt to cash flow levels, capital spending, projected operating and drilling costs, 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; and ability to market crude oil, natural gas and NGL successfully.

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; 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 news 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.

ADDITIONAL READER ADVISORIES

Non-GAAP Financial Measures

This news release includes references to "cash flow" which is a financial measure commonly used in the oil and gas industry and does not have a standardized meaning prescribed by International Financial Reporting Standards ("GAAP"). Accordingly, the Company's use of this term may not be comparable to similarly defined measures presented by other companies. Management uses the term "cash flow" 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 this non-GAAP measure should not be construed as an alternative to net income or cash from operating activities determined in accordance with GAAP as an indication of the Company's performance. See "Non-GAAP Financial Measures" in the November 14, 2016 Management's Discussion and Analysis for the definition and description of this term.

Estimated Drilling Inventory

This news 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 14,713 undrilled locations disclosed in this news release, 906 are proved undeveloped locations, 20 are proved non-producing locations, 893 are probable undeveloped locations, nil are probable non-producing and 12,894 are unbooked. Proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ and Deloitte LLP as of December 31, 2016 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's 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.

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
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
mmbbls	million barrels
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
tcf	trillion cubic feet

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.

SOURCE Tourmaline Oil Corp.

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