TWIN BUTTE
ENERGY LTD.

2015
ANNUAL REPORT

HIGHLIGHTS

Twin Butte Energy Ltd. ("Twin Butte" or the "Company") (TSX: TBE) is pleased to announce its financial and operational results for the three and twelve months ended December 31, 2015.

	Three months ended December 31			Twelve months ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
FINANCIAL *($000's, except per share amounts)*						
Petroleum and natural gas sales	**45,162**	110,219	-59%	**240,770**	555,073	-57%
Funds flow (1)	**32,923**	54,324	-39%	**178,123**	207,927	-14%
Per share basic	**0.09**	0.16	-44%	**0.50**	0.60	-17%
Per share diluted	**0.09**	0.16	-44%	**0.50**	0.60	-17%
Net income (loss)	**(249,252)**	(84,086)	-196%	**(336,932)**	(57,340)	-488%
Per share basic	**(0.70)**	(0.24)	-192%	**(0.95)**	(0.17)	-459%
Per share diluted	**(0.70)**	(0.24)	-192%	**(0.95)**	(0.17)	-459%
Dividends declared	**2,124**	17,394	-88%	**28,997**	67,304	-57%
Dividends declared, Post DRIP	**2,124**	14,482	-85%	**28,454**	58,950	-52%
Capital expenditures (1)	**9,402**	34,128	-72%	**78,039**	137,627	-43%
Net debt (1)	**287,874**	353,299	-19%	**287,874**	353,299	-19%
OPERATING						
Average daily production						
Medium & light crude oil (bbl per day)	**7,460**	9,776	-24%	**7,884**	11,185	-30%
Heavy crude oil (bbl per day)	**6,256**	8,553	-27%	**7,145**	7,870	-9%
Natural gas (Mcf per day)	**9,557**	13,849	-31%	**11,290**	12,616	-11%
Natural gas liquids (bbl per day)	**135**	(207)	165%	**141**	98	44%
Barrels of oil equivalent (boe per day, 6:1)	**15,444**	20,430	-24%	**17,052**	21,256	-20%
% Oil and NGLs	**90%**	89%	1%	**89%**	90%	-1%
Average sales price						
Medium & light crude oil ($ per bbl)	**36.83**	60.78	-39%	**43.91**	74.18	-41%
Heavy crude oil ($ per bbl)	**30.22**	66.17	-54%	**38.76**	80.01	-52%
Natural gas ($ per Mcf)	**2.30**	4.54	-49%	**2.65**	4.47	-41%
Natural gas liquids ($ per bbl)	**37.40**	120.82	-69%	**47.01**	50.43	-7%
Barrels of oil equivalent ($ per boe, 6:1)	**31.79**	58.64	-46%	**38.68**	71.54	-46%
Field netback ($ per boe) (1)						
Petroleum and natural gas sales	**31.79**	58.64	-46%	**38.68**	71.54	-46%
Royalties	**(2.04)**	(8.92)	-77%	**(4.03)**	(12.95)	-69%
Operating expenses	**(19.18)**	(20.89)	-8%	**(18.91)**	(21.19)	-11%
Transportation expenses	**(0.91)**	(1.09)	-17%	**(0.90)**	(1.09)	-17%
Field netback (1)	**9.66**	27.74	-65%	**14.84**	36.31	-59%
Cash gain (loss) on financial derivatives	**17.36**	4.87	256%	**18.10**	(5.63)	421%
Operating netback (1)	**27.02**	32.61	-17%	**32.94**	30.68	7%
Wells drilled						
Gross	**7.0**	19.0	-63%	**49.0**	109.0	-55%
Net	**7.0**	18.0	-61%	**49.0**	105.7	-54%
Success (%)	**100**	100	0%	**98**	97	1%
COMMON SHARES						
Shares outstanding, end of period	**354,122,806**	351,794,723	1%	**354,122,806**	351,794,723	1%
Weighted average shares outstanding – diluted	**354,044,207**	350,507,629	1%	**353,543,644**	347,340,214	2%

(1) Funds flow, Capital expenditures, Net debt, Field netback and Operating netback are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

REPORT TO SHAREHOLDERS

In 2015, the long term horizontal potential of Twin Butte's asset base was confirmed through the drilling of several Provost and Lloydminster area projects which have delivered oil production at rates above expectation with costs below expectation. By year end, horizontal well drilling and completion costs had decreased close to 50% compared to those reported in 2014, primarily due to improved execution. Of particular note has been the success of the Company's open hole multilateral drilling in both the Lloydminster and Provost areas. The most recent Provost area quad-lateral drilled in Q4 2015, and brought online December 1st, has produced in excess of 26,000 barrels of oil to date with a current rate of ~250 barrels of oil per day with an all in on-stream cost of under $1.3MM. This result, amongst several others, is a direct reflection of the Company's strengthened technical team and quality land position, and has opened up a materially larger inventory of future drilling opportunities across the Company's existing asset base. Based upon current cost estimates and average expected type curve production and compared to reported industry results, the Company believes that Twin Butte's inventory has the potential to deliver economic returns at oil prices over $40 US WTI per barrel which are equivalent or better than most, if not all, oil resource plays in Western Canada.

Cash flow for the year of $178 million was materially supported by the Company's strong 2015 oil hedge book, and exceeded guidance largely due to the 11% annual per boe reduction in corporate operating and transportation costs.

Despite 2015's operational successes, and the recent modest recovery in oil price, the current commodity price environment is very challenging for a number of oil and gas companies in Western Canada including Twin Butte. With reduced hedge protection, first quarter 2016 cash flow, based upon commodity prices realized to date and forecast for the balance of the quarter, is expected to be negative. The Company has shut in additional volumes in the quarter primarily associated with our non-core gas properties, with Q1 2016 quarterly production expected to be just under 14,000 boe per day. Due to the current pricing environment and lack of liquidity no development projects have or will be undertaken in Q1 2016.

Twin Butte continues to work cooperatively and proactively with our lending syndicate to ensure adequate liquidity is maintained through the previously announced and ongoing strategic alternatives process. The Company is pleased with the interest in the process to date and will disclose specific developments when the Board of Directors has approved a specific transaction or otherwise determined that disclosure is necessary or required.

HIGHLIGHTS OF 2015 INCLUDE:

- Generated $178 million of funds flow, ($0.50/share).
- Reduced net debt by 19% or $65.4 million from $353.3 million at December 31, 2014 to $287.9 million at December 31, 2015.
- Completed a reduced organic capital program of $80 million ($78 million net of dispositions), including the drilling of 49 gross (49 net) wells, results of which increased the Company's potential horizontal inventory to over 800 wells.
- Initiated water flood operations at our Freemont property.
- Produced an average of 17,052 boe per day for the year (15,444 boe per day in Q4)
- Returned $29 million dollars to shareholders through dividends.

Certain selected financial and operational information for the three and twelve months ended December 31, 2015 and 2014 is outlined below and should be read in conjunction with Twin Butte's audited financial statements for the years ended December 31, 2015 and 2014 and accompanying management discussion and analysis filed with the Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and also on the Company's website.

CORPORATE:

2015 was a year of significant positive transition for Twin Butte continuing the evolution to a horizontal medium and heavy oil drilling focus from its historical vertical heavy oil asset base.

Due to the sharp drop in commodity prices through the year and the Company's focus on decreasing debt and managing its liquidity, Twin Butte, reduced capital, reduced salaries, and first reduced then suspended the monthly dividend. These were all difficult but necessary decisions.

FINANCIAL:

Twin Butte's full year 2015 financial and operating results were boosted as a result of the hedging program in spite of the falling commodity prices through the year. The hedging support allowed the Company to carry out a reduced capital program, pay out a modest dividend and pay down debt substantially. The Company paid $29 million in dividends ($28.5 million post DRIP) in 2015 which when combined with net organic capital spending of $78 million, generated an all-in payout ratio of 60%. At year-end 2015, the Company's net debt decreased to approximately $288 million, from $353 million at December 31, 2014.

Funds flow for 2015 decreased from 2014 by 14% (17% per share), reaching $178 million as a result of lower average sales prices which were down 46% on a BOE basis and production which decreased by 20% as a result of natural declines, the reduced capital program and economic shut-ins, partially offset by lower than anticipated operating costs.

Twin Butte's commodity hedging strategy, provided realized cash gains of $112.6 million in 2015, providing the Company with cash flow protection through the low commodity prices of 2015. The Company does not have the same level of hedge coverage moving into 2016 and as such will see a large reduction to cash flows at current commodity pricing.

OPERATIONS:

The Company's 2015 capital investment of $80 million ($78 million net of dispositions) was focused on horizontal drilling and infrastructure expansion in its medium oil Provost and heavy oil Lloydminster areas. The capital program included the drilling of 49 gross wells (49 net) of which 39 were horizontal oil wells, along with 4 vertical oil wells, 5 service wells and 1 D&A vertical.

Production averaged 17,052 boe/d in 2015, down 20% from the 2014 average of 21,256 boe/d. Fourth quarter 2015 production averaged 15,444 boe/d. Due to current low commodity prices, the Company has over 1000 boe/d shut in.

In the Provost area, development focused on the Sounding Lake South Sparky horizontal project with the drilling of 13 wells and construction of a new fit-for-purpose oil battery, the expansion of the Lithic channel play with the drilling of 8 multistage frac'd horizontal wells and 2 open hole multilateral horizontal wells and infill drilling in the Dina-Cummings project. Per well drill and completion costs dropped materially, as compared to the previous fiscal year. Despite lower commodity prices Twin Butte continued to consolidate land positions in key areas through the year.

Across the Lloydminster area, activity focused on testing the drilling of unlined horizontal single and dual laterals. Success was achieved across multiple areas particularly in Saskatchewan. Drilling and completion costs dropped over 40% compared to 2014 with additional potential savings identified. Similar to Provost, key land positions were consolidated leveraging off the Company's technology advancements.

Preliminary work on several long term water flood projects was initiated including the startup of injection on the Freemont waterflood. These projects deliver excellent returns through improved oil recovery and will be part of the Company's long term objective to reduce corporate decline rates.

RESERVES:

Twin Butte's year end 2015 reserve report, as evaluated by McDaniel & Associates Consultants Ltd ("McDaniel"), with an effective date of December 31, 2015 and prepared in compliance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook, demonstrates strong bookings for new drilled wells across the asset base but with the reduced capital budget and economic factors, total reserves declined in both the proved and probable categories. The proved category saw strong positive technical revisions of 4.9 MMBOE showing continued improvements in the base production and lower operating costs.

Twin Butte's horizontal heavy oil development delivered new reserves efficiently with the 11 wells drilled in this region replacing 91% of production. Before economic factors, proved plus probable Lloydminster heavy area reserves decreased from 20.5 MMBOE to 18.3 MMBOE.

In aggregate, total 2P reserves, impacted by the low oil prices driving economic factor revisions, decreased approximately 5.9 MMBOE from 61.2 to 55.3 MMBOE. Excluding these economic factors, reserve replacement on a proved plus probable basis was 81%.

Core Areas – Reserves Reconciliation, Netback Analysis, and F&D and Recycle Ratio

Reconciliation	Proven Company (Mboe)	NPV10 ($MM)	Proven plus Probable Company (Mboe)	NPV10 ($MM)
December 31, 2014	36,264	$547	61,222	$982
Extensions and Improved Recovery	2,105		2,910	
Technical Revisions	4,947		2,173	
Discoveries	–		–	
Acquisitions	69		88	
Dispositions	(39)		(64)	
Economic Factors	(4,616)		(4,714)	
Production	(6,314)		(6,307)	
December 31, 2015	32,415	$312	55,307	$600
Netback Analysis				
Revenue ($/boe)	–		38.68	
Royalties ($/boe)	–		(4.03)	
Op + Trans. Costs ($/boe)	–		(19.81)	
Operating Netback ($/boe)	–		14.84	
2015 Capital ($MM)	–		78.0	
Corporate Netback ($/boe)	–		28.62	
Change in FDC ($MM)				
Drills and Additions	(13)		(12)	
Revisions	(43)		(53)	
Total	(56)		(65)	

	Proven		Proven plus Probable	
F&D and Recycle Ratio	F&D	Recycle	F&D	Recycle
Additions (Incl Δ FDC)	$30.76	0.9	$22.83	1.3
Adds + Tech Rev (Incl Δ FDC)	$3.12	9.2	$2.63	10.9
FD&A (Incl Δ FDC)	$8.94	3.2	$34.03	0.8
Reserve Replacement				
Excluding Revisions	34%		46%	
Including Revisions	112%		81%	

(1) Refer to the Company's Annual Information Form for details on McDaniel's year end 2015 price forecast, refer to the 2014 Annual information form for McDaniel's year end 2014 price forecast.

(2) See "Reader Advisory" for a description of finding, development and acquisition costs and recycle ratios.

The Company's reserves data set forth below is based on an evaluation and review completed by the independent reserve engineering firm, McDaniel, with an effective date of December 31, 2015.

Summary of Total Company Reserves

	Forecast Prices and Costs					
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserve Category	Gross [1] (Mbbl)	Net [2] (Mbbl)	Gross [1] (Mbbl)	Net [2] (Mbbl)	Gross [1] (Mbbl)	Net [2] (Mbbl)
Proved						
Developed Producing	3,004.2	2,880.1	11,640.1	10,611.2	959.9	651.5
Developed Non-Producing	11.1	11.1	1,275.1	1,162.4	241.6	162.4
Undeveloped	841.9	749.4	6,729.7	5,974.5	183.0	133.2
Total Proved	3,857.2	3,640.6	19,644.9	17,798.2	1,384.6	947.2
Probable	2,355.3	2,080.0	16,832.6	14,645.3	479.7	332.2
Total Proved Plus Probable	**6,212.5**	**5,720.6**	**36,477.5**	**32,443.5**	**1,864.3**	**1,279.4**
Total Proved Plus Probable Developed Producing	4,013.2	3,808.1	15,667.2	14,236.5	1,128.4	767.2

	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent [3]	
Reserve Category	Gross [1] (MMcf)	Net [2] (MMcf)	Gross [1] (Mboe)	Net [2] (Mboe)
Proved				
Developed Producing	32,062.7	27,330.2	20,948.0	18,748.0
Developed Non-Producing	5,681.8	4,712.7	2,474.8	2,121.4
Undeveloped	7,425.1	6.245.8	8,992.1	7,898.1
Total Proved	45,169.7	38,288.7	32,414.9	28,767.5
Probable	19,348.0	16,140.0	22,982.3	19,747.5
Total Proved Plus Probable	**64,517.7**	**54,428.6**	**55,307.2**	**48,514.9**
Total Proved Plus Probable Developed Producing	38,806.7	33,009.3	27,276.6	24,313.3

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Twin Butte before deductions of royalties payable to others.

(2) "Net" reserves means Twin Butte gross reserves less all royalties payable to others.

(3) "Oil Equivalent" amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 Mcf: 1 bbl may be a misleading indication of value.

(4) Numbers in tables may not add due to rounding.

Summary of Net Present Value of Future Net Revenue [1]

As at December 31, 2015
Before Income Taxes and Discounted at (%/year)

Reserve Category	0% *($000s)*	5% *($000s)*	10% *($000s)*
Proved			
Developed Producing	297,772	248,842	220,787
Developed Non-Producing	40,893	23,514	17,379
Undeveloped	140,269	100,650	73,936
Total Proved	478,935	373,006	312,102
Probable	539.552	380,284	287,771
Total Proved Plus Probable	**1,018,486**	**753,290**	**599,874**
Total Proved Plus Probable Developed Producing	463,703	365,292	309,386

(1) Based on McDaniel forecast prices and costs.

Capital Expenditures [1]

Type	2015 Capital Expenditures *$(000's)*
Land	3,062
Seismic	1,395
Drilling & Completions	36,446
Equipping & Facilities	33,655
G&A and Other	5,659
Total Development Costs	80,217
Dispositions	(2,178)
Total Capital	**78,039**

(1) Capital expenditures is a non-GAAP measure calculated as the purchase or sale price of an asset, plus development capital expenditures added to PP&E

Net Asset Value

The following net asset value ("NAV") table shows a NAV calculation under which the Company's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions, including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV per share represents the fair market value of Twin Butte shares. The calculations below do not reflect the value of the Company's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment.

Using Twin Butte's Reserve Value at December 31, 2015 – Forecast Pricing and Costs (Pre-tax)

($MM except as noted)	10%
Proved plus Probable Reserve Value	599.9
Undeveloped Land Value [1]	52.5
Net Debt [2]	(287.9)
Option Proceeds	1.1
Basic Shares Outstanding (MM)	354.1
Estimated Net Asset Value $ per Share – Basic	**1.03**
Fully Diluted Shares Outstanding (MM)	372.5
Estimated Net Asset Value $ per Share – Fully Diluted	**0.98**

(1) Independent assessment of 247,096 net undeveloped acres at an average price of $211/acre.

(2) Net debt is a non-GAAP measure representing the total of bank indebtedness, accounts payable and accrued liabilities, less accounts receivables, deposits and prepaids.

OUTLOOK

Twin Butte has continued to successfully transition to a higher value, more predictable production base. With adequate liquidity, a large portion of Twin Butte's undeveloped asset base has the potential to be economically developed at WTI prices above $40 US per barrel.

With the current low price environment and repayment of the Company's $85 million non-revolving credit facility required by April 30, 2016, the Company is currently operating within a $17 million capital budget for 2016 (under $4.5 million in Q1) which currently includes the drilling of only one well. As such production is expected to continue to decline throughout the year exiting in the 10,000 boe/d range.

Within the context of the ongoing strategic alternatives process, current low oil price environment and the April 30, 2016 debt repayment milestone, there is uncertainty surrounding the Company's ability to continue as a going concern. While the Company is in discussions with its lenders, failure to repay the non-revolving facility when due (unless otherwise extended) will constitute an event of default and entitle the syndicate to exercise its remedies under the credit facility, including acceleration of the credit facility and realization over the assets of the Company. The Management and Board of Directors remain focused on reaching a fair solution to the current liquidity challenges for all stakeholders.

In these challenging times we have had to reduce staff counts and decrease compensation for everyone, while improving efficiencies as the Company adapts to this lower for longer commodity price environment. On behalf of the directors and management of Twin Butte, I would like to thank all our employees and field contractors for their efforts, insights and results.

ABOUT TWIN BUTTE:

Twin Butte Energy Ltd. is a value oriented intermediate producer with a significant low risk, high rate of return drilling inventory focused on large original oil and gas in place play types. With a stable low decline production base, Twin Butte is positioned to provide shareholders with growth potential over the long term. Twin Butte is committed to continually enhance its asset quality while focusing on the sustainability of its dividend. The common shares of Twin Butte are listed on the TSX under the symbol "TBE".

Rob Wollmann
President & CEO

March 22, 2016

READER ADVISORY

Forward-Looking Statements

In the interest of providing Twin Butte's shareholders and potential investors with information regarding Twin Butte, including management's assessment of the future plans and operations of Twin Butte, certain statements contained in this report constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular but without limiting the foregoing, this report contains forward-looking statements pertaining to the following: future operational activities, planned expenditure amounts (and timing thereof); funds flow and cash flow forecasts; the volumes and estimated value of Twin Butte's oil and natural gas reserves; the life of Twin Butte's reserves; the volume and product mix of Twin Butte's oil and natural gas production; estimated drilling locations; estimated future production levels; matters with respect to the Company's debt requirements; estimates of the Company's net asset value (including per share); assessment of the economics of certain of the Company's assets; future oil and natural gas prices; future operational activities; future results from operations and operating metrics, including future production growth and other matters set forth under the heading "Outlook" herein, including estimated budget levels and targeted pay-out ratio in respect of the payment of dividends. 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 exist in the quantities predicted or estimated and can be profitably produced in the future.

With respect to forward-looking statements contained in this report, Twin Butte has made assumptions regarding, among other things: future capital expenditure levels; future oil and natural gas prices and differentials between light, medium and heavy oil prices; results from operations including future oil and natural gas production levels; future exchange rates and interest rates; Twin Butte's ability to obtain equipment in a timely manner to carry out development activities; Twin Butte's ability to continue as a going concern; decline rates based on analogous information; its ability to market its oil and natural gas successfully to current and new customers; the impact of increasing competition; Twin Butte's ability to obtain financing on acceptable terms; and Twin Butte's ability to add production and reserves through its development and exploitation activities. Although Twin Butte believes that the expectations reflected in the forward looking statements contained in this report, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this report, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Twin Butte's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the following: the risks associated with the oil and gas industry; commodity prices; the risk that Twin Butte may be in default of its credit facility; the risk that Twin Butte's strategic alternatives process may not result in an acceptable transaction (or at all) on the timeframes anticipated; operational risks in exploration; development and production; delays or changes in plans; risks associated with the uncertainty of reserve estimates; health and safety risks, and; the uncertainty of estimates and projections of production, costs and expenses. volatility in market prices for oil and natural gas; general economic conditions in Canada, the U.S. and globally; and the other factors described under "Risk Factors" in Twin Butte's most recently filed Annual Information Form available in Canada at www.sedar.com. The recovery and reserve estimates of Twin Butte's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this report speak only as of the date of this report. Except as expressly required by applicable securities laws, Twin Butte does not undertake any obligation to publicly update or revise any forward looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Drilling Locations

This report discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2015 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. Of the drilling locations identified herein, 116 are proved locations, 40 are probable locations and 644 are unbooked locations. Unbooked locations have been identified by management as an estimation of our 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 we actually drill wells will ultimately depend upon the availability of capital, 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.

Barrels of Oil Equivalent

Barrels of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl (barrel) 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 indicated value.

Funds Flow from Operations

The reader is cautioned that this report contains the term funds flow from operations, which is not a recognized measure under generally accepted accounting principles ("GAAP") and is a measure that represents the total of cash provided by operating activities, before adjusting for changes in non-cash working capital items and expenditures on decommissioning liabilities. Management uses this measure in order to assist them in understanding Twin Butte's liquidity and its ability to generate funds to finance its operations. The term funds flow from operations or funds flow should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with GAAP as an indicator of the Company's performance. Twin Butte's method of calculating this measure may differ from other companies, and accordingly, may not be comparable to measures used by other companies.

Capital Expenditures

The reader is cautioned that this report contains the term Capital Expenditures, which is not a recognized measure under generally accepted accounting principles ("GAAP") and is a measure that represents the total of expenditures on property and equipment, expenditures on exploration and evaluation assets, proceeds on disposition of property and equipment and proceeds on disposition of exploration and evaluation assets, as per the Statement of Cash Flows. Management uses this measure in order to assist them in understanding Twin Butte's cash used in investing activities. Twin Butte's method of calculating this measure may differ from other companies, and accordingly, may not be comparable to measures used by other companies.

Corporate and Operating Netback

The reader is also cautioned that this report contains the terms corporate and operating netback, which are not recognized measures under GAAP. Corporate Netback is calculated as operating netback less interest and general and administration expense and divided by total production. Management uses these measures to assist them in understanding Twin Butte's profitability relative to current commodity prices and they provide an analysis tool to benchmark changes in operational performance against prior periods and to peers on a comparable basis. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with GAAP as a measure of performance. Twin Butte's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

Net Debt

The reader is cautioned that this report contains the term net debt, which is not a recognized measure under GAAP and is calculated as bank debt, convertible debentures, and adjusted for working capital excluding mark-to-market derivative contracts. Working capital excluding mark-to-market derivative contracts is calculated as current assets less current liabilities both of which exclude derivative contracts and current liabilities excludes the current portion of debt. Management uses net debt to assist them in understanding Twin Butte's liquidity at specific points in time. Mark-to-market derivative contracts are excluded from working capital, in addition to net debt, as management intends to hold each contract through to maturity of the contract's term as opposed to liquidating each contract's fair value or less.

Future Oriented Financial Information

This report, in particular the information in respect of anticipated cash flows, may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by management of the Company to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. The Company and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

This report contains a number of additional oil and gas metrics, including finding, development and acquisition costs and recycle ratio, 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. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods. Finding, development and acquisition costs are used as a measure of capital efficiency. The calculation includes all capital costs (exploration, development and acquisition capital) for that period plus the change in future development capital for that period. This total capital including the change in the future development capital is then divided by the change in reserves for that period incorporating all revisions and production for that same period. The recycle ratio was calculated by dividing operating netback per boe by the finding, development and acquisition costs for the year.

Dated as of March 22, 2016

INTRODUCTION

The following Management Discussion and Analysis ("MD&A") is management's assessment of Twin Butte Energy Ltd.'s ("Twin Butte" or the "Company") financial and operating results and should be read in conjunction with the message to shareholders and the audited financial statements of the Company for the year ended December 31, 2015 and the audited financial statements and MD&A for the year ended December 31, 2014. This MD&A is presented in Canadian dollars (except where otherwise noted). Additional information relating to the Company, including the Company's Annual Information Form can be found on www.sedar.com.

The Company's principal activity is the acquisition of, exploration for and the development and production of petroleum and natural gas properties in Western Canada.

Basis of Presentation – The reporting and measurement currency is the Canadian dollar.

boe Presentation – Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion rate of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the report are derived by converting gas to oil equivalent barrels at the ratio of six thousand cubic feet of gas to one barrel of oil.

Non-GAAP Financial Measures – Certain measures in this document do not have a standardized meaning as prescribed by IFRS and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's reasoning to use the measures, as well as reconciliation to the closest comparable GAAP measure, is detailed in the section entitled, "Non-GAAP Financial Measures".

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A constitute forward-looking information within the meaning of securities laws. Forward-looking information may relate to our future outlook and anticipated events or results and may include statements regarding the future financial position, business strategy, budgets, projected costs, capital expenditures, financial results, taxes and plans and objectives of or involving Twin Butte. Particularly, statements regarding our future operating results and economic performance are forward-looking statements. In some cases, forward-looking information can be identified by terms such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "intend", "estimate", "predict", "potential", "continue" or other similar expressions concerning matters that are not historical facts.

These statements are based on certain factors and assumptions regarding expected growth, results of operations, performance and business prospects and opportunities. While we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Forward looking-information is also subject to certain factors, including risks and uncertainties that could cause actual results to differ materially from what we currently expect. These factors include risk associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risk, and competition from other producers and ability to access sufficient capital from internal and external resources. Other than as required under securities laws, we do not undertake to update this information at any particular time.

All statements, other than statements of historical fact, which address activities, events, or developments that Twin Butte expects or anticipates will or may occur in the future, are forward-looking statements within the meaning of applicable securities laws. These statements are subject to certain risks and uncertainties, and may be based on estimates or assumptions that could cause actual results to differ materially from those anticipated or implied.

Further, the forward-looking statements contained in this MD&A are made as of the date hereof, and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, as a result of new information, future events or otherwise, except as may be required by applicable securities laws. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. Certain risk factors associated with these forward-looking statements include, but are not limited to, the following:

- Fluctuations in natural gas, condensate, NGL's, and crude oil production levels;
- Twin Butte's inability to successfully market its natural gas, condensate, NGL's, and crude oil;
- Lower than expected market prices for natural gas, condensate, NGL's, and crude oil;
- Adverse changes in foreign currency exchange rates and/or interest rates;
- Uncertainties associated with estimating reserves;
- Competition for capital, asset acquisitions, undeveloped lands, and skilled personnel;
- Operational hazards characteristic of the oil and gas industry such as: geological and drilling problems; and well production, pipeline, and mechanical difficulties;
- Lower than envisaged success in the finding and development of reserves and/or higher than expected costs;
- Changes to dividend payment policy or amounts;
- Adverse changes in general economic conditions in Western Canada, Canada more generally, North America or globally;
- Adverse weather conditions;
- The inability of Twin Butte to obtain financing on favorable terms, or at all;
- Adverse impacts from the actions of competitors;
- Adverse impacts of actions taken and/or policies established by governments or regulatory authorities including changes to tax laws, incentive programs, royalty calculations, and environmental laws and regulations; and
- Reliance on natural gas and NGL processing, pipeline, and storage infrastructure not operated by Twin Butte, the availability of which is essential to Twin Butte's sales and marketing activities.

Additional information relating to Twin Butte, including Twin Butte's financial statements can be found on SEDAR at www.sedar.com or the Company's website at www.twinbutteenergy.com.

PETROLEUM AND NATURAL GAS SALES

Twin Butte realized the following sales, production volumes, and commodity prices:

	Three months ended December 31		Twelve months ended December 31	
	2015	2014	**2015**	2014
Sales *($000's)*				
Medium & light oil	**25,280**	54,666	**126,373**	302,844
Heavy oil	**17,393**	52,064	**101,078**	229,822
Natural gas	**2,023**	5,783	**10,900**	20,591
Natural gas liquids	**466**	(2,294)	**2,419**	1,816
Total petroleum and natural gas sales	**45,162**	110,219	**240,770**	555,073
Average Daily Production				
Medium & light oil (bbl/day)	**7,460**	9,776	**7,884**	11,185
Heavy oil (bbl/day)	**6,256**	8,553	**7,145**	7,870
Natural gas (Mcf/day)	**9,557**	13,849	**11,290**	12,616
Natural gas liquids (bbl/day)	**135**	(207)	**141**	98
Total (boe/d)	**15,444**	20,430	**17,052**	21,256
% oil and liquids production	**90%**	89%	**89%**	90%
Average Twin Butte Realized Commodity Prices (1)				
Medium & light oil ($ per bbl)	**36.83**	60.78	**43.91**	74.18
Heavy oil ($ per bbl)	**30.22**	66.17	**38.76**	80.01
Natural gas ($ per Mcf)	**2.30**	4.54	**2.65**	4.47
Natural gas liquids ($ per bbl)	**37.40**	120.82	**47.01**	50.43
Barrels of oil equivalent ($ per boe, 6:1)	**31.79**	58.64	**38.68**	71.54

(1) The average selling prices reported are before realized derivative instrument gains/losses and transportation charges.

Benchmark Pricing				
WTI crude oil (US$ per bbl)	**42.18**	73.15	**48.80**	93.00
Edmonton crude oil (Cdn$ per bbl)	**52.87**	75.56	**57.14**	94.62
WCS crude oil (Cdn$ per bbl)	**36.87**	67.45	**44.82**	81.76
AECO natural gas (Cdn$ per Mcf) (2)	**2.33**	3.41	**2.55**	4.27
Exchange rate (US$/Cdn$)	**1.34**	1.14	**1.28**	1.14

(2) The AECO natural gas price reported is the average daily spot price.

Sales for the three months ended December 31, 2015 were $45.2 million, as compared to $110.2 million for the three months ended December 31, 2014 representing a decrease of $65.0 million or 59%. Both sales volumes and the average realized commodity price decreased from the prior year quarter, resulting in decreased sales. Excluding the impact of derivative instruments, the average realized commodity price decreased from $58.64 in the fourth quarter of 2014 to $31.79 during the fourth quarter of 2015. The WCS benchmark decreased 45% from the prior year quarter, due to a decrease in the WTI benchmark (US$) combined with the change in WTI to WCS differentials, which widened 23%. As the Company's revenues are substantially denominated in Canadian dollars, the weakened exchange rate has mitigated some of the effect of the 42% WTI benchmark decrease, which was a 32% decrease when converted to Canadian Dollars.

Production decreased from 20,430 boe/d in the three months ended December 31, 2014 to 15,444 boe/d for the three months ended December 31, 2015. This decrease of 4,986 boe/d is across all products, and is due to expected declines, shut-in barrels that are uneconomic in the current pricing environment and reduced drilling.

Revenues for the year ended December 31, 2015 were $240.8 million, as compared to $555.1 million for the year ended December 31, 2014, representing a decrease of $314.3 million or 57%. This decrease in revenue is attributed to a 20% production decrease and a 46% decrease in realized pricing. Production decreased from 21,256 boe/d in the year ended December 31, 2014 to 17,052 boe/d in 2015. The average realized commodity price before hedging decreased from $71.54 per boe in the year ended December 31, 2014 to $38.68 per boe in 2015.

CASH GAIN (LOSS) AND PROCEEDS ON DERIVATIVES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Realized gain (loss) on derivatives	**24,669**	9,152	**112,639**	(43,691)
Realized gain (loss) on derivatives per boe	**17.36**	4.87	**18.10**	(5.63)

The Company realized a cash gain on financial derivatives of $24.7 million ($17.36 per boe) for the three months ended December 31, 2015, compared to a cash gain of $9.2 million ($4.87 per boe) for the prior year quarter. During the quarter, the cash gain was due to fixed price swaps, and was comprised of a $24.2 million gain on crude oil sales price derivatives and a $0.6 million gain on natural gas sales price derivatives and a $0.1 million loss on foreign exchange contracts, as compared to a $9.0 million gain on crude oil sales price derivatives and a $0.2 million gain on natural gas sales price derivatives in the fourth quarter of 2014.

The Company realized a cash gain on financial derivatives of $112.6 million ($18.10 per boe) for the year ended December 31, 2015, compared to a cash loss of $43.7 million ($5.63 per boe) for the prior year. The cash gain was due to fixed price swaps, and was comprised of a $111.5 million gain on crude oil sales price derivatives, a $1.8 million gain on natural gas sales price derivatives and a $0.7 million loss on foreign exchange contracts, as compared to a $42.3 million loss on crude oil sales price derivatives and a $1.4 million loss on natural gas sales price derivatives in the year ended December 31, 2014.

ROYALTIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Medium & light oil	**1,652**	10,103	**13,072**	66,660
Heavy Oil	**1,200**	7,015	**11,197**	30,409
Natural Gas	**(146)**	(205)	**(120)**	1,199
NGLs	**186**	(143)	**909**	2,240
Total Royalties	**2,892**	16,770	**25,058**	100,508
Total royalties per boe	**2.04**	8.92	**4.03**	12.95
% of P&NG Sales	**6%**	15%	**10%**	18%

Royalties for the three months ended December 31, 2015 were $2.9 million, as compared to $16.8 million for the three months ended December 31, 2014. As a percentage of sales, the average royalty rate for the fourth quarter of 2015 decreased to 6%, compared to 15% in the fourth quarter of 2014. Royalty rates decreased from the prior year quarter due to decreased benchmark commodity prices and the corresponding provincial royalty calculation input prices and GORR royalty recoveries dating back to 2014. In Q4 2015, medium & light oil royalty rates averaged 7%, heavy oil averaged 7%, and gas averaged -7% due to prior period royalty adjustments and gas cost allowances.

Royalties for the year ended December 31, 2015 were $25.1 million, as compared to $100.5 million for the year ended December 31, 2014. As a percentage of revenues, the average royalty rate for the year ended December 31, 2015 was 10%, compared to 18% in 2014, in line with decreased commodity pricing. In the year ended December 31, 2015, medium & light oil royalties averaged 10%, heavy oil royalties averaged 11%, and gas averaged -1%.

OPERATING & TRANSPORTATION EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Operating expense	**27,260**	39,263	**117,698**	164,353
Transportation expense	**1,289**	2,039	**5,603**	8,446
Total operating & transportation expense	**28,549**	41,302	**123,301**	172,799
Operating expense per boe	**19.18**	20.89	**18.91**	21.19
Transportation expense per boe	**0.91**	1.09	**0.90**	1.09
Total per boe	**20.09**	21.98	**19.81**	22.28

Operating expenses were $27.3 million or $19.18 per boe for the three months ended December 31, 2015 as compared to $39.3 million or $20.89 per boe for the three months ended December 31, 2014. The decrease on an absolute dollar basis is attributable to both decreased volumes and a reduction in costs per boe. In comparison to the prior year quarter, the reduction on a per boe basis is attributed to reductions in water volumes hauled due to new water disposal and handling facilities, reduced propane costs, as well as a shift in production mix toward properties with lower cost profiles. Although the Company continues to focus on cost reductions, quarterly savings were partially offset by upward pressure due to fixed costs spread over lower volumes.

Operating expenses were $117.7 million or $18.91 per boe for the year ended December 31, 2015, as compared to $164.4 million or $21.19 for the year ended December 31, 2014. The decrease on an absolute dollar basis is attributable to both decreased volumes and a per boe reduction in costs. Similar to the quarter, on a per boe basis cost decreases are related to reduced water handling and disposal costs, lower propane costs and a shift in production mix.

Transportation expenses for the three months ended December 31, 2015 were $1.3 million or $0.91 per boe, down from $2.0 million or $1.09 per boe in the prior year comparative quarter. Transportation expenses for the year ended December 31, 2015 were $5.6 million or $0.90 per boe compared to $8.4 million or $1.09 per boe in the prior year comparative period. Decreases are associated with a higher proportion of volumes from Provost properties, which have reduced transportation costs.

The Company has combined operating and transportation costs of $20.09 per boe for the quarter, a decrease from $21.98 per boe in the fourth quarter of 2014.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
G&A expense	**3,817**	5,421	**19,979**	22,728
Capitalized G&A expense	**(1,053)**	(1,287)	**(4,483)**	(4,892)
Recoveries	**(462)**	(981)	**(2,310)**	(3,768)
Total net G&A expense	**2,302**	3,153	**13,186**	14,068
Total net G&A expense per boe	**1.62**	1.68	**2.12**	1.81
Transaction expense	**100**	–	**100**	–
Transaction expense per boe	**0.07**	–	**0.01**	–

General and administrative expenses, net of recoveries and capitalized G&A, were $2.3 million or $1.62 per boe for the three months ended December 31, 2015 as compared to $3.1 million or $1.68 per boe in the prior year comparative quarter. Net G&A expense for the year ended December 31, 2015 was $13.2 million or $2.12 per boe, compared to $14.1 million or $1.81 per boe in the prior year comparative period. For both the quarter and year, the net G&A decrease is due to reduced employee, executive and director compensation, which was partially offset by a lower level of drilling activity that reduced G&A recoveries. Transaction expense relates to initial costs associated with the Company's strategic alternatives review initiated in December 2015.

FINANCE EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Interest and bank charges	**1,738**	2,515	**8,329**	10,789
Interest on convertible debentures	**1,328**	1,307	**5,312**	5,291
Accretion on convertible debentures	**415**	310	**1,347**	1,242
Accretion on decommissioning provision	**1,134**	934	**4,445**	5,037
Total finance expense	**4,615**	5,066	**19,433**	22,359
Total interest per boe	**2.16**	2.03	**2.19**	2.07
Total accretion per boe	**1.09**	0.66	**0.93**	0.81
Total finance expense per boe	**3.25**	2.69	**3.12**	2.88

For the three months ended December 31, 2015, finance charges were $4.6 million as compared to $5.1 million in the three months ended December 31, 2014. This decrease is due to decreased debt levels throughout the quarter, as the Company directed free cash flow towards debt reduction in 2015. For the year ended December 31, 2015, finance charges also decreased and were $19.4 million, as compared to $22.4 million in the prior year comparative period.

For Q4 2015, the Company's interest charge on the bank line was prime of 2.7% plus a margin of 1% for a total rate of 3.7% and the Company's convertible debentures pay an interest rate of 6.25% annually. The Company utilized Bankers Acceptances to lower the combined effective interest rate for the three months ended December 31, 2015 to 4.2% (4.3% – December 31, 2014). The combined effective interest rate for the year ended December 31, 2015 was 4.4% (4.5% – December 31, 2014).

NETBACKS (1)

The following table summarizes netbacks for the past eight quarters on a barrel of oil equivalent basis:

($ per boe)	**Q4 2015**	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Petroleum and natural gas sales (2)	**31.79**	37.72	48.97	35.79	58.64	74.13	79.42	73.58
Cash gain (loss) on financial derivatives	**17.36**	13.24	16.05	24.81	4.87	(6.26)	(12.02)	(8.71)
Royalties	**(2.04)**	(4.58)	(4.99)	(4.31)	(8.92)	(14.98)	(15.43)	(12.41)
Operating expense	**(19.18)**	(19.23)	(18.40)	(18.87)	(20.89)	(20.01)	(20.94)	(22.81)
Transportation expense (2)	**(0.91)**	(0.92)	(0.81)	(0.96)	(1.09)	(1.17)	(1.18)	(0.93)
Operating netback (1)	**27.02**	26.23	40.82	36.46	32.61	31.71	29.85	28.72
General and administrative expense	**(1.62)**	(2.21)	(2.26)	(2.32)	(1.68)	(1.74)	(2.32)	(1.53)
Transaction costs	**(0.07)**	–	–	–	–	–	–	–
Interest and bank charges	**(2.16)**	(2.12)	(2.47)	(2.03)	(2.03)	(2.15)	(2.27)	(1.85)
Funds flow netback (1)	**23.17**	21.90	36.09	32.11	28.90	27.82	25.26	25.34

(1) Operating netback and Funds flow netback are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

(2) Certain transportation costs previously reported on a gross basis in 2013 were determined to be more accurately reflected on a net basis in petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

Reduced royalties and operating expenses resulted in a higher netback when compared to the third quarter of 2015, however due to the current commodity price environment and a reduced level of hedging, the operating netback and funds flow netback decreased from the first half of 2015.

SHARE-BASED PAYMENT EXPENSE

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Share-based payment expense	**1,233**	1,182	**5,258**	4,485
Share-based payment expense per boe	**0.87**	0.63	**0.84**	0.58

During the three months ended December 31, 2015, the Company expensed $1.2 million in share-based payment expense consistent with $1.2 million in the three months ended December 31, 2014. The Company did not award share or performance share awards in the fourth quarter of 2015 as compared to 230,327 share awards and 203,237 performance share awards in the fourth quarter of 2014. The decrease in share and performance share awards granted is due to no new hires in Q4 2015. Total share awards forfeited due to employee departures were 540,698 in the quarter versus 391,588 awards forfeited in the fourth quarter last year.

During the year ended December 31, 2015, the Company expensed $5.3 million in share-based payment expense as compared to $4.5 million in the year ended December 31, 2014.

At December 31, 2015, the Company has 11,335,724 restricted share awards, 6,685,319 performance share awards and 385,467 options outstanding. The total of these share awards and options represents 5% of common shares outstanding.

UNREALIZED DERIVATIVE ACTIVITIES

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Unrealized gain (loss) on derivatives	**(17,775)**	115,979	**(101,914)**	141,297
Unrealized gain (loss) on derivatives per boe	**(12.51)**	61.70	**(16.37)**	18.21

As part of the financial management strategy to protect cash flows available for capital expenditures, the Company has adopted a commodity price risk management program. The purpose of the program is to stabilize and hedge future cash flow against the unpredictable commodity price environment, with an emphasis on protecting downside risk.

With derivative instruments there is a risk that the counterparty could become illiquid or that Twin Butte may not have the actual sales volumes to offset the hedge position. To manage risk, the Company's counterparties on derivative instruments are major Canadian and international banks and the Company limits the maximum volumes hedged in relation to expected production.

The Company also enters into fixed price power swaps in order to stabilize future operating costs. While pre-hedge power costs were low in 2015, averaging $34 per megawatt hour, costs have risen above $100 per megawatt during the year. As power costs make up a significant percentage of operating expense in the Provost region, these contracts assist the Company in maintaining consistent and low operating costs in these areas. Current contracts are for approximately 82% of estimated power usage in 2016, and 60% in 2017.

Unrealized derivative assets and liabilities

As at December 31, 2015, the Company has a net unrealized financial derivative asset in the amount of $7.1 million, as compared to an asset of $109.1 million at December 31, 2014. This net unrealized asset position reflects weak WTI and WCS crude oil forward pricing for 2016. If WTI and WCS prices meet the current forecasted benchmarks, these gain positions would be realized alongside decreased sales due to the weak commodity pricing.

During the quarter, due to the settlement of 2015 financial instruments, the net unrealized asset decreased, resulting in a loss of $17.8 million for the three months ended December 31, 2015 as compared to a $116.0 million unrealized gain for the prior year comparative quarter. As the net unrealized financial derivative asset has also decreased from December 31, 2014 due to realized derivative gains, the Company has recognized an unrealized loss for the year ended December 31, 2015 of $101.9 million, compared to a gain of $141.3 million in the prior year comparative period.

The following is a summary of derivatives as at December 31, 2015 and their related fair market values (unrealized gain (loss) positions):

Crude Oil Sales Price Derivatives

Daily barrel (bbl) quantity	Term of contract		WTI [1] Fixed price per bbl	WCS [2] Fixed Price per bbl	Fixed price per bbl WCS [2] vs. WTI [1]	Fixed written call price per bbl WTI [1]	Fair market value $ 000's ($CAD)
1,000	January 1, 2016 to December 31, 2016	$CAD	$85.00				10,121
5,500	January 1, 2016 to December 31, 2016	$CAD			$(18.61)		(241)
1,000	January 1, 2017 to December 31, 2017	$CAD				$85.00	(1,068)
Crude oil fair value position at December 31, 2015							8,812

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Power Purchase Price Derivatives

Daily Megawatt (MW) hours quantity	Term of contract	Fixed price per MW	Fair Market Value $ 000's
384	January 1, 2016 to December 31, 2016	$45.48	(1,569)
264	January 1, 2017 to December 31, 2017	$41.28	(97)
Power purchase contract fair value position at December 31, 2015			(1,666)

DEPLETION, DEPRECIATION & IMPAIRMENT

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Depletion & Depreciation	**27,545**	48,038	**129,864**	180,972
Depletion & Depreciation per boe	**19.39**	25.56	**20.87**	23.33

For the three months ended December 31, 2015, depletion and depreciation of capital assets was $27.5 million or $19.39 per boe compared to $48.0 million or $25.56 per boe for the prior year quarter. The total decrease relates to decreased production and lower depletion rates in the Heavy Oil, South East Medium, and Pincher Creek CGUs, following impairment in Q2 and Q3 2015, which also accounts for the decrease on a per boe basis.

For the year ended December 31, 2015, depletion and depreciation of capital assets was $129.9 million, or $20.87 per boe, compared to $181.0 million or $23.33 per boe in the prior year.

At December 31, 2015, the Company assessed for indicators of impairment for all of its CGUs. In comparison to prior periods, the Company noted significant and prolonged reductions to forecasted benchmark pricing, which indicated that CGUs may be impaired. For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment or its reversal, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs of disposal and value in use. These key judgments include estimates about recoverable reserves, forecast benchmark commodity prices, royalties, operating costs and discount rates.

Twin Butte estimated the recoverable amount for all CGUs based on the fair value less costs of disposal, determined with an after-tax discount rate of 11 percent (December 31, 3014 – 9.5 percent), forecasted cash flows over the estimated life of reserves, and an independent industry reserve engineer price forecast. The discount rate represents the rate of return that a market participant would require for asset with similar composition and risk. The forecasted cash flows are prepared over the estimated life of the reserves in the CGUs, which range from 22 to 50 years. The primary source of cash flow information was derived from the Company's oil and gas reserves, as prepared by an independent qualified reserve evaluator as at December 31, 2015.

Based on the assessment, the after-tax recoverable amount did not exceed the carrying value of the South East Medium, Heavy Oil, Plains and West-Central CGUs and the total fourth quarter non-cash pre-tax impairment charge at December 31, 2015 was $211.7 million ($154.5 million after tax). The total pre-tax impairment charge for the year ended December 31, 2015 was $277.0 million ($200.0 million after tax), as Twin Butte recorded impairment due to significant and prolonged reductions to forecasted oil and natural gas pricing on the Pincher Creek CGU in the second quarter of 2015 and on the South East Medium, Heavy Oil, Plains and West-Central CGUs in the third quarter of 2015.

GAIN OR LOSS ON DISPOSITIONS

During the year ended December 31, 2015, Twin Butte completed several minor swaps and dispositions. The transacted assets were primarily non-core E&E assets, but also included $nil value PP&E assets with decommissioning liabilities attached. The Company received total cash proceeds of $2.2 million ($6.5 million – December 31, 2014), resulting in a gain of $3.1 million ($3.5 million – December 31, 2014).

INCOME TAXES

Deferred tax amounted to a $13.7 million recovery for the twelve months ended December 31, 2015 compared to $17.6 million recovery for the twelve months ended December 31, 2014. The recovery is the result of the current commodity price environment and impairment losses resulting in a net income loss for the year, as well as an allowance taken on the net deferred tax asset. Due to the going concern uncertainty disclosed in the Liquidity and Capital Resources section of this MD&A, the Company recorded an allowance of $74.6 million to reduce its net deferred tax asset to $nil.

During the year ended December 31, 2015, the Company received a letter from the Canada Revenue Agency ("CRA") advising the Company that, subject to submissions by Twin Butte, it is proposing to reassess the Company's income tax filings related to Scientific Research and Experimental Development ("SR&ED") tax deductions utilized in 2011 by a predecessor of the Company, and in 2014 by the Company, totaling $32.0 million in deductions ($8.6 million at the Company's expected tax rate), and $7.8 million in non-capital losses currently available. If these tax deductions are disallowed, the Company would incur a non-cash tax expense, but would utilize alternatively available tax pools for the predecessor 2011 and 2014 taxation years. However, as a result of utilizing these pools and the reduction in non-capital losses, the Company would be in a cash taxes payable position in 2015, owing approximately $3 to 8 million, pending the successful application of additional voluntary adjustments. These potentially disallowed amounts would be deductible, and any taxes paid refundable, on a successful appeal of the reassessments.

Twin Butte's management and legal counsel remain of the opinion that, after careful consideration and consultation at the time of the deductions and at this time, Twin Butte's tax returns were correct as filed, and the Company has not recorded a provision for the proposed reassessments. If the proposed reassessments are issued, Twin Butte's management will vigorously defend the Company's tax filing position. Twin Butte has provided its submission in response to CRA's letter and is awaiting further communication.

NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Three months ended December 31		Twelve months ended December 31	
($000's except per share amounts)	**2015**	2014	**2015**	2014
Net Income (loss)	**(249,252)**	(84,086)	**(336,932)**	(57,340)
Net Income (loss) per share	**(0.70)**	(0.24)	**(0.95)**	(0.17)

Net and comprehensive income for the three months ended December 31, 2015 was a loss of $249.3 million, compared to net and comprehensive loss of $84.1 million in the three months ended December 31, 2014. The net loss in the current quarter is mainly due to the current commodity environment, as impairment losses were incurred and cash gains on hedges realized during the quarter were recognized in income during 2014, and was further increased by the allowance taken on the net deferred tax asset. Net and comprehensive income for the year ended December 31, 2015 was a loss of $336.9 million, compared to a net and comprehensive loss of $57.3 million in the prior year. The net loss in the current year is also mainly due to impairments, unrealized mark to market losses on derivatives and the allowance taken on the net deferred tax asset.

SELECTED ANNUAL INFORMATION

	Twelve months ended December 31		
($000's except per share amounts)	**2015**	2014	2013
Petroleum and natural gas sales [(1)]	**240,770**	555,073	386,537
Net Income (loss)	**(336,932)**	(57,340)	(115,633)
Per share basic	**(0.95)**	(0.17)	(0.44)
Per share diluted	**(0.95)**	(0.17)	(0.44)
Total assets	**563,332**	1,043,249	1,165,638
Total non-current financial liabilities	**201,498**	327,063	329,829
Dividends declared	**28,997**	67,304	52,286
Dividends declared per share	**0.082**	0.194	0.197

(1) Certain transportation costs previously reported in 2013 were determined to be more accurately reflected as location differentials for petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

QUARTERLY FINANCIAL SUMMARY

The following table highlights Twin Butte's performance for each of the past eight quarters:

($000, except per share amounts)	**Q4 2015**	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Average production (boe/d)	**15,444**	16,303	17,351	19,158	20,430	20,981	21,109	22,529
Petroleum and natural gas sales [(1)]	**45,162**	56,577	77,318	61,713	110,219	143,088	152,566	149,200
Operating netback (per boe) [(2)]	**27.02**	26.23	40.82	36.46	32.61	31.71	29.85	28.72
Funds flow [(2)]	**32,923**	32,851	56,982	55,367	54,324	53,699	48,520	51,384
Per share basic	**0.09**	0.09	0.16	0.16	0.16	0.15	0.14	0.15
Per share diluted	**0.09**	0.09	0.16	0.16	0.16	0.15	0.14	0.15
Net income (loss)	**(249,252)**	(41,943)	(23,290)	(22,447)	(84,086)	34,805	7,181	(15,240)
Per share basic	**(0.70)**	(0.12)	(0.07)	(0.06)	(0.24)	0.10	0.02	(0.04)
Per share diluted	**(0.70)**	(0.12)	(0.07)	(0.06)	(0.24)	0.10	0.02	(0.04)
Capital expenditures [(2)]	**9,402**	26,583	17,012	25,042	34,128	43,884	21,724	37,890
Total assets	**563,332**	862,128	925,847	989,878	1,043,249	1,150,834	1,152,659	1,174,100
Net debt [(2)]	**287,874**	308,370	307,672	333,916	353,299	355,918	352,198	363,659

(1) Certain transportation costs previously reported in 2013 were determined to be more accurately reflected as location differentials for petroleum and natural gas sales. Prior period amounts have been reclassified to reflect this determination.

(2) Operating netback, Funds flow, Capital expenditures and Net debt are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

Quarterly variances in sales are connected to changes in production volumes and prices. In Q1, Q2, and Q3 2014, increased production, changes in the Company's production mix and high commodity prices resulted in significantly increased sales. Reduced commodity prices and declining production since Q4 2014 have since decreased quarterly sales throughout 2015.

Through its historical strategy to protect cash flows and pay a dividend, Twin Butte hedged a relatively large percentage of production using financial derivatives. As such, in quarters where a large percentage of production was hedged, commodity price swings in oil had a moderated effect on funds flow from operations, as only current quarter realized cash gains or losses are included. In Q1 2014, funds flow increased significantly due to increased production and realized sales prices. In Q2 2014, funds flow was above historical levels, but decreased from Q1 2014 due to slightly reduced production. Funds flow in Q3 and Q4 2014 continued this increasing trend, due to higher netbacks on Provost properties and cost savings. In Q1 and Q2 2015, significant hedging gains and operating cost reductions resulted in record funds flow. Although hedging levels were lower than the first half of 2015, gains from hedging contributed significantly to funds flow in Q3 and Q4 2015.

Quarterly variances in net income, however, are largely driven by non-cash items, such as impairments, unrealized gains or losses on derivatives, deferred tax expense or recovery, and gains or losses on asset acquisitions and dispositions. In Q1 2014 net losses were mainly due to unrealized losses on derivatives. In Q2 and Q3 2014 net income was due to unrealized gains on derivatives and gains on the sale of non-core assets. In Q4 2014, the net loss was related to impairment losses, which offset unrealized gains on derivatives. In Q1 and Q2 2015 as gains on derivatives were recognized in income in 2014, the current commodity price environment contributed to a net loss. Impairments and the current commodity price environment resulted in the losses in Q3 2015 and Q4 2015.

DIVIDENDS

Cash dividends declared for the three months ended December 31, 2015, which includes dividends declared in October and November 2015, were $2.1 million ($14.5 million – December 31, 2014). Cash dividends declared for the year ended December 31, 2015 were $28.5 million ($59.0 million – December 31, 2014). The monthly dividend was reduced from $0.01 per share to $0.003 per share, effective for the dividend declared in August 2015, and suspended in December 2015.

FUNDS FLOW FROM OPERATIONS [(1)] AND TOTAL PAYOUT RATIO [(1)]

Funds flow from operations ("Funds Flow") and the payout and total payout ratios are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures. Twin Butte considers these to be key measures of performance as they demonstrate the Company's ability to generate the cash flow necessary to fund dividends and capital investment and ultimately, satisfy corporate strategy.

	Three months ended December 31		Twelve months ended December 31	
($000's except per share amounts)	**2015**	2014	**2015**	2014
Funds flow [(1)]	**32,923**	54,324	**178,123**	207,927
Funds flow per share	**0.09**	0.16	**0.50**	0.60
Dividends declared	**(2,124)**	(17,394)	**(28,997)**	(67,304)
Capital Expenditures [(1)]	**(9,402)**	(34,128)	**(78,039)**	(137,627)
Payout ratio [(1)]	**35%**	95%	**60%**	99%
Reinvested dividends (DRIP and SDP)	**–**	2,912	**543**	8,354
Cash dividends declared	**(2,124)**	(14,482)	**(28,454)**	(58,950)
Total payout ratio (net of DRIP and SDP) [(1)]	**35%**	89%	**60%**	95%

(1) Funds flow, Capital expenditures, Payout ratio and Total payout ratio are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

The Company uses the total payout ratio to monitor performance, and adjusts capital expenditures and dividends to ensure that the total annual payout does not exceed cash flow, on an on-going basis where required. For the year ended December 31, 2015, the total payout ratio was 35%, as excess cash flow was directed towards debt reduction, capital expenditures reduced and the dividend suspended.

Funds flow from operations for the three months ended December 31, 2015 was $32.9 million, a decrease from fourth quarter 2014 funds flow of $54.3 million, due to the current commodity price environment, reduced hedging levels and declining production associated with reduced drilling. This represents $0.09 per diluted share compared to $0.16 per diluted share in 2014.

Funds flow from operations for the year ended December 31, 2015 were $178.1 million, a decrease from funds flow of $207.9 million in 2014, also associated with the current commodity price environment, reduced hedging levels in the second half of 2015 and declining production associated with reduced drilling. This represents $0.50 per diluted share compared to $0.60 per diluted share for in 2014.

CAPITAL EXPENDITURES AND PP&E ADDITIONS

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2015**	2014	**2015**	2014
Land acquisition	**576**	814	**3,062**	1,531
Geological and geophysical	**110**	776	**1,395**	1,553
Drilling and completions	**3,204**	20,483	**36,446**	92,350
Equipping and facilities	**6,367**	11,375	**33,655**	43,806
Other	**1,061**	1,287	**5,659**	4,892
Development capital (1)	**11,318**	34,735	**80,217**	144,132
Property dispositions - Cash received	**(1,916)**	(607)	**(2,178)**	(6,505)
Capital expenditures (1)	**9,402**	34,128	**78,039**	137,627

(1) Development capital and Capital expenditures are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

During the fourth quarter of 2015, the Company invested $11.3 million on development capital, a decrease from $34.7 million in development capital invested in Q4 2014. The Company's development capital expenditures for the quarter consisted of successful drilling of 5.0 (5.0 net) oil wells in the Provost region, one Strat-Test well and one water disposal well.

For the year ended December 31, 2015, the Company invested $80.2 million on development capital, a decrease from $144.1 million in 2014. Proceeds from property dispositions in 2015 totaled $2.2 million, compared to $6.5 million in the year ended December 31, 2014.

Drilling Results

Three months ended December 31	2015		2014	
	Gross	**Net**	Gross	Net
Medium Oil – Horizontal	**5**	**5.0**	11	11.0
Heavy Oil – Horizontal	**–**	**–**	7	6.0
Heavy Oil – Vertical	**–**	**–**	–	–
Service or Strat-Test	**2**	**2.0**	1	1.0
Dry and abandoned	**–**	**–**	–	–
Total	**7**	**7.0**	19	18.0
Success rate (%)		**100%**		100%

Twelve months ended December 31	2015		2014	
	Gross	**Net**	Gross	Net
Medium Oil – Horizontal	**32**	**32.0**	52	52.0
Heavy Oil – Horizontal	**7**	**7.0**	34	30.7
Heavy Oil – Vertical	**4**	**4.0**	16	16.0
Service or Strat-Test	**5**	**5.0**	4	4.0
Dry and abandoned	**1**	**1.0**	3	3.0
Total	**49**	**49.0**	109	105.7
Success rate (%)		**98%**		97%

Undeveloped Land

The Company's net undeveloped land holdings have decreased from 367,364 acres as at December 31, 2014 to 247,096 acres on December 31, 2015, as conversions from drilling, dispositions and expiries were greater than purchases.

LIQUIDITY AND CAPITAL RESOURCES

The Company evaluates its ability to carry on business as a going concern on a quarterly basis, with the key indicator being whether the non-GAAP measure, funds flow from operations, will be sufficient over time to cover all obligations, specifically the non-GAAP measure of net debt. Twin Butte considers these measures and the related ratio to be key measures of liquidity and the management of capital resources.

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2015**	2014	**2015**	2014
Funds flow (1)	**32,923**	54,324	**178,123**	207,927
Annualized funds flow (1)	**131,692**	217,296	**178,123**	207,927
Net debt (1)	**287,874**	353,299	**287,874**	353,299
Net debt to annualized funds flow (1)	**2.2**	1.6	**1.6**	1.7

(1) Funds flow, Annualized funds flow and Net debt are non-GAAP measures. Refer to "Non-GAAP Measures" in this MD&A for further discussion and reconciliation to GAAP measures if applicable.

For the three months ended December 31, 2015, the net debt to annualized funds flow ratio was 2.2, an increase from the prior year quarter, which was 1.6. This increase is due to reduced funds flow associated with current commodity pricing and a lower level of hedging in the second half of 2015. Based on net debt of $287.9 million at December 31, 2015 and forecasted annual funds flow for 2016 at current benchmark oil pricing, the Company expects the net debt to annualized funds flow ratio to increase significantly in 2016.

The Company reviews capital expenditures on an on-going basis to ensure that funds flow will provide adequate funding. In cases such as the current commodity price environment, where funds flow may not be adequate to provide funding for capital expenditures, the Company will adjust capital expenditures to manage debt levels.

In the management of capital, the Company includes working capital and net debt in the definition of capital. The Company's share capital is not subject to external restrictions; however, its credit facility value is based primarily on its petroleum and natural gas reserves and covenants detailed below. The Company confirms there are no off-balance sheet financing arrangements.

Going Concern

As previously announced, due to the current commodity environment and in an effort to meet debt repayment requirements under its bank facility revised on January 15, 2016 (as outlined in the Subsequent Events section of this MD&A), Twin Butte is currently undergoing a strategic alternatives review. The Company continues to work with its lenders, however, there is no guarantee that the Company will meet the repayment of the $85 million term loan on April 30, 2016. As such, the Company includes a note on going concern uncertainty in its financial statements. Management's attention remains focused on managing the resources of the Company through this difficult commodity price environment.

Net Debt

At December 31, 2015, the Company's net debt of $287.9 million consisted of $205.1 million drawn on its credit facility, a working capital deficit of $2.6 million and $80.2 million of convertible debentures. During the three months ended December 31, 2015, Net Debt decreased by $20.5 million, as the total of capital expenditures, decommissioning provision expenditures and dividends paid was less than funds flow. In the year ended December 31, 2015, Net Debt has decreased by $65.4 million or 19%, as the Company reduced capital spending and suspended its dividend, and directed excess funds flow towards debt reduction.

Credit Facility

As at December 31, 2015, the Company's dedicated bank facility of $325 million consists of a revolving line of credit of $300 million and an operating line of credit of $25 million, extendible annually at the request of the Company for a further 364 days, subject to approval of the lenders and repayable one year after the expiry of the revolving period, which is May 26, 2016. Utilization of this facility is restricted to the borrowing base of $275 million, which was under semi-annual review as of December 31, 2015. The borrowing base is determined primarily on reserves, commodity prices, and other factors estimated by the lenders. As outlined in the subsequent events section of this MD&A, the facility was amended on January 15, 2016 and the borrowing base set at $140 million.

The credit facility is with a syndicate of eight Canadian chartered or international banks and provides that advances may be made by way of Canadian prime rate and U.S. base rate loans, bankers' acceptances, LIBOR Loans, or standby letters of credit/guarantees. The facility contains standard commercial covenants for facilities of this nature, including a requirement for Twin Butte to maintain an adjusted current ratio of not less than 1.0:1.0, which includes the undrawn portion of the credit facility as a current asset. The facility also contains a covenant that limits financial commodity agreements to less than 80% the average daily production of the prior quarter at the time the commodity agreement is signed. As commodity agreements extend beyond 12 months, the maximum percentage decreases to 70%, and then to 60% for those agreements with terms greater than 24 months. Non-commodity financial instruments, such as power and currency agreements, are required by covenant to have a maximum term of 36 months, and aggregate amounts hedged must not be more than 60% of the facility's borrowing base. At December 31, 2015, the Company is in compliance with all debt covenants.

Interest rates on Canadian prime rate loans fluctuate based on revised pricing grid and range from Bank of Canada ("bank") prime plus 1% to bank prime plus 2.5%, depending upon the Company's debt to EBITDA ratio for the preceding twelve months in categories ranging from one to greater than three times. A debt to EBITDA ratio of less than one has interest payable at the bank's prime lending rate plus 1%. A debt to EBITDA ratio greater than three has interest payable at the bank's prime lending rate plus 2.5%. The Company's credit facility is secured by a debenture and a general security agreement covering all assets of the Company.

Convertible Debentures

In December 2013, the Company issued convertible unsecured subordinated debentures for gross proceeds of $85.0 million ($81.4 million net of issuance costs) at a price of $1,000 per debenture. The debentures pay interest at a rate of 6.25% per annum, payable in arrears on a semi-annual basis on June 30 and December 31 of each year. The debentures mature on December 31, 2018.

The debentures are convertible at the option of the holder into common shares at a fixed conversion price of $3.05 per share. After December 31, 2016, the Company may redeem the debentures in whole or part provided the common shares' weighted average trading price during a specified period prior to redemption is not less than 125% of the conversion price. As at December 31, 2015, no conversions or redemptions have occurred.

SHARE CAPITAL

In 2015, 1.7 million shares were issued on account of vested share and performance share awards that were exercised, compared to 2.4 million shares issued on account of share awards in 2014. As a result of the suspension of the DRIP and SDP programs in January 2015, 0.5 million shares were issued on account of these programs in 2015 as compared to 2.2 million in 2014.

As of March 22, 2016 the Company has 354,714,069 Common Shares, 378,800 stock options and 24,482,373 share awards, including reinvested dividends and performance multipliers, outstanding.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company enters into short term contractual obligations in the normal course of business, including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations and employee agreements. These obligations are of a recurring, consistent nature and impact cash flows in an ongoing manner.

Contractual obligations and commitments are as follows:

As at December 31, 2015	Less than one year	One to three years	Three to five years	Total
Derivative liability	2,283	1,183	–	3,466
Bank indebtedness - principal (1)	85,000	120,078	–	205,078
Bank indebtedness - interest	8,203	3,418	–	11,621
Convertible debentures - principal (2)	–	85,000	–	85,000
Convertible debentures - coupon	5,312	10,625	–	15,937
Purchase obligations (3)	6,392	3,989	–	10,381
Other (4)	1,609	2,457	–	4,066
	108,799	226,750	–	335,549

(1) Repayment of this principal amount in one to three years is based on the revolving debt agreement currently in place and does not consider the annual review for extension. Subsequent to December 31, 2015, the bank facility was amended and now requires an $85 million term debt repayment in less than one year, on April 30, 2016. See the Subsequent events section of this MD&A for further information.

(2) Repayment of the Convertible Debentures assumes that all holders of the debentures will not convert their holdings into shares.

(3) Purchase obligations are contracts to purchase and consume electricity during 2016 and 2017. The fair value of these contracts is recorded as a financial liability on the Company's balance sheet.

(4) Other includes contractual obligations and commitments for office rent and equipment.

Twin Butte also has long-term contractual obligations and commitments. The Company is responsible for the retirement of long-lived assets related to its oil and gas properties at the end of their useful lives. Twin Butte has recognized a liability of $202.7 million (December 31, 2014 – $218.2 million) based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation or actual costs.

RELATED PARTY TRANSACTIONS

During the twelve months ended December 31, 2015, the Company incurred related party costs totaling $3.2 million ($5.4 million – December 31, 2014) for oilfield services and legal counsel rendered by three companies of which a director of Twin Butte is a director.

These costs were incurred in the normal course of business and were recorded at the amount exchanged between the parties. As at December 31, 2015, the Company had $0.5 million ($0.8 million – December 31, 2014) included in accounts payable and accrued liabilities related to these transactions.

SUBSEQUENT EVENTS

Bank Debt

On January 15, 2016, the Company completed the semi-annual borrowing base review which reduced the borrowing base for the revolving line of credit from $275 million to $140 million, and established a term loan of $85 million payable on April 30, 2016. As a result of this revised agreement, the debt to EBITDA ratio is no longer applicable in determining interest rates for the revolving facility and interest rates are set at the prime rate plus 3% or 4%. Interest rates for the term loan are set at prime plus 6.5% in January, increasing to prime plus 9.25% by the end of the term.

The Company is also subject to certain non-financial covenants in its revised credit facility agreement. Revised covenants include monthly reporting, strategic alternatives process milestones, permitted dispositions and permitted encumbrances. As at March 22, 2016 the Company is in compliance with all covenants. The available level of credit under the borrowing base of the revolving facility is also subject to a one-time review by the syndicate of banks and may be adjusted for changes in reserves, commodity prices and other factors before the May 26, 2016 renewal date.

Crude Oil Sales Price Derivative Contracts

Subsequent to December 31, 2015 the Company entered into a crude oil sales price derivative as follows:

Daily barrel (bbl) quantity	Term of contract	Currency	Fixed price per bbl WCS (1) vs. WTI (2)
1,000	Jan 1, 2017 to December 31, 2017	USD	$(13.30)

(1) WCS represents the posting price of Western Canadian Select oil

(2) WTI represents posting price of West Texas Intermediate oil

NON-GAAP FINANCIAL MEASURES

Certain measures in this document do not have a standardized meaning as prescribed by IFRS and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's reasoning to use the measures, as well as reconciliation to the closest comparable GAAP measure, is detailed below.

Funds Flow, Funds Flow Netback and Funds Flow - Annualized

Twin Butte uses the term "Funds Flow" and its derivatives, "Funds Flow Netback" and "Funds flow – Annualized" as indicators of financial performance, but the terms should not be considered an alternative to, or more meaningful than the closest comparable GAAP measure, "Cash provided by (used in) Operating Activities" as disclosed on the Statement of Cash Flows in the attached financial statements. Funds flow is presented in the Company's MD&A to assist management and investors in analyzing operating performance in the stated period. A reconciliation of Funds Flow to the Cash provided by (used in) Operating Activities is as follows:

	Three months ended December 31		Twelve months ended December 31	
($000's except per boe amounts)	**2015**	2014	**2015**	2014
Cash provided by (used in) Operating Activities	**24,861**	50,256	**170,323**	203,656
Expenditures on decommissioning provision	**590**	2,785	**3,670**	5,044
Change in non-cash operating working capital	**7,472**	1,283	**4,130**	(773)
Funds flow	**32,923**	54,324	**178,123**	207,927
Total boe in the period (000's)	**1,421**	1,880	**6,224**	7,758
Funds flow netback ($/boe)	**23.17**	28.90	**28.62**	26.80
Annualizing factor	**4.0**	4.0	**1.0**	1.0
Funds flow – Annualized	**131,692**	217,296	**178,123**	207,927

Net Debt

Twin Butte uses the term "Net Debt" as an indicator of financial performance and it is presented in the Company's MD&A and Financial Statements to assist management and investors in analyzing total cash-based obligations in the stated period. A reconciliation of Net Debt to the Balance Sheet is as follows:

($000's except per share amounts)	**December 31, 2015**	December 31, 2014
Bank Indebtedness	**205,078**	247,898
Convertible debentures	**80,237**	78,890
Working Capital Deficit	**2,559**	26,511
Net Debt	**287,874**	353,299

Working Capital Deficit

Twin Butte uses the term "Working Capital Deficit" as an indicator of financial performance. This term is presented in the Company's MD&A and Financial Statements to assist management and investors in analyzing net working capital amounts in the stated period. A reconciliation of Working Capital Deficit to the Balance Sheet is as follows:

($000's except per share amounts)	**December 31, 2015**	December 31, 2014
Accounts receivable	**(28,598)**	(50,142)
Deposits and prepaid expenses	**(3,696)**	(4,958)
Accounts payable and accrued liabilities	**34,853**	76,082
Dividend Payable	**-**	5,529
Working capital deficit (surplus)	**2,559**	26,511

Net debt to funds flow – annualized

"Net debt to funds flow – annualized" is a non-GAAP measure defined as the ratio of Net debt to Funds flow – annualized. Twin Butte uses this term to monitor whether funds flow from operations will be sufficient to cover all obligations, specifically the non-GAAP measure of net debt. Twin Butte considers this ratio to be a key measure of liquidity and management of capital resources.

Operating netback, Field netback and Funds flow netback

"Operating netback", "Field netback" and "Funds flow netback" are common metrics used in the oil and gas industry and are presented in the Company's MD&A to assist management and investors to evaluate oil and gas operating performance in the stated period. As they are industry specific terms, there is no comparable GAAP measure.

Operating Netback is determined as the sum of Petroleum and natural gas sales, Royalties, Operating Expense, and Transportation Expense as defined on the Statement of Income (Loss) and Comprehensive Income (Loss), and the Realized Gain (Loss) on financial instruments per note 5 to the financial statements, all on a per unit basis. Field netback is the operating netback, excluding the realized gain (loss) on financial instruments on a per-unit basis. Funds flow netback is the operating netback, plus general and administrative expense and transaction costs per the Statement of Income (Loss) and Comprehensive Income (Loss), and interest paid per the Statement of Cash Flows on a per-unit basis. Total units (boe) and each of the per-unit line items referenced above are also defined in the related sections of this MD&A.

Corporate Acquisitions

"Corporate Acquisitions" is a non-GAAP measure and includes the IFRS definition of total consideration plus working capital deficit (surplus) acquired in a corporate acquisition. Management uses this measure to analyze the total compensation paid for a corporate acquisition when working capital accounts are acquired.

Capital Expenditures and Development Capital

Management uses the Non-GAAP measures "Capital expenditures" and "Development Capital" in its analysis of cash used in investing activities. Capital expenditures and Development Capital are reconciled to GAAP measures, as defined on the Statement of Cash flows in the attached financial statements, below:

	Three months ended December 31		Twelve months ended December 31	
($000's)	**2015**	2014	**2015**	2014
Expenditures on property and equipment	**(10,422)**	(33,191)	**(75,800)**	(141,322)
Expenditures on exploration and evaluation assets	**(896)**	(1,544)	**(4,417)**	(2,810)
Development capital	**(11,318)**	(34,735)	**(80,217)**	(144,132)
Proceeds on disposition of property and equipment	**–**	31	**–**	3,509
Proceeds on disposition of exploration and evaluation assets	**1,916**	576	**2,178**	2,996
Capital expenditures	**(9,402)**	(34,128)	**(78,039)**	(137,627)

Payout Ratio and Total Payout Ratio

Management uses the Non-GAAP measures "Payout Ratio" and "Total Payout Ratio" as indicators of financial performance and sustainability. A payout ratio of 100% indicates that the company has generated the cash flow necessary to fund dividends and capital investment. Payout ratio is defined as the non-GAAP measure, Funds flow, divided by the sum of the non-GAAP measure Capital expenditures and Dividends declared per the Statement of Changes in Shareholder's Equity in the financial statements. Total payout ratio is defined as Funds flow, divided by the sum of Capital expenditures and Dividends paid per the Statement of Cash Flows, which are net of dividends reinvested in shares per the Dividend Reinvestment Program and the Stock Dividend Program.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 8 – valuation of property and equipment;
- Note 11 – measurement of decommissioning provision;
- Note 12 – measurement of share-based compensation; and
- Note 17 – income tax expense.

Judgements

In the process of applying the Company's accounting policies, management has made the following judgements, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the financial statements.

(a) Exploration and evaluation assets

The decision to transfer assets from exploration and evaluation to property and equipment is based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability (Financial Statements Note 7).

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporate the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs (Financial Statements Note 8).

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is highly 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 and probable reserves.

(c) Depletion of oil and gas assets

Oil and gas properties are depleted using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depletion could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves (Financial Statements Note 8).

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Company, and grouped the properties into cash generating units on the basis of their ability to generate independent cash inflows, similar reserve characteristics, geographical location, and shared infrastructure (Financial Statements Note 8).

(e) Impairment indicators and calculation of impairment

At each reporting date, Twin Butte assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property and equipment are not recoverable, or impaired. Such circumstances include incidents of deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves. At December 31, 2015, Management exercised judgement at determined that there were impairment indicators present for all CGUs (Financial Statements Note 8). When management judges that circumstances clearly indicate impairment, property and equipment and exploration and evaluation assets are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value in use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions that are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates, as well as future development and operating costs.

(f) Going concern

The financial statements have been prepared on a going concern basis, which assumes the realization of assets and discharge of liabilities in the normal course of business within the foreseeable future. Management uses judgment to assess the Company's ability to continue as a going concern and the conditions that cast doubt upon the going concern assumption (Financial Statements Note 2).

Significant Accounting Policies

During the twelve months ended December 31, 2015, the Company did not adopt any new or revised standards. New accounting standards, amendments to accounting standards and interpretations effective for annual periods beginning on or after January 1, 2016 are as follows:

Leases

On January 13, 2016, the IASB issued IFRS 16 - Leases, which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. IFRS 16 is effective for years beginning on or after January 1, 2019. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 16 on the Financial Statements.

Revenue Recognition

On September 11, 2015 the IASB published an amendment to IFRS 15 – *Revenue from Contracts with Customers*, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15, replaces IAS 11 – *Construction Contracts*, IAS 18 - Revenue and several revenue-related interpretations, establishing a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The Company is currently evaluating the impact of adopting IFRS 15 on the Financial Statements.

Financial Instruments

IFRS 9 – *Financial Instruments* was issued in 2014 and is effective for years beginning on or after January 1, 2018 with earlier adoption permitted. The standard introduces multiple changes from IAS 39 – *Financial Instruments: Recognition and Measurement*, including introducing a principle-based approach for classification and measurement of financial assets, a single expected loss impairment model and a substantially-reformed approach to hedge accounting. The Company is currently evaluating the impact of adopting IFRS 9 on the Financial Statements.

The accounting policies followed in the audited financial statements are consistent with those of the previous year ended December 31, 2014.

ASSESSMENT OF BUSINESS RISKS

The following are the primary risks associated with the business of Twin Butte. These risks are similar to those affecting other companies competing in the conventional oil and natural gas sector. Twin Butte's financial position and results of operations are directly impacted by these factors and include:

Operational risk associated with the production of oil and natural gas:

- Reserve risk in respect to the quantity and quality of recoverable reserves;
- Exploration and development risk of being able to add new reserves economically;
- Market risk relating to the availability of transportation systems to move the product to market;
- Commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry; and
- Continued participation of Twin Butte's lenders.

Twin Butte seeks to mitigate these risks where possible by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;

- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a hedging program to hedge commodity prices with creditworthy counterparties;
- Adhering to the Company's safety program and adhering to current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Carrying industry standard insurance;
- Establishing and maintaining adequate resources to fund future abandonment and site restoration costs; and
- Monitoring our joint venture partners' obligations to us and cash calling for capital projects to limit the Company's credit risk.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding disclosure.

Twin Butte's Chief Executive Officer and Chief Financial Officer have evaluated, or caused to be evaluated under their supervision, the effectiveness of Twin Butte's DC&P as at December 31, 2015. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Twin Butte's DC&P were effective as at December 31, 2015.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting ("ICFR"), as defined in National Instrument 52-109, means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management or other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

(a) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements.

Twin Butte's officers used the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to design ICFR. Twin Butte's Chief Executive Officer and Chief Financial officer have evaluated, or caused to be evaluated under their supervision, the effectiveness of ICFR at December 31, 2015. Based on the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Twin Butte's ICFR were effective as at December 31, 2015.

It should be noted that while Twin Butte's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P or ICFR will prevent all errors and/or fraud. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Twin Butte's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting that occurred during our most recent reporting period that has materially affected, or is reasonably likely to affect, the Company's internal controls over financial reporting. During the twelve months ended December 31, 2015, there were no changes to Twin Butte's ICFR that materially affected, or are reasonably likely to materially affect the Company's ICFR.

MANAGEMENT'S REPORT

To the Shareholders of Twin Butte Energy Ltd.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying financial statements of Twin Butte Energy Ltd. and all of the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those methods it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the financial statements.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management has established systems of internal controls, which are designed to provide reasonable assurance the Company's assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information. Internal control systems, no matter how well designed have inherent limitations. Therefore, even those systems that have been determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. It exercises its responsibilities primarily through the Audit Committee, which is comprised of independent, non-management directors. The Audit Committee has reviewed the financial statements with both management and the auditors. This has been reported to the Board of Directors which has approved the financial statements.

The financial statements have been audited by PricewaterhouseCoopers LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

Rob Wollmann	R. Alan Steele
President & CEO	Vice-President, Finance & CFO

March 22, 2016

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Twin Butte Energy Ltd.

We have audited the accompanying financial statements of Twin Butte Energy Ltd., which comprise the balance sheets as at December 31, 2015 and 2014 and the statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the financial position of Twin Butte Energy Ltd. as at December 31, 2015 and 2014 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

EMPHASIS OF MATTER

Without qualifying our opinion, we draw attention to Note 2 in the financial statements which describes matters and conditions that indicate the existence of material uncertainty that may cast significant doubt about the ability of Twin Butte Energy Ltd. to continue as a going concern.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

March 22, 2016

BALANCE SHEET

(Cdn$ thousands)	Note	December 31, 2015	December 31, 2014
ASSETS			
Current Assets			
Accounts receivable	18	$ 28,598	$ 50,142
Deposits and prepaid expenses		3,696	4,958
Derivative assets	5	10,594	117,299
		42,888	172,399
Non-current assets			
Derivative assets	5	18	–
Exploration and evaluation	7	37,090	44,186
Property and equipment	8	483,336	826,664
		$ 563,332	$ 1,043,249
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities	19	$ 34,853	$ 76,082
Dividend payable		–	5,529
Derivative liabilities	5	2,283	7,964
Bank indebtedness	9, 22	85,000	–
		122,136	89,575
Non-current liabilities			
Derivative liabilities	5	1,183	275
Bank indebtedness	9, 22	120,078	247,898
Convertible debentures	10	80,237	78,890
Deferred taxes	17	–	13,709
Decommissioning provision	11	202,652	218,202
		526,286	648,549
Shareholders' Equity			
Share capital	12	737,452	733,812
Contributed surplus		14,556	9,921
Equity component of convertible debenture	10	2,879	2,879
Deficit		(717,841)	(351,912)
		37,046	394,700
		$ 563,332	$ 1,043,249

Going concern (note 2)

Commitments and contingencies (note 21)

Subsequent events (note 22)

The accompanying notes are an integral part of these financial statements.

On Behalf of the Board of Directors:

Jim Saunders
Director

David Fitzpatrick
Director

STATEMENT OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(Cdn$ thousands except per share amounts)	*Note*	Twelve months ended December 31 **2015**	 2014
Petroleum and natural gas sales	*13*	**$ 240,770**	$ 555,073
Royalties		**(25,058)**	(100,508)
Revenues		**$ 215,712**	$ 454,565
Expenses			
Operating		**117,698**	164,353
Transportation		**5,603**	8,446
General and administrative	*14*	**13,186**	14,068
Transaction costs		**100**	–
Share-based payments	*12*	**5,258**	4,485
Finance expense	*15*	**19,433**	22,359
Loss (gain) on derivatives	*5*	**(10,725)**	(97,606)
Loss on sub-lease		**1,187**	–
Exploration and evaluation expense	*7*	**10,906**	7,735
Gain on disposition of property and equipment	*8*	**(497)**	(1,646)
Gain on disposition of exploration asset	*7*	**(2,652)**	(1,824)
Depletion and depreciation	*8*	**129,864**	180,972
Impairment of exploration and evaluation asset		**–**	10,033
Impairment of property and equipment	*8*	**276,992**	218,163
		566,353	529,538
Income (loss) before income taxes		**(350,641)**	(74,973)
Deferred tax expense (recovery)	*17*	**(13,709)**	(17,633)
Net income (loss) and comprehensive income (loss)		**$ (336,932)**	$ (57,340)
Net Income (Loss) per share $			
Basic	*12*	**(0.95)**	(0.17)
Diluted	*12*	**(0.95)**	(0.17)

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CASH FLOWS

(Cdn$ thousands)	*Note*	Twelve months ended December 31 **2015**	 2014
Cash provided by (used in):			
OPERATING ACTIVITIES:			
Net income (loss)		**$ (336,932)**	$ (57,340)
Adjustments for items not involving cash:			
Depletion and depreciation	*8*	**129,864**	180,972
Impairments	*8*	**276,992**	228,196
Deferred tax expense (recovery)	*17*	**(13,709)**	(17,633)
Unrealized loss (gain) on derivatives	*5*	**101,914**	(141,297)
Finance expenses	*15*	**19,433**	22,359
Share-based payments	*12*	**5,258**	4,485
Non-cash loss on sub-lease		**1,187**	–
Exploration and evaluation expenses	*7*	**10,906**	7,735
Gain on disposition of property and equipment	*8*	**(497)**	(1,646)
Gain on disposition of exploration asset	*7*	**(2,652)**	(1,824)
Interest paid	*15*	**(13,641)**	(16,080)
Expenditures on decommissioning provision	*11*	**(3,670)**	(5,044)
Changes in non-cash working capital	*16*	**(4,130)**	773
		170,323	203,656
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	*9*	**(42,820)**	(4,283)
Issuance of share capital		**–**	3,271
Share issue costs	*12*	**–**	(22)
Dividends		**(28,454)**	(58,950)
Changes in non-cash working capital	*16*	**(5,529)**	40
		(76,803)	(59,944)
INVESTING ACTIVITIES			
Expenditures on property and equipment		**(75,800)**	(141,322)
Expenditures on exploration and evaluation assets		**(4,417)**	(2,810)
Proceeds on disposition of property and equipment		**–**	3,509
Proceeds on disposition of exploration and evaluation assets	*7*	**2,178**	2,996
Changes in non-cash working capital	*16*	**(15,481)**	(6,085)
		(93,520)	(143,712)
Change in cash		**$ –**	$ –
Cash and cash equivalents, beginning and end of period		**$ –**	$ –

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(Cdn$ thousands)	*Note*	Share capital	Contributed surplus	Equity component of convertible debenture	Deficit	Total Shareholders' Equity
Balance, December 31, 2013		$ 717,246	$ 8,818	$ 2,879	$ (227,268)	$ 501,675
Common shares issued pursuant to the DRIP and SDP	*12*	8,354	–	–	–	8,354
Common shares issued under share award plan	*12*	4,957	–	–	–	4,957
Common shares issued pursuant to private placement	*12*	3,271				3,271
Share issue costs, net of deferred tax	*12*	(16)				(16)
Share-based payments for share awards exercised	*12*	–	(4,957)	–	–	(4,957)
Share-based payments for share awards granted		–	6,060	–	–	6,060
Dividends	*12*	–	–	–	(67,304)	(67,304)
Net income (loss) and comprehensive income (loss)		–	–	–	(57,340)	(57,340)
Balance, December 31, 2014		$ 733,812	$ 9,921	$ 2,879	$ (351,912)	$ 394,700
Balance, December 31, 2014		$ 733,812	$ 9,921	$ 2,879	$ (351,912)	$ 394,700
Common shares issued pursuant to the DRIP and SDP	*12*	543	–	–	–	543
Common shares issued under share award plan	*12*	3,097	–	–	–	3,097
Share-based payments for share awards exercised	*12*	–	(3,097)	–	–	(3,097)
Share-based payments for share awards granted		–	7,732	–	–	7,732
Dividends	*12*	–	–	–	(28,997)	(28,997)
Net income (loss) and comprehensive income (loss)		–	–	–	(336,932)	(336,932)
Balance, December 31, 2015		**$ 737,452**	**$ 14,556**	**$ 2,879**	**$ (717,841)**	**$ 37,046**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS

For the years ended December 31, 2015 and 2014

All tabular amounts are in thousands of Canadian dollars except as otherwise indicated.

NOTE 1. BUSINESS AND STRUCTURE OF TWIN BUTTE

Twin Butte Energy Ltd. ("Twin Butte" or "the Company") is an oil and natural gas exploration, development and production company with properties located in Western Canada. Twin Butte is domiciled and incorporated in Canada under the Business Corporations Act (Alberta). Twin Butte's head office address is 410, 396 – 11th Avenue SW, Calgary, Alberta, Canada. The Company's primary listing is on the Toronto Stock Exchange under the symbol "TBE".

NOTE 2. BASIS OF PRESENTATION AND GOING CONCERN

The Company prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company has applied the same accounting policies throughout all years presented except as identified in Note 3, Significant Accounting Policies. These financial statements have been prepared on the historical cost basis, except as identified in Note 3, Significant Accounting Policies. They are presented in Canadian dollars, which is the Company's functional currency.

These financial statements were approved and authorized for issue by the Board of Directors on March 22, 2016.

Going Concern

These financial statements are prepared on a going concern basis. The going concern basis of presentation assumes that the Company will continue in operations for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. On January 15, 2016, the Company amended its $275 million credit facility with a syndicate of banks (See note 22 – Subsequent events). Upon amendment, the facility consists of a $140 million borrowing base revolving facility and an $85 million term facility. The borrowing base revolving facility is up for renewal on May 28, 2016, while the term facility requires repayment on April 30, 2016. The terms of the amended credit facility result in an increased working capital deficit.

The Company continues to identify and pursue strategic alternatives, including divestitures or other suitable opportunities to enhance the financial position of the Company. There is no assurance that the Company will be able to formalize a divestiture or other suitable option in order to repay the term facility in accordance with the timing required under the credit facility agreement. The banking syndicate continues to work with the Company and is regularly informed of the strategic alternatives process status.

If the Company is unable to make the required repayment on April 30, 2016, outstanding borrowings may become due and payable immediately. These circumstances result in material uncertainty surrounding the Company's ability to continue as a going concern and lend significant doubt as to the ability of the Company to meet its obligations as they become due and, accordingly the appropriateness of the use of accounting principles applicable to a going concern. These financial statements do not reflect adjustments to the carrying values of assets and liabilities, the reported revenues and expenses or the statement of financial position classifications that would be necessary if the Company were unable to realize its assets and settle its liabilities as a going concern in the normal course of operations. Such adjustments could be material.

NOTE 3. SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used in the preparation of these financial statements are as follows:

(a) Cash and cash equivalents

Cash consists of balances held with banks, and other short-term highly liquid investments with original maturities of three months or less from inception.

(b) Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Gains and or losses on these items are included in the statement of income (loss).

(c) Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have been expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized when the obligation specified in the contract is discharged, cancelled or expires.

All financial instruments are initially recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, are based on how each financial instrument was initially classified. The Company has classified each identified financial instrument into the following categories: fair value through profit or loss, loans and receivables, held-to-maturity investments, available for sale financial assets, and financial liabilities at amortized cost. Fair value through profit or loss financial instruments are measured at fair value with gains and losses recognized in income immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to income when the asset is derecognized. Loans and receivables, held-to-maturity investments and financial liabilities at amortized cost are recognized at amortized cost using the effective interest method and impairment losses are recorded in income when incurred.

The Company's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the conversion feature. As the debentures are converted, a portion of debt and conversion feature components are transferred to share capital. The debt component associated with the convertible debentures is designated as a financial liability at amortized cost.

Derivative instruments executed by the Company to manage market risk associated with volatile commodity prices are classified as held for trading within fair value through profit or loss and recorded on the balance sheet at fair value as derivative assets and liabilities. Gains and losses on these derivative instruments are recorded as gains and losses in the statement of income (loss) in the period they occur.

Gains and losses on derivative instruments are comprised of cash receipts and payments associated with periodic settlement that occurs over the life of the instrument (realized gains/losses), and non-cash gains and losses associated with changes in the fair values of the instruments which are remeasured at each reporting date and recorded on the balance sheet (unrealized gains/losses). Transaction costs attributed to the acquisition or issue of a derivative instrument are expensed immediately. For other financial instruments, transaction costs are added to the fair value initially recognized for a financial asset or liability.

(d) Share capital

Equity instruments issued by the Company are recorded at the proceeds received, with direct issue costs as a deduction there from, net of any associated tax benefit.

(e) Joint arrangements

A portion of the Company's oil and natural gas activities involve joint arrangements classified as joint operations. The Company's share of these joint operations and a proportionate share of the relevant revenue and costs are reflected in the financial statements. Joint control exists for contractual arrangements governing Twin Butte's assets where all partners collectively control the arrangement and share the associated risks, Twin Butte has less than 100 percent working interest, all of the partners have control of the arrangement collectively and spending on the project requires unanimous consent of all parties. Twin Butte does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

(f) Property and equipment and exploration and evaluation assets

(i) Exploration and evaluation (E&E) expenditures

Pre-license costs are recognized in the statement of income (loss) as incurred. All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. Such costs can typically include costs to acquire land rights in areas with no proved or probable reserves assigned, geological and geophysical costs, and exploration wells.

Exploration and evaluation costs initially are capitalized as either tangible or intangible according to the nature of the assets acquired. The costs are accumulated in areas by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are not depreciated, and are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. If an impairment indicator for E&E assets is noted, for purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

The technical feasibility and commercial viability of extracting a mineral resource from exploration and evaluation assets is considered when proved and probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and probable reserves have been discovered. Upon determination of proved and probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to development and production assets within property and equipment. If the well or exploration project did not encounter potentially economic oil and gas quantities, the unrecoverable costs are expensed and reported in exploration and evaluation expense in the period incurred.

(ii) Development and production expenditures

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Costs include E&E expenditures incurred in finding commercial reserves transferred from E&E assets, drilling and completion, production facilities, decommissioning costs, geological and geophysical costs and directly attributable costs related to development and production activities, net of any government incentive programs, and for qualifying assets, borrowing costs The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant parts of an item of property and equipment, including oil and natural gas properties, have different useful lives, they are accounted for as separate items (major components). Gains and losses on disposal of an item of property and equipment, including oil and natural gas properties and E&E assets, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized within the statement of income (loss).

(iii) Subsequent costs

Costs incurred subsequent to commencement of production that are significant are recognized as oil and gas assets only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized against income as incurred.

(iv) Depletion and depreciation

The net carrying value of oil and gas properties is depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually. Major development projects are not depleted until production commences.

The Company records furniture and equipment at cost and provides depreciation on the declining balance method at a rate of 20% per annum which is designed to amortize the cost of the assets over their estimated useful lives. The Company records leasehold improvements at cost and provides depreciation on the straight-line method over the term of the lease. Leased assets are depreciated over the shorter of the lease term and their useful lives. Depreciation methods, useful lives and residual values are reviewed at each financial year end, and, if necessary, changes in useful lives are accounted for prospectively.

(g) Asset swaps

Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the amount given up. Any gain or loss on derecognition of the asset given up is recognized in statement of income (loss). For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at carrying value.

(h) Leased assets

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under the operating leases are charged to income on a straight-line basis over the period of the lease.

(i) Impairment

(i) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income in the period incurred. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the statement of income (loss).

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less cost of disposal.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less cost of disposal is assessed utilizing market valuation based on an arm's length transaction between active participants. In the absence of any such transactions, fair value less costs of disposal is estimated by discounting the expected after-tax cash flows of the cash generating unit at an after-tax discount rate that reflects the risk of the properties in the cash generating unit. The discounted cash flow calculation is then increased by a tax-shield calculation, which is an estimate of the amount that a prospective buyer of the cash generating unit would be entitled. The carrying value of the cash generating unit is reduced by the deferred tax liability associated with its property and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been objective change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized.

(j) Share based payments

The Company's compensation program currently consists of three primary components: (i) annual base salary (ii) discretionary short-term incentive cash bonus; (iii) and periodic grants of long-term incentives in the form of share awards ("equity-settled transactions"). Share awards are granted from time to time to participants at varying levels consistent with the individual's position and level of responsibility.

The Company follows the fair value method of valuing share award grants. Under this method, compensation costs attributable to share awards granted to employees, officers and directors of the Company are measured at fair value at the date of grant determined in reference to the Company's share price on the grant date, and the resulting share-based payment expense is recognized on a graded-vesting basis over the related vesting period with a corresponding increase to contributed surplus.

Certain share awards have been granted with a performance multiplier. This multiplier, ranging from zero to two, will be applied at exercise and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period and the board of directors' discretion. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the exercise of the share awards, consideration paid together with the amount in contributed surplus is recorded as an increase to share capital.

(k) Decommissioning provision

A decommissioning liability is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Decommissioning liabilities are determined by discounting the expected future cash flows at a risk-free rate. A corresponding asset equal to the initial estimated liability is capitalized as part of the long-lived asset. The increase in the provision due to the passage of time is recognized as a finance cost in the statement of income (loss). Actual expenditures incurred are charged against the accumulated liability. Revisions to the estimated amount and timing of the obligations are reflected as increases or decreases to the decommissioning liability.

(l) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party, sales prices and costs can be reasonably measured, and it is probable that future economic benefits will flow to the entity. For natural gas, this is generally at the time product enters the pipeline. For crude oil, this is generally at the time the product reaches a trucking terminal or pipeline. For natural gas liquids, this is generally at the time the product is processed through a gas plant. Revenue is measured net of discounts, customs duties and royalties.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(m) Finance expense

Finance expense comprises interest expense on borrowings, interest on convertible debentures, accretion of the discount on convertible debentures and accretion of the discount on the decommissioning provision.

(n) Borrowing costs

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. The Company considers a qualifying asset to be any significant construction project expected to take more than twelve months to complete. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding general and specific borrowings during the period.

(o) Income tax

Income tax expense comprises current and deferred income tax. Income tax expense is recognized in the statement of income (loss) except to the extent that it relates to items recognized directly in shareholders' equity.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to income tax payable in respect of previous years. Deferred income tax is recognized using the liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred income tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are only offset when they arise within the same tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

(p) Net income (loss) per share

Basic net income (loss) per share is calculated by dividing the net income (loss) of the Company by the weighted average number of common shares outstanding during the period. Diluted net income (loss) per share is determined by adjusting the net income (loss) attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

(q) Dividends

Dividends are accrued when declared by the Board of Directors.

(r) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net income as negative goodwill. At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

(s) New standards and interpretations not yet adopted

During the twelve months ended December 31, 2015, the Company did not adopt any new or revised standards. New accounting standards, amendments to accounting standards and interpretations effective for annual periods beginning on or after January 1, 2016 are as follows:

Leases

On January 13, 2016, the IASB issued IFRS 16 - Leases, which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. IFRS 16 is effective for years beginning on or after January 1, 2019. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 16 on the Financial Statements.

Revenue Recognition

On September 11, 2015 the IASB published an amendment to IFRS 15 – *Revenue from Contracts with Customers*, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15, replaces IAS 11 – *Construction Contracts*, IAS 18 – Revenue and several revenue-related interpretations, establishing a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The Company is currently evaluating the impact of adopting IFRS 15 on the Financial Statements.

Financial Instruments

IFRS 9 – *Financial Instruments* was issued in 2014 and is effective for years beginning on or after January 1, 2018 with earlier adoption permitted. The standard introduces multiple changes from IAS 39 – *Financial Instruments: Recognition and Measurement*, including introducing a principle-based approach for classification and measurement of financial assets, a single expected loss impairment model and a substantially-reformed approach to hedge accounting. The Company is currently evaluating the impact of adopting IFRS 9 on the Financial Statements.

NOTE 4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 8 – valuation of property and equipment;
- Note 11 – measurement of decommissioning provision;
- Note 12 – measurement of share-based compensation; and
- Note 17 – income tax expense.

Judgements

In the process of applying the Company's accounting policies, management has made the following judgements, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the financial statements.

(a) Exploration and evaluation assets

The decision to transfer assets from exploration and evaluation to property and equipment is based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability (Note 7).

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporate the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs (Note 8).

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is highly 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 and probable reserves.

(c) Depletion of oil and gas assets

Oil and gas properties are depleted using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depletion could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves (Note 8).

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Company, and grouped the properties into cash generating units on the basis of their ability to generate independent cash inflows, similar reserve characteristics, geographical location, and shared infrastructure (Note 8).

(e) Impairment indicators and calculation of impairment

At each reporting date, Twin Butte assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property and equipment are not recoverable, or impaired. Such circumstances include incidents of deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves. At December 31, 2015, Management exercised judgement at determined that there were impairment indicators present for all CGUs (Note 8). When management judges that circumstances clearly indicate impairment, property and equipment and exploration and evaluation assets are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value in use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions that are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates, as well as future development and operating costs.

(f) Going concern

These financial statements have been prepared on a going concern basis, which assumes the realization of assets and discharge of liabilities in the normal course of business within the foreseeable future. Management uses judgment to assess the Company's ability to continue as a going concern and the conditions that cast doubt upon the going concern assumption (Note 2).

NOTE 5. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness, convertible debentures, dividends payable, and derivative assets and liabilities.

($000's)	Level in fair value hierarchy	As At December 31, 2015		As At December 31, 2014	
		Carrying Amount	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Financial Assets					
Held For trading					
Derivative assets - oil and gas	Level 2	**10,594**	**10,594**	117,299	117,299
Derivative assets - power	Level 3	**18**	**18**	–	–
Loans and receivables					
Accounts receivable	Level 2	**28,598**	**28,598**	50,142	50,142
Deposits	Level 2	**260**	**260**	1,163	1,163
Financial Liabilities					
Held for trading					
Derivative liabilities - oil and gas	Level 2	**1,782**	**1,782**	5,048	5,048
Derivative liabilities - power	Level 3	**1,684**	**1,684**	1,288	1,288
Derivative liabilities - currency	Level 2	**–**	**–**	1,903	1,903
Financial liabilities at amortized cost					
Accounts payable and accrued liabilities	Level 2	**34,853**	**34,853**	76,082	76,082
Dividends payable	Level 2	**–**	**–**	5,529	5,529
Bank indebtedness	Level 2	**205,078**	**205,078**	247,898	247,898
Convertible debentures	Level 2	**80,237**	**21,062**	78,890	60,753

As at December 31, 2015, the carrying amounts reported on the Balance Sheet approximated the estimated fair values of financial instruments (excluding convertible debentures) due to the short terms to maturity and the floating interest rate on the bank indebtedness.

Fair value is determined following a three level hierarchy:

Level 1: Quoted prices in active markets for identical assets and liabilities. The Company does not have any financial assets or liabilities that require level 1 inputs.

Level 2: Inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly. Such inputs can be corroborated with other observable inputs for substantially the complete term of the contract. Twin Butte uses Level 2 inputs in the determination of the fair value of oil and gas derivative assets and liabilities, and convertible debentures.

Level 3: Fair value is determined using inputs that are not observable. Twin Butte uses Level 3 inputs in the determination of the fair value of power purchase derivative assets and liabilities, and the fair value less costs of disposal used in determining the recoverable amount of a Cash Generating Unit (CGU) for the purpose of impairment testing for PP&E and E&E assets.

Derivative assets and liabilities are carried at fair value and are measured on a recurring basis. The fair values of oil and gas commodity derivatives are determined using a Level 2 valuation model and inputs include quoted forward prices for commodities, foreign exchange rates, volatility and discounting, all of which can be observed or corroborated in the marketplace. Power purchase derivatives are calculated using a Level 3 valuation model, as inputs include forward power prices in less active markets. These inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The fair value of convertible debentures is determined using a Level 2 valuation model and is calculated as the carrying value of the debenture, multiplied by the percentage of the quoted market price compared to the face value for the debentures at the balance sheet date. In testing for impairment of property and equipment, a Level 3 valuation model is used to determine the recoverable amount of a CGU. The fair value less costs of disposal model used contains inputs that are not readily observable or corroborated, such as forecasted cash flows over the estimated life of reserves and independent land valuations.

The Company's policy is to recognize transfers into and out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. During the three and twelve months ended December 31, 2015, there were no transfers between levels 1, 2 or 3.

The table below summarizes the changes in Level 3 measured derivatives:

($000s)	
Level 3, December 31, 2014	(1,288)
Change in fair value of power purchase derivatives	(378)
Level 3, December 31, 2015	**(1,666)**

(a) Risk Management Assets and Liabilities

The table below summarizes the realized and unrealized gain (loss) on derivatives:

	Twelve months ended December 31	
($000s)	**2015**	2014
Realized gain (loss)	**112,639**	(43,691)
Unrealized gain (loss)	**(101,914)**	141,297
Gain on derivatives	**10,725**	97,606

Derivative Position

As at	**Dec 31, 2015**	Dec 31, 2014
Current asset	**10,594**	117,299
Non-current asset	**18**	–
Current liability	**(2,283)**	(7,964)
Non-current liability	**(1,183)**	(275)
Net derivative asset (liability) position	**7,146**	109,060

Derivative Summary

As at	**Dec 31, 2015**	Dec 31, 2014
Crude oil sales price derivatives	**8,812**	110,709
Natural gas sales price derivatives	**–**	1,542
Foreign exchange derivatives	**–**	(1,903)
Power purchase price derivatives	**(1,666)**	(1,288)
Net derivative asset (liability) position	**7,146**	109,060

Crude Oil Sales Price Derivatives

Daily barrel (bbl) quantity	Term of contract		WTI(1) Fixed price per bbl	Fixed price per bbl WCS (2) vs. WTI (1)	Fixed written call price per bbl WTI (1)	Fair market value $ 000's ($CAD)
1,000	January 1, 2016 to December 31, 2016	$CAD	$85.00			10,121
5,500	January 1, 2016 to December 31, 2016	$CAD		$(18.61)		(241)
1,000	January 1, 2017 to December 31, 2017	$CAD			$85.00	(1,068)
Crude oil fair value position at December 31, 2015						8,812

(1) WTI represents posting price of West Texas Intermediate oil

(2) WCS represents the posting price of Western Canadian Select oil

Power Purchase Price Derivatives

Daily Megawatt (MW) hours quantity	Term of contract	Fixed price per MW	Fair Market Value *$000's*
384	January 1, 2016 to December 31, 2016	$45.48	(1,569)
264	January 1, 2017 to December 31, 2017	$41.28	(97)
Power purchase contract fair value position at December 31, 2015			(1,666)

(b) Risks Associated with Financial Assets and Liabilities

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as: credit risk; liquidity risk; price and currency risk; and interest rate risk.

Price and currency risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. Twin Butte monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices and foreign exchange rates. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Twin Butte. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its heavy and medium crude oil sales. This includes swaps to help protect against widening light/heavy crude oil price differentials. When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2015, a 10% increase in pricing would decrease net income for the year ended December 31, 2015 by $3.5 million, excluding the corresponding impact on sales revenues, while a 10% decrease would increase net income for the year ended December 31, 2015 by $5.1 million.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company will utilize swaps, which fix the AECO price. As at December 31, 2015, the swaps in place during 2015 have settled and the Company does not have natural gas hedges outstanding.

Currency – North American oil and natural gas prices are based upon US dollar denominated commodity prices. As a result, although receivables are denominated in Canadian dollars, the price received by Canadian producers is affected by the Cdn$/US$ foreign exchange rate that may fluctuate over time. To minimize this risk, fixed price swaps for crude oil and natural gas are contracted in Canadian dollars, where available.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk is as follows:

($000's)	**Dec 31, 2015**	Dec 31, 2014
Accounts receivable	**28,598**	50,142
Deposits	**260**	1,163
Derivative assets	**10,612**	117,299
	39,470	168,604

Accounts receivable, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect management's assessment of the associated maximum exposure to such credit risk. Substantially all of the Company's accounts receivables are due from customers and partners concentrated in the Canadian oil and gas industry. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic conditions. Management aims to mitigate this risk by dealing with a broad selection of reputable partners within the sector, by reviewing credit ratings of counterparties and partners, and through closely monitoring significant balances. When necessary, the Company requires cash calls from its partners on capital projects before they commence, and with certain counterparties, has the ability to withhold production or offset payables.

Receivables related to the sale of the Company's petroleum and natural gas production are normally collected on the 25th day of the month following delivery. As at December 31, 2015, $0.7 million or 2.3% of accounts receivable are outstanding for 90 days or more (December 31, 2014, $2.2 million or 4.4% of accounts receivables). The Company has provided an allowance for doubtful accounts of $1.3 million at December 31, 2015 (December 31, 2014 - $0.8 million) and believes that the remaining accounts receivable balance, net of this allowance, is collectible.

The Company's deposits are primarily due from the Alberta and British Columbian Provincial governments and are viewed by Management as having minimal credit risk. To the extent that Twin Butte enters into derivatives to manage commodity price risk, the Company is exposed to credit risk associated with counterparties. The Company enters into derivative contracts with major national and international banks to mitigate this credit risk.

Liquidity risk

The timing of cash outflows relating to financial liabilities as at December 31, 2015 are as follows:

($000's)

December 31, 2015	Less than one year	One to three years	Three to five years	Thereafter	Total
Trade and accrued liabilities	**34,853**	**–**	**–**	**–**	**34,853**
Derivative liability	**2,283**	**1,183**	**–**	**–**	**3,466**
Bank indebtedness – principal (1)	**85,000**	**120,078**	**–**	**–**	**205,078**
Bank indebtedness – interest	**4,803**	**2,001**	**–**	**–**	**6,804**
Convertible debenture – principal	**–**	**85,000**	**–**	**–**	**85,000**
Convertible debenture – coupon	**5,312**	**10,625**	**–**	**–**	**15,937**
Total	**132,251**	**218,887**	**–**	**–**	**351,138**

(1) Subsequent to December 31, 2015, the bank facility was amended and requires an $85 million term debt repayment in less than one year, on April 30, 2016.

Liquidity risk is the risk that Twin Butte will not be able to meet all of its financial obligations when they become due. As discussed in Note 2 – Going concern, and Note 22 – subsequent events, on January 15, 2016 the Company amended its $275 million credit facility. This amendment requires an $85 million term debt repayment on April 30, 2016. If the Company is unable to make this repayment, all outstanding borrowings under the facility may become due and payable immediately. These circumstances result in material uncertainty surrounding the Company's ability to meet all of its financial obligations as they become due.

In 2013, the Company issued convertible debentures with a face value of $85 million, convertible into shares of Twin Butte at the holder's option. If not already redeemed or converted at either the holder or the Company's option, on December 31, 2018 the Company will redeem remaining debentures up to the maximum face value of $85 million.

To the extent that Twin Butte enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. Derivative instruments are not entered for speculative purposes and management closely monitors commodity risk exposure in comparison to forecasted sales volumes. Liquidity risk is partially mitigated as losses realized on derivative contracts due to high commodity prices are generally matched by increased cash flows from sales in a high commodity price environment. Conversely, when commodity prices are low, gains realized on derivative contracts can partially offset reduced cash flow.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank indebtedness fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate on bank debt been 1 percent higher throughout the year ended December 31, 2015, net income would have decreased by $1.7 million (December 31, 2014 - $1.9 million) based on the average bank debt balance outstanding during the year.

NOTE 6. CAPITAL MANAGEMENT

The Company's capital structure is comprised of shareholder's equity and the non-GAAP measure of net debt (2). Twin Butte's capital structure as at December 31, 2015 and December 31, 2014 is as follows:

($000's)	**Dec 31, 2015**	Dec 31, 2014
Bank indebtedness	**205,078**	247,898
Convertible debentures	**80,237**	78,890
Working capital deficit (1)	**2,559**	26,511
Net debt (2)	**287,874**	353,299
Shareholders' Equity	**38,928**	394,700

1) Working capital deficit (surplus) is a non-GAAP measure that includes accounts receivables, deposits and prepaid expenses, accounts payable, and accrued liabilities, and dividend payable.

2) Net debt is a non-GAAP measure, defined as the total of bank indebtedness, convertible debenture liability, accounts payable and accrued liabilities, cash dividend payable, less accounts receivable, deposits and prepaids.

As at December 31, 2015, the Company utilized $205.1 million of the available credit facility borrowing base of $275.0 million. The bank debt, working capital deficit of $2.6 million and convertible debenture liability of $80.2 million resulted in $287.9 million of net debt (December 31, 2014 - $353.3 million).

NOTE 7. EXPLORATION AND EVALUATION ASSETS

($000's)		
Balance at December 31, 2013	$	64,025
Acquisitions and purchases		3,620
Transferred to property, plant and equipment (note 8)		(1,558)
Dispositions		(4,133)
Impairment		(10,033)
Exploration and evaluation expense		(7,735)
Balance at December 31, 2014	$	44,186
Acquisitions and purchases	$	4,968
Transferred to property, plant and equipment (note 8)		(770)
Dispositions		(388)
Exploration and evaluation expense		(10,906)
Balance at December 31, 2015	**$**	**37,090**

Exploration and evaluation ("E&E") assets consist of the Company's land and seismic exploration projects which are pending the determination of technical feasibility and commercial viability. In the year ended December 31, 2015, expense of $10.9 million was recognized ($7.7 million – December 31, 2014) for current and future land expiries for which management has neither budgeted nor planned further exploration. In 2014 the Company also recorded a $10.0 million impairment of E&E assets associated with the Heavy Oil CGU.

During the year ended December 31, 2015, Twin Butte completed E&E asset swaps and dispositions for net proceeds of $2.2 million ($3.0 – December 31, 2014). The assets included in these transactions were primarily non-core E&E assets, but also included $nil value PP&E assets with decommissioning liabilities attached. A $2.7 million gain was recognized on these transactions ($1.8 – December 31, 2014).

NOTE 8. PROPERTY AND EQUIPMENT

($000's)	
Cost:	
Balance at December 31, 2013	$ 1,416,873
Additions	143,452
Changes in decommissioning provision	37,556
Transfers from E&E assets (note 7)	1,558
Disposals	(2,626)
Balance at December 31, 2014	$ 1,596,813
Additions	78,656
Changes in decommissioning provision	(15,898)
Transfers from E&E assets (note 7)	770
Balance at December 31, 2015	**$ 1,660,341**
Accumulated depletion, depreciation and impairment losses:	
Balance at December 31, 2013	$ 372,268
Depletion and depreciation expense	180,972
Impairment expense	218,163
Disposals	(1,254)
Balance at December 31, 2014	$ 770,149
Depletion and depreciation expense	129,864
Impairment expense	276,992
Balance at December 31, 2015	**$ 1,177,005**
Net Carrying Value:	
December 31, 2014	$ 826,664
December 31, 2015	**$ 483,336**

The Company capitalized $4.5 million of general and administrative expenses ($4.9 million – December 31, 2014) and $2.5 million of share based compensation expenses ($1.6 million – December 31, 2014) directly related to development and production activities for the year ended December 31, 2015. Future development costs on proved plus probable undeveloped reserves of $257 million as at December 31, 2015 are included in the calculation of depletion ($322 million – December 31, 2014).

At December 31, 2015, the Company assessed for indicators of impairment for all of its CGUs. In comparison to prior periods, the Company noted significant and prolonged reductions to forecasted benchmark pricing, which indicated that CGUs may be impaired. For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment or its reversal, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs of disposal and value in use. These key judgments include estimates about recoverable reserves, forecast benchmark commodity prices, royalties, operating costs and discount rates.

Twin Butte estimated the recoverable amount for all CGUs based on the fair value less costs of disposal, determined with an after-tax discount rate of 11 percent (December 31, 3014 – 9.5 percent), forecasted cash flows over the estimated life of reserves, and an independent industry reserve engineer price forecast. The discount rate represents the rate of return that a market participant would require for assets with similar composition and risk. The forecasted cash flows are prepared over the estimated life of the reserves in the CGUs, which range from 22 to 50 years. The primary source of cash flow information was derived from the Company's oil and gas reserves, as prepared by an independent qualified reserve evaluator as at December 31, 2015.

Based on the assessment, the after-tax recoverable amount did not exceed the carrying value of the South East Medium, Heavy Oil, Plains and West-Central CGUs and the total fourth quarter non-cash pre-tax impairment charge at December 31, 2015 was $211.7 million ($154.5 million after tax). The total pre-tax impairment charge for the year ended December 31, 2015 was $277.0 million ($200.0 million after tax), as Twin Butte recorded impairment due to significant and prolonged reductions to forecasted oil and natural gas pricing on the Pincher Creek CGU in the second quarter of 2015 and on the South East Medium, Heavy Oil, Plains and West-Central CGUs in the third quarter of 2015.

($000's)	Recoverable Amount	Impairment (Pre Tax)	Impairment (Post Tax)
South East Medium CGU	$ 313,632	$ 147,463	$ 107,648
Heavy Oil CGU	147,114	82,926	60,536
Plains CGU	10,989	24,650	17,995
West-Central CGU	5,346	17,053	12,448
Pincher Creek CGU	9,603	4,901	1,323
		$ 276,993	$ 199,950

The forecasted commodity prices used in the impairment test at December 31, 2015 were as follows:

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
WTI Crude oil (US$/bbl)	45.00	53.60	62.40	69.00	73.10	77.30	81.60	86.20	87.90	89.60	91.40

The following table indicates the sensitivity of the December 31, 2015 pre-tax impairment to changes in the discount rate and forecasted commodity prices:

($000s)	Increase in rate or price	Decrease in rate or price
Discount rate, 1% change	25,443	(23,364)
WTI, $5 change	(90,387)	89,892

At December 31, 2014, due to reductions to forecasted oil benchmark pricing and external engineer reserve valuation adjustments, the Company tested all CGUs for impairment. Based on the assessment, after-tax recoverable amount for the Heavy Oil CGU was $273.3 million. This recoverable value did not exceed the carrying value of the CGU and the non-cash pre-tax impairment charge was $188.2 million ($141.1 million after tax). The after-tax recoverable amount for the Pincher Creek CGU was determined to be $11.8 million. This recoverable value did not exceed the carrying value of the CGU and the non-cash pretax impairment charge was $30.0 million ($22.5 million after tax). For the South East Medium, Plains, and West-Central CGUs, the recoverable value exceeded the carrying value.

NOTE 9. BANK INDEBTEDNESS

As at December 31, 2015, the Company's dedicated bank facility of $325 million consists of a revolving line of credit of $300 million and an operating line of credit of $25 million, extendible annually at the request of the Company for a further 364 days, subject to approval of the lenders and repayable one year after the expiry of the revolving period, which is May 26, 2016. Utilization of this facility is restricted to the borrowing base of $275 million, which was under semi-annual review as of December 31, 2015. The borrowing base is determined primarily on reserves, commodity prices, and other factors estimated by the lenders. Subsequent to December 31, 2015, the facility was amended and the borrowing base set at $140 million, with $85 million of term debt due on April 30, 2016 (see note 22 – Subsequent events).

	As at December 31	
($000's)	**2015**	2014
Bank indebtedness – Current (1)	**$ 85,000**	$ –
Bank indebtedness – Long Term	**120,078**	247,898
Total bank indebtedness	**$ 205,078**	$ 247,898

(1) Subsequent to December 31, 2015, the bank facility was amended and requires an $85 million term debt repayment in less than one year, on April 30, 2016.

Interest rates are based on the Bank of Canada prime rate, plus 1% to 2.5% as determined by a pricing grid using the Company's debt to earnings before interest, taxes, depreciation, and amortization (EBITDA) ratio for the preceding four quarters. The convertible debentures pay 6.25% interest annually. The effective interest rate on the total of bank indebtedness and convertible debentures for the twelve months ended December 31, 2015 was 4.4%, respectively (December 31, 2014 – 4.5%).

The Company's revolving credit facility contains standard commercial covenants for facilities of this nature, including a requirement for Twin Butte to maintain an adjusted current ratio of not less than 1.0:1.0, which includes the undrawn portion of the credit facility as a current asset. The facility also contains a covenant that limits financial commodity agreements to less than 80% of the average daily production of the prior quarter at the time the commodity agreement is signed. As commodity agreements extend beyond 12 months, the maximum percentage decreases to 70%, and then to 60% for those agreements with terms greater than 24 months. Non-commodity financial instruments, such as power and currency agreements, are required by covenant to have a maximum term of 36 months, and aggregate amounts hedged must not be more than 60% of the facility's borrowing base. At December 31, 2015, the Company is in compliance with all debt covenants.

NOTE 10. CONVERTIBLE DEBENTURES

On December 18, 2013, the Company completed the issuance of convertible unsecured subordinated debentures for gross proceeds of $85.0 million ($81.4 million net of issuance costs) at a price of $1,000 per debenture. The debentures pay interest at a rate of 6.25% per annum, payable in arrears on a semi-annual basis on June 30 and December 31 of each year. The debentures mature on December 31, 2018.

The debentures are convertible at the option of the holder into common shares at a fixed conversion price of $3.05 per share. After December 31, 2016, the Company may redeem the debentures in whole or part provided the common shares' weighted average trading price during a specified period prior to redemption is not less than 125% of the conversion price. As at December 31, 2015, no conversions or redemptions have occurred.

The debentures are classified as debt (net of issuance costs) with the residual value allocated to shareholders' equity. The issuance costs are amortized over the term of the debentures and the debt portion will accrete to the principle balance at maturity. The accretion of issuance costs and the interest paid are expensed on the statement of income and comprehensive income.

($000's)	
Debt component, December 31, 2014	$ 78,890
Accretion of convertible debentures	1,347
Debt component, December 31, 2015	**$ 80,237**
Equity component, December 31, 2014	$ 2,879
Equity component, December 31, 2015	**$ 2,879**

NOTE 11. DECOMMISSIONING PROVISION

Decommissioning obligations are based on the Company's net ownership in wells and facilities, and management's best estimate of future costs to abandon and reclaim those wells and facilities as well as an estimate of the future timing of the costs to be incurred.

The Company has estimated the present value of its total decommissioning provision to be $202.7 million at December 31, 2015 ($218.2 million – December 31, 2014), based on a total future liability of $278.6 million ($319.0 million – December 31, 2014). Payments to settle the obligations occur over the operating lives of the underlying assets and are estimated to be from 1 to 50 years, with the majority of costs to be incurred after 2030. The estimated risk free discount rate and estimated inflation rates remained unchanged from December 31, 2014 at 2%.

Changes to the decommissioning provision are as follows:

($000's)	Year ended Dec 31, 2015	Year ended Dec 31, 2014
Decommissioning provision, beginning of period	**218,202**	181,758
Liabilities incurred	**4,423**	5,136
Liabilities settled	**(3,670)**	(5,044)
Liabilities acquired from acquisitions	**593**	1,421
Liabilities reduced from dispositions	**(1,020)**	(2,526)
Effect of change in risk free rate (1)	**–**	34,704
Revisions in estimated cash outflows	**(20,321)**	(2,284)
Accretion of decommissioning provision	**4,445**	5,037
Decommissioning provision, end of period	**202,652**	218,202

(1) At December 31, 2014, the risk free rate was changed from 3% to 2%.

NOTE 12. SHAREHOLDERS' EQUITY

Authorized

The Company has authorized an unlimited number of voting Common Shares and an unlimited number of Preferred Shares without nominal or par value.

	Number of common shares *(000's)*	Share capital *($000's)*
Balance at December 31, 2013	343,080	717,246
Common shares issued pursuant to private placement	1,817	3,271
Common shares issued under share award plan	2,384	4,957
Common shares issued pursuant to the DRIP and SDP	4,514	8,354
Share issue costs, net of tax	–	(16)
Balance at December 31, 2014	351,795	733,812
Common shares issued under share award plan	1,685	3,097
Common shares issued pursuant to the DRIP and SDP	767	543
Other	(124)	–
Balance at December 31, 2015	**354,123**	**737,452**

During the year ended December 31, 2015, 1.7 million share and performance share awards were exercised by employees, resulting in the granting of 1.7 million shares (2.4 million awards and 2.4 million shares – December 31, 2014). The total number of shares reserved for share based payments is 35,412,280 (35,179,472 – December 31, 2014). As at December 31, 2015 there were 18,021,043 share and performance share awards, including reinvested dividends (7,218,843 – December 31, 2014) and 385,467 (500,434 – December 31, 2014) options outstanding under the plans or a total of 5% of outstanding shares.

Dividends declared during the year ended December 31, 2015 totaled $29.0 million ($67.3 million – December 31, 2014), equivalent to $0.08 per weighted average share ($0.194 per weighted average share – December 31, 2014). The Company suspended the dividend program in December 2015.

The Dividend Reinvestment Program ("DRIP") and the Stock Dividend Program ("SDP") were suspended beginning with the dividend declared in January 2015. As such, the dividend declared in December 2014 and paid in January 2015 was the only dividend paid in the period with the DRIP and SDP programs available. During the year ended December 31, 2015, $0.5 million from dividends declared were reinvested in shares ($5.3 million – December 31, 2014).

Share-based payments

(a) Share award plan

The following table sets forth a reconciliation of outstanding share awards and related dividend and performance factor activity through December 31, 2015:

	Restricted share awards	Weighted average fair value at grant date	Performance share awards	Weighted average fair value at grant date
Outstanding at December 31, 2013	3,060,543	2.32	2,292,060	2.33
Granted	2,827,233	2.02	2,050,468	1.92
Reinvested dividends	471,389	–	313,693	–
Vested and converted to common shares	(1,273,130)	2.31	(1,108,342)	2.36
Forfeited	(796,343)	2.26	(618,728)	2.23
Outstanding at December 31, 2014	4,289,692	$ 2.12	2,929,151	$ 2.03
Granted	7,530,281	0.78	3,964,092	0.75
Reinvested dividends	1,416,241	–	770,185	–
Vested and converted to common shares	(1,098,991)	2.25	(586,246)	2.22
Forfeited	(801,499)	1.24	(391,863)	1.30
Outstanding at December 31, 2015	**11,335,724**	**$ 1.17**	**6,685,319**	**$ 1.22**

Twin Butte recorded share-based payment expense for the year ended December 31, 2015 of $5.3 million ($4.5 million – December 31, 2014).

A 15% forfeiture rate was used to estimate the Company's share-based payment expense for the year ended December 31, 2015 (15% – December 31, 2014).

(b) Stock option plan

Following the initiation of the Share Award Plan in January 2012, there have been no further stock options granted and remaining outstanding options will be either exercised or forfeited. In the year ended December 31, 2015, no stock options were exercised, and 113,300 stock options were forfeited and 1,667 options expired. As at December 31, 2015, 385,467 options were outstanding at a weighted average exercise price of $2.90, all of which were exercisable.

The following table outlines the weighted average exercise price and years to expiry for all outstanding options:

	December 31, 2015			December 31, 2014		
Exercise Price	**Number of Options Outstanding**	**Weighted Average Exercise Price $**	**Weighted Average Years to Expiry**	Number of Options Outstanding	Weighted Average Exercise Price $	Weighted Average Years to Expiry
$1.00 – 1.50	–	–	–	1,667	1.31	0.26
$2.01 – 2.50	**68,800**	**2.40**	**0.45**	115,433	2.4	1.45
$2.51 – 3.00	**156,667**	**2.69**	**0.48**	223,334	2.67	1.36
$3.01 – 3.50	**160,000**	**3.32**	**0.25**	160,000	3.32	1.25
	385,467	**2.90**	**0.38**	500,434	2.81	1.34

Net Income (loss) Per Share

The following table sets forth the details of the computation of basic and diluted net income per share:

	Twelve months ended December 31	
($000's)	**2015**	2014
Net income (loss) for the period	**$ (336,932)**	$ (57,340)
Weighted average number of basic shares (000's)	**353,544**	347,340
Effect of dilutive securities:		
Stock options and share awards (000's)	**–**	–
Weighted average number of diluted shares (000's)	**353,544**	347,340
Net income (loss) per share basic ($/share)	**(0.95)**	(0.17)
Net income (loss) per share diluted ($/share)	**(0.95)**	(0.17)

Diluted income per share amounts reflect the potential dilution that could occur if stock options were exercised and share awards and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect, whereby any proceeds from the exercise and the amount of compensation expense, if any, attributed to future services not yet recognized, are assumed to be used to purchase common share at the average market price during the periods.

In calculating the weighted average number of diluted shares for the twelve months ended December 31, 2015, the Company excluded 385,467 options because the exercise price was greater than the average common share market price in the periods. Also excluded were 18,021,043 unvested share awards because the compensation expense attributed to future services was greater than the average common share market price. Convertible debentures have further been excluded, as the conversion price was greater than the average share price during the twelve months ended December 31, 2015.

In the twelve months ended December 31, 2015 and 2014, outstanding stock options, share awards, and convertible debentures were the only potentially dilutive instruments.

NOTE 13. SALES PER PRODUCT

	Twelve months ended December 31	
($000's)	**2015**	2014
Light & Medium oil	**$ 126,373**	$ 229,822
Heavy oil	**101,078**	302,844
Natural gas	**10,900**	20,591
Natural gas liquids	**2,419**	1,816
Total petroleum and natural gas sales	**$ 240,770**	$ 555,073

NOTE 14. GENERAL & ADMINISTRATION ("G&A") EXPENSE

	Twelve months ended December 31	
($000's)	**2015**	2014
Staff salaries and benefits	**$ 12,082**	$ 14,480
Rent and insurance	**1,550**	1,795
Office and other costs	**6,347**	6,453
Capitalized G&A	**(4,483)**	(4,892)
Overhead recoveries	**(2,310)**	(3,768)
	$ 13,186	$ 14,068

NOTE 15. FINANCE EXPENSE

($000's)	Twelve months ended December 31 2015	2014
Interest and bank charges	$ 8,329	$ 10,789
Interest on convertible debentures	5,312	5,291
Accretion on convertible debentures	1,347	1,242
Accretion on decommissioning provision	4,445	5,037
Total	$ 19,433	$ 22,359

NOTE 16. SUPPLEMENTAL CASH FLOW INFORMATION

($000's)	Twelve months ended December 31 2015	2014
Changes in non-cash working capital:		
Accounts receivable	$ 21,544	$ (1,468)
Deposits and prepaid expenses	1,262	630
Accounts payable and accrued liabilities	(42,417)	(4,474)
Dividends Payable	(5,529)	40
	$ (25,140)	$ (5,272)
Changes in non-cash working capital relating to:		
Operating activities	$ (4,130)	$ 773
Financing activities	(5,529)	40
Investing activities	(15,481)	(6,085)
	$ (25,140)	$ (5,272)

NOTE 17. INCOME TAX EXPENSE

During the year ended December 31, 2015, the Company received a letter from the Canada Revenue Agency ("CRA") advising the Company that, subject to submissions by Twin Butte, it is proposing to reassess the Company's income tax filings related to Scientific Research and Experimental Development ("SR&ED") tax deductions utilized in 2011 by a predecessor of the Company, and in 2014 by the Company, totaling $32.0 million in deductions ($8.6 million at the Company's expected tax rate), and $7.8 million in non-capital losses currently available. If these tax deductions are disallowed, the Company would incur a non-cash tax expense, but would utilize alternatively available tax pools for the predecessor 2011 and 2014 taxation years. However, as a result of utilizing these pools and the proposed reduction in non-capital losses, the Company would be in a cash taxes payable position in 2015, owing approximately $3 to 8 million, pending the successful application of additional voluntary adjustments. These potentially disallowed amounts would be deductible, and any taxes paid refundable, on a successful appeal of the reassessments.

Twin Butte's management remains of the opinion that, after careful consideration and consultation at the time of the deductions and at this time, Twin Butte's tax returns were correct as filed and the Company has not recorded a provision for the proposed reassessments. If the proposed reassessments are issued, Twin Butte's management will vigorously defend the Company's tax filing position. Twin Butte has provided its submission in response to CRA's letter and is awaiting further communication.

(a) Deferred income tax expense (recovery):

The provision for income taxes reflects an effective tax rate which differs from Federal and Provincial statutory tax rates. The main differences are as follows:

For the twelve months ended *($000s)*	2015	2014
Income (loss) before taxes	$ (350,642)	$ (74,973)
Statutory income tax rate	26.0%	25.0%
Expected income taxes	(91,167)	(18,743)
Stock based compensation	1,596	1,361
Change in statutory tax rate	(2,649)	–
Derecognized tax asset	78,640	–
Return to provision true-up and other	(129)	(251)
Deferred income tax expense / (recovery)	$ (13,709)	$ (17,633)
Effective Tax rate	3.9%	23.5%

The Canadian statutory tax rate per the reconciliation above represents the combined federal and provincial corporate tax rate. The federal corporate tax rate is 15%. Effective July 1, 2015, the Alberta government increased the general corporate tax rate from 10% to 12%, resulting in an average provincial tax rate of 11% for the year ended December 31, 2015.

(b) Deferred income tax asset (liability):

At December 31, 2015, due to the Company's going concern uncertainty (note 2), the calculated deferred tax asset has been derecognized to reduce the deferred tax asset to $nil (December 31, 2014 – $13.7 million liability).

($000s)	2015	2014
Property, plant, and equipment	$ 27,219	$ (48,220)
Decommissioning liabilities	54,716	54,550
Commodity derivatives	(1,929)	(27,265)
Convertible debentures	(615)	(819)
Share issue cost	593	718
Sublease liability	320	–
Scientific research & experimental development	–	3,625
Non-capital loss carryforwards (1)	1,875	7,240
Derecognized deferred tax assets (2)	(82,179)	(3,538)
Deferred income tax asset / (liability)	$ –	$ (13,709)

(1) Non-capital loss carryforwards amounting to $ 6.9 million expire in 2031 and 2032.

(2) The derecognized deferred tax assets relate to net assets allowed for due to going concern uncertainty, and resource tax pools where there is uncertainty as to whether a taxable benefit will be available in the future.

(c) Components of the net deferred income tax asset (liability):

As at *($000s)*	Dec 31, 2015	Dec 31, 2014
Deferred tax assets		
Deferred tax assets to be recovered after more than 12 months	$ 84,604	$ 65,990
Deferred tax assets to be recovered within 12 months	119	143
	84,723	66,133
Deferred tax liabilities		
Deferred tax liabilities to be recovered after more than 12 months	(82,794)	(52,577)
Deferred tax liabilities to be recovered within 12 months	(1,929)	(27,265)
	$ (84,723)	$ (79,842)

The deferred income tax assets and liabilities to be settled (recovered) within 12 months represents Management's estimate of the timing of the reversal of temporary differences and does not relate to the current income tax expense (if any) in the subsequent year.

(d) Movement in Deferred Tax Assets & Liabilities:

($000's)

Deferred Income Tax Assets	Property, Plant and Equipment	Decommissioning Liabilities	Tax Pools	Sublease Liability	Total
As at December 31, 2014	(48,220)	54,550	11,583	–	17,913
Recognized in equity	–	–	–		–
Charged/(credited) to earnings	75,439	166	(9,115)	320	66,810
As at December 31, 2015	**27,219**	**54,716**	**2,468**	**320**	**84,723**

Deferred Income Tax Liabilities	Convertible Debentures	Commodity Derivatives	Unrecognized Deferred Tax Assets	Total
As at December 31, 2014	(819)	(27,265)	(3,538)	(31,622)
Recognized in equity	–	–	–	–
Charged/(credited) to earnings	204	25,336	(78,641)	(53,101)
As at December 31, 2015	**(615)**	**(1,929)**	**(82,179)**	**(84,723)**

Net Deferred Income Tax Asset	Total
As at December 31, 2014	(13,709)
Recognized in equity	–
Charged/(credited) to earnings	(13,709)
As at December 31, 2015	**–**

NOTE 18. ACCOUNTS RECEIVABLE

As At *($000s)*	**Dec 31, 2015**	Dec 31, 2014
Trade	**12,725**	29,293
Joint Operations with Partners	**6,834**	10,603
Other	**9,039**	10,246
	28,598	50,142

NOTE 19. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As At *($000s)*	**Dec 31, 2015**	Dec 31, 2014
Trade	**21,228**	46,981
Royalties	**(219)**	3,425
Joint Operations with Partners	**3,401**	4,205
Accruals	**10,443**	21,471
	34,853	76,082

NOTE 20. RELATED PARTY TRANSACTIONS

During the twelve months ended December 31, 2015, the Company incurred related party costs totaling $3.2 million ($5.4 million – December 31, 2014) for oilfield services and legal counsel rendered by three companies of which a director of Twin Butte is a director.

These costs were incurred in the normal course of business and were recorded at the amount exchanged between the parties. As at December 31, 2015, the Company had $0.5 million ($0.8 million – December 31, 2014) included in accounts payable and accrued liabilities related to these transactions.

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, and Vice-Presidents. The compensation paid or payable to key management is as follows:

	Twelve months ended December 31,	
($000s)	**2015**	2014
Salaries and Benefits [1]	**3,398**	4,762
Stock Based Compensation	**4,025**	4,675
	7,423	9,437

(1) Salaries and Benefits include Director's fees and severance payments if applicable.

As at December 31, 2015, there is a $2.4 million commitment (December 31, 2014 – $3.5 million) relating to change of control or termination of employment of key management personnel.

NOTE 21. COMMITMENTS AND CONTINGENCIES

Contractual obligations and commitments for base office rent and equipment are as follows:

($000's)	2016	2017	2018	thereafter
	1,609	1,632	825	–

NOTE 22. SUBSEQUENT EVENTS

Bank Debt

On January 15, 2016, the Company completed the semi-annual borrowing base review which reduced the borrowing base for the revolving line of credit from $275 million to $140 million, and established a term loan of $85 million payable on April 30, 2016. As a result of this revised agreement, the debt to EBITDA ratio is no longer applicable in determining interest rates for the revolving facility and interest rates are set at the prime rate plus 3% or 4%. Interest rates for the term loan are set at prime plus 6.5% in January, increasing to prime plus 9.25% by the end of the term.

The Company is also subject to certain non-financial covenants in its revised credit facility agreement. Revised covenants include monthly reporting, strategic alternatives process milestones, permitted dispositions and permitted encumbrances. As at March 22, 2016 the Company is in compliance with all covenants. The available level of credit under the borrowing base of the revolving facility is also subject to a one-time review by the syndicate of banks and may be adjusted for changes in reserves, commodity prices and other factors before the May 26, 2016 renewal date.

Crude Oil Sales Price Derivative Contracts

Subsequent to December 31, 2015 the Company entered into a crude oil sales price derivative as follows:

Daily barrel (bbl) quantity	Term of contract	Currency	Fixed price per bbl WCS [1] vs. WTI [2]
1,000	Jan 1, 2017 to December 31, 2017	USD	$ (13.30)

(1) WCS represents the posting price of Western Canadian Select oil.

(2) WTI represents posting price of West Texas Intermediate oil.

CORPORATE INFORMATION

OFFICERS

Rob Wollmann
President and Chief Executive Officer

Claude Gamache
Vice President, Geosciences

Gordon Howe
Vice President, Land

Preston Kraft
Vice President, Engineering

Dave Middleton
Chief Operating Officer

R. Alan Steele
Vice President, Finance & CFO

BOARD OF DIRECTORS

Jim Saunders
Executive Chairman of the Board

David Fitzpatrick (3)
Lead Director

Jim Brown (1) (3)

John Brussa (3)

Tom Greschner (2)

Warren Steckley (1) (2)

William A. (Bill) Trickett (1) (2)

Member of:

(1) Audit Committee
(2) Reserves Committee
(3) Compensation, Nominating and Governance Committee

HEAD OFFICE

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AUDITORS

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, AB

BANKERS

National Bank of Canada
Calgary, AB

SOLICITORS

Burnet, Duckworth & Palmer LLP
Calgary, AB

ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, AB

REGISTRAR & TRANSFER AGENT

Computershare Canada
Calgary, AB

STOCK EXCHANGE LISTING

TSX
Trading Symbol "TBE"