MARQUEE ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per share and per boe amounts)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Financial				
Oil and natural gas sales and processing fee income [1]	**$ 11,521**	$ 9,187	**$ 20,342**	$ 16,790
Funds flow from operations [2]	**$ 1,646**	$ 2,384	**$ 2,353**	$ 3,489
Per share - basic and diluted	**$ 0.00**	$ 0.01	**$ 0.01**	$ 0.01
Per boe	**$ 5.73**	$ 8.66	**$ 7.39**	$ 7.00
Cash flow from operating activities	**$ 2,835**	$ 12	**$ 4,098**	$ 259
Net income (loss)	**$ (4,671)**	$ (1,956)	**$ (9,583)**	$ (5,618)
Per share - basic and diluted	**$ (0.01)**	$ 0.00	**$ (0.02)**	$ (0.01)
Capital expenditures	**$ 276**	$ 1,246	**$ 11,321**	$ 7,486
Net debt [2]			**$ 40,514**	$ 22,914
Total Assets			**$ 166,319**	$ 175,458
Weighted average basic shares outstanding	**435,772,196**	435,772,196	**435,772,196**	435,772,196
Weighted average diluted shares outstanding	**435,772,196**	435,772,196	**435,772,196**	435,772,196
Operational				
Net new wells on production	**-**	-	**5**	3
Daily sales volumes				
Oil (bbls per day)	**1,521**	1,174	**1,398**	1,088
NGL's (bbls per day)	**166**	159	**161**	146
Natural Gas (mcf per day)	**8,835**	10,141	**8,434**	9,117
Total (boe per day)	**3,159**	3,024	**2,964**	2,754
% Oil and NGL's	**53%**	44%	**53%**	45%
Average realized prices				
Light Oil ($/bbl)	**$ 68.87**	$ 52.11	**$ 62.77**	$ 52.36
NGL's ($/bbl)	**$ 51.46**	$ 40.71	**$ 51.31**	$ 41.02
Natural Gas ($/mcf)	**$ 1.27**	$ 3.07	**$ 1.75**	$ 3.04
Netback				
Revenue ($/boe)	**$ 39.39**	$ 32.66	**$ 37.35**	$ 32.93
Royalties ($/boe)	**$ (2.10)**	$ (1.90)	**$ (1.85)**	$ (2.24)
Operating and transportation costs ($/boe)	**$ (21.52)**	$ (16.18)	**$ (21.48)**	$ (16.79)
Operating netback prior to hedging [2]	**$ 15.77**	$ 14.58	**$ 14.02**	$ 13.90
Realized hedging gain (loss) ($/boe)	**$ (3.21)**	$ 1.21	**$ (2.38)**	$ 0.67
Operating netback ($/boe) [2]	**$ 12.56**	$ 15.79	**$ 11.64**	$ 14.57

(1) Before royalties
(2) Non-IFRS Measure. See Non-IFRS Measures advisory.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations for Marquee Energy Ltd. ("Marquee", "we", "our" or the "Company") as at and for the three and six months ended June 30, 2018. This MD&A is dated August 29, 2018 and should be read in conjunction with the Company's unaudited condensed interim Financial Statements and related notes thereto for the three and six months ended June 30, 2018, as well as the audited Financial Statements and related notes thereto for the year ended December 31, 2017. The Company's condensed interim Financial Statements have been prepared in accordance with International Accounting Standard ("IAS") 34, Interim Financial Reporting within International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All figures provided herein are reported in thousands of Canadian dollars unless otherwise stated. The reader should be aware that historical results are not necessarily indicative of future performance.

As previously announced, Marquee commenced a review of strategic alternatives to enhance shareholder value. This review is ongoing. Given the nature of the process, the Company does not intend to provide updates with respect to the process until such time as the Board of Directors approves a definitive transaction or strategic alternative, or otherwise determines that further disclosure is advisable. The Company cautions that there are no guarantees that the review of strategic alternatives will result in a transaction or if a transaction is undertaken, as to its terms or timing.

Additional information relating to Marquee, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com. Marquee is listed on the TSX Venture Exchange (TSX-V) under the symbol "MQL-V", and on the United States OTC Market ("OTCQX") under the symbol "MQLXF".

DESCRIPTION OF BUSINESS

Marquee Energy Ltd. is a publicly traded, Calgary-based, oil and natural gas company focused on high rate of return oil development and production. Marquee is committed to growing the Company through exploitation of existing opportunities and continued consolidation within its core area at Michichi, Alberta which includes a large contiguous land base.

SUBSEQUENT EVENT

On August 29, 2018, the Company has entered into a purchase and sale agreement for the sale of non-core Mannville assets for total cash consideration of $6.6 million, prior to customary closing adjustments (the "Transaction"). The Transaction is expected to close on or about October 1, 2018 and is subject to applicable regulatory approvals and additional environmental due diligence.

The asset includes approximately 70 gross / net wells and averaged approximately 195 boe/d (62% oil and liquids) in the first six months of 2018. The Company expects the disposition to have a positive impact on the Company's asset retirement obligations, while maintaining all of the current upside and flexibility in the extensive land base in the Banff formation at Michichi. In the short term, the gross proceeds from the sale of the assets will be used to reduce the Company's current debt and improve financial flexibility. The disposition is consistent with Marquee's strategy to divest of the Company's non-core assets to further focus the Company on its Banff oil play at Michichi.

RESULTS OF OPERATIONS

Production

	Three months ended June 30,			Six months ended June 30,		
	2018	2017	Change	**2018**	2017	Change
Light oil (bbls/d)	**1,521**	1,174	30%	**1,398**	1,088	28%
NGLs (bbls/d)	**166**	159	4%	**161**	146	10%
Natural gas (mcf/d)	**8,835**	10,141	-13%	**8,434**	9,117	-7%
Total boe/d (6:1)	**3,159**	3,024	4%	**2,964**	2,754	8%
Production split (%)						
Crude oil and NGL	**53%**	44%	9%	**53%**	45%	8%
Natural gas	**47%**	56%	-9%	**47%**	55%	-8%
Total	**100%**	100%	-	**100%**	100%	-

The Company's second quarter production increased 4% to 3,159 boe/d compared to the second quarter of 2017. The increase is due to five new wells that were brought on production in Q1 2018 and continual production from the four wells that were brought on to production in the fourth quarter of 2017, offset by natural declines.

Production for the six months ended June 30, 2018 was 2,964 boe/d, an 8% increase from the 2,754 boe/day in 2017. The production increase for the six months ended June 30, 2018 was a result of the five new wells which were brought on production in the first quarter of 2018.

Average Realized Sales Prices

	Three months ended June 30,			Six months ended June 30,		
	2018	2017	Change	**2018**	2017	Change
Benchmark prices						
WTI ($US/bbl)	**$ 67.88**	$ 48.29	41%	**$ 65.37**	$ 50.10	30%
$CDN/$US foreign exchange rate	**$ 0.77**	$ 0.74	4%	**$ 0.78**	$ 0.75	4%
WTI ($CDN/bbl)	**$ 87.64**	$ 64.95	35%	**$ 83.58**	$ 66.81	25%
MSW ($CDN/bbl)	**$ 80.63**	$ 61.84	30%	**$ 76.40**	$ 62.85	22%
AECO -5A (CDN$/mcf)	**$ 1.18**	$ 2.79	-58%	**$ 1.63**	$ 2.74	-41%
Average sales prices						
Light oil ($/bbl)	**$ 68.87**	$ 52.11	32%	**$ 62.77**	$ 52.36	20%
NGL ($/bbl)	**$ 51.46**	$ 40.71	26%	**$ 51.31**	$ 41.02	25%
Natural gas ($/mcf)	**$ 1.27**	$ 3.07	-59%	**$ 1.75**	$ 3.04	-42%
Combined ($/boe)	**$ 39.39**	$ 32.66	21%	**$ 37.35**	$ 32.93	13%

During the three months ended June 30, 2018, the WTI crude oil price benchmark averaged US$67.88/bbl as compared to US$48.29/bbl in the comparable 2017 period representing a 41% increase. Marquee's realized price for the quarter increased 32% to $68.87/bbl from $52.11/bbl in the comparable period in 2017. The improvement in the realized price for the quarter was a result of the increased WTI price. The increase in the Company's realized oil price is not as large as the increase in WTI as the Company had higher differential to WTI because of pipeline constraints in the three months ended June 30, 2018.

For the six months ended June 30, 2018 WTI increased by 30% to US$65.37/bbl compared to US$50.10/bbl for the comparable 2017 period. Marquee's realized price increased by 20% to $62.77/bbl from $52.36/bbl. The improvement in the realized price for the six months is due to the improvement in the differential between the Edmonton (MSW) price and WTI. The

Company receives a discount from its benchmark (MSW) prices due to a negative price differential for oil quality and transportation adjustments.

Alberta AECO natural gas benchmark pricing decreased 58% to $1.18 per mcf for the three months ended June 30, 2018, as compared to $2.79 per mcf for the same period in 2017. Consequently, Marquee's average realized price for the second quarter of 2018, decreased to $1.27 per mcf as compared to $3.07 per mcf in the second quarter of 2017. For the six months ended June 30, 2018, AECO pricing decreased by 41% to $1.63 per mcf as compared to $2.74 per mcf for the same period in 2017. Marquee's realized gas price decreased 42% to $1.75 per mcf from $3.04 per mcf. Marquee produces natural gas with a higher heating value therefore receives a premium to the AECO price.

Oil and Natural Gas Revenue and Processing Fee Income

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars)	**2018**	2017	Change	**2018**	2017	Change
Processing fee income	**196**	198	-1%	**300**	378	-21%
Light oil	**9,529**	5,568	71%	**15,882**	10,311	54%
NGLs	**779**	589	32%	**1,495**	1,084	38%
Natural gas	**1,017**	2,832	-64%	**2,665**	5,017	-47%
Total revenue	**11,521**	9,187	25%	**20,342**	16,790	21%

Total revenue for the three months ended June 30, 2018 increased by 25% to $11.5 million compared to $9.2 million in the second quarter of 2017 and increased to $20.3 million for the six months as compared to $16.8 million for the comparable period in 2017. The increase in revenue for the three months ended June 30, 2018 is attributable to the increase in average combined prices and increased oil production.

Royalties

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars, except per boe amounts)	**2018**	2017	Change	**2018**	2017	Change
Royalties	**603**	524	15%	**995**	1,115	-11%
As a percentage of revenue	**5%**	6%	-1%	**5%**	7%	-2%
$/boe	**2.10**	1.90	11%	**1.85**	2.24	-17%

The majority of Marquee's royalties are paid to the Crown, which are based on various factors that are dependent on incentives, production volumes and commodity prices. Royalties for the three months ended June 30, 2018, increased to $0.6 million compared to $0.5 million in the comparable period in 2017. During the six months ended June 30, 2018, the royalties decreased to $1.0 million from $1.1 million in the comparable period 2017. On a dollar value and as a percentage of sales, royalties decreased year over year due to lower royalty rates on the new wells drilled in 2017 and 2018. The new wells qualify under the modernized Alberta provincial royalty framework in which the royalty is lower until the average drilling and completion costs are recovered after which higher royalty rates are applicable.

Commodity Price Contracts and Risk Management

The Company's financial results will be dependent on the prices received for crude oil and natural gas production. Management has been proactive in entering into derivatives for hedging and has partially mitigated commodity price risk by entering into crude oil hedging contracts. Marquee's current commodity contract position as at the date of this MD&A is as follows:

Type of Instrument	Volumes	Price	Index	Term
Crude Oil Swap	150 bbl/d	Cdn $69.00/bbl	WTI - Fixed	July 1, 2018 to Dec 31, 2018
Natural Gas Swap	3,000 GJ/d	Cdn $3.15/GJ	Nymex - Fixed	Jul 1, 2019 to Dec 31, 2019
Crude Oil Put	400 bbls/d	USD $45.00/bbl $4.95/bbl Premium	WTI - Fixed	July 1, 2018 to June 30, 2019
Natural Gas Collar	3,000 GJ/d	Cdn $2.20 - $2.715/GJ	AECO - Fixed	Oct 1, 2018 to Dec 31, 2018
Natural Gas Collar	3,000 GJ/d	Cdn $2.40 - $2.915/GJ	AECO - Fixed	Jan 1, 2019 to March 31, 2019
Natural Gas Collar	3,000 GJ/d	Cdn $1.90 - $2.14/GJ	AECO - Fixed	April 1, 2019 to June 30, 2019
Crude Oil Put	450 bbls/d	USD $55.00/bbl, $6.29/bbl Premium	WTI - Fixed	July 1, 2019 to Dec 31, 2019
Crude Oil Swap	250 bbl/day	Cdn $70.52/bbl	WTI - Fixed	April 1, 2018 to Dec 31, 2018
Crude Oil Swap	150 bbl/day	Cdn $66.35/bbl	WTI - Fixed	Jan 1, 2019 to Dec 31, 2019
Natural Gas Collar	3,000 GJ/d	Cdn 2.00 to $2.53/GJ	AECO - Fixed	July 1, 2018 to Sept 30, 2018
Natural Gas Put	1,700 GJ/d	Cdn $1.05/GJ, $0.13/GJ Premium	AECO-Fixed	Jan 1,2019 to Mar 31, 2019
Natural Gas Put	4,000 GJ/d	Cdn $1.1625/GJ, $0.15/GJ Premium	AECO-Fixed	Jan 1, 2020 to Mar 31, 2020
Crude Oil Put	400 bbls/d	Cdn $56.05/bbl, $3.65/bbl Premium	WTI – Fixed	Jan 1, 2020 to Mar 31, 2020

A summary of realized and unrealized commodity contract gains and losses for the three and six months ended June 30, 2018 and 2017 are as follows:

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars)	**2018**	2017	Change	**2018**	2017	Change
Realized gain (loss) on commodity contracts	**(921)**	334	-376%	**(1,278)**	334	-483%
Unrealized gain (loss) on commodity contracts	**(1,399)**	875	-260%	**(2,808)**	613	-558%
	(2,320)	1,209	-292%	**(4,086)**	947	-531%

The Company realized a commodity contract loss for the three and six months ended June 30, 2018, of $0.9 million and $1.3, respectively (2017 – $0.3 million gain for three and six months). For the three and six months ended June 30, 2018, an unrealized loss of $1.4 million and $2.8 million was recognized, respectively (2017 - $0.9 million and $0.6 million gain). The fair value of the net commodity contract asset or liability is the estimated value to settle the outstanding contracts as at a point in time. As such, unrealized derivative gains and losses are not cash and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

Operating and Transportation Expenses

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars, except per boe amounts)	**2018**	2017	Change	**2018**	2017	Change
Operating costs	**5,992**	4,141	45%	**11,098**	7,799	42%
Transportation costs	**195**	311	-37%	**425**	571	-26%
	6,187	4,452	39%	**11,523**	8,370	38%
$/boe	**21.52**	16.18	33%	**21.48**	16.79	28%

Operating and transportation costs for the three and six months ended June 30, 2018 were $6.2 million or $21.53 per boe and $11.5 million of $21.48 per boe as compared to $4.4 million or $16.18 per boe and $8.4 million or $16.79 per boe in the comparable period in 2017. The increase in operating costs are due to the very cold weather conditions in field expenses this past winter as well as increased expenses bringing on the new wells drilled for trucking costs, emulsion treating and water disposal costs related to the increased frac density.

General and Administrative Expenses

(thousands of Canadian dollars, except per boe amounts)	**Three months ended June 30,**			**Six months ended June 30,**		
	2018	2017	Change	**2018**	2017	Change
G&A expense, gross	**1,265**	1,640	-23%	**2,548**	2,988	-15%
Recovered and capitalized	**(133)**	(150)	-11%	**(325)**	(332)	-2%
G&A expense, net	**1,132**	1,490	-24%	**2,223**	2,656	-16%
$/boe, net	**3.94**	5.41	-27%	**4.14**	5.33	-22%

During the three months and six months ended June 30, 2018, general and administrative expenses "G&A", net of capitalized and overhead recovery costs were $1.1 million or $3.94 per boe and $2.2 million or $4.14 per boe, respectively, as compared to $1.5 million or $5.41 per boe and $2.7 million or $5.33 per boe for the comparable periods in 2017. G&A has decreased due to lower salaries from staff attrition.

Share-based Compensation

The Company records share-based compensation expense ("SBC") related to employee stock options with the offsetting amount recorded in contributed surplus. The Company capitalizes a portion of SBC which is directly attributable to personnel involved in exploration and development capital investment activities. The Company uses a Black-Scholes option pricing model to calculate the fair value of stock option grants where the corresponding expense is recognized over the option vesting period.

As at June 30, 2018, the Company had 24,720,000 stock options which were outstanding at an average exercise price of $0.09 per option. For the three and six months ended June 30, 2018 and 2017, the following is recorded related to SBC:

	Three months ended June 30,			**Six months ended June 30,**		
(thousands of Canadian dollars)	**2018**	2017	Change	**2018**	2017	Change
Gross costs	**128**	64	100%	**254**	183	39%
Capitalized costs	**(25)**	(11)	127%	**(52)**	(12)	333%
Total shared-based compensation	**103**	53	94%	**202**	171	18%

Finance Expenses

(thousands of Canadian dollars, except per boe amounts)	**Three months ended June 30,**			**Six months ended June 30,**		
	2018	2017	Change	**2018**	2017	Change
Interest per boe	**2.99**	1.45	106%	**3.01**	1.63	85%
Interest on debt	**859**	400	115%	**1,614**	815	98%
Amortization of debt issue costs	**132**	34	288%	**268**	34	688%
Accretion of decommissioning liabilities	**311**	254	22%	**598**	513	17%
Total Finance Expense	**1,302**	688	89%	**2,480**	1,362	82%

For the three and six months ended June 30, 2018, finance expenses increased by 89% and 82% respectively, as compared to the three and six months ended June 30, 2017. The increase in interest charges are attributable to a higher debt balance and the interest on the term loan which started accumulating on May 30, 2017, thus greater variance between the first two quarters of 2017 and 2018.

Depletion and Depreciation

(thousands of Canadian dollars, except per boe amounts)	**Three months ended June 30,**			**Six months ended June 30,**		
	2018	2017	Change	**2018**	2017	Change
Depletion and depreciation	**4,546**	4,783	-5%	**8,411**	9,001	-7%
$/boe	**15.81**	17.38	-9%	**15.68**	18.05	-13%

The Company's depletion and depreciation expense is computed on a unit-of-production basis using proved plus probable reserves. The unit-of-production rate takes into account capital expenditures incurred to-date, together with future development capital expenditures required to develop those proved plus probable reserves. As a result, the depletion and depreciation provision, on an oil equivalent per-unit basis, may fluctuate period-to-period primarily due to changes in the underlying proved plus probable reserves base and in the amount of costs subject to depletion and depreciation. These costs are segregated and depleted on an area-by-area basis relative to the respective underlying proved plus probable reserves base.

For the three and six months ended June 30, 2018, the Company recorded depletion expense of $4.5 million or $15.81 per boe and $8.4 million or $15.68 per boe, respectively, as compared to $4.8 million or $17.38 per boe and $9.0 million or $18.05 per boe in the comparable period for 2017. The decrease in depletion expense in aggregate and on a per boe basis is due to the increase in proved plus probable reserves as a result of our drilling results.

Funds Flow from Operations

The MD&A contains the term funds flow from operations which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The Company reconciles funds flow from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS (see Non-IFRS Measures section for more information).

(thousands of Canadian dollars, except per share and per boe amounts)	**Three months ended June 30,**			**Six months ended June 30,**		
	2018	2017	Change	**2018**	2017	Change
Funds flow from operations	**1,646**	2,384	-31%	**2,353**	3,489	-33%
Per share, basic and diluted	**0.00**	0.01	-100%	**0.01**	0.01	-

Funds flow from operations for the three and six months ended June 30, 2018 are $1.6 million or $0.00 per share and $2.4 million or $0.01 per share, respectively, as compared to $2.4 million or $0.01 per share and $3.5 million or $0.01 per share for the same periods in 2017.

Operating Netback

The following table summarizes the Company's netbacks, funds flow from operations and net income (loss) on a per boe basis for the three and six months ended June 30, 2018, and 2017:

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2018**	2017	Change	**2018**	2017	Change
Oil and natural gas sales	**39.39**	32.66	21%	**37.35**	32.93	13%
Royalties	**(2.10)**	(1.90)	11%	**(1.85)**	(2.24)	-17%
Production costs	**(20.84)**	(15.05)	38%	**(20.69)**	(15.65)	32%
Transportation costs	**(0.68)**	(1.13)	-40%	**(0.79)**	(1.14)	-31%
Operating netback prior to hedging (1)	**15.77**	14.58	8%	**14.02**	13.90	1%
Realized hedging gain (loss)	**(3.21)**	1.21	-365%	**(2.38)**	0.67	-455%
Operating netback (1)	**12.55**	15.79	-21%	**11.64**	14.57	-20%

(1) Non-IFRS Measure. See Non-IFRS Measures advisory.

Capital Expenditures

	Three months ended June 30,		Six months ended June 30,	
(thousands of Canadian dollars)	**2018**	2017	**2018**	2017
Land and lease (1)	**16**	75	**46**	293
Seismic (1)	**-**	18	**-**	166
Drilling and completions (1)	**464**	507	**9,493**	4,975
Equipment and facilities (1)	**(52)**	476	**1,732**	2,082
Dispositions (2)	**(300)**	-	**(300)**	-
Capitalized general & administrative and other expenses (2)	**148**	170	**350**	330
	276	1,246	**11,321**	7,846

(1) Includes expenditures on exploration and evaluation assets as well as PP&E

(2) Includes non-cash additions

During the three and six months ended June 30, 2018, the Company incurred approximately $11.3 million to complete, equip and tie-in four wells drilled in the first quarter of 2018, and completion and tie-in of one well that was drilled in the fourth quarter of 2017. All of these horizontal wells were drilled into the Banff formation at Michichi, Alberta. One of these wells was brought on production in the second half of January 2018, with the final four wells being brought on production in late March 2018.

CAPITAL RESOURCES AND LIQUIDITY

Credit Facility

The Company has a senior demand revolving credit facility ("Facility") with a Canadian Bank ("Bank") for $12 million, however draws are capped at $10.0 million with special approval required from the Bank to access the remaining $2.0 million. The Facility can be used for general corporate purposes and capital expenditures, and bear interest at either the Bank's prime rate plus an applicable margin (of 75 bps to 275 bps) or, Bankers' Acceptance ("BA") rates plus an additional margin (of 200 bps to 400 bps) both determined quarterly, in accordance with net debt to trailing EBITDA ratio.

At June 30, 2018, the Company had drawn on the Facility in the amount of $7.7 million and had letters of guarantee outstanding for $0.7 million which reduces the amount available under the Facility.
The Company is required to maintain the following covenants at the end of each fiscal quarter:

- Adjusted Working Capital Ratio, of not less than 1:1 (As at June 30, 2018, the Company is at 0.9:1);

- Net Debt to Trailing EBITDA Ratio not to exceed 3.9:1 for the period ending on June 30, 2018 and 3:1 thereafter (As at June 30, 2018, the Company is at 3.67:1); and
- Alberta Energy Regulator Rating Liability Management Rating (LMR) of not less than 1.25:1 (As at June 30, 2018 the Company is at 1.5.

At June 30, 2018, the Company is not in compliance with the adjusted working capital ratio. Subsequent to June 30, 2018, the Bank has notified the Company that it will provide covenant relief for this covenant for the quarter ending June 30, 2018.

For the purposes of compliance with the adjusted working capital ratio, the current portion of bank debt and the fair value of any commodity contracts are excluded, and the unused portion of the Facility (based on the $10 million available above) is included in current assets and the amount drawn on the Facility is excluded from current liabilities.

Net debt includes drawings on the Facility and the Term loan less cash on hand. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and extraordinary, unusual or non-recurring items. For the quarter ended June 30, 2018 and thereafter, the Trailing EBITDA is for the past twelve months.

The next review is scheduled for October 31, 2018. The facility is secured by a first floating charge debenture of $25 million over the Company's assets. The various covenants in the Facility and Term Loan restricts the Company's ability to access the full $12 million on the Facility.

The Company continually monitors it's covenants and works with its lenders to ensure that it's lending criteria are met, or in the event that they are not, both parties come to an agreement to satisfy the agreement.

Term Loan

The Company obtained a Term Loan for $30.0 million, which included the issuance of 37.5 million warrants to purchase common shares on May 30, 2017. The warrants shall be exercisable by the holder, in whole or in part, for four years until May 30, 2021.

The Term Loan matures on May 30, 2022, and bears interest at 10% per annum with interest payments due quarterly beginning June 30, 2017. The effective interest rate is 12.9%. The Term Loan contains certain restrictions that limit the Company's ability to incur additional indebtedness of more than $15 million in a Senior Credit Facility, (including the current facility listed above), and dispose of certain assets.

The principal amount is due upon maturity of the loan. Amounts borrowed under the Term Loan that are repaid are not available for re-borrowing. The Company may not repay the Term Loan prior to the second anniversary thereof. The loan is subject to a prepayment fee of 3%, 2% or 1% if repayments are made during the third, fourth or fifth year. The Term Loan is secured by a general security agreement over all of the present and future property of the Company on a second priority basis, subordinate only to liens securing loans under the Credit Facility.

The Term Loan is subject to financial covenants that require Marquee maintain:

- Adjusted working capital ratio of not less than 1:1;
- Net Debt to Trailing Twelve Month EBITDA not to exceed 3:1;
- Net Debt to Total Proved Develop Producing Reserves (discounted at 10%) Ratio not to exceed 1:1;
- Net Debt to Total Proved Reserves (discounted at 10%) Ratio not to exceed 0.6:1; and
- Alberta Energy Regulator Rating Liability Management Rating (LMR) of not less than 1.25:1.

The Company was not in compliance with the adjusted working capital ratio as at March 31, 2018 or June 30, 2018 but has received a waiver from the term loan lender for this covenant as at June 30, 2018. However, the Company was not in compliance with the adjusted working capital ratio for the bank debt as at June 30, 2018 and did not have the covenant waiver in place as at June 30, 2018 and consequently the term loan has been classified as a current liability as at March 31, 2018 and June 30, 2018.

Liquidity

The current economic environment relating to the oil and gas industry has made access to capital, both debt and equity, challenging for many companies. The Company generally relies on operating cash flows, equity issuances and its credit facility to fund its capital requirements and provide liquidity. Future liquidity depends primarily on funds flow generated from operations, the ability to draw on existing credit facilities and the ability to access debt and equity markets. Bank debt is classified as a short-term liability due to its demand terms.

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business. These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

The Company's credit facility is based on the bank's determination of the Company's borrowing base utilizing the Company's risked reserves and the lenders assessment of future commodity prices. The facility was amended and restated on May 25, 2018 which resulted in the borrowing base being increased to $10 million from $8.5 million. The current economic environment relating to the oil and gas industry has made access to capital, both debt and equity, challenging for many companies. As a result, there are uncertainties with respect to the renewal of the credit facility and there can be no assurance that the Company will be successful in its efforts to maintain the credit facility at acceptable levels or to arrange additional financing or complete additional asset dispositions or other transactions on terms satisfactory to the Company or at all, which could result in a material uncertainty that may cast doubt about the Company's ability to continue as a going concern. In response, management is actively engaged in the following initiatives:

- Management has negotiated with its existing lender, to increase the credit facility to $10 million from $8.5 million.
- On August 29, 2018, the Company has entered into a purchase and sales agreement to sell non-core assets in the amount of $6.6 million, subject to customary closing adjustments.

Management believes the use of the going concern assumption is appropriate based upon the assumption that the Company will be able to secure additional and/or alternative financing to ensure sufficient cash resources exist to meet its ongoing obligations as they become due in the normal course of operations.

Capital Management

The Company carefully monitors capital availability by tracking its current working capital, available credit facility, projected cash flow from operating activities and anticipated capital expenditures. Marquee considers its capital structure to include shareholders' equity and net debt.

In order to maintain or adjust the capital structure, the Company may issue shares, amend, revise or renew terms of the existing credit facility, access alternative forms of debt and equity and adjust its capital spending to manage its current and projected capital structure. The Company's ability to raise additional funds through debt or equity financing may be impacted by external conditions, including future commodity prices and the global economic outlook. The Company continually monitors business conditions including: changes in economic conditions, the risk of its drilling programs, forecasted commodity prices and potential corporate or asset acquisitions.

The Company monitors capital based on two financial ratios: 1) Adjusted Working Capital Ratio and 2) Net Bank Debt to Trailing EBITDA Ratio (See Non-IFRS Measures advisory).

The Company is required to maintain, under its Credit Facility and Term Loan, a working capital ratio of greater than 1 to 1, defined as the ratio of current assets (including undrawn available credit on the revolving and operating portion of the credit facility and excluding the fair value of the commodity contracts) divided by current liabilities (less the current portion of bank debt and the fair value of the commodity contracts). At June 30, 2018, the working capital ratio was 0.9 to 1.0 (June 30, 2017 – 5.0 to 1.0), and thus the Company was not in compliance with the covenant. The following table summarizes the Company's bank adjusted working capital calculation as defined by its lending facility covenants, as at:

(thousands of Canadian dollars)	June 30, 2018
Current assets, excluding commodity price contracts	7,423
Undrawn available credit	1,643
Subtotal	9,066
Current liabilities, excluding bank debt and commodity price contracts	10,237
Bank adjusted working capital ratio	0.90

The Company is required to maintain, under its Credit Facility and Term Loan, a Net Debt to Trailing EBITDA Ratio not to exceed 3:1 (defined above under Credit Facility section). At June 30, 2018, the ratio was 3.67 to 1.0 and the Company was not in compliance with the covenant.

The Company expects cash flow from operations will improve in the current price environment as new wells have come on stream and previous one-time costs and weather conditions have dissipated.

The following table summarizes the Company's Net Debt to Trailing EBITDA Ratio calculation as defined by its lending facility covenants, as at:

(thousands of Canadian dollars, except ratios)	**June 30, 2018**
Cash	**1,468**
Bank debt	**(7,700)**
Term loan	**(30,000)**
Net debt (as defined by the lender)	**(36,232)**
EBITDA	
Net loss	**(25,560)**
Adjusted for:	
Deferred income tax recovery	**(992)**
Cash interest	**3,112**
Depletion and depreciation	**25,505**
Finance expense	**497**
Share based compensation	**906**
Accretion	**1,189**
Transaction costs	**2**
Exploration and evaluation expenditures	**84**
Unrealized gain (loss) on hedging	**4,256**
Non-recurring items	**860**
Annual EBITDA	**9,859**
Net debt to EBITDA ratio	**3.67:1**

(1) Trailing EBITDA for the three months ending June 30, 2018 and the quarters ending thereafter, is calculated by taking the EBITDA for the twelve (12) months immediately preceding such date.

Contractual Obligations

	2018	2019	2020	2021	Thereafter	Total
Office lease	$118	$339	$339	$-	$-	$796
Processing	1,150	2,300	2,300	2,300	2,619	10,669
Bank Debt	7,700	-	-	-	-	7,700
Term Loan	1,512	3,000	3,000	3,000	31,233	41,745
	$10,480	$5,639	$5,639	$5,300	$33,852	$60,910

The Company entered into an office lease effective January 1, 2016 with commitments that expire in 2020.

On August 19, 2015 Marquee completed a facility arrangement with a third party under which the company received $15.0 million in cash, before transaction costs, in exchange for the sale of a gas plant. Under the facility arrangement the Company has been contracted by the purchaser to operate the facility over a 7.5-year term and will continue to process gas from certain producing properties. Marquee will pay the purchaser an annual facility tariff fee of $2.3 million for the life of the agreement but retain all third-party processing revenues generated.

The Company has a net draw balance on its facility of $7.7 million as at June 30, 2018.

The Term Loan dated May 30, 2017 accumulates annual interest at a rate of 10% which is paid quarterly, this loan matures on May 30, 2022.

Common Share, Stock Options and Warrants Outstanding

The following denotes Marquee common shares outstanding, stock options and warrants:

	August 29, 2018, June 30, 2018 and December 31, 2017
Common shares	435,772,196
Stock options	24,720,000
Warrants	37,500,000

RISKS AND UNCERTAINTIES

Business Risks

The oil and gas industry is subject to risks in (among others):

- Finding and developing reserves;
- Commodity prices received for such reserves;
- Availability of equipment, manpower and supplies;
- Availability and cost of capital to achieve projected growth;
- Effect of weather on drilling and production; and
- Operating in an environmentally appropriate fashion.

The Company mitigates these business risks by:

- Maintaining cost-effective operations;
- Maintaining a balance between oil and gas properties;
- Operating our own properties to control the amount and timing of capital expenditures;
- Using a commodity hedging strategy to mitigate price risk
- Using new technology to maximize production and recoveries and reduce operating costs;

- Restricting operations to western, central and southern Alberta where locations are accessible, operating and capital costs are reasonable and on-stream times are shorter; and
- Drilling wells in areas with multiple high deliverability zone potential.

Environmental, Health and Safety Risk

Environmental, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place, as is operational loss insurance coverage. Marquee employees and contractors adhere to the Company's environmental, health and safety program, which is routinely reviewed and updated to ensure that the Company operates in a manner consistent with best practices in the industry. The Board of Directors oversees the risk assessment and risk mitigation process.

Regulation, Tax and Royalty Risk

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Company's financial and operating results. Management, with the assistance of legal and accounting professionals, stay informed of proposed changes in laws and regulations and proactively responds to and plan for the effects of these changes.

Industry and Economic Factors

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to taxation of oil and natural gas by agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size and with similar assets. All current legislation is a matter of public record and the Company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry.

The producers of oil are entitled to negotiate sales and purchase agreements directly with oil purchasers. Most domestic Canadian agreements are linked to standard market oil reference prices being Edmonton Mixed Sweet Blend ("MSW") and Western Canadian Select ("WCS"). Oil prices are set by daily, weekly and monthly physical and financial transactions for crude oil. Those prices are primarily based on worldwide and domestic fundamentals of supply and demand. Specific prices depend in part on oil quality, prices of competing fuels, distance to the markets, value of refined products, the supply/demand balance and other contractual terms. The price of natural gas is also determined by negotiation between buyers and sellers.

Domestic prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond the Company's control. These factors include, but are not limited to, the actions of the Organization of the Oil Exporting Countries (OPEC), world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions.

In addition to federal regulation, each province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters.

For a complete discussion of the risks affecting Marquee, refer to the Company's most recently filed Annual Information Form, available on SEDAR at www.sedar.com.

SUMMARY OF QUARTERLY RESULTS

The following table summarizes the Company's key quarterly financial results for the past eight quarters:

(thousands of Canadian dollars except per share amounts)	**June 30, 2018**	Mar 31, 2018	Dec 31, 2017	Sept 30, 2017	June 30, 2017	Mar 31, 2017	Dec 31, 2016	Sept 30, 2016
Financial								
Oil, natural gas, and processing fee revenue	**11,521**	8,821	9,068	6,569	8,989	7,423	8,013	7,432
Funds flow from (used in) operations	**1,646**	707	972	1,495	2,384	1,105	404	(532)
Basic & diluted ($/share)(1)	**-**	-	-	-	0.01	-	-	-
Net income/(loss)	**(4,671)**	(4,912)	(13,040)	(2,937)	(1,956)	(3,663)	(10,063)	(5,247)
Basic and diluted ($/share)(1)	**(0.01)**	(0.01)	(0.03)	(0.01)	(0.01)	(0.01)	(0.05)	(0.03)
Capital expenditures (2)	**276**	11,045	3,392	7,529	1,235	6,611	1,052	210
Total assets	**166,319**	166,809	163,969	171,620	175,458	174,239	169,162	178,553
Total equity	**61,928**	66,473	71,257	83,447	86,799	86,855	90,412	68,134
Net debt	**40,514**	41,907	31,598	28,944	22,914	22,688	17,165	45,019
Weighted average common shares outstanding	**435,772**	435,772	435,772	435,772	435,772	435,772	266,382	205,687
Operations								
Average daily production								
Crude oil (bbl/d)	**1,521**	1,274	1,265	1,069	1,174	1,000	1,047	1,240
Heavy oil (bbl/d)	**-**	-	-	-	-	-	-	10
NGLs (bbl/d)	**166**	156	155	154	159	132	172	148
Natural gas (mcf/d)	**8,835**	8,028	8,722	9,408	10,141	8,082	8,034	8,241
Total boe/d	**3,159**	2,768	2,874	2,791	3,024	2,479	2,558	2,772

(1) Prior period per share amounts have been recalculated, due to the reverse takeover of AOS by Marquee, to reflect the Marquee number of shares outstanding multiplied by the exchange ratio of 1.67.
(2) Excludes acquisitions and dispositions

Three months ended June 30, 2018 (Q2-2018) compared to March 31, 2018 (Q1-2018)
Total revenue was higher in Q2 2018 compared to Q1 2018 due to increased commodity benchmark and realized prices, and due to increased production. Net income in the Q2 2018 did not change much on a percentage basis from Q1, this is due to higher production and operating costs in Q2 and higher depletion. Capital expenditures in Q2 are lower than Q1 as majority of the drilling and completion costs occurred in Q1.

Three months ended March 31, 2018 (Q1-2018) compared to December 31, 2017 (Q4-2017)
Total revenue was lower in Q1 2018 as compared to Q4 2017 due to lower production and prices. Realized oil price fell by 5% in Q1, 2018 when compared to Q4 of 2017. Capital expenditures in Q1 2018 are noticeably higher than Q4 2017, this is due to the drilling and completions of four new wells in Q1. Total Drill and Completion costs for Q1 were $8.8 million, with the remainder of capital expenditures being allocated to equip and tie in, production facilities, land and lease rentals, and capitalized G&A.

Three months ended December 31, 2017 (Q4-2017) compared to September 30, 2017 (Q3-2017)
Total revenue was higher in Q4 compared to Q3 as a result of the four wells completed in Q3 and therefore increased production. Realized oil prices increased by 24% in Q4 as compared to Q3, and the gas prices increased 21% in Q4 when compared to Q3, which contributed to the increase in revenue for Q4. Capital expenditures in Q4 are $3.7 million, which

dropped nearly 50% from Q3, this is due to the four wells that were drilled in Q3, resulting in greater costs relating to drilling and completion in Q3. With the remainder of capital expenditures being allocated to production facilities, land and lease rentals, and capitalized G&A. The Company also recorded an impairment expense for $8.2 million in the three months ending December 31, 2017.

Three months ended September 30, 2017 (Q3-2017) compared to June 30, 2017 (Q2-2017)
Total revenue was lower in Q3 compared to Q2 as a result of lower production and prices. Realized oil prices fell 8% in Q3 as compared to Q2, and the gas prices fell 49% in Q3 when compared to Q2, which contributed to the decline in revenue for Q3. Capital expenditures in Q3 are $7.5 million, which are noticeably larger than Q2, $6.4 million relate to the drilling and completion of four new wells in Q3, with the remainder of capital expenditures being allocated to equip and tie in, production facilities, land and lease rentals, and capitalized G&A.

Three months ended June 30, 2017 (Q2-2017) compared to March 31, 2017 (Q1-2017)
Volumes increased 22% to 3,024 boe/day compared to 2,479 boe/day in Q1 – due to the three wells drilled in Q1 coming on production in early Q2 at better than expected rates. Revenue increased by 21% to $9.0 million due to increase production and relatively stable prices. Capital expenditures for the period relate to completion, equipping & tie-in costs on the wells drilled in Q1.

Three months ended March 31, 2017 (Q1-2017) compared to December 31, 2016 (Q4-2016)
Volumes decreased by 3% from Q4 and prices on a BOE basis decreased 2% with oil and liquids price up from the prior quarter but gas prices decreased. Total revenue decreased by 7%. Operating costs decreased by $1.8 million to $17.56 per boe. During Q1 the Company, drilled three net wells for a drill and equip expenditures of $5.3 million. The wells came on production in early April.

Three months ended December 31, 2016 (Q4-2016) compared to September 30, 2016 (Q3-2016)
Revenue for the fourth quarter was up 8% compared to Q3. Production was down slightly quarter to quarter, but prices recovered in the fourth quarter, on a boe basis prices in Q4 were up by 17% compared to Q3. Capital for the quarter represent capitalized G&A and lease rentals on producing properties. The reverse acquisition of AOS was recorded as of the date of amalgamation – December 6, 2016. The larger loss in Q4 compared to Q3 is partially attributable to the $3.2 million in transaction costs relating to the AOS acquisition.

Three months ended September 30, 2016 (Q3-2016) compared to June 30, 2016 (Q2-2016)
Total revenue was lower in Q3 compared to Q2 as a result of being the first full quarter of decreased volumes as a result of the properties sold. Realized oil prices remained consistent with Q2 but gas prices increased by 82% to $2.58 compared to $1.42 for Q2. The swing from net income of $1,043 in Q2 to a loss of $5,247 in Q3 is mainly due to the gain on sale of property recorded in Q2. Capital expenditures for the quarter represent capitalized G&A and lease rentals on producing and non-producing lands.

NON-IFRS MEASURES

Operating Netback
This MD&A contains the term "operating netback" which does not have a standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures by other companies. Marquee uses field operating netbacks to analyze operating performance. Marquee believes this benchmark is a key measure of profitability and overall sustainability for the Company and this term is commonly used in the oil and natural gas industry. Field operating netbacks are not intended to represent operating profits, net earnings or other measures of financial performance calculated in accordance with IFRS.

Operating netbacks are calculated by deducting royalties, production and operating and transportation expenses from revenues before other income (losses) and adding (deducting) commodity contract gains (losses).

Operating Netback prior to hedging
This MD&A contains the term "operating netback prior to hedging" which does not have a standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures by other companies. Marquee uses operating netbacks prior to hedging to analyze operating performance. Marquee believes this benchmark is a key measure

of profitability and overall sustainability for the Company and this term is commonly used in the oil and natural gas industry. Operating netbacks prior to hedging are not intended to represent operating profits, net earnings or other measures of financial performance calculated in accordance with IFRS.

Funds Flow from Operations

This MD&A and the financial statements contain the term "funds flow from operations" which should not be considered an alternative to, or more meaningful than "cash flow from operations" as determined in accordance with IFRS as an indicator of the Company's performance. Therefore, reference to funds flow from operations or funds flow from operations per share may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate cash necessary to fund future capital investments and to repay debt. Funds flow from operations per share is calculated using the weighted average number of shares for the period.

	Three months ended June 30,			Six months ended June 30,		
(thousands of Canadian dollars)	**2018**	2017	Change	**2018**	2017	Change
Cash flow from operations	**2,835**	12	n/m	**4,098**	259	n/m
Add back: Changes in non-cash working capital	**(1,189)**	2,372	-150%	**(1,745)**	3,230	-154%
Funds flow from operations	**1,646**	2,384	-31%	**2,353**	3,489	-33%

Net Debt to Annualized Funds Flow

This MD&A and the financial statements also contain the term net debt and net debt to annualized funds flow from operations. Net debt and net debt to annualized funds flow from operations is calculated as net debt, defined as outstanding bank debt plus or minus net working capital (excluding fair value of commodity contracts), divided by annualized quarterly cash flow from operating activities before decommissioning expenditures, transaction costs and changes in non-cash working capital. Management considers net debt and net debt to annualized funds flow as important additional measures of the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds flow from operations remained constant.

Net Debt to EBITDA

The Company uses the terms Net Debt to EBITDA which are used in reference to the financial covenants prescribed by the Company's bank facility and term loan. Under the bank facility and term loan, debt includes drawings on the bank facility and the term loan less cash on hand. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent quarter. Other non-cash items include impairment, gains or losses on divestitures and the premium on flow-through shares.

BOE Conversions

The term "barrels of oil equivalent" (BOE) 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 (6:1) 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 that the value ratio based on the current price of crude oil as compared with natural gas is significantly different than the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. (This conversion conforms to National Instrument 51-101). References to natural gas liquids ("NGL") in this MD&A include condensate, propane, butane and ethane. One barrel of NGL is considered to be equivalent to one barrel of crude oil equivalent (BOE).

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, as at the statement of financial position date and the reported amounts of revenues and expenses during the year. Accordingly, actual results may differ from these estimates.

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accounting estimates will, by definition, seldom equal the actual results. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected.

The following discussion sets forth management's significant judgments and estimates made in preparation of these financial statements.

Management Judgment and Estimates

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of cash-generating units
Oil and natural gas interests, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The classification of assets into CGU's requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Company's operations. The Company has identified Michichi as its core CGU.

Impairment of oil and natural gas assets
Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

Exploration and evaluation assets
The decision to transfer exploration and evaluation assets to property, plant and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves as well as related future cash flows.

Deferred taxes
Judgments are made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit and loss in the period in which the change occurs.

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Reserves
The assessment of reported recoverable quantities proved and probable reserves include estimates regarding production volumes, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. The economical, geological and technical factors used

to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying value of the Company's oil and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning liabilities, and the recognition of deferred tax assets due to changes in expected future cash flows. The Company's petroleum and natural reserves are independently evaluated by reserve engineers at least annually and are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

Decommissioning liabilities
The calculation of decommissioning liabilities and related accretion expense includes management's estimates of current risk-free interest rates, future inflation rates, future restoration and reclamation expenditures and the timing of those expenditures. In most instances, removal of assets occurs many years in the future.

Share based payments
The amounts recorded for share-based compensation expense relating to the fair value of stock options and warrants issued are estimated using the Black-Scholes option pricing model including management's estimates of the future volatility of the Company's share value, quoted market value of the Company's shares at grant date, expected forfeiture rates, expected lives of the options and warrants (based on historical experience and general holder behaviours), and the risk-free interest rate (based on government bonds).

Business combinations and asset acquisitions
The values assigned to the common shares issued in the asset acquisitions completed in 2015 and 2014 and the allocation of the purchase price to the net assets in the acquisitions are based on numerous estimates that affect the valuation of certain assets and liabilities acquired including the discount rates, estimates of proved and probable reserves, estimates of fair values of exploration and evaluation assets, future oil and natural gas prices and other factors.

Commodity Price Contracts
The amounts recorded for the fair value of commodity contracts are based on estimates of future commodity prices, foreign exchange rates and the volatility in those prices.

Deferred tax asset
The amounts recorded for deferred tax assets are based on estimates as to the timing of the reversal of temporary differences, substantially enacted tax rates and the likelihood of tax assets being realized. The availability of tax pools and other deductions are subject to audit and interpretation by tax authorities.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

In January 2016, the IASB issued IFRS 16, "Leases" ("IFRS 16") to replace IAS 17, "Leases." Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. The Company is continuing to evaluate the impact of adopting IFRS 16 on the Company's financial statements.

FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements included or incorporated by reference in this Management's Discussion and Analysis may constitute forward looking statements under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this Management's Discussion and Analysis may include, but are not limited to:

- 2017 capital budget and expenditures;
- business strategies, objectives and outlook;
- Oil and natural gas sales;
- future production levels (including the timing thereof) and rates of average annual production growth;
- exploration and development plans;
- acquisition and disposition plans and the timing and the anticipated benefits thereof;
- anticipated cash flows;
- expected cost reductions and production efficiencies derived from recently acquired assets;
- number and quality of future potential drilling locations future drilling plans;
- expected debt levels;
- operating and other expenses;
- royalty and income tax rates; and
- the timing of regulatory proceedings and approvals.

Such forward-looking statements or information are based on a number of assumptions all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things:

- the ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities;
- the ability of the Company to market crude oil, natural gas liquids and natural gas successfully to current and new customers;
- the ability to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to obtain financing on acceptable terms;
- interest rates;
- regulatory framework regarding taxes, royalties and environmental matters;
- future crude oil, natural gas liquids and natural gas prices; and
- Management’s expectations relating to the timing and results of development activities.

Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking information. The material risk factors affecting the Company and its business are contained in Marquee's Annual Information Form.

The forward-looking information contained in this Management's Discussion and Analysis is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward looking information contained in this Management's Discussion and Analysis is expressly qualified by this cautionary statement.

DIRECTORS

Dr. William Roach
Chairman of the Board

Adrian Goodisman

Stephen J. Griggs

Paul Moase

Leonard Sokolow

Robert J. Waters

OFFICERS AND SENIOR EXECUTIVES

Dr. William Roach
Interim Chief Executive Officer

Howard Bolinger
Executive Vice President, Finance, Chief Financial Officer and Corporate Secretary

Rob Lemermeyer
Vice President, Production

Dave Washenfelder
Vice President, Exploration

Sam Yip
Vice President, Engineering

Adam Jenkins
Vice President, Corporate Development

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TRANSFER AGENT AND REGISTRAR

CST Trust Company
Toronto, Ontario

RESERVE EVALUATORS

Sproule Associates Ltd.
Calgary, Alberta

STOCK MARKET INFORMATION

TSX.V: MQX.V (CAD)
OTC: MQXDF (USD)

ABBREVIATIONS

Oil and Natural Gas Liquids
bbl – barrels
mcf –thousand cubic feet
NGL – natural gas liquids
boe – barrels of oil equivalent (6:1)
bbl/d – barrels per day
mcf/d – thousand cubic feet per day
boe/d – barrel of oil equivalent per day

Other
WTI – West Texas Intermediate
MSW – Mixed Sweet