MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per share and per boe amounts)	Three months ended September 30, **2017**	2016	Nine months ended September 30, **2017**	2016
Financial				
Oil and natural gas sales (1)	**$ 6,569**	$ 7,432	**$ 22,980**	$ 23,525
Funds flow from operations (2)	**$ 1,495**	$ (532)	**$ 4,982**	$ 821
Per share - basic and diluted	**$ 0.00**	$ 0.00	**$ 0.01**	$ 0.00
Per boe	**$ 5.58**	$ (1.99)	**$ 6.47**	$ 1.05
Net income (loss)	**$ (2,937)**	$ (5,247)	**$ (8,555)**	$ (12,122)
Per share - basic and diluted	**$ (0.01)**	$ (0.03)	**$ (0.02)**	$ (0.06)
Capital expenditures	**$ 7,529**	$ 210	**$ 15,375**	$ 687
Net debt (2)			**$ 28,944**	$ 45,019
Total Assets			**$ 171,620**	$ 178,553
Weighted average basic shares outstanding	**435,772,196**	205,686,639	**435,772,196**	205,686,639
Weighted average diluted shares outstanding	**435,772,196**	205,686,639	**435,772,196**	205,686,639
Operational				
Net wells drilled	**4**	-	**7**	-
Daily sales volumes				
Oil (bbls per day)	**1,069**	1,240	**1,082**	1,320
Heavy Oil (bbls per day)	**-**	10	**-**	225
NGL's (bbls per day)	**154**	148	**149**	147
Natural Gas (mcf per day)	**9,408**	8,241	**9,216**	11,861
Total (boe per day)	**2,791**	2,772	**2,767**	3,669
% Oil and NGL's	**44%**	50%	**44%**	46%
Average realized prices				
Light Oil ($/bbl)	**$ 47.84**	$ 44.19	**$ 50.83**	$ 40.27
Heavy Oil ($/bbl)	**$ -**	$ 29.35	**$ -**	$ 24.52
NGL's ($/bbl)	**$ 36.37**	$ 29.33	**$ 39.32**	$ 29.64
Natural Gas ($/mcf)	**$ 1.56**	$ 2.59	**$ 2.53**	$ 1.92
Netback				
Revenue ($/boe)	**$ 25.58**	$ 29.14	**$ 30.42**	$ 23.40
Royalties ($/boe)	**$ (1.25)**	$ (1.51)	**$ (1.90)**	$ (2.05)
Operating and transportation costs ($/boe)	**$ (15.78)**	$ (16.84)	**$ (16.44)**	$ (15.77)
Operating netback prior to hedging (2)	**$ 8.55**	$ 10.79	**$ 12.08**	$ 5.58
Realized hedging gain (loss) ($/boe)	**$ 3.80**	$ (1.17)	**$ 1.74**	$ 2.02
Operating netback ($/boe) (2)	**$ 12.35**	$ 9.62	**$ 13.82**	$ 7.60

(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 nine months ended September 30, 2017. This MD&A is dated November 20, 2017 and should be read in conjunction with the Company's unaudited condensed interim Financial Statements and related notes thereto for the three and nine months ended September 30, 2017, as well as the audited Financial Statements and related notes thereto for the years ended December 31, 2016. 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.

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 are large contiguous land base.

RESULTS OF OPERATIONS

Production

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Light oil (bbls/d)	**1,069**	1,240	-14%	**1,082**	1,320	-18%
Heavy oil (bbls/d)	**-**	10	-100%	**-**	225	-100%
NGLs (bbls/d)	**154**	148	4%	**149**	147	1%
Natural gas (mcf/d)	**9,408**	8,241	14%	**9,216**	11,861	-22%
Total boe/d (6:1)	**2,791**	2,772	1%	**2,767**	3,669	-25%
Production split (%)						
Crude oil and NGL	**44%**	50%	-12%	**44%**	46%	-4%
Natural gas	**56%**	50%	12%	**56%**	54%	4%
Total	**100%**	100%		**100%**	100%	

The Company's third quarter production increased 1% to 2,791 boe/d compared to the third quarter of 2016. The increase is due to the increase of three wells that were completed in the first quarter of 2017 offset by natural declines.

Production for the nine months ended September 30, 2017, was 2,767 boe/day, a 25% decrease from the 3,669 boe/day of 2016. Production declines year over year are a result of the Lloyd and non-core property dispositions, and the natural decline of existing light oil wells which was partially offset by the new production from the three wells drilled in the first quarter of 2017.

Average Realized Sales Prices

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Benchmark prices						
WTI ($US/bbl)	**$ 48.21**	$ 44.94	7%	**$ 49.47**	$ 41.33	20%
$CDN/$US foreign exchange rate	**$ 0.80**	$ 0.77	4%	**$ 0.77**	$ 0.76	1%
WTI ($CDN/bbl)	**$ 60.35**	$ 58.65	3%	**$ 64.65**	$ 54.43	19%
MSW ($CDN/bbl)	**$ 56.62**	$ 54.67	4%	**$ 60.78**	$ 50.01	22%
AECO -5A (CDN$/mcf)	**$ 1.45**	$ 2.31	-37%	**$ 2.31**	$ 1.84	26%
Average sales prices						
Light oil ($/bbl)	**$ 47.84**	$ 44.19	8%	**$ 50.83**	$ 40.27	26%
Heavy oil ($/bbl)	**$ -**	$ 29.35	-100%	**$ -**	$ 24.52	-100%
NGL ($/bbl)	**$ 36.37**	$ 29.33	24%	**$ 39.32**	$ 29.64	33%
Natural gas ($/mcf)	**$ 1.56**	$ 2.59	-40%	**$ 2.53**	$ 1.92	32%
Combined ($/boe)	**$ 25.58**	$ 29.14	-12%	**$ 30.42**	$ 23.40	30%

During the three months ended September 30, 2017, the WTI crude oil price benchmark averaged US$48.21/bbl as compared to US$44.94/bbl in the comparable 2016 period representing a 7% increase. Marquee's realized price for the quarter increased 8% to $47.84/bbl from $44.19/bbl in the prior year. The improvement in the realized price for the quarter was a result of the increased WTI price.

For the nine months ended September 30, 2017, WTI increased by 20% to $US49.47/bbl compared to $US41.33/bbl for the comparable 2016 period. Marquee's realised price increased 26% to $50.83/bbl from $40.27/bbl. The improvement in the realized price for the nine months ended September 30, 2017 is due to the improvement in the differential between the Edmonton (MSW) price and WTI.

The Company receives a discount from its benchmark prices due to a price differential for quality and transportation adjustments.

Alberta AECO natural gas benchmark pricing decreased 37% to $1.45 per mcf for the three months ended September 30, 2017, as compared to $2.31 per mcf for the same period in 2016. Consequently, Marquee's average realized price for the third quarter of 2017, decreased to $1.56 per mcf as compared to $2.59 per mcf in the third quarter of 2016. For the nine months ended September 30, 2017, AECO-5A increased by 26% from $1.84 per mcf in 2016 to $2.31 per mcf. The Company's realized gas price increased to $2.53 per mcf from $1.92 per mcf, a 32% increase. The Company produces natural gas with a higher heating value therefore receives a premium to the AECO price.

Oil and Natural Gas Revenue

	Three months ended September 30,			Nine months ended September 30,		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Light oil	**4,705**	5,041	-7%	**15,016**	14,567	3%
Heavy oil	**-**	27	-100%	**-**	1,512	-100%
NGLs	**515**	399	29%	**1,599**	1,194	34%
Natural gas	**1,349**	1,965	-31%	**6,365**	6,252	2%
Total revenue	**6,569**	7,432	-12%	**22,980**	23,525	-2%

Total revenue for the three months ended September 30, 2017 decreased by 12% to $6.6 million compared to $7.4 million in the third quarter of 2016 and decreased to $23.0 million for the nine months as compared to $23.5 million for the comparable period in 2016, a 2% decrease. The decrease in revenue for the three months ended September 30, 2017 is attributable to the decrease in natural gas prices, which is slightly offset by the increase in oil prices. For the nine months ended September 30, 2017, the decrease of 2 percent is due to the decrease in production volumes offset by the increase in both the oil and natural gas prices.

Royalties

(thousands of Canadian dollars, except per boe amounts)	**Three months ended September 30,**			**Nine months ended September 30,**		
	2017	2016	Change	**2017**	2016	Change
Royalties	**320**	384	-17%	**1,435**	2,058	-30%
As a percentage of revenue	**5%**	5%	0%	**6%**	9%	-3%
$/boe	**1.25**	1.51	-17%	**1.90**	2.05	-7%

Royalties for the three months ended September 30, 2017, decreased 17 percent compared to the same period in 2016. However, on a percentage of sales the amount remained consistent. For the nine months ending September 30, 2017 royalties decreased to $1.4 million compared to $2.1 million the previous year. As a percentage of sales, royalties decreased year over year due to the disposition of higher royalty rate properties in 2016 as well as lower royalty rates on the three wells drilled in 2017. 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 the purpose of hedging and has partially mitigated commodity price risk by entering into crude oil hedging contracts extending to June 30, 2019. Marquee's current commodity contract position as at the date of this MD&A is as follows:

Type of Instrument	**Notional Volumes**	**Price**	**Index**	**Term**
Crude Oil Collar	400 bbl/day	US$40.00 - $56.25/bbl	WTI-Fixed	October 1, 2017 to June 30, 2018
Crude Oil Put	400 bbl/day	US$45.00 Strike, $4.95 Premium	WTI-Fixed	July 1, 2018 to June 30, 2019
Natural Gas Swap	3,000 GJ/day	Cdn$3.05/GJ	AECO-Fixed	January 1, 2018 to March 31 ,2018
Natural Gas Swap	3,000 GJ/day	Cdn$3.00/GJ	AECO-Fixed	October 1, 2017 to December 31, 2017
Natural Gas Collar	3,000 GJ/day	Cdn$2.00 to $2.53/GJ	AECO-Fixed	April 1, 2018 to September 30, 2018
Natural Gas Collar	3,000 GJ/day	Cdn$2.20 to $2.72/GJ	AECO-Fixed	October 1, 2018 to December 31, 2018
Natural Gas Collar	3,000 GJ/day	Cdn$2.40 to $2.92/GJ	AECO-Fixed	January 1, 2019 to March 31, 2019
Natural Gas Collar	3,000 GJ/day	Cdn$1.90 to $2.14/GJ	AECO-Fixed	April 1, 2019 to June 30, 2019

Subsequent to September 30, 2017 the Company entered into the following commodity prices contracts:

Type of Instrument	**Volumes**	**Price**	**Index**	**Term**
Crude Oil Swap	300 bbl/day	Cdn$69.23	WTI-Fixed	Nov 1, 2017 to December 31, 2017
Crude Oil Swap	150 bbl/day	Cdn$69.00	WTI-Fixed	January 1, 2018 to December 31, 2018
Crude Oil Basis	550 bbl/day	USD$ -1.56	Edmonton SW	Nov 1, 2017 to December 31, 2017
Crude Oil Swap	100 bbl/day	Cdn$71.75	WTI-Fixed	Dec 1, 2017 to December 31, 2017
Crude Oil Swap	250 bbl/day	Cdn$70.52	WTI-Fixed	January 1, 2018 to December 31, 2018
Crude Oil Swap	150 bbl/day	Cdn$66.35	WTI-Fixed	January 1, 2019 to December 31, 2019

A summary of realized and unrealized commodity contract gains and losses for the three and nine months ended September 30, 2017 and 2016 are as follows:

(thousands of Canadian dollars)	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Realized gain (loss) on commodity contracts	**977**	(298)	428%	**1,311**	2,031	-35%
Unrealized gain (loss) on commodity contracts	**(442)**	644	-169%	**173**	(1,883)	109%
	535	346	55%	**1,484**	148	903%

The Company realized a commodity contract gain for the three and nine months ended September 30, 2017 of $1.0 million and $1.3 million, respectively (2016 – ($0.3) million and $2.0 million). 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

(thousands of Canadian dollars, except per boe amounts)	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Operating costs	**3,780**	3,990	-5%	**11,579**	14,545	-20%
Transportation costs	**271**	305	-11%	**842**	1,305	-35%
	4,051	4,295	-6%	**12,421**	15,850	-22%
$/boe	**15.78**	16.84	-6%	**16.44**	15.77	4%

Operating and transportation costs for the three months ended September 30, 2017 were $4.1 million or $15.78 per boe compared to $4.3 million or $16.84 per boe for the third quarter of 2016. On a year to date basis operating and transportation costs were $12.4 million for 2017 compared to $15.9 million for 2016, a 22% decrease. The overall decrease in operating costs are due to reductions in field expenses due to management's cost containment strategy and reduced operational activity due to the sale of the Lloydminster and shallow gas assets in Q2 2016. Due to higher fixed costs on older wells, operating costs are not declining at the same rate as production.

General and Administrative Expenses

(thousands of Canadian dollars, except per boe amounts)	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
G&A expense, gross	**1,066**	1,591	-33%	**4,011**	4,297	-7%
Recovered and capitalized	**(126)**	(369)	66%	**(458)**	(854)	46%
G&A expense, net	**940**	1,222	-23%	**3,553**	3,443	3%
$/boe, net	**3.66**	4.79	-24%	**4.70**	3.42	37%

During the three months ended September 30, 2017, general and administrative expense "G&A", net of capitalized and overhead recovery costs was $0.9 million or $3.66 per boe as compared to the previous quarter ended September 30, 2016 where G&A expenses were $1.2 million or $4.79 per boe. Gross G&A expenses prior to the effects of capitalized and overhead recoveries amounts were $1.1 million compared to $1.6 million for 2016. G&A expenses for the three months ended

September 30, 2017 were lower due to a higher overhead recovery as a result of the property dispositions in 2016 and severance costs in the prior year. The Net G&A expenses for the nine months ended September 30, 2017 are fairly consistent with prior period.

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 September 30, 2017, the Company had 23,240,000 stock options which were outstanding at an average exercise price of $0.13 per option. For the three months and nine months ended September 30, 2017 and 2016, the following is recorded related to SBC:

	Three months ended September 30,			**Nine months ended September 30,**		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Gross costs	**79**	126	-37%	**262**	435	-40%
Capitalized costs	**(4)**	(11)	64%	**(16)**	(29)	45%
Total shared-based compensation	**75**	115	-35%	**246**	406	-39%

Finance Expenses

	Three months ended September 30,			**Nine months ended September 30,**		
(thousands of Canadian dollars, except per boe amounts)	**2017**	2016	Change	**2017**	2016	Change
Interest per boe	**4.39**	4.94	-11%	**3.35**	2.94	14%
Interest on debt	**732**	1,047	-30%	**1,591**	2,156	-26%
Amortization of debt issue costs	**112**	-	100%	**146**	-	100%
Accretion of decommissioning liabilities	**282**	214	32%	**795**	802	-1%
Total Finance Expense	**1,126**	1,261	-11%	**2,532**	2,958	-14%

For the three and nine months ended September 30, 2017, finance expenses decreased compared to the prior year. The decrease in interest charges are attributable to a lower average debt balance.

Transaction Costs

	Three months ended September 30,			**Nine months ended September 30,**		
(thousands of Canadian dollars)	**2017**	2016	Change	**2017**	2016	Change
Transaction costs	**2**	688	-100%	**149**	982	-85%

Transaction costs are the costs specific to transactions the Company enters into such as acquisitions and dispositions. For the nine months ending September 30, 2017, $0.1 million of costs relate to final adjustments on transactions from 2016.

Depletion and Depreciation

((thousands of Canadian dollars, except per boe amounts)	Three months ended September 30, 2017	2016	Change	Nine months ended September 30, 2017	2016	Change
Depletion and depreciation	**4,577**	5,060	-10%	**13,578**	18,885	-28%
$/boe	**17.83**	19.84	-10%	**17.97**	18.79	-4%

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 months ended September 30, 2017, the Company recorded depletion expense of $4.6 million or $17.83 per boe compared to $5.1 million or $19.84 per boe in the third quarter of 2016. For the nine months ended September 30, 2017 the Company recorded depletion and depreciation expenses of $13.6 million compared to $18.9 million in the prior year. The reduction in depletion expense in aggregate and on a per boe basis is due to decreased production, and the reduction to the depletable reserve base due to the Lloydminster and shallow gas asset dispositions.

Gain (loss) on disposition of oil and gas interests

On May 31, 2016, the Company completed a shallow gas disposition for net proceeds of $5.0 million with a net book value of $18.2 million and an associated decommissioning liability of $26.7 million. The asset included approximately 500 gross (396 net) wells and average production of approximately 5,700 mcf/d. The gross proceeds were used to reduce the Company's current debt. The disposition is consistent with Marquee's strategy to divest non-core assets to further focus on development of its core Banff light oil play at Michichi.

On June 6, 2016, the Company disposed of its heavy oil Lloydminster assets for net proceeds of $0.1 million with a net book value of $9.6 million and an associated decommissioning liability of $4.8 million. The property averaged approximately 350 barrels per day of heavy oil production and generated minor cash flow after payment of operating and royalty costs. As previously reported in 2015, Marquee sold a production volume royalty ("PVR") on its Lloydminster property in return for $20 million. A portion of these proceeds were used to fund a strategic acquisition by the Company in its core light oil property at Michichi. Under the PVR agreement, Marquee committed the first 137.5 bbl/d of production from the Lloydminster property to the royalty owner and made a commitment to spend a minimum of $2.75 million per year for 8 years beginning in 2016 on drilling activities related to the PVR lands. Marquee has assigned its interest in the Lloydminster property along with all related PVR obligations and capital commitments to the buyer.

Taxes

Deferred income taxes arise from differences between the accounting and tax basis of assets and liabilities. The estimate of deferred income taxes is based on the current tax status of the Company, enacted legislation and management's best estimates of future events. The effective tax rate differs from the statutory tax rate as it primarily takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, and the actual amounts subsequently reported on the Company's corporate tax return.

For the nine months ended September 30, 2017, as a result of incurring the qualifying expenditures for its flow though shares the Company had a deferred tax recovery of $0.5 million. The Company also recorded a deferred tax recovery to tax effect the original amounts issued on the warrants of $0.5 million.

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 September 30,**			**Nine months ended September 30,**		
	2017	2016	Change	**2017**	2016	Change
Funds flow from operations	**1,495**	(532)	381%	**4,982**	821	507%
Per share, basic and diluted	**0.00**	0.00	0%	**0.01**	0.00	0%

Funds flow from operations for the three months ended September 30, 2017 was $1.5 million or $0.00 per share compared to ($0.5) million or $0.00 per share for the third quarter of 2016. For the nine months ended September 30, 2017 funds flow from operations was $5.0 million compared to $0.8 million for the same period of 2016. The increase compared to the 2016 periods is due to higher prices in 2017.

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 nine months ended September 30, 2017, and 2016:

	Three months ended September 30,			**Nine months ended September 30,**		
($/boe)	**2017**	2016	Change	**2017**	2016	Change
Oil and natural gas sales	**25.58**	29.14	-12%	**30.42**	23.40	30%
Royalties	**(1.25)**	(1.51)	17%	**(1.90)**	(2.05)	7%
Production costs	**(14.72)**	(15.65)	6%	**(15.33)**	(14.47)	-6%
Transportation costs	**(1.06)**	(1.19)	11%	**(1.11)**	(1.30)	15%
Operating netback prior to hedging	**8.55**	10.79	-21%	**12.08**	5.58	116%
Realized hedging gain (loss)	**3.80**	(1.17)	425%	**1.74**	2.02	-14%
Operating netback [1]	**12.35**	9.62	28%	**13.82**	7.60	82%
General and administrative expenses	**(3.66)**	(4.79)	24%	**(4.70)**	(3.42)	-37%
Decommissioning expenditures	**(0.25)**	-	-100%	**(0.21)**	-	-100%
Interest expense	**(2.85)**	(4.12)	31%	**(2.11)**	(2.15)	2%
Transaction costs	**(0.01)**	(2.70)	100%	**(0.20)**	(0.98)	80%
Exploration and evaluation cash	**-**	**-**	0%	**(0.13)**	**-**	-100%
Funds flow from operations [1]	**5.58**	(1.99)	380%	**6.47**	1.05	516%
Depletion and depreciation	**(17.83)**	(19.84)	10%	**(17.97)**	(18.79)	4%
Deferred income tax recovery	**3.86**	-	100%	**1.31**	-	100%
Decommissioning expenditures	**0.25**	-	100%	**0.21**	-	100%
Accretion	**(1.09)**	(0.84)	-30%	**(1.05)**	(0.80)	-31%
Amortization of debt issue costs	**(0.44)**	-	-100%	**(0.19)**	-	-100%
Share-based compensation	**(0.29)**	(0.45)	36%	**(0.33)**	(0.40)	18%
Unrealized gain (loss) on commodity price contracts	**(1.72)**	2.52	-168%	**0.23**	(1.87)	112%
Exploration and evaluation non-cash	**0.23**	**-**	100%	**-**	**-**	0%
Gain on disposition	**-**	-	**-**	**-**	8.74	-100%
Net loss and comprehensive loss	**(11.45)**	(20.60)	44%	**(11.32)**	(12.07)	6%

[1] Non-IFRS Measure. See Non-IFRS Measures advisory.

Capital Expenditures

(thousands of Canadian dollars)	Three months ended September 30, **2017**	2016	Nine months ended September 30, **2017**	2016
Land and lease [1]	**126**	113	**419**	288
Seismic [1]	**2**	10	**168**	72
Drilling and completions [1]	**6,442**	84	**11,417**	84
Equipment and facilities [1]	**871**	(164)	**2,953**	(351)
Dispositions [2]	**-**	-	**-**	(5,127)
Capitalized general & administrative and other expenses [2]	**88**	167	**418**	594
	7,529	210	**15,375**	(4,440)

(1) Includes expenditures on exploration and evaluation assets as well as PP&E
(2) Includes non-cash additions

During the three months ended September 30, 2017, the Company incurred approximately $7.3 million to complete, equip and tie-in costs relating to the four wells drilled in the third quarter of 2017.

CAPITAL RESOURCES AND LIQUIDITY

Credit Facility

The Company obtained a senior demand revolving credit facility (“facility”) for $12.0 million, with a Canadian Bank (“Bank”) on May 30, 2017. 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 September 30, 2017, the Company has not drawn on the facility, however, the Company has letters of guarantee outstanding for $0.7 million which reduces the amount available under the revolving loan.

The Company is required to maintain the following covenants at the end of each fiscal quarter which the Bank set to mirror certain covenants of its Term Loan:

- Adjusted Working Capital Ratio, of not less than 1:1 (As at September 30, 2017, the Company is at 2.6:1);
- Net Bank Debt to Trailing EBITDA Ratio not to exceed 3:1 (As at September 30, 2017, the Company is at 2.6:1); and
- Alberta Energy Regulator Rating Liability Management Rating (LMR) of not less than 1.25:1 (As at September 30, 2017 the Company is at 1.38.

At September 30, 2017, the Company was in compliance with all covenants.

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 is added to working capital.

Net Bank 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, 2017 Trailing EBITDA is annualized by multiplying Q2 2017 by four; for the fiscal quarter ended September 30, 2017 Trailing EBITDA is annualized by multiplying Q2 and Q3 2017 by 2; for the quarter ended December 31, 2017 Trailing EBITDA is annualized by multiplying Q2, Q3, and Q4 2017 by 4/3 and for the quarter ended March 31, 2018 and thereafter, the Trailing EBITDA is for the past for twelve months.

The next semi-annual reviews are scheduled for December 1, 2017 and May 1, 2018. The facility is secured by a general security agreement and 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. Based on the covenant calculations at September 30, 2017, the Company would be able to fully draw on the $12 million and remain in compliance with its covenants.

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 Bank Debt to Trailing Twelve Month EBITDA not to exceed 3:1;
- Net Bank Debt to Total Proved Develop Producing Reserves (discounted at 10%) Ratio not to exceed 1:1;
- Net Bank 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 in compliance with all financial covenants at September 30, 2017.

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 September 30, 2017, the working capital ratio was 2.6 to 1.0 (June 30, 2017 – 5.0 to 1.0) and the Company was 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)	**September 30, 2017**	June 30, 2017
Current assets, excluding commodity price contracts	**8,768**	11,698
Undrawn available credit	**11,343**	11,343
Subtotal	**20,111**	23,041
Current liabilities, excluding bank debt and commodity price contracts	**7,712**	4,612
Bank adjusted working capital ratio	**2.6:1**	5.0:1

The Company is required to maintain, under its Credit Facility and Term Loan, a Net Bank Debt to Trailing EBITDA Ratio not to exceed 3:1 (defined above under Credit Facility section). At September 30, 2017, the ratio was 2.6 to 1.0 and the Company was in compliance with the covenant.

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

(thousands of Canadian dollars, except ratios)	**September 30, 2017**	**June 30, 2017**
Cash	**3,373**	**5,707**
Term loan	**(30,000)**	**(30,000)**
Net Bank Debt	**(26,627)**	**(24,293)**
EBITDA		
Net income	**(2,937)**	**(1,956)**
Adjusted for:		
Deferred income tax recovery	**(992)**	
Cash interest	**732**	**400**
Depletion and depreciation	**4,577**	**4,783**
Finance expense	**112**	**35**
Share based compensation	**75**	**53**
Accretion	**282**	**254**
Transaction costs	**2**	**9**
Exploration and evaluation expenditures	**(58)**	**96**
Unrealized gain (loss) on hedging	**440**	**(875)**
Quarterly EBITDA	**2,233**	**2,799**
Annualized EBITDA[1]	**10,064**	**11,196**
Net debt to funds flow from operations	**2.6:1**	**2.2: 1**

[1]Annualized EBITDA for the three months ending September 30, 2017 is calculated by using the EBITDA for the three months ended September 30, 2017 plus the three months ended June 30, 2017 multiplied by 2.

Contractual Obligations

(thousands of Canadian dollars)	2017	2018	2019	2020	2021	Remainder	Total
Office lease	65	361	361	361	-	-	1,148
Processing	572	2,300	2,300	2,300	2,300	2,859	12,631
Term Loan	-	-	-	-	-	30,000	30,000
	637	2,661	2,661	2,661	2,300	32,859	43,779

The Company entered into a new 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 Term Loan matures on May 30, 2022.

Common Share, Stock Options and Warrants Outstanding

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

	November 20, 2017	June 30, 2017	December 31, 2016
Common shares	**435,772,196**	435,772,196	435,772,196
Stock options	**23,240,000**	23,440,000	11,700,000
Warrants	**37,500,000**	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)	**Sept 30 2017**	June 30 2017	March 31 2017	Dec 31 2016	Sept 30 2016	June 30 2016	March 31 2016	Dec 31 2015
Financial								
Oil and natural revenue	**6,569**	8,989	7,423	8,013	7,432	8,344	7,749	12,153
Funds flow from (used in) operations	**1,495**	2,384	1,106	(3,886)	(532)	31	1,322	2,304
Basic & diluted ($/share)[1]	**-**	0.01	-	-	-	0.01	0.01	0.01
Net income/(loss)	**(2,937)**	(1,956)	(3,663)	(10,063)	(5,247)	1,043	(7,918)	(26,701)
Basic and diluted ($/share)[1]	**(0.01)**	(0.01)	(0.01)	(0.05)	(0.03)	0.01	(0.04)	(0.13)
Capital expenditures [2]	**7,529**	1,235	6,611	1,052	210	377	100	2,386
Total assets	**171,620**	175,458	174,239	169,162	178,553	182,647	217,189	227,941
Total equity	**83,447**	86,799	86,855	90,412	68,134	73,258	72,098	79,821
Net debt	**28,944**	22,914	22,688	17,165	45,019	44,275	49,058	50,279
Weighted average common shares outstanding	**435,772**	435,772	435,772	266,382	205,687	205,687	205,687	201,430
Operations								
Average daily production								
Crude oil (bbl/d)	**1,069**	1,174	1,000	1,047	1,240	1,265	1,457	1,691
Heavy oil (bbl/d)	**-**	-	-	-	10	261	407	461
NGLs (bbl/d)	**154**	159	132	172	148	136	157	176
Natural gas (mcf/d)	**9,408**	10,141	8,082	8,034	8,241	12,864	14,451	15,578
Total boe/d	**2,791**	3,024	2,479	2,558	2,772	3,806	4,430	4,924

(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 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 3 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.

Three months ended June 30, 2016 (Q2-2016) compared to March 31, 2016 (Q1-2016)
Total revenue was higher in Q2 2016 compared to Q1 2016 due to increased commodity benchmark and realized prices slightly offset by decreased production. Net income in the Q2 2016 was mainly attributable to the net gain on petroleum and natural gas interests related to the disposition of the Lloydminster and shallow gas assets. Capital expenditures in the period represent capitalized G&A and lease rentals on producing and non-producing lands.

Three months ended March 31, 2016 (Q1-2016) compared to December 31, 2015 (Q4-2015)
Total revenue was lower in Q1 2016 compared to Q4 2015 due to decreased production volumes and decreased commodity benchmark and realized prices. The lower net loss in Q1 2016 compared to Q4 2015 was due to decreased depletion charges, prior quarter impairment charges and exploration and evaluation expenses relating to expired undeveloped land, offset by decreased Q1 2016 operating netbacks. Reduced capital expenditures in the quarter are reflective of zero wells drilled since Q3 2015 and a corporate strategy to defer further optional capital spending until commodity price recovery.

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).

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.

(thousands of Canadian dollars)	Three months ended September 30, **2017**	2016	Change	Nine months ended September 30, **2017**	2016	Change
Cash flow from operations	**737**	(811)	191%	**996**	1,879	-47%
Add back: Changes in non-cash working capital	**(758)**	(279)	-172%	**(3,986)**	1,058	-477%
Funds flow from (used in) operations	**1,495**	(532)	381%	**4,982**	821	507%

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 Bank Debt to EBITDA

The Company uses the terms Net Bank 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.

For the quarter ended June 30, 2017 Trailing EBITDA is annualized by multiplying Q2 2017 by four; for the fiscal quarter ended September 30, 2017 Trailing EBITDA is annualized by multiplying Q2 and Q3 2017 by 2; for the quarter ended December 31, 2017 Trailing EBITDA is annualized by multiplying Q2, Q3 and Q4 2017 by 4/3 and for quarter ended March 31, 2018 and thereafter, the Trailing EBITDA is for the past for twelve months.

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 July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes 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 mandatory effective date of IFRS 9 is for annual periods on or after January 1, 2018, and must be applied retrospectively with some exceptions. Early adoption is permitted. The Company is evaluating the impact of this standard on the financial statements and does not anticipate a material change to the valuation of its financial assets.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has commenced the process of identifying and reviewing sales and other contracts with customers to determine the extent of the impact, if any, that this standard will have on the financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which replaces IAS 17 "Leases". For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, which required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15, Revenue from Contracts with Customers. The Company is evaluating the impact of the standard 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

CORPORATE HEADQUARTERS

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DLA Piper (Canada) LLP
Calgary, Alberta

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