MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE YEARS ENDED

DECEMBER 31, 2018 and 2017

ORYX PETROLEUM

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The following Management's Discussion and Analysis ("**MD&A**") should be read in conjunction with the consolidated financial statements of Oryx Petroleum Corporation Limited ("**OPCL**" or, the "**Company**") and its subsidiaries for the years ended December 31, 2018 and 2017 (the "**Financial Statements**"), which have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").*

The date of this MD&A is March 13, 2019.

Unless otherwise noted, all amounts are in thousands of U.S. dollars.

Selected terms and abbreviations used in this MD&A are listed and described in the "Glossary and Abbreviations" section.

This MD&A contains non-IFRS measures. Please refer to the "Non-IFRS Measures" section for further information.

Readers should refer to the "Forward-Looking Information" advisory on page 29. Additional information relating to OPCL, including OPCL's Annual Information Form dated March 23, 2018, is on SEDAR at www.sedar.com. The Company will file an Annual Information Form for the year ended December 31, 2018 on or before April 1, 2019.

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Company Overview

The Company is a public company incorporated in Canada under the Canada Business Corporations Act and is the holding company for the Oryx Petroleum group of companies (together, the "**Group**" or "**Oryx Petroleum**").

Oryx Petroleum is an upstream oil and gas entity with operating activities focused on the Middle East and West Africa. The Group holds interests in the following License Areas:

License Area	Location	Participating Interest	Working Interest	Role
Hawler	Iraq – Kurdistan Region	65%	65%	Operator
AGC Central	Senegal and Guinea Bissau	85%	80%(1)	Operator
Haute Mer B(2)	Congo (Brazzaville)	30%	30%	Non-operator

Notes:

(1) Assuming the AGC exercises back-in rights.

(2) On April 23, 2018, the Group entered into an agreement providing for the transfer of the Group's 30% participating interest in the Haute Mer B license to a subsidiary of Total S.A. Refer to the Critical Estimates section of this MD&A for further information on the status of this transaction.

Operational Highlights

2018

- Average gross (100%) oil production of 6,500 bbl/d (working interest 4,200 bbl/d) for the year ended December 31, 2018 versus 3,300 bbl/d (working interest 2,100 bbl/d) for the year ended December 31, 2017;
  - 97% increase in gross (100%) oil production in 2018 versus 2017; 46% increase in gross (100%) oil production in the fourth versus the third quarter of 2018;
  - Successful completion of six producing wells during the year;
  - Commencement of production from the Tertiary and Cretaceous reservoirs at the Banan field;
- Gross (working interest) proved plus probable oil reserves of 127 million barrels as at December 31, 2018;
  - 4% increase versus 2017;
- Processing and interpretation of 3D seismic data covering the AGC Central License Area completed with prospects remapped and ranked;
  - Best estimate unrisked gross (working interest) prospective oil resources of 2.2 billion barrels as at December 31, 2018.

2019

- Average gross (100%) oil production of 11,400 bbl/d (working interest 7,400 bbl/d) and 9,800 bbl/d (working interest 6,300 bbl/d) in January and February 2019, respectively. Production in February was curtailed for a number of days due to a temporary shut-down of the Kurdistan Region Export Pipeline;
- The Banan-6 appraisal well targeting the Cretaceous reservoir is expected to be spudded in the coming days. The well is expected to be drilled to a measured depth of 1,840 metres and completed as a producing well;
- Final prospect ranking has been completed in the AGC Central License Area with preparations for an environmental impact assessment planned for 2019 with preparation for drilling in 2020 to follow.

Financial Highlights and Outlook

Liquidity outlook

The Group expects cash on hand as at December 31, 2018, cash receipts from net revenues and export sales, and cash proceeds available under a credit facility provided by shareholders in late 2018 will allow it to fund its forecasted capital expenditures and operating and administrative costs through the end of 2019. Additional capital is likely required to be able to both meet obligations expected to become payable in 2019 and to fund drilling in the AGC Central License Area planned in 2020.

Financial performance

The following table contains financial performance highlights for the three and twelve months ended December 31, 2018 and December 31, 2017.

($ thousands unless otherwise stated)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Revenue	36,456	12,508	97,642	37,368
Cash generated by / (used in) operating activities	7,354	(6,135)	8,101	(9,729)
Operating Funds Flow(1)	9,079	(333)	23,207	(5,686)
Operating Funds Flow(1) per basic and diluted share ($/share)	0.02	(0.00)	0.05	(0.02)
Profit / (Loss) for the period	56,765	(28,128)	43,753	(39,050)
Earnings / (Loss) per basic and diluted share ($/share)	0.11	(0.06)	0.09	(0.11)
Average sales price ($/bbl)	52.37	50.04	57.00	43.17
Field production costs(2) ($/bbl)	8.43	13.06	9.54	15.20
Operating expense ($/bbl)	11.03	17.07	12.48	19.88
Field Netback(1) ($/bbl)	17.15	11.40	18.30	5.90
Oryx Petroleum Netback(1) ($/bbl)	20.36	12.93	21.68	6.00
Capital additions	9,027	4,611	36,418	3,338(3)

Notes:

(1) Operating Funds Flow, Field Netback, and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

(2) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum. See the "Operating expense" section of this MD&A.

(3) Includes non-cash credits of $7.3 million relating to revisions in previously estimated costs recorded in the Hawler and OML 141 License Areas and a $2.4 million non-cash credit relating to revision to assumptions used to calculate decommissioning obligations.

Revenue and cash receipts

Revenue of $36.5 million was recorded for the three months ended December 31, 2018. Included in revenue is $32.8 million ($52.37/bbl) realised on the sale of 626,700 bbl (WI) of crude oil and $3.6 million related to the recovery of costs carried on behalf of partners. Revenue for the fourth quarter of 2018 increased by $23.9 million compared to the same period in 2017. The increase is attributable to a 179% increase in sales volumes combined with a 5% increase in realised sales price.

Revenue of $97.6 million was recorded for the year ended December 31, 2018. Included in revenue is $87.9 million ($57.00/bbl) realised on the sale of 1,542,300 bbl (WI) of crude oil and $9.7 million related to the recovery of costs carried on behalf of partners. Revenue for the year ended December 31, 2018 increased by $60.3 million compared to the same period in 2017. The increase is attributable to a 97% increase in sales volumes combined with a 32% increase in realised sales price.

All sales during the year ended December 31, 2018 were made via the Kurdistan Region Export Pipeline.

The Group has received payment in full for all crude oil delivered and sold through the Kurdistan Region Export Pipeline up to and including November 30, 2018. At the date of this MD&A, the Group's entitlement share of amounts receivable from the KRG for crude oil delivered to the pipeline during December 2018, January 2019 and February 2019 totals $17.1 million.

Field production costs and netbacks

During the three months ended December 31, 2018, the Group achieved its lowest quarterly Field production costs per barrel and highest absolute Field and Oryx Petroleum Netbacks on record.

Field production costs during the fourth quarter of 2018 amounted to $5.3 million ($8.43/bbl) in comparison to $2.9 million ($13.06/bbl) during the fourth quarter of 2017, representing a 35% decrease on a per barrel basis. The per barrel decrease was primarily due to increases in sales volumes.

Field Netback of $17.15/bbl for the three months ended December 31, 2018 has improved from $11.39/bbl for the fourth quarter of 2017. Field Netback per barrel increased by 51% in comparison to the fourth quarter of 2017. The primary drivers for improved Field Netbacks from the fourth quarter of 2017 has been the decrease in per barrel field operating costs.

Operating Funds Flow

Operating Funds Flow for the fourth quarter of 2018 was $9.1 million compared to negative $0.3 million for the three months ended December 31, 2017. The Group's highest quarterly Operating Funds Flow on record is primarily due to higher Oryx Petroleum Netbacks which have contributed cash in excess of cash general and administrative expenditures.

For the year ended December 31, 2018, Operating Funds Flow was $23.2 million compared to negative $5.7 million during the same period in 2017. The significant improvement in Operating Funds Flow is also primarily due to higher Oryx Petroleum Netbacks which have contributed cash in excess of cash general and administrative expenditures.

Cash generated by operating activities during the quarter ended December 31, 2018 amounted to $7.4 million reflecting Operating Funds Flow of $9.1 million offset by a $1.7 million increase in non-cash working capital which was primarily related to an increase in oil sales receivables.

Profit / Loss

Profit for the three months ended December 31, 2018 was $56.8 million compared to a $28.1 million loss during the fourth quarter of 2017. The variance in profit/loss for three months ended December 31, 2018 in comparison to the same period in 2017 is primarily attributable to i) a $19.4 million impairment expense recorded in the three months ended December 31, 2017 compared to a $54.1 million impairment reversal during the same period in 2018, ii) an increase in net revenue of $13.4 million, and iii) a $4.0 million gain related to the change in fair value of contingent consideration during the three months ending December 31, 2018 versus a $0.6 million charge during the three months ended December 31, 2017. These positive factors were partially offset by i) a $3.1 million increase in operating expense that is primarily attributable to increased costs due to the expanded operations at the Zeg Gawra and Banan fields and ii) a $2.5 million increase in the depletion charge during the fourth quarter of 2018 resulting from higher production during 2018, partially offset by a lower depletion charge per barrel.

Profit for the year ended December 31, 2018 was $43.8 million compared to a $39.1 million loss during the same period in 2017. The variance in profit/loss for the year ended December 31, 2018 in comparison to the same period in 2017 is primarily attributable to i) an $18.3 million impairment expense recorded during the year ended December 31, 2017 compared to a $54.1 million impairment reversal during the same period in 2018, and ii) an increase in net revenue of $33.8 million. These positive factors were partially offset by i) a $7.6 million gain on settlement of the finance lease obligation related to Hawler production facilities in 2017, ii) a $2.7 million expense related to the change in fair value of contingent consideration during the year ended December 31, 2018 versus a $0.1 million charge during the year ended December 31, 2017, iii) a $3.8 million increase in operating expense that is primarily attributable to increased costs due to the expanded operations at the Zeg Gawra and Banan fields, iv) an $8.0 million increase in the depletion charge during 2018 resulting from higher production during 2018, and v) a $1.8 million provision on trade and other receivables recorded in 2018.

Capital additions

During the fourth quarter of 2018, the Group recorded net capital additions of $9.0 million. The Group invested $7.7 million primarily on drilling activities in the Zey Gawra and Banan fields in the Hawler License Area, and $1.3 million to interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area.

During the year ended December 31, 2018, the Group recorded net capital additions of $36.4 million. The Group invested $28.5 million primarily on drilling activities in the Zey Gawra and Banan fields in the Hawler License Area, and $7.7 million to license, interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area.

Financial position

The following table contains highlights of the Group's financial position as at the dates indicated below.

($ thousands)	December 31, 2018	December 31, 2017
Total cash and cash equivalents	14,410	38,572
Working Capital	(8,627)	27,133
Total assets	812,976	744,798
Borrowings	76,624	75,854
Total long-term liabilities	133,526	147,837

The cash and cash equivalents balance of $38.6 million as at December 31, 2017 decreased to $14.4 million at December 31, 2018. This decrease is due to $33.8 million in cash used in investing activities, partially offset by $8.1 million in cash generated by operating activities.

Working capital decreased to negative $8.6 million at December 31, 2018 from $27.1 million at December 31, 2017. The decrease was due to a $24.2 million decrease in cash and cash equivalents and a $4.1 million decrease in inventories, partially offset by a $27.3 million increase in trade and other payables primarily comprised of a $22.9 increase in contingent consideration payable, a $14.3 million increase in the trade and other receivables balance, and a $5.3 million increase in assets held for disposal.

The undiscounted balance owed under the Loan Facility as at December 31, 2018 was $77.1 million, including $1.1 million in accrued interest which will be settled through the issuance of Common Shares.

The undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation to the vendor of the Hawler License Area as at December 31, 2018 was $80.8 million.

2019 capital expenditure forecast

The Group's reforecasted capital expenditures for 2019 amount to $41 million, reduced from the previously announced budget of $52 million. The reduction reflects the deferment of the construction of a pipeline from the Banan field to the Hawler production facilities from 2019 to 2020 and a revised drilling program in the Hawler License Area. The Group now does not plan to drill a sidetrack of the Zey Gawra-2 well and has replaced a second well targeting the Banan Cretaceous reservoir with another horizontal sidetrack of an existing well targeting the Demir Dagh Cretaceous. The following table summarises the Group's 2019 forecasted capital expenditure program against budget:

Location	License/Field/Activity	2019 Budget	2019 Forecast
		$ millions	$ millions
Kurdistan Region	Hawler		
	Demir Dagh	4	7
	Zey Gawra	6	3
	Banan	26	16
	Ain Al Safra	2	2
	Other[(2)]	2	3
	Total Hawler	**41**	**30**
West Africa & Corporate	AGC Central	11	11
	Capex Total	**52**	**41**

Note:

(1) Totals in rows and columns may not add-up due to rounding

(2) Other is comprised primarily of license maintenance costs

Kurdistan Region of Iraq -- Hawler License Area

Demir Dagh drilling – consists of forecast costs related to short radius sidetrack wells of the previously drilled Demir Dagh-5 and Demir Dagh-9 wells. Demir Dagh-5 is expected to be drilled mid-year with Demir Dagh-9 to be drilled in the fourth quarter**.**

Zey Gawra drilling – consists of a sidetrack of the previously drilled Zab-1 well targeting the Tertiary reservoir planned in the second half of the year. The drilling of the previously planned sidetrack of the Zey Gawra-2 well has been removed from the 2019 drilling program.

Banan drilling –the first half of 2019 consists of the drilling of two new wells targeting the Tertiary reservoir, one of which will be used as a surveillance well and not a producing well. One well targeting the Banan Cretaceous reservoir is also planned for the first half of 2019. The drilling of an additional well targeting the Banan Cretaceous reservoir has been deferred to 2020.

Ain Al Safra drilling -- -consists of costs related to the testing of the Ain Al Safra-2 well targeting the Triassic reservoirs. The Ain Al Safra-2 well was suspended in 2014 prior to testing due to security developments. The testing of the Ain Al Safra-2 well is expected to be completed in the first half of the year.

Demir Dagh facilities – comprised of minor infrastructure works.

Banan facilities expenditures – comprised of new pads and infrastructure needed to accommodate drilling plans and additional production. The previously planned construction of a pipeline between the Banan field and the Hawler processing facilities located at the Demir Dagh field has been deferred to 2020.

AGC Central License Area

Activity consists of preparation costs for drilling, studies as well as license maintenance costs.

Summary of Reserves

The following is a summary of the Company's proved plus probable oil reserves. The net present value of future net revenue related to the proved plus probable oil reserves is also presented. The information is derived from a report dated February 8, 2019, prepared with an effective date as at December 31, 2018 by Netherland, Sewell & Associates, Inc. ("**NSAI**"), an independent oil and gas consulting firm. Where applicable, comparative information derived from NSAI's report as at December 31, 2017 is provided. The reserves information set out in this MD&A should be read in conjunction with the advisories in the "Forward-Looking Information" and "Reserves Advisory" sections. Further details regarding the below estimates, including the risks and level of uncertainty associated with recovery, are available in the Company's Material Change Report dated February 13, 2019 filed on SEDAR at www.sedar.com.

Oil reserves [(1)]

		Proved plus Probable Gross (Working Interest) Oil			
		December 31, 2018		December 31, 2017	
License Area	Location	Reserves (MMbbl)	Future Net Revenue[(2)] ($ million)	Reserves (MMbbl)	Future Net Revenue[(2)] ($ million)
Hawler	Iraq – Kurdistan Region	127	814	122	704
Total oil reserves		**127**	**814**	**122**	**704**

Notes:

(1) The oil reserves data is based upon evaluations by NSAI, with effective dates as at December 31, 2018 and December 31, 2017, as indicated. Volumes are based on commercially recoverable volumes within the life of the production sharing contract.

(2) After-tax net present value of related future net revenue using forecast prices and costs assumed by NSAI and a 10% discount rate as at December 31, 2018 and December 31, 2017, as indicated. Gross proved plus probable oil reserves estimates used to calculate future net revenue are estimated based on economically recoverable volumes within the development/exploitation period specified in the production sharing contract, risk exploration contract or fiscal regime applicable to each License Area. The estimated values disclosed do not represent fair market value.

The Group's Gross (Working Interest) proved plus probable oil reserves increased by 4% from 122 million barrels ("**MMbbl**") as at December 31, 2017 to 127 MMbbl as at December 31, 2018. The increase is attributable to successful drilling in the Banan Tertiary reservoir in 2018 leading to the reclassification of the related volumes from contingent oil resources. This increase was partially offset by i) decreases in volumes attribute to the Zey Gawra Cretaceous reservoir based on logging results from wells drilled at Zey Gawra in 2018 and well performance data, and ii) the reclassification of volumes attributable to the Demir Dagh Jurassic reservoir as contingent resources due to the absence of plans to appraise or develop the reservoir.

The after-tax net present value utilising a 10% discount rate of the future net revenues attributable to the Group's Gross (Working Interest) proved plus probable oil reserves increased to $814 million from $704 million as at December 31, 2017. This increase is due to higher volumes and significantly lower estimated per barrel development costs, partially offset by a more gradual increase in production and lower oil prices.

Business Environment

On September 25, 2017, the KRG held an independence referendum. In the weeks following the referendum, the Government of Iraq initiated military movements to assert and establish control over geographic areas under dispute. Following these events, efforts were undertaken to resolve political disputes including control over geographic territory, border and transportation infrastructure including international airports, and to determine mechanisms to administer budget allocations, and internal and international trade including exports and sales of crude oil among other matters. During the first quarter of 2018, international flights into the Erbil International Airport resumed, having been suspended for some months. While partial restoration of political stability through the conduct of regional and federal elections have followed the above events and operating conditions are now such that the Group has been able to continue its activities in the Kurdistan Region of Iraq, the eventual impact of the underlying and unresolved political disputes on the Group's operations may be significant and remains uncertain.

Uncertainty related to global, social, political, and economic conditions and the resulting changes in global oil supply chains and infrastructure investment contribute to volatility in the price of crude oil. The related uncertainty regarding returns on investments in upstream oil and gas exploration and development has impacted the availability and cost of capital resources. Furthermore, future oil prices, which directly impact the Group's expected cash inflows, are difficult to forecast reliably. The Group's ability to fund its ongoing operations and its forecasted capital investments is consequently subject to significant uncertainty. See the "Liquidity and Capital Resources" section of this MD&A for further discussion.

The ongoing political instability in Iraq and other risk factors which are disclosed in OPCL's Annual Information Form could have an adverse effect on Oryx Petroleum's performance.

On March 14, 2016, the Group initiated crude oil deliveries to international markets through the Kurdistan Region Export Pipeline. Although management does not expect restrictions on its ability to access pipeline capacity, Oryx Petroleum is not aware of official allocations of export pipeline capacity and is uncertain of the extent to which its future production will continue to be sold through this export pipeline. Arrangements currently in place to sell oil produced from the Hawler License Area may not continue to be in effect. Furthermore, there remains an ongoing risk that any renewed worsening of the regional security situation could have a material adverse effect on the operating and financial performance of the Group.

The market on which oil produced from the Hawler License Area is sold affects the price realised and, consequently, Oryx Petroleum's cash flows. Complexities in local, regional, and international market access dynamics may impact the Group's realised oil sales prices and its future ability to sell its produced oil.

The Group's future revenues and cash flows from operating activities are dependent on the Group's ability to produce and deliver crude oil. Production rates are subject to fluctuation over time and are difficult to predict.

The timing and execution of the Group's capital expenditure program may also be affected by the availability of services from third party oil field contractors and the Group's ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities.

With the exception of the items discussed above together with risks disclosed in the OPCL's Annual Information Form dated March 23, 2018, management has not identified trends or events that are expected to have a material adverse effect on the financial performance of Oryx Petroleum.

Operations Review

Kurdistan Region of Iraq

The following table summarises production and sales data for the three months ended December 31, 2018, September 30, 2018, and December 31, 2017 and for the year ended December 31, 2018 and December 31, 2017:

	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Gross (100%) Production (bbl)	965,900	661,900	347,800	2,372,200	1,202,200
Gross (100%) Production per day (bbl/d)	10,500	7,200	3,800	6,500	3,300
WI Production (bbl)	627,900	430,200	226,100	1,541,900	781,400
WI Production per day (bbl/d)	6,800	4,700	2,500	4,200	2,100
WI sales (bbl)	626,700	430,900	225,000	1,542,300	779,200
WI sales per day (bbl/d)	6,800	4,700	2,400	4,200	2,100

Production and sales

Gross (100%) oil production for the three months ended December 31, 2018 was 965,900 bbl representing an average rate of 10,500 bbl/d. The Group's Working Interest share of oil production during this period was 627,900 bbl representing an average rate of 6,800 bbl/d.

The increase in production and sales volumes during the fourth quarter of 2018 is attributable to production from i) a new Zey Gawra field well drilled during the quarter, and ii) sustained production from Banan and Zey Gawra field wells completed and brought on to production during the second and third quarters of 2018.

Gross (100%) oil production for the year ended December 31, 2018 was 2,372,200 bbl representing an average rate of 6,500 bbl/d. The Group's Working Interest share of oil production during this period was 1,541,900 bbl representing an average rate of 4,200 bbl/d.

The Group recognised revenue on the sale of 626,700 bbl (Working Interest) and 1,542,300 bbl (Working Interest) of crude oil during the three and twelve months ended December 31, 2018, respectively.

Crude oil sale prices

Commencing in March 2016, the Group began selling crude oil to the KRG's Ministry of Natural Resources via deliveries at the Hawler License Area into the Kurdistan Region Export Pipeline. The realised sales prices on export sales through this pipeline made after February 1, 2018 are referenced to monthly average Brent crude oil prices, discounted by approximately $8/bbl for pipeline system tariffs and fees, and adjusted for differences in API gravity and sulphur from standard Brent specifications. For sales made prior to February 1, 2018, the realised sales prices on export sales through this pipeline were referenced to monthly average Brent crude oil prices, discounted by $12/bbl for crude oil quality and transport, and adjusted for actual API gravity and sulphur content outside of agreed quality specification ranges.

The following table indicates average Brent crude oil prices and the Group's realised crude oil sales prices for each quarter ended on the dates indicated below:

	2018				2017			
	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31
Brent average price ($/bbl)	68.81	75.16	74.39	66.82	61.26	51.72	50.28	54.13
Realised sales price ($/bbl)	52.37	61.33	61.51	56.31	50.04	41.07	37.93	41.92

Netbacks

The following table summarises the Field Netback and Oryx Petroleum Netback for the three months ended December 31, 2018 and 2017:

	Three months ended December 31, 2018		Three months ended December 31, 2017	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	32,821	52.37	11,261	50.05
Royalties	(16,042)	(25.60)	(5,504)	(24.46)
Field production costs(1)	(5,284)	(8.43)	(2,939)	(13.06)
Current taxes	(744)	(1.19)	(255)	(1.13)
Field Netback(2)	**10,751**	**17.15**	**2,563**	**11.40**
Recovery of Carried Costs	3,635	5.80	1,247	5.54
Partner share of production costs	(1,626)	(2.59)	(903)	(4.01)
Oryx Petroleum Netback(2)	**12,760**	**20.36**	**2,907**	**12.93**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Field Netback for the three months ended December 31, 2018 of $10.8 million incorporates field production costs of $5.3 million. On a per barrel basis, Field Netback has increased to $17.15/bbl for the three months ended December 31, 2018 from $11.39/bbl for the three months ended December 31, 2017. This variance is attributable to an increase in the realised sales prices and to a decrease in per barrel field production costs.

The following table summarises the Field Netback and Oryx Petroleum Netback for the year ended December 31, 2018 and 2017:

	Year ended December 31, 2018		Year ended December 31, 2017	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	87,905	57.00	33,642	43.18
Royalties	(42,967)	(27.87)	(16,444)	(21.10)
Field production costs(1)	(14,714)	(9.54)	(11,843)	(15.20)
Current taxes	(1,994)	(1.29)	(763)	(0.98)
Field Netback(2)	**28,230**	**18.30**	**4,592**	**5.90**
Recovery of Carried Costs	9,737	6.32	3,726	4.78
Partner share of production costs	(4,527)	(2.94)	(3,644)	(4.68)
Oryx Petroleum Netback(2)	**33,440**	**21.68**	**4,674**	**6.00**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Field Netback for the year ended December 31, 2018 of $28.2 million incorporates field production costs of $14.7 million. On a per barrel basis, Field Netback has improved to $18.30/bbl for the year ended December 31, 2018 from $5.89/bbl for the year ended December 31, 2017. This variance is attributable to an increase in the realised sales prices and to a decrease in per barrel field production costs.

Hawler license operation, appraisal and early production

Zey Gawra field

The Zey Gawra-2 appraisal well targeting the Cretaceous reservoir was spudded in January 2018, drilled to a measured depth of 2,120 metres, logged and successfully completed as a producer during the second quarter of 2018.

The Zey Gawra-3 appraisal well targeting the Cretaceous reservoir was spudded in May 2018, drilled to a measured depth of 2,100 metres utilising a horizontal well design, completed, stimulated and placed on extended test in late June.

The Zey Gawra-4 appraisal well also targeting the Cretaceous reservoir was spudded in September 2018, drilled to a measured depth of 2,271 metres utilising a horizontal well design and has been completed and placed on extended well test.

Crude oil from the Zey Gawra field is being processed through temporary facilities at the Zey Gawra field and is being delivered by truck to the Group's offloading and storage facilities and the Kurdistan Region Export Pipeline injection point located at the Demir Dagh field.

Banan field

Following security restrictions arising from militant activity during 2014, the Group's operation at the Banan field resumed during the second quarter of 2018. The Group then installed the temporary facilities required to produce and temporarily process oil from its Banan field. Temporary loading facilities were also constructed allowing crude oil produced from the Banan field to be delivered by truck to storage facilities and the Kurdistan Region Export Pipeline injection point located at the Demir Dagh field.

The Banan-3 appraisal well targeting the Tertiary reservoir was spudded in May 2018, drilled to a measured depth of 500 metres, completed in open hole, and placed on extended test in early June.

The Banan-2 well in the Cretaceous reservoir was successfully completed and the well was placed on extended test in late July 2018.

The Banan-4 appraisal well targeting the Tertiary reservoir was spudded in August 2018, drilled to a measured depth of 810 metres utilizing a horizontal well design, completed in open hole, and placed on extended well test in late September.

Demir Dagh

During 2018, activity at the Demir Dagh field continued to include offloading, storage, and processing activities and all Hawler License Area crude oil continues to be injected for sale into Kurdistan Region Export Pipeline.

Ain Al Safra

The Group is preparing for the resumption of operations required to complete a testing program on the Ain Al Safra-2 well which was suspended during August of 2014 prior to testing due to security developments.

West Africa

The Group has licensed approximately 2,000 km^2 of 3D seismic data acquired in December 2016 and January 2017 over the AGC Central License Area. The data has been processed and interpretation is positive. Final prospect ranking has been completed in the AGC Central License Area. An environmental impact assessment is planned for 2019 with preparation for drilling in 2020 to follow.

Other than the above, activities in West Africa during the year ended December 31, 2018 were limited to license maintenance and data analysis.

Divestment of Interest in the Haute Mer B License Area

On April 23, 2018, a subsidiary of Oryx Petroleum (the "**Seller**") entered into an agreement providing for the sale of a 30% participating interest in the Haute Mer B exploration license offshore Congo (Brazzaville) ("**HMB License**") to a subsidiary of Total S.A. (the "**Buyer**") (the "**Sale Agreement**"). Upon closing, the Seller's interest in the HMB License is expected to be transferred for cash consideration of $8 million, payable at closing with the sale to be deemed effective from January 1, 2018. The Sale Agreement provides for the Buyer to reimburse the Seller for costs incurred by it in relation to the HMB License between January 1, 2018 and the date of the Sale Agreement and to carry the Seller's share of costs from the date of the Sale Agreement to the closing of the transaction. This is expected to result in a further payment to the Seller, at closing, of $5.3 million.

The Group's position that all conditions to closing have been either satisfied or waived, notwithstanding, the Buyer has declined to close the transaction and has purported to terminate the Sale Agreement. The Seller has engaged external legal counsel, has initiated arbitration to settle the dispute, believes strongly in the merits of its position, and expects the transaction to close during 2019. Consequently, management estimates that the asset's recoverable amount continues to be equivalent to its carrying value. Management has assessed that it is improbable that the arbitration panel will rule against the Seller, or that the Group may otherwise be unsuccessful in realizing the contracted amounts. In the event that conditions to closing are determined not to have been met and the Sale Agreement is terminated, the Seller may be adjudged to have an obligation to fund the Seller's share of HMB License expenditures incurred by the Buyer following the date of the Sale Agreement. As at December 31, 2018, these unrecognised, contingent liabilities amount to approximately $13.4 million including interest charges.

Capital Additions

The following table summarises the capital additions incurred by activity during the three and twelve months ended December 31, 2018 and December 31, 2017:

	Three months ended		Year ended	
($ thousands)	December 31, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Middle East				
Drilling	5,260	108	25,455	1,387
Facilities	479	205	707	165
Studies, license, and support	1,952	2,190	2,314	(1,023)
Sub-Total Middle East	**7,691**	**2,503**	**28,476**	**529**(1)
West Africa				
Exploration drilling	139	(216)	295	(2,068)
Facilities	52	54	181	54
Seismic	440	428	5,861	1,577
Studies, license, and support	701	1,842	1,362	3,240
Sub-Total West Africa	**1,332**	**2,108**	**7,699**	**2,803**(2)
Corporate	**4**	**-**	**243**	**6**
Total capital additions	**9,027**	**4,611**	**36,418**	**3,338**

Notes:

(1) Included in capital additions for the Middle East for the year ended December 31, 2017 are non-cash credits of $6.0 million related to revisions to estimates of costs incurred in prior period and a non-cash credits of $2.4 million primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.

(2) West African capital additions for the year ended December 31, 2017 includes a non-cash credit of $2.2 million due to revisions to estimates of costs incurred in prior periods and a non-cash addition of $0.7 million.

The following table summarises the capital additions incurred by License Area during the three and twelve months ended December 31, 2018 compared to the same periods in 2017:

($ thousands)	Three months ended		Year ended	
	December 31, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Middle East				
Hawler	7,691	2,053	28,476	529
Sub-Total Middle East	**7,691**	**2,053**	**28,476**	**529**[(1)]
West Africa				
AGC Shallow[(3)]	-	(33,561)	-	(33,320)
AGC Central[(3)]	1,332	35,949	7,699	37,535
OML 141[(4)]	-	(280)	-	(1,513)
Haute Mer B	-	-	-	101
Sub-Total West Africa	**1,332**	**2,108**	**7,699**	**2,803**[(2)]
Corporate	**4**	**-**	**243**	**6**
Total capital additions	**9,027**	**4,611**	**36,418**	**3,338**

Notes:

(1) Included in capital additions for the Middle East for the year ended December 31, 2017 are non-cash credits of $6.0 million related to revisions to estimates of costs incurred in prior period and a non-cash credits of $2.4 million primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.

(2) West African capital additions for the year ended December 31, 2017 includes a non-cash credit of $2.2 million due to revisions to estimates of costs incurred in prior periods and a non-cash addition of $0.7 million.

(3) During the fourth quarter of 2017, the Group executed an amendment to the AGC Central PSC ("AGC Central Amendment"). Under the terms of the AGC Central Amendment, recoverable costs incurred under the AGC Shallow PSC are recoverable from potential sales of oil produced and sold from the AGC Central license area. Consequently, the Group transferred all costs previously associated with the AGC Shallow CGU to the AGC Central GCU. As a result of the transfer, the carrying value of the AGC Shallow license was reduced to Nil. The Group concurrently relinquished its interest in the AGC Shallow license area.

(4) During 2017, the Company divested of and derecognised its interest in the OML 141 license area in Nigeria for nominal consideration.

Middle East

During the three months ended December 31, 2018, the Group invested $7.7 million in the Hawler License Area. The Group invested $5.3 million related to drilling the Banan-4 and Zey Gawra-4 wells, and $2.0 million on license costs and studies.

The Group recorded capital additions of $36.4 million during the year ended December 31, 2018. These additions are primarily comprised of $25.5 million to drill and complete the Banan-2, Banan-3, Banan-4, Zey Gawra-2, Zey Gawra-3 and Zey Gawra-4 wells. Facilities expenditure of $0.7 million and license and studies costs of $2.3 million were also incurred during the period.

West Africa

Capital additions of $7.7 million for the year ended December 31, 2018 was primarily comprised of the final $4.6 million investment related to the licensing of 3D seismic data over the AGC Central License Area. Remaining costs related to seismic interpretation and directly attributable technical support costs also in the AGC Central License Area.

Cost Pools

Cost Pools for each License Area, which are available for recovery through future oil sales from such License Area, as at December 31, 2018, are detailed in the table below:

License Area	Location	Gross Cost Pool	Group Participating Interest Cost Pool	Costs carried by Oryx Petroleum	Costs recovered through cost oil	Group share of recoverable costs available[(1)(2)]
		($ million)	($ million)	($ million)	($ million)	($ million)
Hawler	Iraq – Kurdistan Region	831.3	524.8	184.6[(3)]	(85.5)	623.9
AGC Central	Senegal and Guinea Bissau	51.4	43.7	7.7	-	51.4
Haute Mer B[(4)]	Congo (Brazzaville)	22.8	-	-	-	-
		905.5	**568.5**	**192.3**	**(85.5)**	**675.3**

Notes:

(1) Cost Pool balances are subject to audit by relevant government entities.

(2) Oryx Petroleum share of costs available for future recovery through the sale of cost oil.

(3) Carried costs include $113.2 million in expenditures related to a commitment to carry $300 million on behalf of a partner for the Hawler License Area development.

(4) On April 23, 2018, a subsidiary of Oryx Petroleum entered into an agreement providing for the sale of the Group's 30% participating interest in the Haute Mer B license to a subsidiary of Total S.A. Please refer to the Critical Estimates section of this MD&A for further information on the status of the transaction.

Property, plant and equipment and intangible assets

The capital additions described in the sections above, net of depletion, depreciation and amortisation ("**DD&A**") and net impairment reversals, have resulted in the following movements in intangible asset and PP&E balances during the three months ended March 31, 2018, June 30, 2018, September 30, 2018 and December 31, 2018:

($ thousands)	Exploration and Evaluation Assets	Other Intangible Assets	Total Intangible Assets
As at January 1, 2018	**92,180**	**27**	**92,207**
Capital additions	480	-	480
DD&A	-	(3)	(3)
As at March 31, 2018	**92,660**	**24**	**92,684**
Capital additions	558	-	558
DD&A	-	(24)	(24)
As at June 30, 2018	**93,218**	**-**	**93,218**
Capital additions	5,288	4	5,292
DD&A	-	-	-
As at September 30, 2018	**98,506**	**4**	**98,510**
Capital additions	1,346	21	1,367
DD&A	-	(2)	(2)
As at December 31, 2018	**99,852**	**23**	**99,875**

($ thousands)	Oil & Gas assets	Furniture and fixtures	Total PP&E
As at January 1, 2018	**582,619**	**3**	**582,622**
Capital additions	5,683	-	5,683
DD&A	(2,224)	-	(2,224)
As at March 31, 2018	**586,078**	**3**	**586,081**
Capital additions	8,216	-	8,216
DD&A	(2,620)	(2)	(2,622)
As at June 30, 2018	**591,674**	**1**	**591,675**
Capital additions	6,926	236	7,162
DD&A	(4,308)	-	(4,308)
As at September 30, 2018	**594,292**	**237**	**594,529**
Capital additions	7,679	(18)	7,661
Impairment reversal	54,109	-	54,109
DD&A	(4,704)	(16)	(16)
As at December 31, 2018	**651,376**	**203**	**651,579**

Financial Results

Revenue

The following table summarises Oryx Petroleum's revenue for the three and twelve months ended December 31, 2018 and 2017. All oil sold during each of the below periods was produced at the Hawler License Area.

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Oil Sales	32,821	11,261	87,905	33,642
Recovery of Carried Costs	3,635	1,247	9,737	3,726
Revenue	**36,456**	**12,508**	**97,642**	**37,368**

The Group recognised revenue on the sale of 626,700 bbl (Working Interest) of oil during the three months ended December 31, 2018, compared to revenue on the sale of 225,000 bbl (Working Interest) of oil during the same period in the previous year. Revenue of $36.5 million during the fourth quarter of 2018 increased by $23.9 million compared to the three months ended December 31, 2017. The increase in oil sales is attributable to a 5% increase in realised sales price and a 179% increase in sales volumes.

The Group recognised revenue on the sale of 1,542,300 bbl (Working Interest) of oil during the year ended December 31, 2018, compared to revenue on the sale of 779,200 bbl (Working Interest) of oil during the same period in the previous year. Revenue of $97.6 million during the year ended December 31, 2018 increased by $60.3 million compared to the year ended December 31, 2017. The increase in oil sales is attributable to a 32% increase in realised sales price combined with a 97% increase in sales volumes.

Sales volumes are determined by the timing of deliveries to customers and are not directly correlated with production volumes. As at December 31, 2018, the Group's Working Interest share of oil inventory amounted to 10,600 bbl.

The Group has received payment in full for all crude oil delivered and sold through the Kurdistan Region Export Pipeline up to and including November 30, 2018. At the date of the MD&A, the Group's entitlement share of amounts receivable from the KRG for crude oil delivered to the pipeline during December 2018, January 2019 and February 2019 totals $17.1 million.

Royalties

The following table summarises royalty expense during the three and twelve months ended December 31, 2018 and December 31, 2017:

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Royalties	**16,042**	**5,504**	**42,967**	**16,444**

All remittances to governments that are directly attributable to the sale of oil during the reporting period, including the government share of Profit Oil but excluding income taxes, are reported as royalties. Royalties increased by $10.6 million during the three months ended December 31, 2018, and increased by $26.5 million during the year ended December 31, 2018, compared to the same periods in the previous year. The variances in royalties from period to period are attributable to the same factors as those applicable to revenues from oil sales as discussed above.

Operating expense

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Field production costs[1]	5,284	2,939	14,714	11,843
Partner's share of production costs carried by Oryx Petroleum	1,626	903	4,527	3,644
Operating expense	**6,910**	**3,842**	**19,241**	**15,487**
Sales[2] (bbl)	626,700	225,000	1,542,300	779,200
Field production costs[1] ($/bbl)	**8.43**	**13.06**	**9.54**	**15.20**
Operating expense ($/bbl)	**11.03**	**17.07**	**12.48**	**19.88**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Oryx Petroleum's Working Interest share.

Operating expense of $6.9 million in the three months ended December 31, 2018 increased by $3.1 million compared to the same period in the previous year. The increase in operating expenses is primarily attributable to increased facilities costs due to the expanded operations at the Zeg Gawra field and the commencement of production from the Banan field in the second quarter of 2018. Operating costs per barrel decreased during the three months ended December 31, 2018 compared to the three months ended December 31, 2017 due to a 179% increase in sales volumes.

Operating expense for the year ended December 31, 2018 increased by $3.8 million compared to the year ended December 31, 2017. The increase in operating expenses is primarily attributable to increased facilities costs due to the expanded operations at the Zeg Gawra field and the commencement of production from the Banan field in the second quarter of 2018. Operating costs per barrel decreased to $12.48/bbl during the year ended December 31, 2018 compared to $19.88/bbbl during the year ended December 31, 2017. This decrease was due to a due to a 97% increase in sales volumes, partially offset by a 24% increase in operating expenses.

The following table indicates the impact of the variances in operating expense between the third and fourth quarters of 2018:

($ thousands)	($000)	($/bbl)
Operating expense – three months ended September 30, 2018	**5,571**	**12.93**
Contribution of the following to variance:		
Personnel and camp costs	178	0.28
Well maintenance	90	0.14
Facilities lease and maintenance, diesel and operation	964	1.55
Security	107	0.17
Increase in production	-	(4.04)
Operating expense – three months ended December 31, 2018	**6,910**	**11.03**

General and administration

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Total General and Administration	**4,439**	**3,404**	**11,923**	**10,683**

General and administration expenses of $4.4 million and $11.9 million, incurred during the three and twelve months ended December 31, 2018, respectively, versus $3.4 million and $10.7 million in the comparable periods during 2017. The increased costs are primarily attributable to an increase in personnel costs.

Impairment of oil and gas assets

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Impairment reversal of intangible assets	-	(8,280)	-	(9,412)
Impairment (reversal) / expense of property, plant and equipment	(54,109)	27,726	(54,109)	27,726
Total impairment reversal	**(54,109)**	**19,446**	**(54,109)**	**18,314**

During the fourth quarter of 2018, the Group recorded an impairment reversal of $54.1 million related to the Hawler License Area. The carrying value of this asset at December 31, 2018 is $651.4 million. Refer to the "New Accounting Pronouncements, Policies and Critical Estimates" section of this MD&A for further information.

During the fourth quarter of 2017, the Group recorded impairment charges of $27.7 million related to the Hawler License Area. The carrying value of this asset at December 31, 2017 is $582.6 million. Subsequent to December 31, 2017, the Group accepted a non-binding offer to dispose of its interest in the Haute Mer B License Area. Management concluded that the agreement constituted an indication that the net realisable value of the Group's interest in the Haute Mer B License Area was greater than nil as previously estimated and consequently recorded an $8.0 million impairment reversal.

Depletion, depreciation and amortisation

The following table summarises the component parts of depletion, depreciation and amortisation for the three and twelve months ended December 31, 2018 and 2017:

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Intangible assets: Amortisation	2	6	28	80
PP&E assets: Depreciation	18	-	18	4
Depletion	4,723	2,218	13,890	5,835
Total DD&A	**4,743**	**2,224**	**13,936**	**5,919**

Depletion is calculated on a unit of production basis, which is the ratio of oil production volume during the period to the estimated quantities of proved plus probable oil reserves at the beginning of the period.

The increased depletion charge for the twelve months ended December 31, 2018 is due to increased production and a higher depletion rate per barrel compared to the same periods in 2017. The per barrel charge for depletion has increased primarily as a result of reductions to estimated proved plus probable oil reserves from the Hawler License Area recorded at December 31, 2017.

The depletion charge for the three months ended December 31, 2018 increased to $4.7 million from $2.2 million during the same period in 2017. This increase is due to higher production during the fourth quarter of 2018, partially offset by a lower per barrel depletion charge, primarily due to a decrease in estimated future developments costs.

Other expense / (income)

The following table summarises the components of other expense / income for the three and twelve months ended December 31, 2018 compared to the same periods in 2017:

($ thousands)	Three months ended December 31		Year ended December 31	
	2018	2017	2018	2017
Impairment of trade and other receivables	346	-	1,766	-
Settlement of finance lease liability	-	-	-	(7,605)
Increase / (Reduction) to impairment of materials inventory	1,500	(728)	671	(694)
Restructuring charge	-	-	-	(63)
Relinquishment expense	-	1,523	-	1,523
Other	(15)	(116)	144	(191)
Other expense / (income)	**1,831**	**679**	**2,581**	**(7,030)**

Other expense for the three months ended December 31, 2018 relates primarily to a $1.5 million increase in the inventory impairment provision, combined with a $0.3 million impairment provision on trade and other receivables.

Other expense for the year ended December 31, 2018 relates primarily to a $1.8 million impairment provision on trade and other receivables combined with a $0.7 million increase in the inventory impairment provision.

The $7.0 million other income for the year ended December 31, 2017 is primarily attributable to a $7.6 million gain related to the early settlement of the finance lease obligation related to Hawler production facilities, partially offset by a $1.5 million fee paid in connection with the relinquishment of the AGC Shallow License Area.

Finance expense / (income)

	Three months ended December 31		Year ended December 31	
($ thousands)	2018	2017	2018	2017
Interest expense on Loan Facility	2,012	2,012	7,983	8,794
Accretion of deferred financing costs on Loan Facility	88	201	770	2,081
Change in fair value of contingent consideration	(4,036)	628	2,704	59
Interest on contingent consideration	839	896	3,502	2,002
Accretion of decommissioning liability	116	96	421	342
Interest expense on finance lease obligation	-	-	-	443
Finance expense / (income)	**(981)**	**3,833**	**15,380**	**13,721**

Finance expense for the three and twelve months ended December 31, 2018 primarily relates to accrued interest associated with the Loan Facility and to the change in fair value and accrued interest associated with the contingent consideration.

Finance expense for the three and twelve months ended December 31, 2018 includes a $4.0 million gain and a $2.7 million charge, respectively, relating to the change in the fair value of previously recognised contingent consideration compared to a $0.6 million charge recorded during the three months ended December 31, 2017 and a $0.1 million charge recorded during the year ended December 31, 2017.

For the specific purpose of estimating the fair value of the contingent consideration obligation, management's estimate assumes that the Group will achieve a second declaration of commercial discovery in the Hawler License Area, that the contingent consideration will consequently become payable, and that the timing and amount of resulting cash outflows will be consistent with the terms outlined in 2018 Amendment (refer to the "Liquidity and Capital Resources" section of this MD&A for further information). The fair value of the liability was established using observable inputs other than quoted prices (IFRS 13 Level 2 hierarchy category) and was determined by calculating the present value of estimated future cash flows using the discount rate adjustment technique. The future cash flows have been estimated based on the terms outlined in the agreement with the counterparty and discounted using an observed market rate for similar obligations. As at December 31, 2018, management has assumed an interest rate of 5% per annum and a 10% discount rate (December 31, 2017 – 5% interest rate, 10% discount rate).

Income tax expense

The following table summarises the component parts of income tax expense for the three and twelve months ended December 31, 2018 and December 31, 2017.

	Three months ended December 31		Year ended December 31	
($ thousands)	2018	2017	2018	2017
Current income tax expense	831	329	2,202	1,020
Deferred tax (benefit) / expense	9	1,226	18	1,095
Total income tax expense	**840**	**1,555**	**2,220**	**2,115**

The current income tax expense includes amounts deemed to be collected by the KRG through its allocation of Profit Oil under the Hawler PSC.

Liquidity and Capital Resources

During 2018, the Group met its day to day working capital requirements and funded its capital and operating expenditures through funding received from the proceeds of share issuances and its share of oil sales revenues from the Hawler License Area.

Loan Facility

On March 11, 2015, the Group entered into a committed and unsecured term loan facility agreement (the "**Loan Facility**") with a subsidiary of its indirect controlling shareholder AOG (the "**Lender**"). The $100 million Loan Facility has been fully drawn and had an initial maturity of March 10, 2018 (the "**Maturity Date**").

On April 28, 2017, the Loan Facility was amended to extend the Maturity Date from March 10, 2018 to July 1, 2019 and to amend interest payment terms (the "**Loan Amendment**"). Under the terms of the Loan Amendment, interest, which up to and including May 11, 2017 accrued at an annual compound rate of 10.5%, and principal amounts owing to the Lender up to and including May 11, 2017 (the "**Loan Amount**"), are payable at the Maturity Date or earlier, at the option of the borrower. Interest accrued on the Loan Amount after May 11, 2017 was determined on each of November 11, 2017, May 11, 2018, November 11, 2018 (each, an "**Interest Calculation Dates**") and has been paid to the Lender by way of issuance of Common Shares with the number of Common Shares determined using an issue price per share equal to the volume weighted average trading price for the five trading days immediately preceding the Interest Calculation Dates.

On June 20, 2017, OPCL issued 131,933,226 Common Shares to a subsidiary of AOG for consideration of $44.1 million. $24.1 million of the proceeds from the issue and sale of Common Shares has been applied to extinguish principal and accrued interest under the Loan Facility.

On December 8, 2017, OPCL issued 24,481,049 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between May 11, 2017 and November 10, 2017.

On July 3, 2018, OPCL issued 22,188,975 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between November 11, 2017 and May 10, 2018.

On November 12, 2018, OPCL issued 23,051,817 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between May 11, 2018 and November 10, 2018.

On December 31, 2018, the Group agreed with the Lender to amend the Loan Facility to further extend the Maturity Date from July 1, 2019 to July 1, 2020 and to amend interest provisions (the "**2nd Loan Amendment**"). The Company has agreed to issue warrants to acquire between 3,637,262 and 6,132,804 Common Shares to the Lender or one of its affiliates. The Loan Amount and interest rate remain unchanged from the terms agreed under the Loan Amendment. Interest accrued on the Loan Amount for the period beginning on November 12, 2018 and ending on July 1, 2019 is to be paid to the Lender by way of issuance of Common Shares as contemplated in the Loan Amendment. If cash payments to the Lender are then permitted under the terms of other corporate agreements, interest on the Loan Amount accruing after July 1, 2019 will be payable in cash on January 1, 2020 and July 1, 2020. If interest is not paid in cash, the interest due on January 1, 2020 will be capitalised ("**Capitalised Interest**") and added to the Loan Amount and interest on the Loan Amount and Capitalised Interest shall then accrue and be payable at the Maturity Date. The 2nd Loan Amendment was approved by the Toronto Stock Exchange on March 11, 2019.

The Group is continuously engaged with the Lender and management expects to reach agreement to further amend or settle the Loan Facility prior to the Maturity Date such that cash outflows align with then available cash inflows arising from operating and/or financing activities.

As at December 31, 2018, the carrying value of the balance owed under the Loan Facility was $76.6 million, including $1.1 million in accrued interest that will paid through the issuance of Common Shares. The total undiscounted principal plus accrued interest owed at December 31, 2018 was $77.1 million.

Interim credit facility

On November 13, 2018, the Group entered into a committed and unsecured term loan agreement ("**Interim Credit Facility**") jointly with an affiliate of AOG and Zeg Oil and Gas Limited. The amount of the Interim Credit Facility was subsequently reduced to $7.25 million and the availability period to draw funds under the facility was extended to March 25, 2019. Amounts drawn under the Interim Credit Facility ("**Principal**") shall bear interest at an annual rate of 10.5% calculated daily and compounding at the end of each calendar month ("**Interest**"). Principal and Interest are payable on the earlier of i) two business days after receipt by the Group of the proceeds from the sale of assets held for disposal, and ii) March 31, 2019 (the "**Interim Credit Facility Maturity Date**"). If drawn down, the Interim Credit Facility is repayable in cash or through the issuance of common shares at an issue price equal to the greater of i) $0.1731 per Common Share, and ii) the market price of Common Shares on the Interim Credit Facility maturity date. As at December 31, 2018 no amounts have been drawn under the Interim Credit Facility.

Common Share issuance to Zeg Oil and Gas Limited

On December 27, 2018, the Company issued 7,312,764 Common Shares to Zeg Oil and Gas Limited for consideration of $1.3 million.

Contingent consideration

During 2011, the Group acquired OP Hawler Kurdistan Limited under the terms of a sale and purchase agreement (the "**Purchase Agreement**"). The Group has agreed with the vendor of the Hawler License Area to amend terms of Purchase Agreement (the "**2018 Amendment**"), with the vendor's final execution pending.

The 2018 Amendment provides for an $11.4 million deferral payment which the Group expects to make upon the vendor's final execution of the agreement. Subject to the declaration of a second commercial discovery within the Hawler License Area, the 2018 Agreement provides for fixed payments of principal plus interest scheduled as follows: $20.0 million plus accrued interest in September 2019, $25.0 million plus accrued interest in September 2020, and $11.0 million plus accrued interest in September 2021. The estimated fair value of the contingent consideration as at December 31, 2018 was $71.0 million (December 31, 2017 - $64.8 million).

If the Group has not declared a second commercial discovery by September 30, 2019 (previously September 30, 2018), the instalment payment schedule would no longer apply and the contingent consideration obligation, if subsequently triggered by a second commercial discovery, would revert to a single lump-sum payment obligation.

Although Oryx Petroleum has executed the 2018 Amendment, execution of the agreement by the vendor of the Hawler License Area has been delayed due to administrative reasons. The Group expects the 2018 Amendment to be executed in due course, followed by the $11.4 million deferral payment.

Oryx Petroleum paid $20.0 million plus interest during 2014 in satisfaction of the obligation arising upon the first commercial discovery and $5 million plus interest during the third quarter of 2017 as a non-refundable prepayment against the contingent obligation arising upon a possible second commercial discovery.

During the three and twelve months ended December 31, 2018, contingent interest accrued at a rate of 5.0% per annum. During the nine months ended September 30, 2017, contingent interest accrued at a rate of 1.9% per annum which increased to 5% during the three months ended December 31, 2017. For periods beginning on October 1, 2018, if the average price of crude oil exceeds $75/bbl during any year ending on September 30, the amended Purchase Agreement prescribes that the annually compounding interest rate increase to 10% per annum for interest calculated during such year.

The total undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation was $80.8 million as at December 31, 2018.

Liquidity outlook

The Group expects cash on hand as of December 31, 2018, cash receipts from net revenues and export sales, and cash proceeds available under a credit facility provided by shareholders in late 2018 will allow it to fund its forecasted capital expenditures and operating and administrative costs through the end of 2019. Additional capital is likely required to be able to both meet obligations expected to become payable in 2019 and to fund drilling in the AGC Central License Area planned in 2020.

See the "New Accounting Pronouncements, Policies, and Critical Estimates – Going Concern" section of this MD&A for discussion regarding uncertainties and risks associated with the Group's ability to continue as a going concern.

The following table summarises the components of Oryx Petroleum's consolidated cash flows for the periods indicated:

	Three months ended December 31		Year ended December 31	
($ thousands)	2018	2017	2018	2017
Operating Funds Flow[1]	9,079	(333)	23,207	(5,686)
Change in non-cash working capital	(1,725)	(5,802)	(15,106)	(4,043)
Net cash generated by / (used in) operating activities	**7,354**	**(6,135)**	**8,101**	**(9,729)**
Additions to E&E and PP&E	(8,882)	(4,773)	(34,232)	(21,275)
Additions to Assets held for disposal	-	-	(5,266)	-
Change in non-cash working capital	(2,387)	3,216	6,689	(1,053)
Net cash used in investing activities	**(11,269)**	**(1,557)**	**(32,809)**	**(22,328)**
Net cash generated by financing activities	**1,277**	**-**	**546**	**29,897**
Total change in cash	**(2,638)**	**(7,692)**	**(24,162)**	**(2,160)**
Cash and cash equivalents at beginning of the period	17,048	46,264	**38,572**	40,732
Cash and cash equivalents at end of the period	**14,410**	**38,572**	**14,410**	**38,572**

Note:

(1) Operating Funds Flow is a non-IFRS measure. See the "Non-IFRS Measures" section of this MD&A.

During the three months ended December 31, 2018, the Group invested $11.3 million in exploration, appraisal, and development activities in the Hawler and AGC Central License Areas. The Group invested $7.5 million primarily on drilling activities in the Banan and Zey Gawra fields in the Hawler License Area, and $1.3 million to licence, interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area. Operating activities for the three months ended December 31, 2018 generated $7.4 million in cash, reflecting Operating Funds Flow of $9.1 million, partially offset by a $1.7 million increase in non-cash working capital which was primarily related to an increase in trade and other receivables partially offset by an increase in accounts payable.

The Group invested $32.8 million during the year ended December 31, 2018 in exploration, appraisal, and development in the Hawler and AGC Central License Areas. During this period, the Group invested $26.3 million primarily on drilling activities in the Banan and Zey Gawra fields in the Hawler License Area, and $7.7 million to licence, interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area. Investing activities during the year ended December 31, 2018 also include $5.3 million to fund Haute Mer B License Area cash calls, which is expected to be recovered upon closing of the sale of the Group's interest in this License Area. Operating activities for the period generated $8.1 million in cash reflecting Operating Funds Flow of $23.2 million, partially offset by an increase in non-cash working capital comprising of an increase in trade and other receivables and a decrease in trade and other payables. Financing activities for the period generated $0.5 million, reflecting $1.3 million of cash received from a private placement of Common Shares, offset by $0.7 million in cash to purchase the remaining minority shares in KPA Western Desert Energy Limited.

Risks and uncertainties

The Group's ability to realise cash inflows from crude oil sales is subject to significant uncertainty related to the future performance and productivity of individual wells and production facilities, future crude oil prices, and customer credit risk. In particular, credit risk is impacted by the uncertainty associated with political tensions between the governments of Iraq and the Kurdistan Region of Iraq as discussed in the "Business Environment" section of this MD&A. The Group's ability to secure external financing, if and when required, is also subject to significant uncertainty and is dependent on the Group's performance and on market conditions. Furthermore, the execution of capital investment plans requires significant capital expenditures. Long lead times between initiation of commitments to capital projects and completion thereof are common in the industry. During these lead times, Oryx Petroleum expects to incur significant costs at a level which may be difficult to predict. The Group expects to finance its activities through the end of 2019 through current cash reserves, positive Operating Funds Flow and drawdowns on the Interim Credit Facility. Additional capital is likely required to i) fund legacy obligations expected to become payable during 2019 and ii) fund drilling in the AGC Central License Area planned in 2020. Prevailing market conditions, together with Oryx Petroleum's business performance, will impact the Group's ability to realise required Operating Funds Flows and to arrange further financing as needed. While the Group retains the flexibility to defer certain budgeted expenditures and to adjust the timing of its expenditures on the development of the Hawler License Area, slowing the rate of development expenditures related to the Hawler License Area would be likely to impede the Group's ability to achieve expected production and sales levels. Refer to the "Critical estimates" section of this MD&A for additional discussion regarding management's going concern assumption which contemplates that the Group will realise its assets and settle its liabilities and commitments in the normal course of business for the foreseeable future.

Economic Sensitivities

The following table shows the estimated effect that changes to crude oil prices, Gross (100%) oil sale volumes, operating costs and interest rates would have had on the Group's profit for the year ended December 31, 2018, had these changes occurred on January 1, 2018. These calculations are based on business conditions, production and sales volumes existing during the year ended December 31, 2018. The 1,000 bbl/d increase assumes the increase is to Gross (100%) sale volumes and the Group's entitlement is calculated according to the provisions of the Hawler PSC and Joint Operating Agreement.

	Change	Profit impact ($000s)	Profit impact ($ per basic share)
Change in average realised price	$10.00/bbl	10,527	0.02
Change in crude oil sales volumes	1,000 bbl/d	9,227	0.02
Change in operating expenses	$1.00/bbl	1,543	-
Change in interest rate	1%	700	-

The future cash flows relating to the contingent consideration balance (refer to the "Liquidity and Capital Resources" section of this MD&A) have been estimated based on the terms outlined in the agreement with the counterparty and discounted using an observed market rate for similar obligations. As at December 31, 2018, management has assumed a 5% interest rate and a 10% discount rate. The following table shows the estimated effect that a 5% change in the interest and discount rates would have had on the Group's profit for the year ended December 31, 2018.

	Change	Profit impact ($000s)	Profit impact ($ per basic share)
Change in interest rate	5%	5,293	0.01
Change in discount rate	5%	3,980	0.01

The impact of the above changes may be compounded or offset by changes to other business conditions. In addition, the tables do not reflect any inter-relationships between the above factors. Changes in foreign exchange rates have not been considered in this analysis as they do not have a significant impact on the Group's operations.

Non-IFRS Measures

Field Netback

Field Netback is a non-IFRS measure that represents the Group's Working Interest share of oil sales net of the Group's Working Interest share of Royalties, the Group's Working Interest share of operating expense and the Group's Working Interest share of taxes.

Management believes that Field Netback is a useful supplemental measure to analyse operating performance and provides an indication of the results generated by the Group's principal business activities prior to the consideration of PSC and Joint Operating Agreement financing characteristics, and other income and expenses. Field Netback does not have a standard meaning under IFRS and may not be comparable to similar measures used by other companies. See the "Operations Review" section of this MD&A for a reconciliation of Field Netback.

Oryx Petroleum Netback

Oryx Petroleum Netback is a non-IFRS measure that represents Field Netback adjusted to reflect the impact of Carried Costs incurred and recovered through the sale of Cost Oil during the reporting period. Management believes that Oryx Petroleum Netback is a useful supplemental measure to analyse the net cash impact of the Group's principal business activities prior to the consideration of other income and expenses. Oryx Petroleum Netback does not have a standard meaning under IFRS and may not be comparable to similar measures used by other companies. See the "Operations Review" section of this MD&A for a reconciliation of Oryx Petroleum Netback.

Operating Funds Flow (previously referred to as "Operating Cash Flow")

Operating Funds Flow is a non-IFRS measure that represents cash generated from operating activities before changes in non-cash working capital. The term Operating Funds Flow should not be considered an alternative to or more meaningful than "net cash used in operating activities" as determined in accordance with IFRS.

Management considers Operating Funds Flow to be a key measure as it demonstrates the Group's ability to generate the cash necessary to fund future growth through capital investment. Operating Funds Flow does not have any standardised meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. In previous disclosure, Operating Funds Flow was referred to as Operating Cash Flow.

The following table reconciles Operating Funds Flow to the IFRS measure of 'Net cash used in operating activities':

	Three months ended December 31		Year ended December 31	
($ thousands)	2018	2017	2018	2017
Net cash generated by / (used in) operating activities	7,354	(6,135)	8,101	(9,729)
Changes in non-cash working capital	1,725	5,802	15,106	4,043
Operating Funds Flow	**9,079**	**(333)**	**23,207**	**(5,686)**

Outstanding Share Data

In January 2017, the directors of OPCL were awarded 248,755 Common Shares ($0.1 million) for services provided in the third and fourth quarters of 2016.

On March 15, 2017, the Company issued 15.5 million Common Shares to settle a $4.8 million trade payable.

On June 20, 2017, OPCL issued 131,933,226 Common Shares to a subsidiary of AOG for consideration of $44.1 million. $24.1 million of the proceeds from the issue and sale of Common Shares has been applied to extinguish principal and accrued interest under the Loan Facility. On June 20, 2017, the Company also issued 29,916,831 Common Shares to Zeg Oil and Gas for consideration of $10.0 million.

In July 2017, the directors of OPCL were awarded 163,073 Common Shares ($0.1 million) for services provided in the first and second quarters of 2017.

On July 3, 2017, the Group issued 62,173 Common Shares to an employee under the Group's Long Term Incentive Plan ("**LTIP**"). On September 1, 2017, the Group issued 2,248,616 Common Shares to employees under the LTIP.

On December 4, 2017, the Group issued 147,103 Common Shares to an employee under the LTIP.

On December 8, 2017, OPCL issued 24,481,049 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between May 11, 2017 and November 10, 2017.

In January 2018, the directors of OPCL were awarded 360,372 Common Shares ($0.1 million) for services provided in the third and fourth quarters of 2017.

On July 3, 2018, OPCL issued 22,188,975 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between November 11, 2017 and May 10, 2018.

On September 4, 2018, the Group issued 4,054,887 Common Shares to employees under the LTIP. Upon vesting, OPCL LTIP share awards granted to the date of this MD&A will result in the issuance of up to an additional 19,670,514 Common Shares in 2019 and 2020.

On November 12, 2018, OPCL issued 23,051,817 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility.

On December 27, 2018, the Company issued 7,312,764 Common Shares to Zeg Oil and Gas for consideration of $1.3 million.

At the date of this M&DA, a total of 515,031,222 Common Shares are issued and outstanding.

On November 13, 2018, the Group agreed with the Lender to amend the Loan Facility to further extend the Maturity Date from July 1, 2019 to July 1, 2020 and to amend interest payment terms. The Company has agreed to issue warrants to acquire between 3,637,262 and 6,132,804 Common Shares of the Company to the Lender. The warrants will have an exercise price of $0.2094 per Common Share and the warrants will expire on November 13, 2021. On February 26, 2019, the Group issued warrants to an affiliate of the Lender to acquirer 3,637,262 Common Shares in accordance with this agreement.

If drawn down, the Interim Credit Facility is repayable in cash or through the issuance of common shares at an issue price equal to the greater of i) $0.1731 per Common Share, and ii) the market price of Common Shares on the Interim Credit Facility maturity date.

At the date of this MD&A, other than the warrants and unvested LTIP shares described above, there are no securities convertible into or exercisable or exchangeable for voting shares.

There were no repurchases of OPCL's equity securities by the Company during the three or twelve months ended December 31, 2018.

Commitments and Contractual Obligations

The table below sets forth information relating to Oryx Petroleum's commitments and contractual obligations as at December 31, 2018.

($ thousands)	Within One Year	From 1 to 5 Years	More than 5 Years	Total
Operating leases(1)	296	26	-	**322**
Other obligations(2)	2,523	38,428	14,503	**55,454**
Total	**2,819**	**38,454**	**14,503**	**55,776**

(1) Operating leases primarily relate to office rent.

(2) Consists principally of obligations related to PSC commitments and capital expenditure commitments. The main purpose of these commitments is to develop the Group's oil and gas assets.

Summary of Quarterly Results

The following table sets forth a summary of Oryx Petroleum's results for the indicated quarterly periods.

($ thousands, unless otherwise stated)	2017				2018			
	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
Revenue, net of royalties	4,426	3,982	5,512	7,004	7,800	10,024	16,437	20,414
Operating expense	(4,249)	(4,032)	(3,364)	(3,840)	(3,128)	(3,632)	(5,571)	(6,910)
Depletion	(1,108)	(1,101)	(1,409)	(2,276)	(2,224)	(2,622)	(4,315)	(4,723)
G&A	(2,584)	(2,512)	(2,183)	(3,404)	(2,712)	(2,358)	(2,414)	(4,439)
Profit / (Loss)	4,137	(9,199)	(5,860)	(28,128)	(4,275)	(3,522)	(5,216)	56,765
Earnings / (Loss) per basic and diluted share ($/share)	0.02	(0.03)	(0.01)	(0.06)	(0.01)	(0.01)	(0.01)	0.11
Operating Funds Flow(2)	(2,606)	(2,102)	(645)	(333)	1,428	4,298	8,400	9,079
Gross Production (bbl)	263,300	260,200	330,900	347,800	341,700	402,600	661,900	965,900
WI Production (bbl)	171,200	169,100	215,100	226,100	222,100	261,700	430,200	627,900
Gross Sales (bbl)	261,100	259,600	332,000	346,100	342,600	403,000	662,900	964,100
WI Sales (bbl)	169,800	168,800	215,800	225,000	222,700	262,000	430,900	626,700
Field production costs(1)	(3,249)	(3,083)	(2,572)	(2,939)	(2,392)	(2,777)	(4,260)	(5,284)
Field Netback(2)	228	44	1,757	2,563	3,735	5,096	8,649	10,751
Oryx Petroleum Netback(2)	16	(196)	1,947	2,907	4,388	6,026	10,266	12,760
Brent price ($/bbl)	54.13	50.28	51.72	61.26	66.82	74.39	75.16	68.81
Sales price ($/bbl)	41.92	37.93	41.07	50.05	56.31	61.51	61.33	52.37
Royalties ($/bbl)	(20.48)	(18.55)	(20.08)	(24.46)	(27.53)	(30.06)	(29.98)	(25.60)
Field production costs(1) ($/bbl)	(19.13)	(18.25)	(11.92)	(13.06)	(10.74)	(10.60)	(9.89)	(8.43)
Current taxes ($/bbl)	(0.95)	(0.86)	(0.93)	(1.13)	(1.28)	(1.40)	(1.39)	(1.19)
Field Netback(2) ($/bbl)	1.35	0.27	8.14	11.40	16.76	19.45	20.07	17.15
Oryx Petroleum Netback(2) ($/bbl)	0.10	(1.15)	9.02	12.93	19.70	23.00	23.83	20.36
Capital additions	(5,911)	814	3,823	4,611	6,164	8,774	12,454	9,027

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum. See the "Operating expense" section of this MD&A.

(2) Operating Funds Flow, Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Variations in revenue are attributable to changes in realised sales prices which have been broadly referenced to Brent crude oil prices and sales volumes which have fluctuated due to the variations in production from the Hawler License Area. There were no significant interruptions in production during the three or twelve months ended December 31, 2018 and production and sale volumes began to increase in the second, third, and fourth quarters of 2018 as a result of incremental production from the Hawler License Area's Zey Gawra and Banan fields, respectively.

Variations in Field Netback and Oryx Petroleum Netback reflect changes in revenue discussed above and the impact of changes in field production costs. Field production costs increased during 2017 and into 2018 as wells from the Zey Gawra and Banan fields have been brought onto production. Total capital additions for the three months ended March 31, 2017 include $7.3 million in non-cash credits relating to revised estimates of previously recorded costs. Capital additions are otherwise primarily associated with appraisal activity in the Hawler license area for all quarterly periods presented. Capital additions during the three months ended September 30, 2018 include $5.3 million related to the AGC Central License Area.

The increase in Operating Funds Flow over the periods presented is primarily attributable to increased production and crude oil prices.

Selected Annual Information

The following table sets forth a summary of Oryx Petroleum's results for the years indicated, in each case prepared in accordance with IFRS as issued by the IASB.

	Year ended December 31		
($ thousands except per share amounts)	2018	2017	2016
Revenue	97,642	37,368	22,809
Profit / (Loss) attributable to owners	43,753	(39,033)	(65,707)
Earnings / (Loss) per share (basic and diluted)	0.09	(0.11)	(0.31)
Total assets	812,796	744,798	766,445
Non-current financial liabilities[1]	130,819	144,689	170,427

Notes:
(1) Includes non-current trade and other payables, borrowings, decommissioning obligation and finance lease obligation.

There have been no changes due to changes in accounting policies, significant acquisitions or dispositions.

Financial and Other Instruments and Off Balance Sheet Arrangements

Oryx Petroleum was not party to any off-balance sheet arrangements during the nine months ended December 31, 2018 that have, or are reasonably likely to have, a current or future effect on the financial performance or financial condition of Oryx Petroleum. Further, on the date of this MD&A, Oryx Petroleum is not party to any such off-balance sheet arrangements.

Refer to the Financial Statements for further information on significant assumptions made in determining the fair value and classification of financial instruments recognised during the period.

Transactions with Related Parties

On March 11, 2015, the Group entered into a committed and unsecured term loan facility agreement with a subsidiary of its indirect controlling shareholder AOG. Interest and accretion expense of $8.8 million relating to this transaction has been recorded for the year ended December 31, 2018 (2017 - $10.9 million). On June 20, 2017, OPCL issued 131,933,226 Common Shares to a subsidiary of AOG for consideration of $44.1 million. $24.1 million of the proceeds from the issue and sale of Common Shares has been applied to extinguish principal and accrued interest under the Loan Facility. On June 20, 2017, the Company also issued 29,916,831 Common Shares to Zeg Oil and Gas for consideration of $10.0 million. On December 8, 2017, OPCL issued 24,481,049 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between May 11, 2017 and November 10, 2017. On July 3, 2018 OPCL issued 22,188,975 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between November 11, 2017 and May 10, 2018. On November 12, 2018, OPCL issued 23,051,817 Common Shares of the Company to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility. The Loan Amendment discussed in the "Liquidity and Capital Resources" section of this MD&A was a transaction involving related parties. Management believes the terms and conditions negotiated to be materially comparable to terms applicable to similar market transactions.

On December 27, 2018, the Company issued 7,312,764 Common Shares to Zeg Oil and Gas for consideration of $1.3 million.

On November 13, 2018, the Group entered into an Interim Credit Facility jointly with an affiliate of AOG and Zeg Oil and Gas. The Interim Credit Facility provides the Group with access to $7.25 million, to be drawn no later than March 25, 2019. Refer to the "Liquidity and Capital Resources" section of this MD&A.

On October 19, 2016, the Group entered into an office lease agreement with a subsidiary of its indirect controlling shareholder. Rental expense of $49 thousand and $198 thousand relating to this agreement was recorded for the three and twelve months ended December 31, 2018, respectively.

For the three and twelve months ended December 31, 2018, the Group incurred costs of $0.4 million and $1.7 million, respectively, for goods and services provided by related parties, all of which are subsidiaries of AOG (2017: $0.4 million and $1.5 million). Costs related to trademark license fees, parent company guarantees, and management services have been incurred under agreements between the Group and AOG. Additional information relating to such agreements is available in OPCL's Annual Information Form dated March 23, 2018 available on SEDAR at www.sedar.com. Management exercised judgment, which was based on its industry specific knowledge and experience, to determine that i) the transactions described above did not contain any unusual commercial terms, and ii) the fees charged under the agreements were reasonable and not materially inconsistent with fees which would normally be associated with broadly comparable agreements.

In January 2019, the directors of OPCL were awarded $0.2 million in cash as remuneration for services provided in the third and fourth quarters of 2018. In July 2018, directors of OPCL were awarded $0.3 million in cash as remuneration for services provided in the first and second quarters of 2018. In January 2018, directors of OPCL were awarded 360,372 Common Shares

($0.1 million) and $0.2 million in cash as remuneration for services provided in the third and fourth quarters of 2017. In July 2017, the directors of OPCL were awarded 163,073 Common Shares ($0.1 million) and $0.1 million in cash remuneration for services provided in the first and second quarters of 2017. In January 2017, directors of OPCL were awarded 248,755 Common Shares ($0.1 million) and $0.1 million in cash as remuneration for services provided in the third and fourth quarters of 2016.

New Accounting Pronouncements, Policies, and Critical Estimates

New Pronouncements

Oryx Petroleum has adopted the new and revised standards and interpretations issued by the IASB and the International Financial Reporting Interpretations Committee that are relevant to its operations and effective for accounting periods beginning on or after January 1, 2018 as described in Note 2 of the Financial Statements. The adoption of these standards and interpretations has not had a material effect on OPCL.

IFRS 9 – Financial Instruments

On January 1, 2018, the Group adopted IFRS 9 "Financial Instruments" as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward looking expected-credit loss model.

The Group has revised its accounting policy for financial assets and trade and other receivables to reflect the new classification approach as follows:

Financial assets

The Group classifies its financial assets in the following categories: amortised cost and fair value through profit or loss. The classification depends on the Company's business model for managing the financial assets and the contractual cash flow characteristics of the financial assets. Management determines the classification of its financial assets upon initial recognition.

Financial assets are derecognised when the rights to receive cash flows from the investments have expired or have been transferred and the Group has transferred substantially all risks and rewards of ownership.

i. Financial assets at amortised cost

Financial assets classified as amortised cost are held to collect contractual cash flows that solely represent repayments of the carrying amount of the asset upon initial recognition and interest, if any. These financial assets are initially measured at fair value and subsequently measured at amortised cost using the effective interest rate method.

iii. Financial assets at fair value through profit or loss

All other financial assets, not classified at amortised cost or at fair value through other comprehensive income, are classified and subsequently measured at fair value through profit or loss.

Trade and other receivables

Trade and other receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. A provision for impairment of trade receivables is established based on the probabilities of possible defaults scenarios, and on changes in those possible defaults scenarios at each reporting date.

IFRS 15 – Revenue from contracts with customers

On January 1, 2018, the Group adopted IFRS 15 "Revenue from contracts with customers". IFRS 15 establishes a comprehensive framework to determine whether, how much, and when revenue from contracts with customers is recognised.

The Group implemented IFRS 15 using the modified retrospective approach with no impact on retained earnings and no changes or adjustments to comparative figures in prior reporting periods.

The Group has revised its accounting policy for revenue as follows:

Revenue

The Group recognises revenue associated with the sale of the Group's working interest share of oil and natural gas products when control of the product is transferred to its customer(s) at which point the Group has satisfied its performance obligations. Revenue is measured on the basis of the consideration specified in the commercial agreements governing the sale of oil and natural gas products.

The Group incurs operating and capital costs for the exploration and development of various License Areas. Agreements governing the exploration and development activities establish terms for the Group to recover these costs from the value of the sales of oil and natural gas products (Cost Recovery Oil) and to share in the value of the remaining oil and natural gas products (Profit Oil). The Group's revenue includes the value of gross sales representing the sum of Cost Recovery Oil and Profit Oil.

All remittances to governments who are party to the applicable PSC that are directly attributable to the sale of oil and natural gas products during the reporting period including the government share of Profit Oil described above, except for income taxes, are reported as royalties.

Under the terms of certain PSCs, the governments' share of Profit Oil includes an amount in respect of income taxes payable by the Group under the laws of the respective jurisdiction. As this amount is classified as income tax in accordance with IAS 12, the Group recognises the amount as a deduction to royalties with a corresponding income tax expense when the oil and natural gas products are sold.

Critical estimates

In the process of applying the Group's accounting policies management makes estimates, judgments and assumptions concerning the future. These accounting estimates, judgments and assumptions may differ from actual results. The estimates and underlying assumptions are reviewed on an ongoing basis. Such estimates, judgments and assumptions have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities

Going Concern

Financial statement disclosure

The Financial Statements have been prepared on a going concern basis which contemplates the realisation of assets and the satisfaction of liabilities and commitments in the normal course of business for the foreseeable future. During 2018, the Group met its day to day working capital requirements and funded its capital and operating expenditures through funding received from the proceeds of share issuances and its share of oil sales revenues from the Hawler License Area.

The Group's ability to continue as a going concern in accordance with management's estimates and forecasts is primarily dependent on a) the Group's ability to produce and sell crude oil from the Hawler License Area in accordance with its 2019 work program and budget, and b) positive contributions to net cash flow of at least $25 million through a combination of measures described below. These uncertainties may cast significant doubt about the Group's ability to continue as a going concern.

The Directors expect that cash resources will be sufficient to fund the Group's capital and operating expenditures and to meet forecast obligations as they fall due in the 15 months following December 31, 2018.

In preparing forecasts supporting the going concern assumption, management has applied the following significant judgments and assumptions:

i) Oil production volumes are based on current gross production rates adjusted to account for production increases expected to result from the execution of the Group's 2019 work program.

ii) The timing and extent of forecast capital and operating expenditures is based on the Group's 2019 reforecast budget. The Group retains a high degree of control and flexibility over both the extent and timing of expenditure under its capital investment program.

iii) Positive contributions to net cash flow of at least $25 million through a combination of a) rescheduling of currently estimated future cash outflows, b) receipt of proceeds from the sale of assets held for disposal and, so far as may be necessary, c) additional financing.

iv) The agreement to the amend terms of the contingent consideration will be executed.

Management continually monitors the Group's financing requirements and has plans to secure external funding, if required. Specifically, but not exclusively, management is engaged in discussions with existing principal shareholders regarding a potential financing requirement during the third quarter of 2019. Management further expects that sufficient time is available to clarify precise requirements for additional financing, if any, and to subsequently conclude the arrangements required to fund cash outflows.

Should the Group be unable to meet its obligations as they fall due and to fund its anticipated capital investments and operating expenditures, the preparation of the Financial Statements on a going concern basis may not be appropriate. The Financial Statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. Such adjustments may be material.

The directors have considered the judgments, estimates, and related uncertainties discussed above and have concluded that there is a reasonable expectation that the Group will have adequate resources to continue operations for the foreseeable future and, therefore, continue to adopt the going concern basis in preparing the Financial Statements.

Forward-looking information

The table below outlines the material differences between actual and previously forecasted “net cash receipts from sales of the Group’s share of oil production from the Hawler License Area”:

Forecast period ($ millions)	Net cash receipts from oil sales		
	Forecast	Actual	Variance(1)
October 1, 2016 – March 31, 2018	68	28	$40
January 1, 2017 – June 30, 2018	67	32	$35
April 1, 2017 – September 30, 2018	87	34	$53
July 1, 2017 – December 31, 2018	71	48	$23

Notes:
The difference between forecasted and actual net cash receipts from oil sales is primarily due to lower production volumes than forecast. The interpretation of technical data (including crude oil productivity rates) from appraisal drilling activities caused the Group to defer capital investment, and consequently, the associated forecasted production increases were also deferred. The deferment of capital investment also had a significant impact on expenditure profiles that reduced the requirements for the contribution of cash from the sale of the Group’s share of oil production from the Hawler License Area during the above forecast periods.

Carrying value of intangible exploration and evaluation assets

The carrying amounts for E&E assets represent costs incurred on exploration projects. For the purpose of impairment assessments and testing, E&E assets are aggregated in cash-generating units (“CGU”). Determination of what constitutes a CGU is subject to management judgments and the circumstances. Management has determined that each license area constitutes a CGU. The carrying amounts remain capitalised, provided there are no indications of impairment, until the process to determine whether commercial reserves are established is complete. At that stage the relevant costs are either transferred to PP&E or written-off to the statement of profit and loss as an impairment of oil and gas assets.

Management has exercised significant judgment in determining that for the Hawler – Ain al Safra, and AGC Central CGUs, there are no substantive indicators suggesting that the carrying amounts of exploration and evaluation assets exceed their recoverable amounts. Most significantly, assessments regarding the presence of impairment indicators include complex judgments and estimates relating to i) management’s current and future capital allocation priorities, and ii) the Group’s ability to finance its commitments within the time limitations imposed by the agreements governing the Group’s activities in each of the related license areas / CGUs.

Carrying value of Oil and Gas assets

The carrying amounts for Oil & Gas assets are subject to impairment assessment and testing in accordance with IAS 36.

For the purpose of impairment assessments and testing, Oil & Gas assets are aggregated in CGUs. Determination of what constitutes a CGU is subject to management judgments and the circumstances. For the purposes of impairment assessments and testing of Oil & Gas assets, management has determined that the Oil & Gas assets in the Hawler License Area outside of the Ain al Safra area constitute the group’s single CGU which contains property, plant and equipment.

In conducting impairment assessments and tests, management considers internal and external sources of information regarding the manner in which assets are expected to be used, and indications of economic performance of the assets. Estimates include but are not limited to the determination of expected future cash flows from the asset being tested and the discount rate used to determine the value of the cash flows at the measurement date. Reductions in oil price forecasts, increases in estimated future costs of production, increases in estimated future capital costs, reductions in the amount of recoverable reserves and resources and/or adverse economic conditions can result in estimated carrying amounts exceeding the recoverable amounts of the Group’s Oil & Gas assets. An impairment loss is recognised if and when the carrying amount exceeds the recoverable amount. An impairment reversal is recognised if and when there has been a change in the estimates used to determine the asset’s recoverable amount since the last impairment loss was recognised.

Following the presence of indicators of a possible impairment reversal primarily related to changes in Hawler License Area future cash flow assumptions, management conducted an impairment test on the Hawler License Area CGU at December 31, 2018.

In performing the impairment test as at December 31, 2018, management used significant assumptions and estimates derived from and consistent with those incorporated in the proved and probable reserves development case contained in the independent evaluator’s report referenced in the Group’s Material Change Report dated February 13, 2019, adjusted to reflect management’s current assumptions related to future crude oil sale prices and expenditure estimates.

Expected cash inflows from oil sales are based on quoted Brent Crude forward contract prices for 2019, 2020, and 2021. Management’s Brent Crude assumptions beyond 2021 are benchmarked against the forward contract prices and pricing forecasts prepared by external firms. Expected cash inflows assume that all sales of crude oil from the Hawler License Area are completed through the Kurdistan Region Export Pipeline. In accordance with management's best estimate of the terms most likely to govern future sales of Hawler License Area crude oil, realized prices are referenced to management's estimated future Brent Crude prices discounted by approximately $8/bbl for pipeline system tariffs and fees, and adjusted for differences in forecast API gravity and sulphur from standard Brent specifications

Based on the above, expected cash inflows from oil sales are determined using the following estimated average nominal sales prices:

Year ending December 31,	Brent Crude Price ($/bbl)	Assumed realised Price ($/bbl)
2019	60.98	45.97
2020	60.36	45.07
2021	59.86	44.80
2022	69.30	54.19
2023	70.74	54.85
2024	76.99	60.70
2025	78.86	62.09
2026	80.83	63.65
2027	82.42	65.02
2028	84.06	66.59
2029	85.70	68.18
Thereafter	2% escalation	

Expected cash outflows are based on the capital, operating, and abandonment expenditure profiles incorporated in the independent evaluator's report referenced in the Group's Material Change Report dated February 13, 2019, adjusted to reflect 30% contingencies on all future estimated expenditures.

Management has applied the fair value less costs of disposal methodology to establish the net present value of expected after-tax cash flows associated with proved and probable reserves as at December 31, 2018 using a 15% after-tax discount rate. The 15% discount rate is based on management's estimate of the cost of capital invested in upstream oil & gas assets in the Kurdistan Region of Iraq.

In measuring the recoverable amount of the Hawler License Area CGU as defined in IFRS 13, management has relied on i) observable inputs other than quoted prices for identical assets, and ii) inputs that are not publicly observable and are the result of management's estimates and judgments arising from analysis of internally generated data.

Application of the fair value less costs of disposal methodology using the assumptions described above indicates an estimated recoverable amount of the Hawler License Area CGU as at December 31, 2018 to be $564.8 million. Consequently, the Group has recorded a $54.1 million impairment reversal as at December 31, 2018. The impairment reversal represents the difference between the estimated recoverable amount of the Hawler License Area CGU and its carrying amount prior to the impairment reversal which includes the carrying values of decommissioning obligation and the contingent consideration, for which settlement is included in the discounted expected after-tax cash-flows.

The net present value of expected after-tax cash-flows associated with the proved and probable reserves development case described above has been subjected to sensitivities arising from changes in crude oil price forecasts and discount rates. The following table indicates the estimated recoverable amounts as at December 31, 2018 that result from applying various crude oil price forecasts and discount rates:

	Discount rate		
Estimated recoverable amount ($ millions)	12.5%	15%	17.5%
Above prices less $5/bbl	589.0	510.6	449.9
Prices listed above	644.7	564.8	497.5
Above prices plus $5/bbl	702.3	620.4	551.2

The following table indicates the estimated recoverable amounts as at December 31, 2018, that result from applying various contingencies on future estimated expenditures:

	Contingency on future estimated expenditures			
Estimated recoverable amount ($ millions)	0%	10%	30%	50%
Above prices less $5/bbl	554.9	539.4	510.6	472.5
Prices listed above	607.8	595.3	564.8	537.9
Above prices plus $5/bbl	650.2	645.5	620.4	590.1

The net present value of expected cash-flows associated with the proved and probable reserves development case is also highly sensitive to the Group's independently evaluated estimation of proved and probable reserves and to the production profile associated with the exploitation of these reserves. The estimated recoverable and carrying values of the Group's Hawler License Area CGU are subject to significant adjustment should there be significant changes to estimates of proved and probable reserves and their production profile.

Carrying value of assets held for disposal

The Group's position that all conditions to closing have been either satisfied or waived notwithstanding, the Buyer has declined to close the transaction and has purported to terminate the agreement. Oryx Petroleum has engaged external legal counsel, has initiated arbitration to settle the dispute, believes strongly in the merits of its position, and expects the transaction to close during 2019. Consequently, management estimates that asset's recoverable amount continues to be equivalent to its carrying value. Nevertheless, management has assessed that it is improbable that the arbitration panel will rule against Oryx Petroleum, or that the Group may otherwise be unsuccessful in realizing the contracted amounts. In the event that conditions to closing are determined not to have been met and the Sale Agreement is terminated, Oryx Petroleum may be adjudged to have an obligation to fund their share of Haute Mer B License expenditures incurred by the license operator following the date of the Sale Agreement. As at December 31, 2018, these unrecognised, contingent liabilities amount to approximately $13.4 million including interest charges.

Contingent liabilities

For the specific purpose of estimating the fair value of the contingent liability, management's estimate assumes that the Group will achieve a second declaration of commercial discovery in the Hawler License Area, that the contingent consideration will consequently become payable, and that the timing and amount of resulting cash outflows will be consistent with the terms outlined in 2018 Amendment. The fair value of the contingent liability was established using observable inputs other than quoted prices (IFRS 13 Level 2 hierarchy category) and was determined by calculating the present value of estimated future cash flows using the discount rate adjustment technique. The future cash flows have been estimated based on the terms outlined in the agreement with the counterparty and discounted using an observed market rate for similar obligations. As at December 31, 2018, management has assumed an interest rate of 5% per annum and a 10% discount rate (December 31, 2017 – 5% interest rate, 10% discount rate).

Financial Controls

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("**DC&P**") have been designed under the supervision of the Chief Executive Officer ("**CEO**") and the Head of Corporate Finance and Planning (acting as CFO), with the participation of other management, to provide reasonable assurance that information required to be disclosed is recorded, processed, summarised and reported within the time periods specified in applicable securities legislation, and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and Head of Corporate Finance and Planning (acting as CFO), as appropriate to allow timely decisions regarding required disclosure.

An evaluation of the design and operational effectiveness of Oryx Petroleum's DC&P in place during 2018 was carried out under the supervision of, and with the participation of, management, including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the DC&P were effective as at December 31, 2018.

Internal Controls over Financial Reporting

Internal Controls over Financial Reporting ("**ICFR**") have been designed under the supervision of the CEO and the Head of Corporate Finance and Planning (acting as CFO), with the participation of other management, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Financial Statements in accordance with IFRS. ICFR can only provide reasonable assurance and may not prevent or detect misstatements. Projections of an evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate due to changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

An evaluation of the design and operational effectiveness of Oryx Petroleum's ICFR in place during 2018 was carried out under the supervision of, and with the participation of management, including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the ICFR were effective as at December 31, 2018. There were no changes in Oryx Petroleum's ICFR during the year ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, Oryx Petroleum's ICFR.

Forward-Looking Information

Certain statements in this MD&A constitute "forward-looking information" within the meaning of applicable Canadian securities legislation, including statements related to the nature, timing and effect of Oryx Petroleum's forecast capital expenditure for 2019, budgeted capital expenditures for 2019, financing and capital activities, the additional liquidity required to fund future expenditures, expectations that cash on hand as of December 31, 2018, cash receipts from net revenues and export sales, and cash proceeds available under a credit facility provided by shareholders in late 2018, will allow the Group to fund its forecasted capital expenditures and operating and administrative costs through the end of 2019, expected closing of a transaction to transfer the Corporation's interests in the Haute Mer B License Area and the expected cash consideration to result therefrom, expectations with respect to the spudding and completion of the Banan-6 well, plans to undertake an environmental impact assessment and prepare for drilling in the AGC Central License Area, business and acquisition strategy and goals, opportunities, drilling and well workover plans, development plans and schedules and chance of success, results of exploration activities, declarations of commercial discovery, contingent liabilities and government approvals, the ability to consistently access the export pipeline or other exterior facilities to sell oil production, sales channels for future sales, future drilling of new wells and the reservoirs to be targeted, costs and drilling times for new wells, ultimate recoverability of current and long-term assets, estimates of oil reserves and resources, future royalties and tax levels, access to and sources of future financing and liquidity, future debt levels, availability of committed credit facilities, possible commerciality of our projects, expected operating capacity, expected operating costs, estimates on a per share basis, future foreign currency exchange rates, the issuance of shares as a result of the vesting of LTIP awards and in consideration of interest under the Loan Facility, exercise of outstanding warrants, the issuance of warrants to AOG pursuant to the 2nd Loan Amendment, estimates for the fair value of the contingent consideration arising from the acquisition of OP Hawler Kurdistan Limited in 2011, the expected timing for settlement of liabilities including the Loan Facility and the contingent consideration arising from the acquisition of OP Hawler Kurdistan Limited in 2011, expected execution of an agreement to amend the terms of such contingent consideration with a payment to follow, changes in any of the foregoing, and statements that contain words such as "may", "will", "would", "could", "should", "anticipate", "believe", "intend", "expect", "plan", "estimate", "budget", "outlook", "propose", "potentially", "project", "forecast" or the negative of such expressions and statements relating to matters that are not historical fact. Although Oryx Petroleum believes these statements to be reasonable, the assumptions upon which they are based may prove to be incorrect. In making certain statements in this MD&A, Oryx Petroleum has made assumptions with respect to the following: the general continuance of the current or, where applicable, assumed industry conditions, the continuation of assumed tax, royalties and regulatory regimes, forecasts of capital expenditures and the sources of financing thereof, timing and results of exploration activities, access to local and international markets for future crude oil production and future crude oil prices, Oryx Petroleum's ability to obtain and retain qualified staff, contractors and personnel and equipment in a timely and cost-efficient manner, the political situation and stability in jurisdictions in which Oryx Petroleum has licenses, the ability to renew its licenses on attractive terms, Oryx Petroleum's future production levels, the applicability of technologies for the recovery and production of Oryx Petroleum's oil reserves and resources, the amount, nature, timing and effects of capital expenditures, geological and engineering estimates in respect of Oryx Petroleum's reserves and resources, the geography of the areas in which Oryx Petroleum is conducting exploration and development activities, operating and other costs, the extent of Oryx Petroleum's liabilities, and business strategies and plans of management and Oryx Petroleum's business partners. For more information about these assumptions and risks facing the Group, refer to the Group's Annual Information Form dated March 23, 2018, available at www.sedar.com and the Group's website at www.oryxpetroleum.com.

Any forward-looking information concerning prospective exploration, results of operations, financial position, production, expectations of capital expenditures, cash flows and future cash flows or other information described above that is based upon assumptions about future results, economic conditions and courses of action are presented for the purpose of providing readers with a more complete perspective on Oryx Petroleum's present and planned future operations and such information may not be appropriate for other purposes and actual results may differ materially from those anticipated in such forward-looking information. In addition, included herein is information that may be considered financial outlook and/or future-oriented financial information. Its purpose is to indicate the potential results of Oryx Petroleum's intentions and may not be appropriate for other purposes.

Readers are strongly cautioned that the above list of factors affecting forward-looking information is not exhaustive. Although OPCL believes that the expectations conveyed by the forward-looking information are reasonable based on information available to it on the date such forward-looking information was made, no assurances can be given as to future results, levels of activity and achievements. Readers should not place undue importance or reliance on the forward-looking information and should not rely on the forward-looking information as of any date other than the date hereof. Further, statements including forward-looking information are made as at the date they are given and, except as required by applicable law, Oryx Petroleum does not intend, and does not assume any obligation, to update any forward-looking information, whether as a result of new information or otherwise. If OPCL does update one or more statements containing forward-looking information, it is not obligated to, and no inference should be drawn that it will make additional updates with respect thereto or with respect to other forward-looking information. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

Reserves and Resources Advisory

Oryx Petroleum's reserves and resource estimates have been prepared and evaluated in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Proved oil reserves are those reserves which are most certain to be recovered. There is at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved oil reserves. Probable oil reserves are those additional reserves that are less certain to be recovered than proved oil reserves. There is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable oil reserves.

Contingent oil resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. Contingent oil resources entail additional commercial risk than reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent oil resources. Moreover, the volumes of contingent oil resources reported herein are sensitive to economic assumptions, including capital and operating costs and commodity pricing.

Prospective oil resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective oil resources have both a chance of discovery and a chance of development. Prospective oil resources entail more commercial and exploration risks than those relating to oil reserves and contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

Glossary and Abbreviations

The following abbreviations and definitions are used in this MD&A:

AGC
Agence de Gestion et de Cooporation, an inter-governmental agency established in 1993 to manage and administer petroleum and fishing activities in the maritime zone between Senegal and Guinea Bissau

AOG
The Addax and Oryx Group PLC

bbl
Barrel(s) of oil

bbl/d
Barrel(s) of oil per day

Carried Cost
Costs related to the Group's funding another party's share of costs, by agreement, in excess of the Group's Participating Interest. Carried Costs are typically recovered through Cost Oil

Common Shares
Common shares of the Company

Company
Oryx Petroleum Corporation Limited

Contractor
An oil company operating in a country under a PSC on behalf of the host government, for which it receives either a share of production or a fee

Cost Oil
The portion of oil sold used to reimburse the Contractor for exploration, development, and operating costs

Cost Pool
Costs incurred to explore and/or develop a License Area to be recovered as Cost Oil through future oil sales

Farm-in
To acquire an interest in a license from another party

G&A
General and administration

Gross
In respect of reserves, resources, future net revenue, production, sales, area, capital expenditures or operating expenses, the total reserves, resources, future net revenue, production, sales, area, capital expenditures or operating expenses, as applicable, attributable to either (i) 100% of the License Area or field; or (ii) the Group's working interest in the License Area or field, as indicated, prior to the deductions specified in the applicable PSC, REC or fiscal regime for each License Area.

IAS
International Accounting Standards

IFRS
International Financial Reporting Standards

KRG
Kurdistan Regional Government of Iraq

License Area
Area of specified size, which is licensed to a company by a government for the production of oil and gas

Loan Facility
A committed and unsecured term loan facility agreement that the Group entered into with a subsidiary of its indirect controlling shareholder AOG. Refer to Liquidity and Capital Resources section

Operator
A company that organises the exploration and productions programs in a License Area on behalf of all the interest holdings in the license

Participating Interest
The Group's current interest in an applicable License Area

PP&E
Property, plant and equipment

Profit Oil
Production remaining after contractual Royalties and Cost Oil, which is split between the government and the Contractors according to the prevailing contract terms in the PSC

Production Sharing Agreement (PSA) / Production Sharing Contract (PSC)
A contractual agreement between a Contractor and a host government, whereby the Contractor bears certain defined exploration costs, risks, and development and production costs in return for a stipulated share of the production resulting from this effort

Reserves
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable

Royalty
All remittances to governments who are party to the applicable PSCs/PSAs that are directly attributable to the sale of oil and natural gas products during the reporting period including the government share of Profit Oil described above, except for income taxes

Working Interest or WI
The Group's interest in an applicable License Area, assuming the exercise of back-in rights or options