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

FOR THE THREE AND SIX MONTHS ENDED

JUNE 30, 2018 and 2017

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

ORYX PETROLEUM

*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 three and six months ended June 30, 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 August 8, 2018.

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 25. Additional information relating to OPCL, including OPCL's Annual Information Form dated March 23, 2018, is on SEDAR at www.sedar.com.

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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 A(2)	Congo (Brazzaville)	20%	20%	Non-operator
Haute Mer B(3)	Congo (Brazzaville)	30%	30%	Non-operator

Notes:

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

(2) During 2017, the Group determined to cease further investments in the Haute Mer A License Area.

(3) 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. The transaction is expected to close during the third quarter of 2018.

Operational Highlights

- Average gross (100%) oil production of 6,100 bbl/d in July 2018 and 4,400 bbl/d (working interest 2,900 bbl/d) for the three months ended June 30, 2018 vs 2,900 bbl/d (working interest 1,900 bbl/d) for the second quarter of 2017;
  - 52% increase in versus the second quarter of 2017 and 16% increase versus the three months ended March 31, 2018,
- 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;
  - Average gross (100%) oil production of approximately 1,600 bbl/d for the month of July 2018,
  - Gravity of stock tank oil has been measured at 26 degrees API with sulphur measured at 4%,
  - The well demonstrates the productivity of the Tertiary reservoir at the Banan West field and management expects that oil reserves will be booked in this reservoir for the first time in 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;
  - Average gross (100%) oil production of approximately 800 bbl/d for the month of July 2018 and 1,700 bbl/d over the past 10 days,
  - Gravity of stock tank oil has been measured at 35 degrees API,
  - Horizontal well design enabled an isolation of the producing interval from overlying gas and underlying water in the reservoir.
- Completion of the Banan-2 well in the Cretaceous reservoir was successfully completed and the well was placed on extended test in late July 2018;
  - Average gross (100%) oil production of approximately 1,100 bbl/d over the last 5 days with rate increases expected in the coming days,
  - Gravity of stock tank oil has been measured at 21 degrees API.
- Four additional new wells and one workover are planned for the remainder of 2018 targeting the Cretaceous reservoir at the Zey Gawra field, the Tertiary reservoir at the Banan field, and the Cretaceous reservoir at the Demir Dagh field, subject to performance of existing wells and funding availability;
  - Infrastructure work needed to enable drilling of additional wells at the Banan and Zey Gawra fields has commenced.
- Further interpretation of 3D seismic data covering the AGC Central License Area and prospect ranking is ongoing with preparation for drilling to follow.
- Sale of the Group's 30% interest in the Haute Mer B License Area offshore Congo (Brazzaville) ("Haute Mer B") to a subsidiary of Total S.A., concluded in April 2018, is expected to close during the third quarter of 2018;
  - Upon closing, Oryx Petroleum expects to receive cash consideration of $8.0 million plus $5.3 million reimbursement of costs incurred by Oryx Petroleum between January 1, 2018 and the date of the agreement.

Financial Highlights and Outlook

Liquidity outlook

- The AOG Credit Facility, which matures in July 2019, is expected to be restructured / rescheduled such that no cash outflow arises before 2020.
- The expanded discretionary drilling program planned for the second half of 2018 is conditional upon availability of sufficient funding. If existing and internally generated funds are insufficient, the Group's major shareholders have indicated that additional debt or equity capital could be made available in the range of $10-$15 million in order to commit to the drilling program as envisaged.
- The Group expects cash on hand as of June 30, 2018, cash receipts from export sales exclusively through the Kurdistan Region-Turkey Export Pipeline, expected net proceeds from the sale of its interest in the Haute Mer B License Area, and, if needed, additional debt or equity capital of $10 - $15 million will allow it to fund its forecasted cash expenditures and to meet its obligations through the end of 2019, with the exception of the repayment of the AOG Credit Facility, which is expected to be restructured. Further capital is likely required in late 2019 and beyond to fund expected drilling in the AGC Central License Area.

Financial performance

The following table contains financial performance highlights for the three and six months ended June 30, 2018 and June 30, 2017.

	Three months ended		Six months ended	
($ thousands unless otherwise stated)	June 30, 2018	June 30, 2017	June 30, 2018	June 30, 2017
Revenue	17,901	7,112	31,831	15,016
Cash (used in) / generated by operating activities	(1,590)	(1,161)	(4,172)	1,030
Operating Funds Flow[(1)]	4,088	(2,101)	6,117	(4,451)
Operating Funds Flow[(1)] per basic and diluted share ($/share)	0.01	(0.01)	0.01	(0.02)
Loss for the period	(3,522)	(9,199)	(7,796)	(5,062)
Loss per basic and diluted share ($/share)	(0.01)	(0.03)	(0.02)	(0.02)
Average sales price ($/bbl)	61.51	37.93	59.12	39.94
Field production costs[(2)] ($/bbl)	10.60	18.25	10.66	18.71
Operating expense ($/bbl)	13.86	23.89	13.94	24.46
Field Netback[(1)] ($/bbl)	19.45	0.27	18.22	0.80
Oryx Petroleum Netback[(1)] ($/bbl)	23.00	(1.15)	21.49	(0.53)
Capital additions	8,774	814[(4)]	14,937	(5,097)[(3)(4)]

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 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.
(4) Includes a $2.8 million non-cash credit relating to revision to assumptions used to calculate decommissioning obligations.

Revenue and cash receipts

Revenue of $17.9 million was recorded for the three months ended June 30, 2018. Included in revenue is $16.1 million ($61.51/bbl) realised on the sale of 262,000 bbl (WI) of crude oil and $1.8 million related to the recovery of costs carried on behalf of partners. Revenue for the second quarter of 2018 increased by $10.8 million compared to the same period in 2017. The increase is attributable to a 62% increase in realised sales price combined with a 55% increase in sales volumes.

Revenue of $31.8 million was recorded for the six months ended June 30, 2018. Included in revenue is $28.7 million ($59.12/bbl) realised on the sale of 484,700 bbl (WI) of crude oil and $3.2 million related to the recovery of costs carried on behalf of partners. Revenue for the six months ended June 30, 2018 increased by $16.8 million compared to the same period in 2017. The increase is attributable to a 48% increase in realised sales price combined with a 43% increase in sales volumes.

All sales during the six months ended June 30, 2018 were made via the KRG's international export pipeline.

The Group has received payment in full for all crude oil delivered and sold through the KRG's international export pipeline up to and including April 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 May - July 2018 totals $13.7 million.

Field production costs and netbacks

During the three months ended June, 2018, on a per barrel basis, the Group achieved its lowest quarterly Field production costs per barrel and highest absolute and per barrel Field and Oryx Petroleum Netbacks since inception.

Field production costs during the second quarter of 2018 amounted to $2.8 million ($10.60/bbl) in comparison to $3.1 million ($18.25/bbl) during the second quarter of 2017 representing a 42% decrease on a per barrel basis. The per barrel decrease was primarily due to increases in production and sales volumes.

Field Netback of $19.45/bbl for the three months ended June 30, 2018 has improved from $0.27/bbl for the second quarter of 2017 and $16.76/bbl for the first quarter of 2018. Field Netback per barrel increased by 16% in comparison to the first quarter of 2018. The primary drivers for improved Field Netbacks have been higher oil prices combined with higher sales volumes.

Operating Funds Flow

Operating Funds Flow for the second quarter of 2018 was $4.1 million compared to negative $2.1 million for the three months ended June 30, 2017. The Group's highest ever quarterly Operating Funds Flow is primarily due to higher Oryx Petroleum Netbacks which have contributed cash in excess of cash general and administrative expenditures.

For the six months ended June 30, 2018, Operating Funds Flow was $6.1 million compared to negative $4.5 million during the same period in 2017. The significant improvement in Operating Funds Flow is primarily due to higher Oryx Petroleum Netbacks which have contributed cash in excess of cash general and administrative expenditures.

Cash used in operating activities during the quarter ended June 30, 2018 amounted to $1.6 million reflecting a $5.7 million increase in non-cash working capital which was primarily related to a decrease in trade and other receivables offset by Operating Funds Flow of $4.1 million.

Loss

Loss for the three months ended June 30, 2018 was $3.5 million compared to a $9.2 million loss during the second quarter of 2017. The reduction in loss for the three months ended June 30, 2018 in comparison to the same period in 2017 is primarily attributable to i) an increase in net revenue of 6.0 million, ii) a $1.4 million decrease in finance expense and iii) a $0.4 million decrease in operating expense. These positive factors were partially offset by a $1.5 million increase in the depletion charge during the second quarter of 2018 and a $0.9 million provision against trade and other receivables recorded during the three months ended June 30, 2018.

Loss for the six months ended June 30, 2018 was $7.8 million compared to a $5.1 million loss during the same period in 2017. The change in loss for the six months ended June 30, 2018 in comparison to the same period in 2017 is primarily attributable to i) a $7.6 million gain on settlement of the finance lease obligation related to Hawler production facilities in 2017, ii) a $1.8 million gain related to the change in fair value of contingent consideration during the first half of 2017 versus a $1.4 million charge in the six months ended June 30, 2018, iii) a $1.1 million impairment reversal recorded in the six months ended June 30, 2017, iv) a $2.6 million increase in the depletion charge during 2018 and v) a $0.9 million provision on trade and other receivables recorded during the three months ended June 30, 2018. These negative factors were largely offset by i) an increase in net revenue of $9.4 million and ii) a $1.5 million decrease in operating expense.

Capital additions

During the second quarter of 2018, the Group recorded capital additions of $8.8 million. The Group invested $8.2 million primarily on facilities and drilling activities in the Zey Gawra and Banan fields in the Hawler License Area, and $0.6 million to interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area.

During six months ended June 30, 2018, the Group recorded net capital additions of $14.9 million. The Group invested $13.9 million primarily on facilities and drilling activities in the Zey Gawra and Banan fields in the Hawler License Area, and $1.1 million to 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)	June 30, 2018	December 31, 2017
Total cash and cash equivalents	21,326	38,572
Working Capital	17,161	27,133
Total assets	744,357	744,798
Borrowings	80,238	75,854
Total long-term liabilities	155,455	147,837

The cash and cash equivalents balance of $38.6 million as at December 31, 2017 decreased to $21.3 million at June 30, 2018. This decrease is due to $12.3 million used in investing activities combined with $4.2 million in cash used in operating activities.

Working capital decreased to $17.2 million at June 30, 2018 from $27.1 million at December 31, 2017. The decrease was due to a $17.2 million decrease in cash and cash equivalents and a $2.0 million decrease in inventories, partially offset by a $5.3 million increase in assets held for disposal, a $2.9 million increase in the trade and other receivables balance, a $0.6 million increase in other current assets, and a $0.5 million decrease in trade and other payables.

The undiscounted balance owed under the Loan Facility as at June 30, 2018 was $81.1 million, including $4.0 million in accrued interest which has since been settled through the issuance of Common Shares on July 3, 2018 and $1.1 million in accrued interest which is expected to be settled through the issuance of Common Shares in November 2018.

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 June 30, 2018 was $80.8 million.

2018 re-forecast work program and capital expenditures

The Group's planned capital expenditures for the second half of 2018 are $36 million as summarised as follows:

Location	License/Field/Activity	2H 2018 Forecast
		$ millions
Kurdistan Region	Hawler	
	Zey Gawra-Drilling	8
	Demir Dagh-Drilling	4
	Demir Dagh-Facilities	2
	Banan-Drilling	8
	Banan-Facilities	2
	Other(1)	3
	Total Hawler	**27**
West Africa	AGC Central--Drilling Prep	2
	AGC Central--Other	7
	Capex Total(2)	**36**

Note:

(1) Other is comprised primarily of license maintenance costs

(2) Totals may not add-up due to rounding.

Kurdistan Region of Iraq -- Hawler License Area

Demir Dagh drilling – consists of costs related to the workover of the Demir Dagh-8 well and, subject to the results of the Demir Dagh-8 workover, a short radius sidetrack of the previously drilled Demir Dagh-5 well.

Zey Gawra drilling – consists of the drilling of one new well targeting the Zey Gawra Cretaceous reservoir. This well was not previously planned.

Banan drilling – consists of i) the re-entry, completion and testing of the Banan-2 well targeting the Cretaceous reservoir, which had been suspended since 2014 due to security developments, and ii) the drilling of two new wells targeting the Tertiary reservoir subject to the ongoing performance of the first well targeting the Tertiary reservoir successfully drilled and completed in June 2018.

Demir Dagh facilities – comprised of modifications to the Hawler truck loading station needed to accommodate increased production, and minor infrastructure works.

Banan facilities – comprised of the construction of a truck loading station, a new drilling pad, and flowlines at the Banan field.

AGC Central License Area

Consists of preparation for drilling, facilities, studies, and a final payment for the acquisition of 3D seismic data contingent upon entering the first renewal of the exploration period under the applicable production sharing contract which is expected in September 2018.

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. Resolution of the resulting political tensions and disputes is uncertain. 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 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.

During 2014, militants engaged in armed conflict with government forces in various regions of Iraq. The Group implemented precautionary measures to protect employees and operations from the impacts of the conflict. Together with the successes of government forces, these precautionary measures have permitted the Group to continue appraisal and development activities.

On March 14, 2016, the Group initiated crude oil deliveries to international markets through the KRG's international 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. The political tensions which have followed the KRG independence referendum contribute to an increase in the risk that the KRG's arrangements currently in place to sell oil produced from the Hawler License Area may not continue to be in effect.

The market on which oil produced from the Hawler Licence 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.

Appraisal activities at the Banan and Ain Al Safra discoveries had been suspended due primarily to security risks. During 2018 KRG security restrictions have been eased in the area of the Banan field such that the Group has been able to resume activity there. However, 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 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 Group'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 June 30, 2018, March 31, 2018, and June 30, 2017 and for the six months ended June 30, 2018 and June 30, 2017:

	Three months ended			Six months ended	
	June 30, 2018	March 31, 2018	June 30, 2017	June 30, 2018	June 30, 2017
Gross Production (bbl)	402,600	341,700	260,200	744,400	523,500
Gross Production per day (bbl/d)	4,400	3,800	2,900	4,100	2,900
WI Production (bbl)	261,700	222,100	169,100	483,800	340,300
WI Production per day (bbl/d)	2,900	2,500	1,900	2,700	1,900
WI sales (bbl)	262,000	222,700	168,800	484,700	338,500
WI sales per day (bbl/d)	2,900	2,500	1,900	2,700	1,900

Production and sales

Gross (100%) oil production for the three months ended June 30, 2018 was 402,600 bbl representing an average rate of 4,400 bbl/d. The Group's Working Interest share of oil production during this period was 261,700 bbl representing an average rate of 2,900 bbl/d.

The increase in production and sales volumes during the second quarter of 2018 is primarily attributable to the contribution from the Banan-3 well, which was drilled during the second quarter and began contributing approximately 1,500 bbl/d during June 2018.

Gross (100%) oil production for the six months ended June 30, 2018 was 744,400 bbl representing an average rate of 4,100 bbl/d. The Group's Working Interest share of oil production during this period was 483,800 bbl representing an average rate of 2,700 bbl/d.

The Group recognised revenue on the sale of 262,000 bbl (Working Interest) and 484,700 bbl (Working Interest) of crude oil during the three and six months ended June 30, 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 KRG's international export pipeline. The realised sales prices on export sales through this pipeline made subsequent to 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				2016	
	June 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31	Dec 31	Sept 30
Brent average price ($/bbl)	74.39	66.82	61.26	51.72	50.28	54.13	49.96	45.85
Realised sales price ($/bbl)	61.51	56.31	50.04	41.07	37.93	41.92	38.75	35.19

Netbacks

The following table summarises the Field Netback and Oryx Petroleum Netback for the three months ended June 30, 2018 and June 30, 2017:

	Three months ended June 30, 2018		Three months ended June 30, 2017	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	16,116	61.51	6,403	37.93
Royalties	(7,877)	(30.06)	(3,130)	(18.55)
Field production costs[1]	(2,777)	(10.60)	(3,083)	(18.25)
Current taxes	(366)	(1.40)	(146)	(0.86)
Field Netback[2]	**5,096**	**19.45**	**44**	**0.27**
Recovery of Carried Costs	1,785	6.81	709	4.20
Partner share of production costs	(855)	(3.26)	(949)	(5.62)
Oryx Petroleum Netback[2]	**6,026**	**23.00**	**(196)**	**(1.15)**

Notes:

(1) Field production costs represent 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 June 30, 2018 of $5.1 million incorporates field production costs of $2.8 million. On a per barrel basis, Field Netback has increased to $19.45/bbl for the three months ended June 30, 2018 from $0.27/bbl for the three months ended June 30, 2017. This variance is primarily 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 six months ended June 30, 2018 and June 30, 2017:

	Six months ended June 30, 2018		Six months ended June 30, 2017	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	28,657	59.12	13,519	39.94
Royalties	(14,007)	(28.90)	(6,608)	(19.52)
Field production costs[1]	(5,169)	(10.66)	(6,332)	(18.71)
Current taxes	(650)	(1.34)	(307)	(0.91)
Field Netback[2]	**8,831**	**18.22**	**272**	**0.80**
Recovery of Carried Costs	3,174	6.55	1,497	4.42
Partner share of production costs	(1,591)	(3.28)	(1,950)	(5.76)
Oryx Petroleum Netback[2]	**10,414**	**21.49**	**(181)**	**(0.53)**

Notes:

(1) Field production costs represent 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 six months ended June 30, 2017 of $8.8 million incorporates field production costs of $5.2 million. On a per barrel basis, Field Netback has improved to $18.22/bbl for the six months ended June 30, 2018 from a Field Netback of $0.80/bbl for the six months ended June 30, 2017. This variance is primarily attributable to an increase in the realised sales prices and to a decrease in per barrel field production costs.

Hawler license 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 six months ended June 30, 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.

- Average gross (100%) oil production of approximately 800 bbl/d for month of July 2018 and 1,700 bbl/d over the past 10 days,
- Gravity of stock tank oil has been measured at 35 degrees API,
- Horizontal well design enabled an isolation of the producing interval from overlying gas and underlying water in the reservoir.

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 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.

- Average gross (100%) oil production of approximately 1,600 bbl/d for month of July 2018,
- Gravity of stock tank oil has been measured at 26 degrees API with sulphur measured at 4%.

Completion of the Banan-2 well in the Cretaceous reservoir successfully completed and the well was placed on extended test in late July 2018;

- Average gross (100%) production of approximately 1,000 bbl/d over the last 5 days with significant rate increases expected in the coming days,
- Gravity of stock tank oil has been measured at 21 degrees API.

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. Finalisation of prospect identification and mapping is in progress with preparations for drilling to follow.

Other than the above, activities in West Africa during the six months ended June 30, 2018 were limited to license maintenance and data analysis, and preparation for future drilling activity in the AGC Central License Area.

Divestment of Interest in the Haute Mer B License Area

On April 23, 2018, the Group entered into an agreement providing for the sale of the Group's 30% participating interest in the Haute Mer B License Area to a subsidiary of Total S.A. (the "**Buyer**") (the "**Sale Agreement**"). Upon closing, the Group's interest in the Haute Mer B License Area will be transferred for cash consideration of $8 million, payable at closing. The sale will be deemed to be made with effect from January 1, 2018. As a result, the Buyer has agreed to reimburse the Group for costs incurred by it in relation to the Haute Mer B License Area between January 1, 2018 and the date of the Sale Agreement and to carry the Group'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 Group, at closing, of $5.3 million. Subject to completion of customary due diligence and closing conditions, the transaction is expected to close during the third quarter of 2018. The license interest is presented as an asset held for disposal as at June 30, 2018.

Capital Additions

The following table summarises the capital additions incurred by activity during the three and six months ended June 30, 2018 and June 30, 2017:

($ thousands)	Three months ended		Six months ended	
	June 30, 2018	June 30, 2017	June 30, 2018	June 30, 2017
Middle East				
Drilling	7,497	188	12,785	(1,886)
Facilities	537	243	850	(389)
Studies, license, and support	142	(21)	223	(3,127)
Sub-Total Middle East	**8,176**	**410**[(1)]	**13,858**	**(5,402)**[(1)]
West Africa				
Exploration drilling	42	27	81	(1,879)
Facilities	30	-	56	-
Seismic	321	103	539	1,018
Studies, license, and support	205	269	403	1,161
Sub-Total West Africa	**598**	**399**	**1,079**	**300**[(2)]
Corporate	**-**	**5**	**-**	**5**
Total capital additions	**8,774**	**814**	**14,937**	**(5,097)**

Notes:

(1) Included in capital additions for the Middle East for the six months ended June 30, 2017 are non-cash credits of $7.3 million related to revisions to estimates of costs incurred in prior periods. Included in capital additions for the three and six months ended June 30, 2017 are non-cash credits of $2.8 million and $2.4 million, respectively, primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.

(2) West African capital additions for the six months ended June 30, 2017 includes a non-cash credit of $1.9 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 six months ended June 30, 2018 compared to the same periods in 2017:

($ thousands)	Three months ended		Six months ended	
	June 30, 2018	June 30, 2017	June 30, 2018	June 30, 2017
Middle East				
Hawler	8,176	410	13,858	(5,042)
Sub-Total Middle East	**8,176**	**410**[(1)]	**13,858**	**(5,042)**[(1)]
West Africa				
AGC Shallow	-	63	-	155
AGC Central	598	336	1,079	1,276
OML 141	-	-	-	(1,233)
Haute Mer B	-	-	-	101
Sub-Total West Africa	**598**	**399**	**1,079**	**300**[(2)]
Corporate	**-**	**5**	**-**	**5**
Total capital additions	**8,774**	**814**	**14,937**	**(5,097)**

Notes:

(1) Included in capital additions for the Middle East for the six months ended June 30, 2017 are non-cash credits of $7.3 million related to revisions to estimates of costs incurred in prior periods. Included in capital additions for the three and six months ended June 30, 2017 are non-cash credits of $2.8 million and $2.4 million, respectively, primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.

(2) West African capital additions for the six months ended June 30, 2017 includes a non-cash credit of $1.9 million due to revisions to estimates of costs incurred in prior periods and a non-cash addition of $0.7 million.

Middle East

During the three months ended June 30, 2018, the Group invested $8.2 million in the Hawler License Area. The Group invested $7.5 million related to appraisal drilling activities primarily on the Banan and Zey Gawra fields, $0.5 million on facilities associated with the drilling program, and $0.2 million on technical support.

The Group recorded capital additions of $13.9 million during the six months ended June 30, 2018. These additions are primarily composed of $12.8 million in appraisal drilling expenditure on the Banan and Zey Gawra fields. Facilities expenditure of $0.9 million and technical support costs of $0.2 million were also incurred during the period.

West Africa

Capital additions of $0.6 million and $1.1 million for three and six months ended June 30, 2018, respectively, were comprised of seismic interpretation and directly attributable technical support costs 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 June 30, 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	803.8	506.8	179.1[(3)]	(57.6)	628.3
AGC Central	Senegal and Guinea Bissau	45.1	38.3	6.8	-	45.1
Haute Mer A[(4)]	Congo (Brazzaville)	246.3	-	-	-	-
Haute Mer B[(5)]	Congo (Brazzaville)	22.8	-	-	-	-
		1,118.0	**545.1**	**185.9**	**(57.6)**	**673.4**

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 $107.7 million in expenditures related to a commitment to carry $300 million on behalf of a partner for the Hawler License Area development.*

(4) *During 2017, the Group determined to cease further investments in the Haute Mer A License Area. It is anticipated that the Group's interest in the Haute Mer A License Area will be assigned to the other partners in the License Area. Consequently, the Group has assumed its share of recoverable costs to be Nil.*

(5) *On April 23, 2018, the Group 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. The transaction is expected to close during the third quarter of 2018. Consequently, the Group has assumed its share of recoverable costs to be Nil.*

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 and June 30, 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**

($ 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**

Financial Results

Revenue

The following table summarises Oryx Petroleum's revenue for the three and six months ended June 30, 2018 and 2017. All oil sold during each of the below periods was produced at the Hawler License Area.

	Three months ended June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Oil Sales	16,116	6,403	28,657	13,519
Recovery of Carried Costs	1,785	709	3,174	1,497
Revenue	**17,901**	**7,112**	**31,831**	**15,016**

The Group recognised revenue on the sale of 262,000 bbl (Working Interest) of oil during the three months ended June 30, 2018, compared to revenue on the sale of 168,800 bbl (Working Interest) of oil during the same period in the previous year. Revenue of $17.9 million during the second quarter of 2018 increased by $10.8 million compared to the three months ended June 30, 2017. The increase in oil sales is attributable to a 62% increase in realised sales price and a 55% increase in sales volumes.

The Group recognised revenue on the sale of 484,700 bbl (Working Interest) of oil during the six months ended June 30, 2018, compared to revenue on the sale of 338,500 bbl (Working Interest) of oil during the same period in the previous year. Revenue of $31.8 million during the six months ended June 30, 2018 increased by $16.8 million compared to the six months ended June 30, 2017. The increase in oil sales is attributable to a 48% increase in realised sales volumes combined with a 43% 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 June 30, 2018, the Group's Working Interest share of oil inventory amounted to 11,200 bbl.

The Group has received payment in full for all crude oil delivered and sold through the KRG's international export pipeline up to and including April 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 May - July 2018 totals $13.7 million.

Royalties

The following table summarises royalty expense during the three and six months ended June 30, 2018 and June 30, 2017:

	Three months ended June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Royalties	**7,877**	**3,130**	**14,007**	**6,608**

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 $4.7 million during the three months ended June 30, 2018, and increased by $7.4 million during the six months ended June 30, 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 June 30		Six months ended June 30	
	2018	2017	2018	2017
Field production costs[1]	2,777	3,083	5,169	6,332
Partner's share of production costs carried by Oryx Petroleum	855	949	1,591	1,949
Operating expense	**3,632**	**4,032**	**6,760**	**8,281**
Sales[2] (bbl)	262,000	168,800	484,700	338,500
Field production costs[1] ($/bbl)	**10.60**	**18.25**	**10.66**	**18.71**
Operating expense ($/bbl)	**13.86**	**23.89**	**13.94**	**24.46**

Notes:

(1) Field production costs represent 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 $3.6 million in the three months ended June 30, 2018 decreased by $0.4 million compared to the same period in the previous year. The decrease in operating expense is primarily attributable to lower security costs resulting from the implementation of a cost reduction program, together with reduced technical support costs. In addition to the impact of gross reductions in costs, operating costs per barrel decreased further during the three months ended June 30, 2018 compared to the three months ended June 30, 2017, due to a 55% increase in sales volumes.

The variance between operating expenses for the six month period ended June 30, 2018 and compared with the same period in 2017 is due to the same factors as those applicable to the three month period as discussed above.

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

($ thousands)	($000)	($/bbl)
Operating expense – three months ended March 31, 2018	**3,128**	**14.04**
Contribution of the following to variance:		
Personnel and camp costs	142	0.54
Well maintenance	12	0.05
Facilities lease and maintenance, diesel and operation	316	1.21
Security	34	0.13
Increase in production	-	(2.11)
Operating expense – three months ended June 30, 2018	**3,632**	**13.86**

General and administration

($ thousands)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Total General and Administration	**2,358**	**2,512**	**5,070**	**5,096**

General and administration expenses of $2.4 million and $5.1 million, incurred during the three and six months ended June 30, 2018, respectively, are consistent with expenses incurred during the comparable periods during 2017.

Exploration expense

($ thousands)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Total exploration expense	**-**	**273**	**(61)**	**400**

Exploration costs relate to expenses incurred on the OML 141, Haute Mer A and Haute Mer B License Areas subsequent to the impairment of these License Areas during 2016 and 2017. A credit of $0.1 million in the six months ended June 30, 2018 related to revisions to estimates of costs incurred in prior periods.

Impairment of oil and gas assets

($ thousands)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Impairment reversal	-	-	-	(1,132)
Total impairment reversal	**-**	**-**	**-**	**(1,132)**

During 2015, the Group fully impaired capitalised expenditures relating to its interest in the OML 141 License Area. An impairment reversal of $1.1 million was recorded during the first quarter of 2017 based on revised estimates of previously impaired costs.

Depletion, depreciation and amortisation

The following table summarises the component parts of depletion, depreciation and amortisation for the three and six months ended June 30, 2018 and 2017:

($ thousands)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Intangible assets: Amortisation	23	19	26	58
PP&E assets: Depreciation	-	(4)	-	4
Depletion	2,622	1,101	4,852	2,209
Total DD&A	**2,645**	**1,116**	**4,878**	**2,271**

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.

Primarily as a result of reductions to estimated proved plus probable oil reserves from the Hawler License Area, recorded at December 31, 2017, the per barrel charge for depletion has increased during the three and six months ended June 30, 2018.

Other expense / income

The following table summarises the components of other expense / income for the three and six months ended June 30, 2018 compared to the same periods in 2017:

($ thousands)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Impairment of trade and other receivables	880	-	880	-
Settlement of finance lease liability	-	-	-	(7,605)
Increase / (Reduction) to impairment of materials inventory	(204)	163	(286)	163
Restructuring charge	-	(63)	-	(63)
Other	(21)	(80)	(38)	(124)
Other expense / (income)	**655**	**20**	**556**	**(7,629)**

Other income for the three months ended June 30, 2018 relates primarily to a $0.9 million impairment provision on trade and other receivables and a $0.2 million reduction in inventory impairment provision.

Other income for the six months ended June 30, 2018 relates primarily to a $0.9 million impairment provision on trade and other receivables and a $0.3 million reduction in inventory impairment provision.

The $7.6 million other income for the six months ended June 30, 2017 is primarily a $7.6 million gain related to the early settlement of the finance lease obligation related to Hawler production facilities.

Finance expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Interest expense on Loan Facility	1,991	2,429	3,959	4,770
Accretion of deferred financing costs on Loan Facility	230	1,161	425	1,707
Change in fair value of contingent consideration	712	1,278	1,398	(1,761)
Interest on contingent consideration	887	352	1,765	745
Accretion of decommissioning liability	99	77	195	151
Interest expense on finance lease obligation	-	-	-	443
Finance expense	**3,919**	**5,297**	**7,742**	**6,055**

Finance expense for the three and six months ended June 30, 2018 primarily relates to accrued interest and accretion of deferred financing costs associated with the Loan Facility and to accrued interest associated with the contingent consideration.

Finance expense for the three and six months ended June 30, 2018 also includes a $0.7 million and a $1.4 million charge, respectively, relating to the increase in the fair value of previously recognised contingent consideration compared to a $1.2 million charge recorded during the three months ended June 30, 2017 and a $1.8 million gain recorded during the six months ended June 30, 2017.

The contingent consideration referenced above relates to a 2011 agreement for acquisition of OP Hawler Kurdistan Limited, which holds the Group's interest in the Hawler License Area. Under this agreement, Oryx Petroleum was scheduled to provide additional consideration upon declaration of each of the first two commercial discoveries.

During the second quarter of 2017, the Group reached an agreement with the vendor of OP Hawler Kurdistan Limited to restructure the contingent consideration related to a potential second declaration of commercial discovery. The Group has recorded the contingent liability at management's estimate of fair value which, as at June 30, 2018, amounted to $64.8 million. 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 contained in the agreement with the vendor.

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.

Income tax expense

The following table summarises the component parts of income tax expense for the three and six months ended June 30, 2018 and June 30, 2017.

	Three months ended June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Current income tax expense	355	197	740	462
Deferred tax (benefit) / expense	4	(76)	5	(142)
Total income tax expense	**359**	**121**	**745**	**320**

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 the six months ended June 30, 2018, the Group met its day-to-day working capital requirements primarily through funding received through the cash receipts from oil sales and the previous issuance of Common Shares.

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 March 18, 2016, the Group extinguished $8.2 million of the principal and accrued interest under the Loan Facility, in consideration for 20,581,247 Common Shares.

On October 24, 2016, OPCL issued 23,032,871 Common Shares to the Lender as consideration to extinguish a further $9.1 million of principal and accrued interest under the Loan Facility.

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, which includes interest accrued up to that date (the "**Loan Amoun**t"), are payable at the Maturity Date or earlier, at the option of the borrower. Interest accrued on the Loan Amount after May 11, 2017 is to be determined on each of November 11, 2017, May 11, 2018, November 11, 2018, and July 1, 2019 (each, an "**Interest Calculation Date**") and paid to the Lender by way of issuance of Common Shares with the number of Common Shares issuable to be determined using the issue price per share equal to the volume weighted average trading price for the five trading days immediately preceding the Interest Calculation Date. The Loan Amendment was accepted by the Toronto Stock Exchange and on June 7, 2017 was approved by disinterested shareholders.

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.

As at June 30, 2018, the carrying value of the balance owed under the Loan Facility was $80.2 million, including $5.1 million in accrued interest. The total undiscounted principal plus accrued interest owed at June 30, 2018 was $81.1 million.

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.

Contingent consideration

During the second quarter of 2017, the Group reached an agreement with the vendor of OP Hawler Kurdistan Limited to restructure contingent consideration related to a potential second declaration of commercial discovery.

Under the terms of the agreement, the Group paid $5.0 million plus accrued interest on August 1, 2017. Contingent upon declaration of a second commercial discovery in the Hawler License Area, the agreement provides for fixed payments of principal plus interest scheduled as follows: $10.0 million plus accrued interest in September 2018, $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 June 30, 2018 was $67.9 million. The total undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation was $73.9 million as at June 30, 2018. The contingent principal payments bear interest and during the three and six months ended June 30, 2018 contingent interest accrued at a rate of 5.0% per annum. During the three and six months ended June 30, 2017, contingent interest accrued at a rate of 1.9% per annum. Although management does not currently expect the following to apply, for periods beginning on September 30, 2018 and in the event that the average price of crude oil were to exceed $75/bbl during any year ending on September 30, the agreement prescribes that the annually compounding interest rate would increase to 10%.

Liquidity outlook

The AOG Credit Facility, which matures in July 2019, is expected to be restructured / rescheduled such that no cash outflow arises before 2020.

The expanded discretionary drilling program planned for the second half of 2018 is conditional upon availability of sufficient funding. If existing and internally generated funds are insufficient, the Group's major shareholders have indicated that additional debt or equity capital could be made available in the range of $10-$15 million in order to commit to the drilling programme as envisaged.

The Group expects cash on hand as of June 30, 2018, cash receipts from export sales exclusively through the Kurdistan Region-Turkey Export Pipeline, expected net proceeds from the sale of its interest in the Haute Mer B License Area, and, if needed, additional debt or equity capital of $10 - $15 million will allow it to fund its forecasted cash expenditures and to meet its obligations through the end of 2019, with the exception of the repayment of the AOG Credit Facility, which is expected to be restructured. Further capital is likely required in late 2019 and beyond to fund expected drilling in the AGC Central License Area.

With the exception of specific funding requirements discussed above, the Group does not expect to require additional financing to fund obligations falling due beyond 2019.

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 June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Operating Funds Flow[1]	4,088	(2,101)	6,117	(4,451)
Change in non-cash assets and liabilities relating to operating activities	(5,678)	940	(10,289)	5,481
Net cash (used in) / generated by operating activities	**(1,590)**	**(1,161)**	**(4,172)**	**1,030**
Additions to E&E and PP&E	(8,315)	(3,512)	(13,868)	(12,782)
Additions to Assets held for disposal	-	-	(5,266)	-
Change in non-cash working capital	(3,288)	(7,413)	6,791	(1,503)
Net cash used in investing activities	**(5,027)**	**(10,925)**	**(12,343)**	**(14,285)**
Net cash (used in) / generated by financing activities	**-**	**29,897**	**(731)**	**29,897**
Total change in cash	**(6,617)**	**17,811**	**(17,246)**	**16,642**
Cash and cash equivalents at beginning of the period	27,943	39,563	**38,572**	40,732
Cash and cash equivalents at end of the period	**21,326**	**57,374**	**21,326**	**57,374**

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 June 30, 2018, the Group invested $8.3 million in exploration, appraisal, and development in the Hawler and AGC Central License Areas. The Group invested $7.9 million primarily on facilities and drilling activities in the Banan and Zey Gawra fields in the Hawler License Area, and $0.3 million to 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 June 30, 2018 used $1.6 million in cash, reflecting a $5.7 million increase in non-cash working capital which was primarily related to an increase in trade and other receivables and a reduction in accounts payable, partially offset by positive Operating Funds Flow of $4.1 million.

The Group invested $13.9 million during the six months ended June 30, 2018 in exploration, appraisal, and development in the Hawler and AGC Central License Areas. During this period, the Group invested $13.0 million in facilities and drilling activities in the Banan and Zey Gawra fields in the Hawler License Area, and $1.0 million to interpret and analyse 3D seismic data and to prepare for drilling activities in the AGC Central License Area. Investing activities during the six months ended June 30, 2018 also used $5.2 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 used $4.2 million in cash

reflecting an increase in non-cash working capital comprising of an increase in trade and other receivables and a decrease in trade and other payables, partially offset by positive Operating Funds Flow of $6.1 million. Financing activities for the period used $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. Through late 2018, the Group plans to finance its activities through current cash reserves, proceeds from the sale of assets held for disposal, and positive Operating Funds Flow. Further capital is likely required in late 2019 and beyond to fund further development of the Hawler License Area and for expected drilling in the AGC Central License Area. Beyond 2018, additional capital is likely required to fund further development of the Hawler License Area and for drilling anticipated in the AGC Central License Area. 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 six months ended June 30, 2018, had these changes occurred on January 1, 2018. These calculations are based on business conditions, production and sales volumes existing during the six months ended June 30, 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	Loss impact ($000s)	Loss impact ($ per basic share)
Change in average realised price	$10.00/bbl	3,307	0.01
Change in crude oil sales volumes	1,000 bbl/d	4,746	0.01
Change in operating expenses	$1.00/bbl	485	-
Change in interest rate	1%	353	-

The impact of the above changes may be compounded or offset by changes to other business conditions. In addition, the table does 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 and changes in the retirement benefit obligation balance. 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 June 30		Six months ended June 30	
($ thousands)	2018	2017	2018	2017
Net cash (used in) / generated by operating activities	(1,590)	(1,161)	(4,172)	1,030
Changes in non-cash assets and liabilities	5,678	(940)	10,289	(5,481)
Operating Funds Flow	**4,088**	**(2,101)**	**6,117**	**(4,451)**

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. Upon vesting, OPCL LTIP share awards granted to the date of this MD&A will result in the issuance of up to an additional 9,496,149 Common Shares in 2018 and 2019.

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, 2017.

At the date of this M&DA, a total of 480,611,754 Common Shares are issued and outstanding.

The following table summarises warrants which were issued in conjunction with the Loan Facility and are outstanding and exercisable at June 30, 2018.

	Warrants	Exercise price USD	Expiry date
Issued December 15, 2015	4,000,000	0.50	December 15, 2018
Total outstanding and exercisable	**4,000,000**		

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 six months ended June 30, 2018.

Commitments and Contractual Obligations

The table below sets forth information relating to Oryx Petroleum's commitments and contractual obligations as at June 30, 2018.

($ thousands)	Within One Year	From 1 to 5 Years	More than 5 Years	Total
Operating leases[1]	167	36	-	**203**
Other obligations[2]	7,133	38,844	16,114	**62,091**
Total	**7,300**	**38,880**	**16,114**	**62,294**

(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)	2016		2017				2018	
	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30
Revenue, net of royalties	3,766	4,386	4,426	3,982	5,512	7,004	7,800	10,024
Operating expense	(2,839)	(3,066)	(4,249)	(4,032)	(3,364)	(3,840)	(3,128)	(3,632)
Depletion	(1,616)	(1,204)	(1,108)	(1,101)	(1,409)	(2,276)	(2,224)	(2,622)
G&A	(2,150)	(2,628)	(2,584)	(2,512)	(2,183)	(3,404)	(2,712)	(2,358)
Profit / (Loss)	(8,738)	(26,205)	4,137	(9,199)	(5,860)	(28,128)	(4,275)	(3,522)
Earnings / (Loss) per share (basic and diluted) ($/share)	(0.04)	(0.10)	0.02	(0.03)	(0.01)	(0.06)	(0.01)	(0.01)
Operating Funds Flow[2]	(645)	(1,676)	(2,350)	(2,101)	(646)	(331)	2,028	4,090
Gross Production (bbl)	264,500	286,000	263,300	260,200	330,900	347,800	341,700	402,600
WI Production (bbl)	172,000	186,000	171,200	169,100	215,100	226,100	222,100	261,700
Gross Sales (bbl)	264,800	279,900	261,100	259,600	332,000	346,100	342,600	403,000
WI Sales (bbl)	172,100	182,000	169,800	168,800	215,800	225,000	222,700	262,000
Field production costs[1]	(2,171)	(2,345)	(3,249)	(3,083)	(2,572)	(2,937)	(2,392)	(2,777)
Field Netback[2]	788	1,099	228	44	1,757	2,564	3,735	5,096
Oryx Petroleum Netback[2]	790	1,160	16	(196)	1,947	2,908	4,388	6,026
Brent price ($/bbl)	45.85	49.96	54.13	50.28	51.72	61.26	66.82	74.39
Sales price ($/bbl)	35.19	38.75	41.92	37.93	41.07	50.04	56.31	61.51
Royalties ($/bbl)	(17.20)	(18.93)	(20.48)	(18.55)	(20.08)	(24.46)	(27.53)	(30.06)
Field production costs[1] ($/bbl)	(12.61)	(12.88)	(19.13)	(18.25)	(11.92)	(13.06)	(10.74)	(10.60)
Current taxes ($/bbl)	(0.80)	(0.88)	(0.95)	(0.86)	(0.93)	(1.13)	(1.28)	(1.40)
Field Netback[2] ($/bbl)	4.58	6.04	1.35	0.27	8.14	11.39	16.76	19.45
Oryx Petroleum Netback[2] ($/bbl)	4.59	6.37	0.10	(1.15)	9.02	12.92	19.70	23.00
Capital additions	4,227	10,513	(5,911)	814	3,823	4,611	6,164	8,774

Notes:

(1) Field production costs represent 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 six months ended June 30, 2018 and production and sale volumes began to increase during June 2018 as a result of incremental production from the Hawler License Area's Zey Gawra and Banan fields.

Variations in Field Netback and Oryx Petroleum Netback reflect changes in revenue discussed above and the impact of changes in field production costs. Following revised and lowered production forecasts during the second quarter of 2015, field production costs incurred during the years ended December 31, 2016 and 2017 and the six months ended June 30, 2018 reflect management's consequent efforts to reduce costs. 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.

Loss for the three months ended June 30, 2018 was $3.5 million compared to a $9.2 million loss during the second quarter of 2017. The change in loss for the three months ended June 30, 2018 in comparison to the same period in 2017 is primarily attributable to i) an increase in net revenue of 6.0 million, ii) a $1.4 million decrease in finance expense and iii) a $0.4 million decrease in operating expense. These positive factors were partially offset by a $1.5 million increase in the depletion charge during the second quarter of 2018 and a $0.9 million provision against trade and other receivables recorded during the three months ended June 30, 2018.

Operating expense of $3.6 million in the three months ended June 30, 2018 decreased by $0.4 million compared to the same period in the previous year. The decrease in operating expense is primarily attributable to lower security costs resulting from the implementation of a cost reduction program, together with reduced technical support costs.

Financial and Other Instruments and Off Balance Sheet Arrangements

Oryx Petroleum was not party to any off-balance sheet arrangements during the six months ended June 30, 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 expense of $4.0 million relating to this transaction has been recorded for the six months ended June 30, 2018 (2017 - $4.8 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. The Loan Amendment discussed in the "Liquidity and Capital Resources" section of this MD&A was a transaction involving related parties. Management has assessed the terms and conditions to be materially comparable to terms applicable to similar market transactions.

On October 19, 2016, the Group entered into an office lease agreement with a subsidiary of its indirect controlling shareholder. Rental expense of $43 thousand and $93 thousand relating to this agreement was recorded for the three and six months ended June 30, 2018, respectively. An operating lease commitment of $0.1 million has been included in commitments as at June 30, 2018.

For the three and six months ended June 30, 2018, the Group incurred costs of $0.4 million and $0.9 million, respectively, for goods and services provided by related parties, all of which are subsidiaries of AOG (2017: $0.4 million and $0.8 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 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, fair value through other comprehensive income, 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.

ii. Financial assets at fair value through other comprehensive income

Financial assets classified at fair value through other comprehensive income are held to both collect contractual cash flows and to sell the debt instrument. The contractual cash flows solely relate to repayments of the carrying amount of the asset upon initial recognition and interest, if any. These financial assets are subsequently measured at fair value through other comprehensive income.

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 Production Sharing Contract ("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. The critical estimates discussed in the Group's MD&A for the year ended December 31, 2017 remain applicable to the six month period ended June 30, 2018 and, with the exception of the estimates discussed below, there have been no material changes in estimates.

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. The Group has 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 receipt of proceeds from the sale of assets held for disposal, and on the Group's ability to a) increase production from the Hawler License Area and b) restructure the scheduled cash outflow related to borrowings. These estimates are subject to material uncertainties that may cast significant doubt on the Group's ability to continue as a going concern.

The Directors expect that cash resources on hand as at June 30, 2018, proceeds from the sale of assets held for disposal, and future cash receipts from sales of its share of oil production from the Hawler License Area will be sufficient to fund the Group's capital and operating expenditures and, with the exception of the repayment of Borrowings, to meet forecast obligations as they fall due in the 15 months following June 30, 2018. Provided sufficient funds are available, the Group plans to accelerate certain discretionary drilling activities during the third and fourth quarters of 2018. Accordingly and in order to ensure sufficient liquidity, the Group is engaged in specific discussions with various parties to secure further financing of $10 - $15 million. In preparing forecasts supporting the going concern assumption, management has applied the following significant judgments and assumptions:

i) Oil production volume assumptions are based on July 2018 gross production of 6,100 bbl/d rising to at least 10,000 bbl/d as management expects to bring one recently completed and four further wells on stream over the coming months in the Hawler License Area.

ii) The timing and extent of forecast capital and operating expenditures is based on the Group's 2018 reforecast budget adjusted to exclude certain discretionary activities and related expenditures, and on management's estimate of non-contingent expenditures expected to be incurred beyond 2018. The Group retains a high degree of control and flexibility over both the extent and timing of expenditure under its capital investment program.

iii) Management has developed specific plans to address longer term corporate funding requirements which are under discussion and consideration by parties including the Lender. Based on these discussions, management has anticipated that Borrowings maturing in July 2019 will be rescheduled or restructured, such that no related cash outflows occur during 2019. While agreements to reschedule or restructure the Borrowings have not been concluded, substantive and detailed discussions are ongoing. Given the substance of the discussions undertaken to date, and the time available to conclude definitive agreements, the directors believe that the assumption that the Borrowings will be rescheduled or restructured is reasonable and appropriate. However, so long as definitive agreements have not been concluded, the directors have determined that the uncertainty related to the Group's ability to restructure or to reschedule cash outflows related to Borrowings is material to the conclusion that the Group will be able to continue operations on a going concern basis.

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		Variance
	Forecast	Actual	
October 1, 2016 – March 31, 2018	68	28	$40[1]
January 1, 2017 – June 30, 2018	67	32	$35[1]

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.

Financial Controls

Disclosure Controls and Procedures

Disclosure Controls and Procedures 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.

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.

There were no changes in Oryx Petroleum's ICFR during the three months ended June 30, 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 2018, financing and capital activities, the additional liquidity required to fund future expenditures, expectations that cash on hand as of June 30, 2018, cash receipts from exports sales exclusively through the Kurdistan Region-Turkey Export Pipeline, expected net proceeds from the sale of its interest in the Haute Mer B License Area, and, if needed, additional debt or equity capital of $10 - $15 million, will allow the Group to fund forecasted cash expenditures needed to sustain the Group's operations and to meet its obligations through the end of 2019, expected closing of a transaction to transfer the Corporation's interests in the Haute Mer B License Area in Q3 2018, expected restructuring of the Loan Facility, expected production rate increases for individual wells, 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, management expectations regarding revisions to oil reserves estimates, 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, guidance regarding operating expenses on a per barrel basis, plans to continue interpreting 3D seismic data from the AGC Central License Area and identifying prospects and preparing for drilling, expected entry into the first renewal of the exploration period under the AGC Central PSC in September 2018, estimates on a per share basis, future foreign currency exchange rates, the issuance of shares as a result of the vesting of LTIP awards, exercise of outstanding warrants, and in lieu of interest under the Loan Facility, 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, 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.

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