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

FOR THE YEARS ENDED

DECEMBER 31, 2017 and 2016

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

*The following Management's Discussion and Analysis ("**MD&A**") should be read in conjunction with the consolidated financial statements of Oryx Petroleum Corporation Limited ("**OPCL**" or, the "**Company**") and its subsidiaries for years ended December 31, 2017 and 2016 (the "**Financial Statements**"), which have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").*

The date of this MD&A is March 7, 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 28. Additional information relating to OPCL, including OPCL's Annual Information Form dated March 23, 2017, is on SEDAR at www.sedar.com. The Company will file an Annual Information Form for the year ended December 31, 2017 on or before March 31, 2018.

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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
AGC Shallow(2)	Senegal and Guinea Bissau	85%	80%(1)	Operator
Haute Mer A(3)	Congo (Brazzaville)	20%	20%	Non-operator
Haute Mer B(4)	Congo (Brazzaville)	30%	30%	Non-operator

Notes:

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

(2) On November 2, 2017 the Group relinquished its participating interest in the AGC Shallow License Area.

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

(4) During February 2018, the Group accepted an offer to dispose of its interest in the Haute Mer B License Area. Subject to completion of customary due diligence, definitive documentation, and closing conditions, the transaction is expected to close during the second quarter of 2018.

Operational Highlights

2017

- Average gross (100%) oil production of 3,300 bbl/d (WI - 2,100 bbl/d) for the year ended December 31, 2017 versus 2,500 bbl/d (WI - 1,600 bbl/d) for the year ended December 31, 2016;
  - 32% increase in 2017 versus 2016;
  - Successful re-completion of the ZAB-1 sidetrack ("ST") well in the Cretaceous reservoir and increased production from the ZEG-1 ST well in the Cretaceous reservoir;
- Gross (WI) proved plus probable oil reserves of 122 million barrels as at December 31, 2017;
- Processing and interpretation of 3D seismic data covering AGC Central License Area is largely completed;
- Best estimate unrisked gross (WI) prospective oil resources of 3,750 MMbbl as at December 31, 2017;
  - Upward revision of estimates for the AGC Central License Area;
- Divestment/relinquishment of OML 141 and AGC Shallow Licence Areas completed;

2018

- Average gross (100%) oil production of 3,600 bbl/d and 3,900 bbl/d in January and February 2018, respectively
- The ZEG-2 appraisal well targeting the Cretaceous reservoir was spudded in January 2018 and was drilled to a measured depth of 2,120 metres. The well is currently being logged and is expected to be completed as a producer in the coming weeks;
- Preparations for drilling at the Banan field are underway with drilling expected to commence during the second quarter of 2018;
- Final interpretation of 3D seismic data covering the AGC Central License Area in advanced stages and is expected to be completed in the coming months with prospect selection and preparation for drilling to follow;
- Recently accepted non-binding offer to transfer the Group's full interest in Haute Mer B License Area for cash consideration.

Financial Highlights and Outlook

Liquidity outlook

The Group expects cash on hand as of December 31, 2017 and cash receipts from net revenues and export sales exclusively through the KRG's international export pipeline, will allow it to fund its forecasted cash expenditures and operating and administrative costs and to meet its obligations through the end of 2018. Beyond 2018, additional capital is likely required to fund further development of the Hawler License Area and for planned drilling in the AGC Central License Area.

Financial performance

The following table contains financial performance highlights for the three and twelve months ended December 31, 2017 and December 31, 2016.

	Three months ended		Year ended	
($ thousands unless otherwise stated)	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Revenue	12,508	7,832	37,368	22,809
Cash used in operating activities	(6,134)	(584)	(9,728)	(11,457)
Operating Cash Flow(1)	(331)	(1,676)	(5,428)	(9,231)
Operating Cash Flow(1) per basic and diluted share ($/share)	(0.00)	(0.01)	(0.02)	(0.04)
Loss for the period	(28,128)	(26,205)	(39,050)	(65,725)

	Three months ended		Year ended	
($ thousands unless otherwise stated)	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Loss per basic and diluted share ($/share)	(0.06)	(0.10)	(0.11)	(0.31)
Average sales price ($/bbl)	50.04	38.75	43.17	34.61
Field production costs(2) ($/bbl)	13.06	12.88	15.20	16.28
Operating expense ($/bbl)	17.07	16.85	19.87	21.28
Field Netback(1) ($/bbl)	11.39	6.04	5.89	0.63
Oryx Petroleum Netback(1) ($/bbl)	12.92	6.37	5.99	(0.54)
Capital expenditures	4,611	10,513	3,338(3)	36,301(4)

Notes:

(1) Operating Cash 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 $7.5 million relating to revisions in previously estimated costs recorded in the Hawler and OML 141 License Areas and $2.4 million in non-cash credits relating to revisions to estimates associated with decommissioning obligations.

(4) Includes non-cash items totalling $13.8 million reflecting changes in assumptions used in calculating decommissioning obligations and finance lease assets related to the Hawler License Area, and a non-cash revision to previous costs incurred in the OML 141 License Area.

Revenue and cash receipts

Revenue of $12.5 million was recorded for the three months ended December 31, 2017. Included in revenue is $11.3 million ($50.04/bbl) realised on the sale of 225,000 bbl (WI) of crude oil and $1.2 million related to the recovery of costs carried on behalf of partners. Oil sales for the fourth quarter of 2017 increased by $4.2 million compared to 2016. The increase is attributable to a 29% increase in realised sales price combined with a 24% increase in sales volumes.

Revenue of $37.4 million was recorded for the year ended December 31, 2017. Included in revenue is $33.6 million ($43.17/bbl) realised on the sale of 779,200 bbl (WI) of crude oil and $3.7 million related to the recovery of costs carried on behalf of partners. 2017 oil sales increased by $13.1 million compared to 2016. The increase is attributable to a 25% increase in realised sales price combined with a 31% increase in sales volumes.

All sales during the year ended December 31, 2017 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 during January-November 2017. At the date of the MD&A, the Group's entitlement share of amounts receivable totalling $7.3 million are due from the KRG for crude oil delivered to the pipeline during December 2017 - February 2018.

Operating cash flow

Operating Cash Flow for the fourth quarter of 2017 was negative $0.3 million compared to negative $1.7 million for the three months ended December 31, 2016. For the year ended December 31, 2017, Operating Cash Flow was negative $5.4 million compared to $9.2 million during 2016. The reduction in Operating Cash Flow for the three and twelve months ended December 31, 2017 in comparison to 2016 is primarily attributable to higher revenues.

Field production costs and netbacks

Field production costs during the fourth quarter of 2017 amounted to $2.9 million ($13.06/bbl) in comparison to $2.3 million ($12.88/bbl) during the fourth quarter of 2016. The increase in costs is associated with operations at the Zey Gawra field which were initiated during December 2016.

Field production costs during the year ended December 31, 2017 amounted to $11.8 million ($15.20/bbl) in comparison to $9.7 million ($16.28/bbl) during 2016. The increase in costs is also associated with operations at the Zey Gawra field which were initiated during December 2016.

Field Netback of $11.39/bbl for the three months ended December 31, 2017 has improved from $6.04/bbl for the fourth quarter of 2016. Field Netback of $5.89/bbl for the year ended December 31, 2017 has improved from $0.63/bbl for 2016. The primary driver for improved Field Netbacks has been higher oil prices.

Loss

Loss for the three months ended December 31, 2017 was $28.1 million compared to $26.2 million during the fourth quarter of 2016. The increase in loss for the period is primarily attributable to i) an $3.1 million increase in impairment charge (primarily relating to the Hawler License Area), ii) a $1.5 million increase in income tax expense as a result of the deferred tax asset balance write off in relation to the pension obligation, iii) a $1.0 million increase in the depletion charge mainly related to the decrease in estimated reserves base and iv) a $0.8 million increase in operating expense primarily related to costs associated with production from the Zey Gawra field in the Hawler License Area which commenced in December 2016. These negative factors were partially offset by i) an increase in net revenue of $2.6 million, and ii) a $1.4 million decrease in finance expense which was primarily related to the decrease in the Loan Facility's principal balance outstanding.

Net loss of $39.1 million for the year ended December 31, 2017 decreased by $26.7 million compared to 2016. The change in loss for the period is primarily attributable to i) an increase in net revenue of $8.2 million, ii) a $7.6 million gain recorded on the settlement of the finance lease obligation during the first quarter of 2017, iii) an $8.3 million materials inventory impairment charge and a $2.2 million restructuring charge recorded during the year ended December 31, 2016 versus $0.7 million inventory impairment recovery recorded in 2017, iv) a $3.1 million decrease in finance expense primarily related to the decrease in the Loan Facility's principal balance outstanding and v) a $0.5 million decrease in impairment expense as a result of $9.4 million impairment reversal in the Haute Mer B and OML 141 License Areas partially offset by a $27.7 million Hawler License Area impairment charge during 2017 versus a $18.8 million impairment charge during 2016 (mainly $16.3 million impairment in the Congo Haute Mer B License Area). These positive factors were partially offset by a $1.3 million increase in G&A expenses and a $2.9 million increase in operating expense for the year ended December 31, 2017 compared to the same period in 2016. The increase in G&A expenses was due to less support costs capitalised in 2017 and the increase in operating expense during 2017 is primarily related to costs associated with production from the Zey Gawra field in the Hawler License Area from December 2016 onward.

Capital expenditures

During the year ended December 31, 2017, the Group recorded net capital additions of $3.3 million. The Group invested $6.8 million primarily on drilling activities on the Demir Dagh and Zey Gawra fields in the Hawler License Area, $1.7 million to sponsor the acquisition of 3D seismic data in the AGC Central License Area, and $4.7 million in directly attributable capital support costs. These capital investments were offset primarily by $7.5 million in non-cash revisions to previous estimates of costs recorded related to the Hawler and OML 141 License Areas and $2.4 million in non-cash credits relating to the revision of the discount and inflation rates used to calculate the Hawler License Area decommissioning obligation.

Financial position

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

($ thousands)	December 31, 2017	December 31, 2016
Total cash and cash equivalents	38,572	40,732
Working Capital	27,133	(2,149)
Total assets	744,798	766,445
Borrowings	75,854	93,103
Total long-term liabilities	147,837	174,942

The cash and cash equivalents balance of $40.7 million as at December 31, 2016 decreased to $38.6 million at December 31, 2017. This decrease is due to $9.7 million cash used in operating activities and $22.3 million used in investing activities partially offset by the receipt of $30.0 million in funds received upon the issuance of Common Shares.

Working capital increased to positive $27.1 million at December 31, 2017 from a negative working capital balance of $2.1 million as at December 31, 2016. The increase was mainly due to a $14.0 million decrease in trade and other payables, an $8.0 million increase in assets held for disposal, a $3.0 million increase in the trade and other receivables balance, and the elimination of the $6.4 million finance lease obligation balance upon the settlement of this liability. These positive factors were partially offset by a $2.2 million decrease in cash and cash equivalents.

The balance owed under the Loan Facility as at December 31, 2017 was $77.1 million, including $1.1 million in accrued interest which will be settled through the issuance of Common Shares.

The undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation to the vendor of the Hawler License Area as at December 31, 2017 was $72.1 million.

2018 capital expenditure forecast

The Group's reforecasted capital expenditures for 2018 amount to $48 million, reduced from the previously announced budget of $55 million. The reduction reflects revised estimated drilling costs in the Hawler License Area, and a revised estimate of drilling preparation costs to be incurred relating to the AGC Central License Area. OPCL now plans one workover at the Demir Dagh field rather than two. The following table summarises the Group's 2018 reforecast cash capital expenditure program versus budget:

Location	License/Field/Activity	2018 Budget	2018 Forecast
		$ millions	$ millions
Kurdistan Region	Hawler		
	Zey Gawra-Drilling	11	9
	Demir Dagh-Drilling	5	4
	Demir Dagh-Facilities	2	2
	Banan-Drilling	14	11
	Banan-Facilities	6	6
	Other(1)	2	3
	Total Hawler(2)	**40**	**35**
West Africa	AGC Central – Drilling Preparation	8	6
	AGC Central – Other	7	7
	Capex Total(2)	**55**	**48**

Note:
(1) Other is comprised primarily of technical support, seismic acquisition, and 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 short radius sidetrack of the previously drilled Demir Dagh-5 well. Sidetrack operations are expected to be completed in the first half of 2018.

Zey Gawra drilling – consists of drilling two new wells targeting the Zey Gawra Cretaceous reservoir. One well has been drilled in early 2018 and is expected to be completed in the coming weeks and the other is planned in late 2018 subject to performance of existing wells.

Banan drilling – consists of i) the re-entry, completion and testing of the Banan-2 well targeting the Cretaceous reservoir, which was suspended in 2014 due to security developments and ii) the drilling of three new wells targeting the Tertiary. The Banan-2 re-entry and the drilling of the first new well targeting the Tertiary are planned in the first half of 2018 while a further two wells targeting the Tertiary reservoir are planned for the second half of the year subject to the success/performance of the first well.

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

Banan facilities expenditures – comprised of site remediation, construction of a truck loading station at Banan, the construction of a new drilling pad needed to drill wells planned in the second half of the year, and flowlines.

AGC Central License Area

Activity consists of preparation for drilling which is planned in 2019, facilities studies, and a final payment for the acquisition and ongoing processing of 3D seismic data contingent upon entering the first renewal of the exploration period under the PSC which is expected in September 2018.

Summary of Reserves and Resources

The following is a summary of the Company's proved plus probable oil reserves, and contingent and prospective oil resources. The net present value of future net revenue related to the proved plus probable oil reserves, and the risked net present value of future net revenue related to contingent oil resources sub-classified as development pending is also presented. The information is derived from a report dated February 9, 2018, prepared with an effective date as at December 31, 2017 by Netherland, Sewell & Associates, Inc. ("**NSAI**"), an independent oil and gas consulting firm. Where applicable, comparative information derived from NSAI's report as at December 31, 2016 is provided. The reserves and resources information set out in this MD&A should be read in conjunction with the advisories in the "Forward-Looking Information" and "Reserves and Resources Advisory" sections. Further details regarding the below estimates, including the risks and level of uncertainty associated with recovery, are available in the Company's Material Change Report dated February 15, 2018 filed on SEDAR at www.sedar.com.

Oil reserves [(1)]

		Proved plus Probable Gross (Working Interest) Oil			
		December 31, 2017		December 31, 2016	
License Area	Location	Reserves (MMbbl)	Future Net Revenue[(2)] ($ million)	Reserves (MMbbl)	Future Net Revenue[(2)] ($ million)
Hawler	Iraq – Kurdistan Region	122	704	202	1,014
Total oil reserves		**122**	**704**	**202**	**1,014**

Notes:

(1) The oil reserves data is based upon evaluations by NSAI, with effective dates as at December 31, 2017 and December 31, 2016, as indicated. Volumes are based on commercially recoverable volumes within the life of the production sharing contract.

(2) After-tax net present value of related future net revenue using forecast prices and costs assumed by NSAI and a 10% discount rate as at December 31, 2017 and December 31, 2016, as indicated. Gross proved plus probable oil reserves estimates used to calculate future net revenue are estimated based on economically recoverable volumes within the development/exploitation period specified in the production sharing contract, risk exploration contract or fiscal regime applicable to each License Area. The estimated values disclosed do not represent fair market value.

The Group's Gross (Working Interest) proved plus probable oil reserves decreased by 40% from 202 million barrels ("**MMbbl**") as at December 31, 2016 to 122 MMbbl as at December 31, 2017. The decrease is primarily attributable to the Zey Gawra Cretaceous reservoir based on logging results and performance data of the ZAB-1 sidetrack well drilled in 2017. Decreased volumes attributable to the Demir Dagh and Banan Cretaceous reservoirs based on performance data from existing Demir Dagh Cretaceous wells.

The after-tax net present value utilising a 10% discount rate of the future net revenues attributable to the Group's Gross (Working Interest) proved plus probable oil reserves decreased to $704 million from $1,014 million as at December 31, 2016. Lower volumes, forecasted Brent crude oil prices and assumed export oil prices are partially offset by the positive impact of PSC mechanics.

Contingent oil resources [(1)]

		Best Estimate Gross (Working Interest) Oil December 31, 2017		
License Area	Location	Unrisked Contingent Resources (MMbbl)	Risked Contingent Resources[(2)] (MMbbl)	Future Net Revenue[(3)] ($ million)
Contingent Oil Resources – Development Pending[(4)]				
Hawler	Iraq – Kurdistan Region	54	47	106
	Total Development pending	**54**	**47**	**106**

		Best Estimate Gross (Working Interest) Oil December 31, 2017	
License Area	Location	Unrisked Contingent Resources (MMbbl)	Risked Contingent Resources[(2)] (MMbbl)
Contingent Oil Resources – Development Unclarified[(5)]			
Hawler	Iraq – Kurdistan Region	94	65
	Total Development unclarified	**94**	**65**

Notes:

(1) The contingent oil resource data is based on evaluations by NSAI, and the classification of such resources as "contingent oil resources" by NSAI, with effective date as at December 31, 2017. The figures shown are NSAI's best estimate using deterministic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent oil resources actually recovered will equal or exceed the estimated amounts is 50% for the best estimate. Contingent oil resources estimates are volumetric estimates prior to economic calculations.

(2) These are risked contingent resources that have been risked for chance of development. There is uncertainty that it will be commercially viable to produce any portion of the resources.

(3) After-tax risked net present value of related future net revenue using forecast prices and costs assumed by NSAI and a 10% discount rate. Gross contingent oil resource estimates used to calculate future net revenue are estimated based on economically recoverable volumes within the development/production period specified in the production sharing contract, risk exploration contract or fiscal regime applicable to each License Area. The estimated values disclosed do not represent fair market value.
(4) Classification of a project's maturity as Development Pending indicates that there is a high chance of development (i.e., probability that a known accumulation will be commercially developed), where resolution of the final conditions for development is being actively pursued.
(5) Classification of a project's maturity as Development Unclarified indicates that evaluation of the project is incomplete and there is ongoing activity to resolve any risks or uncertainties regarding commercial development of the project. An economic evaluation has not been performed by NSAI on the contingent oil resources classified as Development Unclarified.

Prospective oil resources [1]

		Best Estimate Gross (Working Interest) Oil December 31, 2017	
License Area	Location	Unrisked (MMbbl)	Risked[2] (MMbbl)
Hawler	Iraq – Kurdistan Region	105	4
AGC Central	Senegal and Guinea Bissau	3,450	392
Haute Mer B[3]	Congo (Brazzaville)	195	2
Total oil resources		**3,750**	**398**

Notes:
(1) The prospective oil resource data is based on evaluations by NSAI, and the classification of such resources as "prospective oil resources" by NSAI, with effective date as at December 31, 2017. The figures shown are NSAI's best estimate using a combination of deterministic and probabilistic methods and are dependent on a petroleum discovery being made. If discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the risked estimates is 50% for the best estimate. Prospective oil resources estimates are volumetric estimates prior to economic calculations.
(2) These are risked prospective resources that have been risked for both chance of discovery and chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.
(3) During February 2018, the Group accepted a non-binding offer to dispose of its interest in the Haute Mer B License Area. Subject to completion of customary due diligence, definitive documentation, and closing conditions, the transaction is expected to close during the second quarter of 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. The Group understands that efforts are under way to resolve political disputes regarding 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. The impact 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 have contributed to reductions and volatility to 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. 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 political instability in the regions in which Oryx Petroleum operates 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 recent successes of government forces, these precautionary measures have permitted the Group to continue appraisal and development activities at the Demir Dagh and Zey Gawra fields and to begin preparations to resume activities at the Banan field.

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 production will be sold through the export pipeline. The political tensions which have followed the KRG independence referendum contribute to an increase in the risk that 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 have been limited due to capital allocation priorities and also to security risks. There is an ongoing risk that 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. Timing and execution risks are amplified by the political tension arising following the KRG independence referendum described above.

With the exception of the items discussed above together with risks disclosed in the Group's Annual Information Form dated March 23, 2017, management has not identified trends or events that are expected to have a material adverse effect on the financial performance of Oryx Petroleum.

Operations Review

Kurdistan Region of Iraq

The following table summarises production and sales data for the three months ended December 31, 2017, September 30, 2017, and December 31, 2016 and for the year ended December 31, 2017 and December 31, 2016:

	Three months ended			Year ended	
	December 31, 2017	September 30, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Gross Production (bbl)	347,800	330,900	286,000	1,202,200	904,000
Gross Production per day (bbl/d)	3,800	3,600	3,100	3,300	2,500
WI Production (bbl)	226,100	215,100	186,000	781,400	588,000
WI Production per day (bbl/d)	2,500	2,300	2,000	2,100	1,600
WI sales (bbl)	225,000	215,800	182,000	779,200	593,300
WI sales per day (bbl/d)	2,400	2,300	2,000	2,100	1,600

Production and sales

Gross (100%) oil production for the three months ended December 31, 2017 was 347,800 bbl representing an average rate of 3,800 bbl/d. The Group's Working Interest share of oil production during this period was 226,100 bbl representing an average rate of 2,500 bbl/d. The increase in production volumes was mainly due to the added production from the Zey Gawra field.

Gross (100%) oil production for year ended December 31, 2017 was 1,202,200 bbl representing an average rate of 3,300 bbl/d. The Group's Working Interest share of oil production during this period was 781,400 bbl representing an average rate of 2,100 bbl/d.

The Group recognised revenue on the sale of 225,000 bbl (Working Interest) and 779,200 bbl (Working Interest) of crude oil during the three and twelve months ended December 31, 2017, 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 through the KRG's international export pipeline. The realised sales prices on export sales through this pipeline are 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:

	2017				2016			
	Dec 31	Sept 30	Jun 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31
Brent average price ($/bbl)	61.26	51.72	50.28	54.13	49.96	45.85	45.89	34.54
Realised sales price ($/bbl)	50.04	41.07	37.93	41.92	38.75	35.19	34.15	20.25

Netbacks

The following table summarises the Field Netback and Oryx Petroleum Netback for the three months ended December 31, 2017 and December 31, 2016:

	Three months ended December 31, 2017		Three months ended December 31, 2016	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	11,260	50.04	7,050	38.74
Royalties	(5,504)	(24.46)	(3,446)	(18.93)
Field production costs(1)	(2,937)	(13.06)	(2,345)	(12.88)
Current taxes	(255)	(1.13)	(160)	(0.88)
Field Netback(2)	**2,564**	**11.39**	**1,099**	**6.04**
Recovery of Carried Costs	1,247	5.54	782	4.30
Partner share of production costs	(903)	(4.01)	(721)	(3.96)
Oryx Petroleum Netback(2)	**2,908**	**12.92**	**1,160**	**6.37**

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 December 31, 2017 of $2.6 million incorporates field production costs of $2.9 million. On a per barrel basis, Field Netback has increased to $11.39/bbl for the three months ended December 31, 2017 from $6.04/bbl for the three months ended December 31, 2016. This variance is primarily attributable to an increase in the realised sales prices.

The following table summarises the Field Netback and Oryx Petroleum Netback for the year ended December 31, 2017 and December 31, 2016:

	Year ended December 31, 2017		Year ended December 31, 2016	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	33,641	43.17	20,534	34.61
Royalties	(16,444)	(21.10)	(10,037)	(16.92)
Field production costs(1)	(11,842)	(15.20)	(9,657)	(16.28)
Current taxes	(763)	(0.98)	(466)	(0.79)
Field Netback(2)	**4,592**	**5.89**	**374**	**0.63**
Recovery of Carried Costs	3,726	4.78	2,275	3.83
Partner share of production costs	(3,644)	(4.68)	(2,971)	(5.01)
Oryx Petroleum Netback(2)	**4,674**	**5.99**	**(322)**	**(0.54)**

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 year ended December 31, 2017 of $4.6 million incorporates field production costs of $11.8 million. On a per barrel basis, Field Netback has improved to $5.89/bbl for the year ended December 31, 2017 from $0.63/bbl for the year ended December 31, 2016. This variance is primarily attributable to an increase in the realised sales prices.

Hawler license appraisal and early production

Zey Gawra field

During the second quarter of 2017, the ZAB-1ST well was drilled to a measured depth of 2,069 metres and completed in the Cretaceous reservoir in the Zey Gawra field of the Hawler License Area. After an acid stimulation treatment in August 2017 daily oil production from the well initially reached approximately 700 bbl/d.

Following observation and interpretation of data obtained from the ZAB-1ST and ZEG-1ST wells, the Group has spud the ZEG-2 appraisal well targeting the Zey Gawra Cretaceous reservoir. The well has been drilled to a measured depth of 2,120 metres, is currently being logged, and is expected to be completed as a producer in the coming weeks.

Banan field

Preparations for the resumption of operations at the Banan field are underway with the re-entry of the Banan-2 well, targeting the Cretaceous reservoir, and the drilling of a new well targeting the Tertiary reservoir both planned for the first half of 2018. Resumption of operations at the Banan field requires various authorisations from the KRG.

Demir Dagh field

The Group completed workover operations on the Demir Dagh-8 and Demir Dagh-7 wells during 2017. Intervention on the Demir Dagh-8 well in the Cretaceous reservoir is ongoing. While initial efforts to bring this well onto production have not succeeded, additional efforts to stimulate the well are ongoing. No further intervention is expected on the Demir Dagh-7 well.

West Africa

The Group has licensed approximately 2,000 km^2 of 3D seismic data acquired in December 2016 and January 2017 from the AGC Central License Area. The data has been processed and interpretation is positive. Finalisation of prospect identification and mapping is expected in the coming months with preparations for drilling to follow.

Relinquishment of the AGC Shallow License Area

On November 2, 2017, Oryx Petroleum concluded an agreement with the Agence de Gestion et de Coopération entre le Sénégal et la Guinée – Bissau ("**AGC**") to relinquish its 80% interest in the AGC Shallow License Area. In consideration of the relinquishment, the PSC applicable to the AGC Central License Area (the "**AGC Central PSC**") has been amended to add a commitment to drill a second exploration well during the first renewal to the exploration period, which is expected to be entered in October 2018. In addition, Oryx Petroleum has paid the AGC a $1.5 million fee and has also accelerated and executed payment of a $1 million renewal fee that was due under the AGC Central PSC upon entry into the first renewal to the exploration period.

If the Group determines to not enter into the first renewal to the exploration period under the AGC Central PSC, Oryx Petroleum will be required to pay the AGC a financial indemnity of $13.5 million, representing the $15 million financial penalty that would have otherwise applied under the PSC applicable to the AGC Shallow License Area (the "**AGC Shallow PSC**"), reduced by the $1.5 million fee described above. In such event, the Group will also forgo any claim to the $1 million renewal fee described above.

Recoverable costs in the amount of $33.5 million incurred under the AGC Shallow PSC have been transferred to the AGC Central PSC and will be recoverable from potential future oil sales under the terms of the AGC Central PSC.

Other than as provided above, the AGC has released Oryx Petroleum from all obligations and liabilities under the AGC Shallow PSC and otherwise related to the AGC Shallow License Area.

Other than the above, activities in West Africa during the year ended December 31, 2017 were limited to license maintenance and data analysis, and preparation for future drilling activity.

Divestment of Interest in the Haute Mer B License Area

During February 2018, the Group accepted a non-binding offer to dispose of its interest in the Congo Haute Mer B License Area for cash consideration. Subject to completion of customary due diligence, definitive documentation, and closing conditions, the transaction is expected to close during the second quarter of 2018.

Capital Expenditures

The following table summarises the capital expenditures incurred by activity during the three and twelve months ended December 31, 2017 and December 31, 2016:

	Three months ended		Year ended	
($ thousands)	December 31, 2017	December 31, 2016	December 31, 2017	December 31, 2016
Middle East				
Drilling	108	5,050	1,387[1]	16,317[6]
Facilities	205	922	165[2]	7,056[7]
Seismic acquisition and interpretation	-	(9)[4]	-	238
Studies, license, and support	2,190	2,515	(1,023)[3]	6,872
Sub-Total Middle East	**2,503**	**8,478**	**529**	**30,483**
West Africa				
Exploration drilling	(216)[4]	26	(2,068)[4]	2,301[8]
Seismic acquisition and interpretation	427	1,072	1,576	1,073
Studies, license, and support	1,897	937	3,295[5]	2,425
Sub-Total West Africa	**2,108**	**2,035**	**2,803**	**5,799**
Corporate	**-**	**-**	**6**	**19**
Total capital expenditures	**4,611**	**10,513**	**3,338**	**36,301**

Notes:

(1) *Included in the drilling capital expenditures for the Middle East for the year ended December 31, 2017 is a non-cash credit of $2.9 million related to revisions to estimates of costs incurred in prior periods and a non-cash credit of $2.4 million primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.*

(2) *Facilities capital expenditures in the Middle East for the year ended December 31, 2017 includes a credit related to revisions to estimates of costs incurred in prior periods.*

(3) *Included in studies, license and support costs for the Middle East for the year ended December 31, 2017 is a non-cash credit of $3.2 million related to revisions to estimates of costs incurred in prior periods.*

(4) *The credits relate to actual expenditure incurred at values below those estimated in prior periods. For the year ended December 31, 2017, West Africa exploration drilling costs include a non-cash credit of $2.2 million related to revisions to estimates of costs recorded in prior period. For the three months ended December 31, 2017, costs include a non-cash credit of $0.3 million related to revisions to estimates of costs recorded in prior periods.*

(5) *Included in West African studies, license and support costs for the year ended December 31, 2017 is a non-cash addition of $0.7 million.*

(6) *Included in the drilling capital expenditures for the Middle East for the year ended December 31, 2016 is a $6.9 million non-cash addition relating to the change in discount and inflation rates used to calculate the decommissioning obligation.*

(7) *Included in the facilities capital expenditures for the Middle East for the year ended December 31, 2016 is a $4.7 million non-cash addition relating to the change in the purchase date assumption used to calculate the finance lease asset.*

(8) *During 2015, the Group fully impaired capitalised expenditures relating to its interest in the OML 141 License Area. During the second quarter of 2016, the Group recorded a $2.2 million non-cash addition to exploration and evaluation assets ("**E&E assets**") relating to revisions to previous cost estimates. As the OML 141 License Area had been previously impaired a concurrent impairment charge of $2.2 million was also recorded during the second quarter of 2016. A $0.1 million adjustment to this figure was recorded during the third quarter of 2016 which related to actual expenditures incurred at values below those estimated in prior periods.*

The following table summarises the capital expenditures incurred by License Area during the three and twelve months ended December 31, 2017 compared to the same periods in 2016:

($ thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Middle East				
Hawler	2,503	8,477	529[(1)]	31,186[(3)]
Sindi Amedi	-	1	-	(703)[(4)]
Sub-Total Middle East	**2,503**	**8,478**	**529**	**30,483**
West Africa				
AGC Shallow	(33,561)	474	(33,320)	976
AGC Central	35,949	1,488	37,535	2,049
OML 141	(280)[(2)]	(15)[(5)]	(1,513)[(2)]	2,109[(5)]
Haute Mer B	-	88	101	665
Sub-Total West Africa	**2,108**	**2,035**	**2,803**	**5,799**
Corporate	**-**	**-**	**6**	**19**
Total capital expenditures	**4,611**	**10,513**	**3,338**	**36,301**

Notes:

(1) Included in Hawler License Area capital expenditure for the year ended December 31, 2017 are non-cash credits totalling $6.0 million related to revisions to estimates of costs incurred in prior periods and a non-cash credit of $2.4 million primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.

(2) For the year ended December 31, 2017, capital expenditures recorded in the OML 141 License Area include a non-cash credit of $2.2 million related to revisions to estimates of costs recorded in prior periods and a $0.7 million non-cash addition. For the three month period ended December 31, 2017, additions include a non-cash credit of $0.3 million related to revisions to estimates of costs recorded in prior periods.

(3) Included in Hawler License Area capital expenditure for the year ended December 31, 2016 is a $6.9 million non-cash addition relating to the change in discount and inflation rates used to calculate the decommissioning obligation and a $4.7 million non-cash addition relating to the change in the purchase date assumption used to calculate the finance lease asset.

(4) Non-cash credits relate to updated information received from the Operator which indicated a reduction in estimates of expenditures incurred in prior periods.

(5) During 2015, the Group fully impaired capitalised expenditures relating to its interest in the OML 141 License Area. During the second quarter of 2016, the Group recorded a $2.2 million non-cash addition to E&E assets relating to revisions to previous cost estimates. As the OML 141 License Area had been previously impaired a concurrent impairment charge of $2.2 million was also recorded during the second quarter of 2016. A $0.1 million adjustment to this figure was recorded during the third quarter of 2016 which related to actual expenditures incurred at values below those estimated in prior periods.

Middle East

During the three months ended December 31, 2017, the Group recorded capital additions of $2.5 million. The Group invested $0.1 million related to appraisal drilling activities on the Zey Gawra field, $0.2 million relating to facilities in the Hawler License Area, and $2.2 million related to PSC compliance.

During the year ended December 31, 2017, the Group recorded capital additions of $0.5 million. The Group invested $6.7 million related to appraisal activities on the Demir Dagh and Zey Gawra fields in the Hawler License Area and $2.2 million related to PSC compliance. These capital investments were offset primarily by $6.0 million in revisions to previous estimates of costs recorded related to the Hawler License Area and $2.4 million in non-cash credits relating to the revision of the discount and inflation rates used to calculate the Hawler License Area decommissioning obligation.

West Africa

Capital expenditures for West Africa for three and twelve months ended December 31, 2017 are primarily comprised of $0.4 million and $1.6 million, respectively, in seismic acquisition, processing and interpretation costs in the AGC Central License Area. The Group also invested $1.4 million in AGC Central PSC compliance costs during the fourth quarter of 2017. Remaining capital expenditures relate to investments in planning for drilling activities in the AGC Central License Area and directly attributable technical support costs.

Cost Pools

Cost Pools for each License Area, which are available for recovery through future oil sales from such License Area, as at December 31, 2017, 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	778.6	490.5	174.1(3)	(44.1)	620.5
AGC Central(4)	Senegal and Guinea Bissau	44.2	37.6	6.6	-	44.2
AGC Shallow(4)	Senegal and Guinea Bissau	-	-	-	-	-
Haute Mer A(5)	Congo (Brazzaville)	246.3	-(5)	-	-	-(5)
Haute Mer B(6)	Congo (Brazzaville)	22.8	-(6)	-	-	-(6)
		1,091.9	**594.0**	**180.7**	**(44.1)**	**664.7**

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 or deduction for tax purposes.

(3) Carried costs include $102.7million in expenditures related to a commitment to carry $300 million on behalf of a partner for the Hawler License Area development.

(4) On November 2, 2017 the Group relinquished its participating interest in the AGC Shallow License Area. Recoverable costs incurred under the terms of the AGC Shallow PSC have been transferred and are recoverable from future oil sales under the terms of the AGC Central License Area.

(5) 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 in the near future. Consequently, the Group has assumed its share of recoverable costs to be Nil.

(6) During February 2018, the Group accepted a non-binding offer to dispose of its interest in the Haute Mer B License Area. Subject to completion of customary due diligence and closing conditions, the transaction is expected to close during the second 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 expenditures described in the sections above, net of depletion, depreciation and amortisation ("**DD&A**") and net impairment recovery, have resulted in the following movements in intangible asset and PP&E balances during the three months ended March 31, 2017, June 30, 2017, September 30, 2017 and December 31, 2017:

($ thousands)	Exploration and Evaluation Assets	Other Intangible Assets	Total Intangible Assets
As at January 1, 2017	**89,829**	**102**	**89,931**
Capital additions	(1,722)(1)	-	(1,722)
Impairment recovery	1,132(1)(2)	-	1,132
DD&A	-	(39)	(39)
As at March 31, 2017	**89,239**	**63**	**89,302**
Capital additions	235	5	240
DD&A	-	(19)	(19)
As at June 30, 2017	**89,474**	**49**	**89,523**
Capital additions	292	-	292
DD&A	-	(16)	(16)
As at September 30, 2017	**89,766**	**33**	**89,799**
Capital additions	2,135	1	2,136
Impairment recovery	8,279(1)(2)	-	8,279
Transfer to Assets held for disposal	(8,000)	-	(8,000)
DD&A	-	(7)	(7)
As at December 31, 2017	**92,180**	**27**	**92,207**

Notes:

(1) Included in capital additions is a $1.9 million non-cash credit relating to revisions in cost estimates recorded in prior periods related to the OML 141 License Area. A further credit of $0.3 million relating to revisions in cost estimates recorded in prior periods related to the OML 141 License Area was recorded in the three months ending December 31, 2017. During 2015, the Group fully impaired capitalised expenditures related to its interest in the OML 141 License Area. An impairment recovery of $1.2 million has been recorded during the first quarter of 2017.

(2) *During 2016, the Group fully impaired capitalised expenditures related to its interest in the Congo Haute Mer B License Area. An impairment charge of $0.1 million has been recorded during the first quarter of 2017 based on updated estimates of costs previously recorded. In the fourth quarter of 2017 $8.0 million impairment reversal was recorded subsequent to the Group's entering into an agreement to dispose of its interest in the Haute Mer B License Area.*

($ thousands)	Oil & Gas assets	Finance lease asset	Furniture and fixtures	Total PP&E
As at January 1, 2017	**566,687**	**47,157**	**6**	**613,850**
Capital additions	(4,189)[(1)]	-	-	(4,189)
Transfers	47,157[(2)]	(47,157)[(2)]	-	-
DD&A	(1,119)	-	(6)	(1,125)
As at March 31, 2017	**608,536**	**-**	**-**	**608,536**
Capital additions	574[(3)]	-	-	574
DD&A	(1,102)	-	2	(1,100)
As at June 30, 2017	**608,008**	**-**	**2**	**608,010**
Capital additions	3,531	-	-	3,531
DD&A	(1,404)	-	1	(1,403)
As at September 30, 2017	**610,135**	**-**	**3**	**610,138**
Capital additions	2,475	-	-	2,475
Impairment charge	(27,726)[(4)]	-	-	(27,726)
DD&A	(2,266)	-	-	(2,266)
As at December 31, 2017	**582,619**	**-**	**3**	**582,622**

Notes:

(1) *Included in Hawler License Area capital expenditure for the three months ended March 31, 2017 are non-cash credits totalling $8.3 million relating to revisions in costs previously estimated.*

(2) *The Group entered into a leasing arrangement for production facilities in the Hawler License Area in September 2015. During the first quarter of 2017, an agreement to settle the finance lease was concluded and the production facilities previously classified as Finance lease assets were reclassified to Oil & Gas assets.*

(3) *Included in Hawler License Area capital expenditure for the three months ended June 30, 2017 is a non-cash credit of $2.8 million primarily related to the change in discount and inflation rates used to calculate the decommissioning obligation.*

(4) *During the fourth quarter of 2017, the Group recorded impairment charges of $27.7 million related to the Hawler License Area. Management used significant assumptions and estimates in determining the presence of indicators of impairment. See the "New Accounting Pronouncements, Policies, and Critical Estimates" sections of this MD&A for further information on the estimates used.*

Financial Results

Revenue

The following table summarises Oryx Petroleum's revenue for the three and twelve months ended December 31, 2017 and December 31, 2016. All oil sold during each of the below periods was produced at the Hawler License Area.

($ thousands)	Three months ended December 31		Year ended December 31	
	2017	2016	2017	2016
Oil Sales	11,260	7,050	33,641	20,534
Recovery of Carried Costs	1,247	782	3,726	2,275
Revenue	**12,507**	**7,832**	**37,367**	**22,809**

The Group recognised revenue on the sale of 225,000 bbl (Working Interest) of oil during the three months ended December 31, 2017, compared to revenue on the sale of 182,000 bbl (Working Interest) of oil during the same period in the previous year. Oil sales of $11.3 million during the fourth quarter of 2017 increased by $4.2 million compared to the three months ended December 31, 2016. The increase in oil sales is attributable to a 29% increase in realised sales price and a 24% increase in sales volumes.

The Group recognised revenue on the sale of 779,200 bbl (Working Interest) of oil during the year ended December 31, 2017, compared to revenue on the sale of 593,300 bbl (Working Interest) of oil during the same period in the previous year. Oil sales of $33.6 million during the year ended December 31, 2017 increased by $13.1 million compared to the year ended December 31, 2016. The increase in oil sales is attributable to a 25% increase in realised sales price combined with a 31% increase in sales volumes.

Production and sales were suspended for a total of 48 days during the first quarter of 2016 due primarily to the closure of the international land border crossing to Turkey.

Sales volumes are determined by the timing of deliveries to customers and are not directly correlated with production volumes in the same period. Sales exclude oil produced and held in oil inventory at the end of the reporting period. As at December 31, 2017, the Group's Working Interest share of oil inventory amounted to 12,000 bbl.

The Group has received full payment in accordance with PSC entitlements for all oil deliveries into the KRG's international export pipeline through the end of November 2017. At the date of the MD&A, the Group's entitlement share of amounts receivable totalling $7.3 million are due from the KRG for crude oil delivered to the pipeline during December 2017 - February 2018.

Royalties

The following table summarises royalty expense during the three and twelve months ended December 31, 2017 and December 31, 2016:

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Royalties	**5,504**	**3,446**	**16,444**	**10,037**

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 $2.1 million and $6.4 million, respectively, during the three and twelve months ended December 31, 2017 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 on oil sales as discussed above.

Operating expense

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Field production costs(1)	2,937	2,345	11,842	9,657
Partner's share of production costs carried by Oryx Petroleum	903	721	3,644	2,971
Operating expense	**3,840**	**3,066**	**15,486**	**12,628**
Sales(2) (bbl)	225,000	182,000	779,200	593,300
Field production costs(1) ($/bbl)	**13.06**	**12.88**	**15.20**	**16.28**
Operating expense ($/bbl)	**17.07**	**16.85**	**19.87**	**21.28**

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 $3.8 million in the three months ended December 31, 2017 increased by $0.8 million compared to the same period in the previous year. The increase in operating expense is primarily attributable to the costs associated with the operation of the Zey Gawra field that commenced production in December 2016, partially offset by lower operating costs at the Demir Dagh field resulting from the implementation of a cost reduction program.

Operating expense for the year ended December 31, 2017 amounted to $15.5 million ($19.87/bbl) in comparison to $12.6 million ($21.28/bbl) during 2016. The increase in costs is also attributable to operations at the Zey Gawra field which were initiated during December 2016, partially offset by lower operating costs at the Demir Dagh field resulting from the implementation of a cost reduction program.

General and administration

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Total General and Administration	**3,404**	**2,628**	**10,683**	**9,426**

General and administration expenses incurred during the three and twelve months ended December 31, 2017 include $1.1 million and $3.7 million, respectively, in support costs which were allocated to capital expenditures in prior periods. The increase in support costs allocated to general and administration expenditures has been mitigated by structural cost containment measures undertaken by the Group.

Exploration expense

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Total exploration expense	**223**	**314**	**1,026**	**954**

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.

Impairment of oil and gas assets

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Impairment (recovery) / expense of intangibles	(8,280)	16,324	(9,412)	17,751
Impairment expense of property, plant and equipment	27,726	-	27,726	1,039
Total impairment (recovery) / expense	**19,446**	**16,324**	**18,314**	**18,790**

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

During 2015, the Group fully impaired capitalised expenditures relating to its interest in the OML 141 License Area. An impairment recovery of $1.2 million has been recorded during the first quarter of 2017 based on revised estimates of previously impaired costs. A further $0.3 million impairment recovery was recorded during the fourth quarter of 2017. During the first quarter of 2017, a $0.1 million impairment expense was recorded relating to the Haute Mer B License Area which was fully impaired during the fourth quarter of 2016. The impairment expense for the year ended December 31, 2016 included a $16.3 million expense relating to the Haute Mer B License Area, a $2.2 million expense relating to a revision of estimates of previously capitalised costs in the OML 141 License Area and an impairment recovery of $0.7 million relating to the Sindi Amedi License Area. An impairment provision of $1.0 million was also recorded in relation to the Group's fixtures and equipment during the first quarter of 2016.

Depletion, depreciation and amortisation

The following table summarises the component parts of depletion, depreciation and amortisation for the three and twelve months ended December 31, 2017 and December 31, 2016:

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Intangible assets: Amortisation	-	47	81	252
PP&E assets: Depreciation	-	17	3	250
Depletion	2,276	1,204	5,894	5,068
Total DD&A	**2,276**	**1,268**	**5,978**	**5,570**

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 reserves from the Hawler License Area, the rate of depletion has increased during the fourth quarter of 2017.

Other income / expense

The following table summarises the components of other income / expense for the three and twelve months ended December 31, 2017 compared to the same periods in 2016:

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Settlement of finance lease liability	-	-	(7,605)	-
Impairment of materials inventory	(728)	808	(694)	9,087
Curtailment of retirement benefit obligation	-	298	-	(3,505)
Change in fair value of contingent consideration	628	1,252	59	5,344
Restructuring charge	-	-	(63)	2,192
Relinquishment Expense	1,523	-	1,523	-
Other (income)/expense	(116)	(128)	(191)	(310)
Other (income) / expense	**1,307**	**2,230**	**(6,971)**	**12,808**

Other expense for the three months ended December 31, 2017 relate primarily to a $1.5 million fee paid in connection with the relinquishment of the AGC Shallow License Area and a $0.6 million charge relating to the increase in the fair value of previously recognised contingent consideration partially offset by a $0.7 million reduction in inventory provision.

Other income for the twelve months ended December 31, 2017 in the amount of $7.0 million is primarily comprised of a $7.6 million gain related to the settlement of the finance lease obligation and a $0.7 million reduction in a previously recorded materials inventory provision partially offset by a $1.5 million fee paid in connection with the relinquishment of the AGC Shallow License Area.

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 December 31, 2017, amounts 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.

Finance expense

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Interest expense on Loan Facility	2,012	2,417	8,794	10,140
Accretion of deferred financing costs on Loan Facility	201	1,263	2,081	3,131
Interest expense on finance lease obligation	-	464	443	1,921
Interest on contingent costs	896	352	2,002	1,210
Accretion of decommissioning liability	96	148	342	386
Finance expense	**3,205**	**4,644**	**13,662**	**16,788**

Finance expense 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 described above.

Income tax expense

The following table summarises the component parts of income tax expense for the three and twelve months ended December 31, 2017 and December 31, 2016.

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Current income tax expense	329	210	1,020	1,019
Deferred tax (benefit) / expense	(1,226)	(133)	(1,095)	575
Total income tax expense	**(1,555)**	**77**	**(2,115)**	**1,594**

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 twelve months ended December 31, 2017, the Group met its day-to-day working capital requirements primarily through funding received through the cash receipts from oil sales and the 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 Group has drawn the full $100 million in funding available under the Loan Facility.

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 Amount**"), are payable at the Maturity Date or earlier, at the option of the borrower. Interest accrued on the Loan Amount after May 11, 2017 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 of the Company to a subsidiary of AOG for consideration of $4.0 million, which has been applied to extinguish accrued interest under the Loan Facility.

As at December 31, 2017 the carrying value of the balance owed under the Loan Facility was $75.9 million, including $1.1 million in accrued interest which the parties have agreed to settle through the issuance of Common Shares. The total undiscounted principal plus accrued interest owed at December 31, 2017 was $77.1 million.

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 December 31, 2017 was $64.8

million. The total undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation was $72.1 million as at December 31, 2017.

Liquidity outlook

The Group expects cash on hand as of December 31, 2017 and cash receipts from net revenues and export sales exclusively through the KRG's international export pipeline, will allow it to fund its forecasted cash expenditures and operating and administrative costs and to meet its obligations through the end of 2018. Beyond 2018, additional capital is likely required to fund further development of the Hawler License Area and for planned drilling in the AGC Central License Area.

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

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

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Operating Cash Flow[1]	(331)	(1,673)	(5,428)	(9,231)
Change in non-cash assets and liabilities relating to operating activities	(5,803)	1,089	(4,300)	(2,226)
Net cash used in operating activities	**(6,134)**	**(584)**	**(9,728)**	**(11,457)**
Additions to E&E and PP&E	(4,774)	(10,885)	(21,276)	(26,623)
Change in non-cash working capital	3,216	5,610	(1,053)	(8,050)
Net cash used in investing activities	**(1,558)**	**(5,275)**	**(22,329)**	**(34,673)**
Net cash generated by financing activities	-	-	**29,897**	**32,636**
Total change in cash	**(7,692)**	**(5,859)**	**(2,160)**	**(13,494)**
Cash and cash equivalents at beginning of the period	46,264	46,591	40,732	54,226
Cash and cash equivalents at end of the period	**38,572**	**40,732**	**38,572**	**40,732**

Note:

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

During the three months ended December 31, 2017, the Group invested $4.8 million in cash in exploration, appraisal, and development primarily in the Hawler and AGC Central License Areas. This amount is primarily composed of $2.2 million related to Hawler License Area PSC compliance, and $1.8 million of technical support costs mainly in the Hawler and AGC Central License Areas Operating activities during the quarter ended December 31, 2017 also consumed $6.1 million in cash resources reflecting a negative operating cash flow of $0.3 million and a $5.8 million increase in non-cash working capital which was primarily related to an increase in the revenue receivable balance outstanding at December 31, 2017 and a decrease in current accounts payable.

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 Kurdish 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. During 2018, the Group plans to fulfil financing requirements through current cash reserves, proceeds from the sale of assets held for disposal, and Operating Cash Flow. Beyond 2018, additional capital is likely required to fund further development of the Hawler License Area and for planned drilling 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 Cash Flows and to arrange further financing as needed.

While the Group retains the flexibility to defer certain budgeted expenditures and to adjust the timing of its expenditures on the development of the Hawler License Area, slowing the rate of development expenditures related to the Hawler License Area would be likely to impede the Group's ability to achieve expected production and sales levels.

Refer to the "Critical estimates" section of this MD&A for additional discussion regarding management's going concern assumption which contemplates that the Group will realise its assets and settle its liabilities and commitments in the normal course of business for the foreseeable future.

Economic Sensitivities

The following table shows the estimated effect that changes to crude oil prices, Gross (100%) oil sale volumes, operating costs and interest rates would have had on the Group's profit for the year ended December 31, 2017, had these changes occurred on January 1, 2017. These calculations are based on business conditions, production and sales volumes existing during the year ended December 31, 2017. 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	5,317	0.01
Change in crude oil sales volumes	1,000 bbl/d	6,988	0.02
Change in operating expenses	$1.00/bbl	779	-
Change in interest rate	1%	562	-

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 Cash Flow

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

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

	Three months ended December 31		Year ended December 31	
($ thousands)	2017	2016	2017	2016
Net cash used in operating activities	(6,134)	(584)	(9,728)	(11,457)
Changes in non-cash assets and liabilities	5,803	(1,089)	4,300	2,226
Operating Cash Flow	**(331)**	**(1,673)**	**(5,428)**	**(9,231)**

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. On September 1, 2017, the Group issued 2,248,616 Common Shares to employees under the Group's Long Term Incentive Plan. 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 Group's Long Term Incentive Plan.

On December 8, 2017, the Group issued 24,481,049 Common Shares for consideration of $4.0 million used to extinguish accrued interest under the Loan Facility.

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.

At the date of this M&DA, a total of 458,422,779 Common Shares were issued and outstanding.

The following table summarises warrants which were issued in conjunction with the Loan Facility and are outstanding and exercisable at December 31, 2017:

	Warrants	Exercise price USD	Expiry date
Issued March 11, 2015	1,000,000	3.29	March 10, 2018
Issued May 11, 2015	7,000,000	3.56	May 11, 2018
Issued December 15, 2015	4,000,000	0.50	December 15, 2018
Total outstanding and exercisable	**12,000,000**		

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 twelve months ended December 31, 2017.

Commitments and Contractual Obligations

The table below sets forth information relating to Oryx Petroleum's commitments and contractual obligations as at December 31, 2017.

($ thousands)	Within One Year	From 1 to 5 Years	More than 5 Years	Total
Operating leases(1)	286	46	-	**332**
Other obligations(2)(3)	5,900	38,500	16,100	**60,500**
Total	**6,186**	**38,546**	**16,100**	**60,832**

(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			
	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
Revenue, net of royalties	671	3,949	3,766	4,386	4,426	3,982	5,512	7,004
Operating expense	(3,493)	(3,230)	(2,839)	(3,066)	(4,249)	(4,032)	(3,364)	(3,840)
Depletion	(502)	(1,746)	(1,616)	(1,204)	(1,108)	(1,101)	(1,409)	(2,276)
G&A	(2,590)	(2,058)	(2,150)	(2,628)	(2,584)	(2,512)	(2,183)	(3,404)
Loss	(19,429)	(11,354)	(8,738)	(26,205)	4,137	(9,199)	(5,860)	(28,128)
Loss per share (basic and diluted) ($/share)	(0.13)	(0.05)	(0.04)	(0.10)	0.02	(0.03)	(0.01)	(0.06)
Operating cash flow	(5,691)	(1,222)	(645)	(1,676)	(2,350)	(2,101)	(646)	(331)
Gross Production (bbl)	69,100	284,700	264,500	286,000	263,300	260,200	330,900	347,800
WI Production (bbl)	44,900	185,100	172,000	186,000	171,200	169,100	215,100	226,100
Gross Sales (bbl)	82,000	286,100	264,800	279,900	261,100	259,600	332,000	346,100
WI Sales (bbl)	53,300	186,000	172,100	182,000	169,800	168,800	215,800	225,000
Field production costs(1)	(2,671)	(2,470)	(2,171)	(2,345)	(3,249)	(3,083)	(2,572)	(2,937)
Field Netback(2)	(2,143)	631	788	1,099	228	44	1,757	2,564
Oryx Petroleum Netback(2)	(2,846)	574	790	1,160	16	(196)	1,947	2,908
Brent price ($/bbl)	34.54	45.89	45.85	49.96	54.13	50.28	51.72	61.26
Sales price ($/bbl)	20.25	34.15	35.19	38.75	41.92	37.93	41.07	50.04
Royalties ($/bbl)	(9.90)	(16.70)	(17.20)	(18.93)	(20.48)	(18.55)	(20.08)	(24.46)
Field production costs(1) ($/bbl)	(50.11)	(13.28)	(12.61)	(12.88)	(19.13)	(18.25)	(11.92)	(13.06)
Current taxes ($/bbl)	(0.45)	(0.78)	(0.80)	(0.88)	(0.95)	(0.86)	(0.93)	(1.13)
Field Netback(2) ($/bbl)	(40.21)	3.39	4.58	6.04	1.35	0.27	8.14	11.39
Oryx Petroleum Netback(2) ($/bbl)	(53.40)	3.09	4.59	6.37	0.10	(1.15)	9.02	12.92
Capital expenditures	4,322	17,243	4,227	10,513	(5,911)	814	3,823	4,611

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 Cash 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 months ended December 31, 2017. During the first quarter of 2016, production and sales were interrupted primarily due to the closure of the land border crossing between the Kurdistan Region of Iraq and Turkey.

Variations in Field Netback and Oryx Petroleum Netback reflect changes in revenue discussed above and the impact of changes in field production costs. Field production costs were initially subject to significant fluctuation as management aligned operating procedures and the related expenditures with fluctuating actual and expected production volumes. 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 reflect management's consequent efforts to reduce costs.

Total capital expenditures 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 December 31, 2017 was $28.1 million compared to $26.2 million during the fourth quarter of 2016. The increase in loss for the period is primarily attributable to i) an $3.1 million increase in impairment charge (primarily relating to the Hawler License Area), ii) a $1.5 million increase in income tax expense as a result of the deferred tax asset balance write off in relation to the pension obligation, iii) a $1.0 million increase in the depletion charge mainly related to the decrease in estimated reserves base and iv) a $0.8 million increase in operating expense primarily related to costs associated with production from the Zey Gawra field in the Hawler License Area which commenced in December 2016. These negative factors were partially offset by i) an increase in net revenue of $2.6 million, and ii) a $1.4 million decrease in finance expense which was primarily related to the decrease in the Loan Facility's principal balance outstanding.

Operating expense of $3.8 million in the three months ended December 31, 2017 increased by $0.8 million compared to the same period in the previous year. The increase in operating costs is primarily attributable to the costs associated with the operation of the Zey Gawra field that commenced production in December 2016, partially offset by lower operating costs at the Demir Dagh field resulting from the implementation of a cost reduction program.

Selected Annual Information

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

	Year ended December 31		
($ thousands except per share amounts)	2017	2016	2015
Revenue	37,368	22,809	20,467
Loss attributable to owners	39,033	65,707	415,235
Loss per share (basic and diluted)	0.11	0.31	*3.43*
Total assets	744,798	766,445	779,661
Long-term debt	**75,854**	**93,103**	**97,120**

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

Financial and Other Instruments and Off Balance Sheet Arrangements

Oryx Petroleum operates internationally and has foreign exchange risk arising from various currency exposures, notably the Swiss Franc. In January 2017, the Group entered into five foreign exchange contracts. The Group entered into these contracts to sell $0.3 million and to receive Swiss Francs at various rates for each of the five months from February to June 2017 in order to hedge its exposure to foreign exchange risk for each of the subsequent five months. In July 2017, the Group entered into five foreign exchange contracts. The Group committed to sell $0.2 million and to receive Swiss Francs during each of the five months from August to December 2017.The group has recorded an unrealised foreign exchange loss of Nil during the three months ended December 31, 2017. During the year ended December 31, 2017, the Group recorded a realised foreign exchange gain of $12,000 and an unrealised foreign exchange loss of $52,000 relating to these agreements.

Other than the above, Oryx Petroleum was not party to any off-balance sheet arrangements during the year ended December 31, 2017 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 $8.8 million relating to this transaction has been recorded for the year ended December 31, 2017 (2016 - $10.1 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 of the Company to a subsidiary of AOG for consideration of $4.0 million, which has been applied to extinguish accrued interest under the Loan Facility. Management has estimated 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 $50 thousand and $183 thousand relating to this agreement was recorded for the three and twelve months ended December 31, 2017, respectively. An operating lease commitment of $0.2 million has been included in commitments as at December 31, 2017.

For the three and twelve months ended December 31, 2017, the Group incurred costs of $0.4 million and $1.5 million, respectively, for goods and services provided by related parties, all of which are subsidiaries of AOG (2016: $0.4 million and $1.8 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, 2017 available on SEDAR at www.sedar.com. Management exercised judgment, which was based on its industry specific knowledge and experience, to determine that i) the transactions described above did not contain any unusual commercial terms, and ii) the fees charged under the agreements were reasonable and not materially inconsistent with fees which would normally be associated with broadly comparable agreements.

In January 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. In July 2016, directors of OPCL were awarded 171,399 Common Shares ($0.1 million) and $0.2 million in cash as remuneration for services provided in the first and second quarters of 2016. In January 2016, directors of OPCL were awarded 405,316 Common Shares ($0.2 million) and $0.2 million in cash as remuneration for services provided in the third and fourth quarters of 2015. Of this amount, 155,659 Common Shares ($0.1 million) were issued to directors in January 2016. The balance of 249,657 Common Shares ($0.1 million) was issued to directors of OPCL in July 2016.

The Loan Amendment as discussed in the Liquidity and Capital Resources section of this MD&A are transactions involving related parties.

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, 2017 as described in Note 2 of the Financial Statements. The adoption of these standards and interpretations has not had a material effect on OPCL.

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, 2016 remain applicable to the three and twelve month periods ended December 31, 2017 and, with the exception of the estimates discussed below, there have been no material changes in estimates.

Going Concern

These Financial Statements have been prepared on a going concern basis which contemplates the realisation of assets and the satisfaction of liabilities and commitments in the normal course of business for the foreseeable future. During 2017, the Group met its day to day working capital requirements, and funded its capital and operating expenditures through funding received from the proceeds of share issuances (note 18) and its share of oil sales revenues from the Hawler License Area.

Management expects that the cash resources on hand as at December 31, 2017, proceeds from the sale of assets held for disposal (note 12), 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 to meet obligations as they fall due in the 15 months following December 31, 2017.

The Group's ability to continue as a going concern in accordance with management's estimates and forecasts is primarily dependent on realisation of forecasted revenues. The estimates related to the realisation of forecasted revenues are subject to uncertainties.

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

i) Oil sales volume assumptions are based on historical production volumes adjusted to recognise the impact of production increases expected to result from planned drilling activities. Crude oil price assumptions are based on Brent forward contract prices adjusted for transportation costs and quality differentials. Management's forecast assumes net cash receipts from sales of its share of oil production from the Hawler License Area of $62.9 million during the 15 months ending March 31, 2019.

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

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 these 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 these Financial Statements.

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.

An evaluation of the design and operational effectiveness of Oryx Petroleum's DC&P in place during 2017 was carried out under the supervision of, and with the participation of management including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the DC&P were effective as at December 31, 2017.

Internal Controls over Financial Reporting

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

An evaluation of the design and operational effectiveness of Oryx Petroleum's ICFR in place during 2017 was carried out under the supervision of, and with the participation of management, including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the ICFR were effective as at December 31, 2017. There were no changes in Oryx Petroleum's ICFR during the year ended December 31, 2017 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, and cash receipts from net revenues and exports sales exclusively through the pipeline will allow the Corporation to fund forecasted cash expenditures needed to sustain the Group's operations and meet license commitments through the end of 2018, business and acquisition strategy and goals, opportunities, drilling and well workover plans, development plans and schedules and chance of success, results of exploration activities, declarations of commercial discovery, contingent liabilities and government approvals, the ability to consistently access the export pipeline or other exterior facilities to sell oil production, sales channels for future sales, future drilling of new wells and the reservoirs to be targeted, costs and drilling times for new wells, ultimate recoverability of current and long-term assets, estimates of oil reserves and resources, future royalties and tax levels, access to and sources of future financing and liquidity, future debt levels, availability of committed credit facilities, possible commerciality of our projects, expected operating capacity, expected operating costs, guidance regarding operating expenses on a per barrel basis, plans to continue processing and interpreting 3D seismic data from the AGC Central License Area and identifying prospects, 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, 2017, available at www.sedar.com and the Group’s website at www.oryxpetroleum.com.

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

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

Reserves and Resources Advisory

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

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

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

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

Glossary and Abbreviations

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

AGC
Agence de Gestion et de Cooperation, 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