SAHARA ENERGY LTD.
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION
(Form 51-101F1)

Part 1 – Date of Statement

This statement of reserves data and other oil and gas information is dated March 10, 2017.

The effective date is December 31, 2016.

The preparation date is March 10, 2017.

Part 2 – Disclosure of Reserves Data

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Sahara Energy Ltd. (the "Company") as evaluated by Chapman Petroleum Engineering Ltd. ("Chapman") as at December 31, 2016, and dated March 10, 2017 (the "Chapman Report"). Chapman is an independent qualified reserves evaluator and auditor.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Chapman Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Chapman Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

All monetary values presented in this document are expressed in terms of Canadian dollars.

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2016

	Company Reserves[1]							
	Light and Medium Oil		Heavy Oil		Conventional Natural Gas[9]		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing[2][6]	7	6	0	0	0	0	0	0
Developed Non-Producing[2][7]	0	0	12	11	0	0	0	0
Undeveloped[2][8]	0	0	17	14	0	0	0	0
TOTAL PROVED[2]	**7**	**6**	**30**	**26**	**0**	**0**	**0**	**0**
TOTAL PROBABLE[3]	3	3	622	535	0	0	0	0
TOTAL PROVED + PROBABLE[2][3]	**10**	**9**	**651**	**561**	**0**	**0**	**0**	**0**
TOTAL POSSIBLE[4]	0	0	179	153	0	0	0	0
TOTAL PROVED + PROBABLE + POSSIBLE	**10**	**9**	**830**	**714**	**0**	**0**	**0**	**0**

SUMMARY OF NET PRESENT VALUES BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2016

	Net Present Values of Future Net Revenue									
	Before Income Tax Discounted at					After Income Tax Discounted at				
Reserves Category	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M
PROVED										
Developed Producing(2)(6)	186	156	132	114	100	186	156	132	114	100
Developed Non-Producing(2)(7)	45	51	55	57	58	45	51	55	57	58
Undeveloped(2)(8)	127	88	60	39	23	127	88	60	39	23
TOTAL PROVED(2)	**358**	**295**	**247**	**210**	**181**	**358**	**295**	**247**	**210**	**181**
TOTAL PROBABLE(3)	7,104	5,325	4,083	3,194	2,537	7,104	5,325	4,083	3,194	2,537
TOTAL PROVED + PROBABLE(2)(3)	**7,462**	**5,620**	**4,330**	**3,403**	**2,718**	**7,462**	**5,620**	**4,330**	**3,403**	**2,718**
TOTAL POSSIBLE(4)	1,190	555	156	(99)	(262)	1,190	555	156	(99)	(262)
TOTAL PROVED + PROBABLE + POSSIBLE	**8,652**	**6,175**	**4,486**	**3,304**	**2,456**	**8,652**	**6,175**	**4,486**	**3,304**	**2,456**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2016

	Revenue ($M)	Royalties ($M)	Operating Costs ($M)	Development Costs ($M)	Abandonment and Reclamation Costs ($M)	Future Net Revenue Before Income Taxes ($M)	Income Taxes ($M)	Future Net Revenue After Income Taxes ($M)
Total Proved(2)	2,018	218	1,100	170	173	358	0	358
Total Proved Plus Probable(2)(3)	35,582	4,794	17,701	4,524	1,101	7,462	0	7,462
Total Proved Plus Probable Plus Possible(4)	46,123	6,293	23,495	6,259	1,425	8,652	0	8,652

FUTURE NET REVENUE BY PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2016

Reserve Category	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($M)
Total Proved(2)	Light and Medium Oil (including solution gas and other by-products)	132
	Heavy Oil (including solution gas and other by-products)	116
	Conventional Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable(2)(3)	Light and Medium Oil (including solution gas and other by-products)	180
	Heavy Oil (including solution gas and other by-products)	4,150
	Conventional Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable Plus Possible(4)	Light and Medium Oil (including solution gas and other by-products)	180
	Heavy Oil (including solution gas and other by-products)	4,306
	Conventional Natural Gas (including by-products but not solution gas)	0

OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2016

	Reserves						Net Present Value (BIT)	Unit Values @ 10%/yr
	Oil		Conventional Natural Gas[9]		NGL			
Product Type by Reserve Category	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl	10% M$	
Light and Medium Oil								
Proved								
Developed Producing	7	6	0	0	0	0	132	21.3
Developed Non-Producing	0	0	0	0	0	0	0	N/A
Undeveloped	0	0	0	0	0	0	0	N/A
Total Proved	**7**	**6**	**0**	**0**	**0**	**0**	**132**	**21.3**
Probable	3	3	0	0	0	0	48	17.0
Proved Plus Probable	**10**	**9**	**0**	**0**	**0**	**0**	**180**	**19.9**
Possible	0	0	0	0	0	0	0	N/A
Proved + Probable + Possible	**10**	**9**	**0**	**0**	**0**	**0**	**180**	**19.9**
Heavy Oil								
Proved								
Developed Producing	0	0	0	0	0	0	2	N/A
Developed Non-Producing	12	11	0	0	0	0	55	4.8
Undeveloped	17	14	0	0	0	0	60	4.2
Total Proved	**30**	**26**	**0**	**0**	**0**	**0**	**116**	**4.5**
Probable	622	535	0	0	0	0	4,034	7.5
Proved Plus Probable	**651**	**561**	**0**	**0**	**0**	**0**	**4,150**	**7.4**
Possible	179	153	0	0	0	0	156	1.0
Proved + Probable + Possible	**830**	**714**	**0**	**0**	**0**	**0**	**4,306**	**6.0**

Notes:

1. "Gross Reserves" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.
2. "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
3. "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
4. "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
5. "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.
6. "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
7. "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
8. "Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.
9. Includes associated, non-associated and solution gas where applicable.

Part 3 - Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Company operated, as at December 31, 2016, reflected in the reserves data disclosed above under “Part 2 – Disclosure of Reserves Data”. The forecast price assumptions assume the continuance of current laws and regulations and take into account inflation with respect to future operating and capital costs. There will be adjustments to field prices from the benchmarks below:

CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES

January 1, 2017

Date		**WTI [1] $US/STB**	**Brent Spot (ICE)[2] $US/STB**	**AB Synthetic Crude Price [3] $CDN/STB**	**Western Canada Select [4] $CDN/STB**	**Exchange Rate $US/$CDN**
HISTORICAL PRICES						
2009		61.95	61.74	76.77	53.04	0.88
2010		79.48	79.61	80.56	66.58	0.97
2011		94.88	111.26	102.45	77.43	1.01
2012		94.05	111.63	92.56	71.70	1.00
2013		97.98	108.56	100.17	75.76	0.97
2014		93.12	99.43	101.07	82.07	0.91
2015		48.69	53.32	62.17	46.23	0.78
2016	12 mos	43.17	45.06	57.98	38.90	0.76
CONSTANT PRICES (The average of the first-day-of-the-month price for the preceding 12 months-SEC)						
		42.71	44.49	57.08	38.06	0.75
FORECAST PRICES						
2017		**55.00**	57.20	73.20	51.24	0.76
2018		**60.00**	62.40	75.83	56.11	0.80
2019		**65.00**	67.60	79.14	58.57	0.83
2020		**70.00**	72.80	85.17	63.02	0.83
2021		**72.50**	75.40	86.12	63.73	0.85
2022		**75.00**	78.00	89.07	65.91	0.85
2023		**77.50**	80.60	92.01	68.08	0.85
2024		**80.00**	83.20	94.95	70.26	0.85
2025		**82.50**	85.80	97.89	72.44	0.85
2026		**85.00**	88.40	100.83	74.61	0.85
2027		**87.50**	91.00	103.77	76.79	0.85
2028		**89.25**	92.82	105.83	78.31	0.85
2029		**91.04**	94.68	107.93	79.87	0.85
2030		**92.86**	96.57	110.07	81.45	0.85
2031		**94.71**	98.50	112.26	83.07	0.85
2032		**96.61**	100.47	114.49	84.72	0.85
Constant thereafter						

Notes:
[1] West Texas Intermediate quality (D2/S2) crude (40API) landed in Cushing, Oklahoma.
[2] The Brent Spot price is estimated based on historic data.
[3] Equivalent price for Light Sweet Crude (D2/S2) & Synthetic Crude landed in Edmonton.
[4] Western Canada Select (20.5API), spot price for B.C., Alberta, Saskatchewan, and Manitoba.

The Company’s weighted average prices received this fiscal year are: $41.68/Bbl for light-medium oil and $12.94/Bbl for heavy oil.

Part 4 – Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at December 31, 2016 against such reserves as at December 31, 2015 based on the forecast price and cost assumptions:

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2016

	Light and Medium Oil					Heavy Oil					Conventional Natural Gas (Associated and Non-Associated)				
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (MMscf)	Gross Probable (MMscf)	Gross Proved Plus Probable (MMscf)	Gross Possible (MMscf)	Gross Proved Plus Probable Plus Possible (MMscf)
At Dec. 31, 2015	**6**	**3**	**9**	**0**	**9**	**32**	**617**	**650**	**179**	**829**	**0**	**0**	**0**	**0**	**0**
Production(Sales)	-1	0	-1	0	0	-1	0	-1	0	-1	0	0	0	0	0
Acquisitions Dispositions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions & Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	-1	0	4	0	0	-1	5	2	0	2	0	0	0	0	0
At Dec. 31, 2016	**7**	**3**	**10**	**0**		**30**	**622**	**651**	**179**	**830**	0	0	0	0	0

Numbers are subject to rounding errors

Part 5 – Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Conventional Natural Gas (MMscf)**	**Natural Gas Liquids (Mbbl)**
Aggregate prior to 2014	0	0	0	0
2014	0	15	0	0
2015	0	17	0	0
2016	0	0	0	0

The following table sets forth the volumes of probable undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2014	0	0	0	0
2014	0	374	0	0
2015	0	0	0	0
2016	0	0	0	0

The following table sets forth the volumes of possible undeveloped reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before such time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2014	0	0	0	0
2014	0	177	0	0
2015	0	2	0	0
2016	0	0	0	0

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developing those undeveloped reserves.

Probable Undeveloped Reserves

The Company's probable undeveloped reserves are assigned to three drilling locations in the Bodo developed pool, three drilling locations in the Lloydminster developed pool and one location and one re-entry well incremental in the Lashburn with a mapped and potentially developed oil pool. These reserves are to be developed in 2017, 2018 and 2019.

Possible Undeveloped Reserves

The Company's Possible Undeveloped reserves are assigned to those drilling locations in the Lloydminster developed pool and one location in the Maidstone developed pool.

Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. All of the Company's reserves are evaluated by Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which have been deducted in the estimation of the future net revenues of the proved and probable reserves.

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)
2017	0	2000
2018	170	425
2019	0	2050
2020	0	0
2021	0	0
Total for five years	170	4475
Remainder	0	50
Total for all years	170	4525

The Company has been successful in raising its required capital through equity financings and plans to continue to do so for the development costs specified above. The effect of the costs of the expected funding would have no impact on the revenues or reserves currently being reported.

Part 6 – Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2016:

	Oil		Conventional Natural Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]
ALBERTA				
Bodo Area				
Producing	0	0	0	0
Non-producing	2	2	0	0
Czar Area				
Producing	3	0.6	0	0
Non-producing	0	0	0	0
Lloydminster Area				
Producing	1	1	0	0
Non-producing	0	0	0	0
SASKATCHEWAN				
Dee Valley Area				
Producing	0	0	0	0
Non-producing	2	1	0	0
Lashburn Area				
Producing	0	0	0	0
Non-producing	4	1.3	0	0
Maidstone Area				
Producing	0	0	0	0
Non-producing	3	1	0	0

[1] Total number of wells in which the Company has a working interest.
[2] Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

All of the Company's wells are located onshore in Alberta and Saskatchewan.

Properties with No Attributed Reserves

The Company has an interest in some land or shut-in wells in Alberta and Saskatchewan for which the Company has no development plans, and which are not included in the evaluation.

Forward Contracts

Currently, the Company has no forward contracts.

Tax Horizon

The Company is not expected to become taxable under the proved plus probable plus possible cash flows forecast in this report.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and conventional natural gas properties for the year ended December 31, 2016.

Property Acquisition Costs ($M)		Exploration Costs ($M)	Development Costs ($M)
Proved Properties	**Unproved Properties**		
Nil	Nil	Nil	Nil

The Company has no unconventional oil and gas projects for which exploration costs would be required.

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2016 financial year:

	Exploratory Wells		Development Wells	
	Gross[1]	**Net[2]**	**Gross[1]**	**Net[2]**
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Dry Holes	0	0	0	0
Total Completed Wells	0	0	0	0

[1] Total number of wells in which the Company has a working interest.
[2] Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

The Company did not drill or develop any additional reserves in the fiscal year.

Production Estimates

The following table sets forth the volume of production estimated by Chapman for 2017 (12 mo.)

TOTAL PROVED RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
ALBERTA				
Bodo Area	0	0	0	0
Czar Area	0.74	0	0	0
Lloydminster Area	0	0	0	0
SASKATCHEWAN				
Dee Valley Area	0	0	0	0
Lashburn Area	0	0	0	0
Maidstone Area	0	1.2	0	0
Total for all areas	**0.74**	**0**	**0**	**0**

TOTAL PROVED PLUS PROBABLE RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
ALBERTA				
Bodo Area	0	50	0	0
Czar Area	0.75	0	0	0
Lloydminster Area	0	1.3	0	0
SASKATCHEWAN				
Dee Valley Area	0	0	0	0
Lashburn Area	0	0	0	0
Maidstone Area	0	2.2	0	0
Total for all areas	**0.75**	**53.4**	**0**	**0**

These values are gross to Company’s working interest before the deduction of royalties payable to others.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year:

	Three Months Ended March 31, 2016	**Three Months Ended June 30, 2016**	**Three Months Ended September 30, 2016**	**Three Months Ended December 31, 2016**
Average Daily Production				
Light and Medium Oil (Bbl/d)	2.7	2.9	2.9	2.8
Heavy Oil (Bbl/d)	4.0	0.1	–	–
Conventional Natural Gas (Mscf/d)	–	–	–	–
Average Net Prices Received				
Light and Medium Oil ($/Bbl)	27.55	44.12	44.19	50.10
Heavy Oil ($/Bbl)	13.26	4.47	–	–
Conventional Natural Gas ($/Mscf)	–	–	–	–
Royalties				
Light and Medium Oil ($/Bbl)	0.77	1.26	1.25	1.44
Heavy Oil ($/Bbl)	0.34	–	–	–
Conventional Natural Gas ($/Mscf)	–	–	–	–
Production Costs				
Light and Medium Oil ($/Bbl)	76.90	109.62	100.82	118.38
Heavy Oil ($Bbl)	104.79	258.42	–	–
Conventional Natural Gas ($/Mscf)	–	–	–	–
Netback Received				
Light and Medium Oil ($/Bbl)	(50.12)	(66.77)	(57.88)	(69.72)
Heavy Oil ($Bbl)	(91.87)	(253.95)	–	–
Conventional Natural Gas ($/Mscf)	–	–	–	–

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
MSTB	1,000 stock tank barrels
Bbls/d	barrels per day
NGLs	natural gas liquids
STB	stock tank barrels of oil
STB/d	stock tank barrels of oil per day

Natural Gas

Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
Mscf/d	thousand standard cubic feet per day
MMscf/d	million standard cubic feet per day
MMBTU	million British Thermal Units
Bscf	billion standard cubic feet
GJ	gigajoule

Other

AECO	Niska Gas Storage's natural gas storage facility located at Suffield, Alberta.
BIT	Before Income Tax
AIT	After Income Tax
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mscf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
$M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade