FORM 51-101F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

Oil and Gas Reserves and Net Present Value of Future Net Revenue

In accordance with National Instrument 51-101 – Standard of Disclosure for Oil and Gas Activities, McDaniel & Associates Consultants Ltd. ("McDaniel"), independent petroleum engineering consultants, prepared a report (the "McDaniel Report") dated 24 March 2016. This statement of reserves data and other oil and gas information (this "Statement") uses the information provided in the McDaniel Report. All financial information in this Statement is in US dollars. This Statement was prepared on 13 April 2016 and is effective 31 December 2015.

The McDaniel Report evaluated, as at 31 December 2015, Orca Exploration Group Inc.'s (the "Company" or "Orca Exploration") Tanzanian conventional natural gas reserves for the period to the end of its licence in October 2026. The tables below are a summary of the conventional natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Report utilising forecast price and cost assumptions. The tables summarize the data contained in the McDaniel Report and as a result may contain slightly different numbers due to rounding. The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and out of country general and corporate administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by the Company and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Orca Exploration to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

RESERVES DATA – FORECAST PRICES AND COSTS

Summary of Oil and Gas Reserves as of December 31, 2015

	Company Gross Reserves			Company Net Reserves		
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Conventional Natural Gas**	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Conventional Natural Gas**
	Mbbl	*Mbbl*	*MMcf*	*Mbbl*	*Mbbl*	*MMcf*
Proved						
Developed Producing	-	-	245,928	-	-	158,514
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	121,896	-	-	70,483
Total Proved	-	-	367,823	-	-	228,997
Probable	-	-	49,125	-	-	40,937
Total Proved plus Probable	-	-	416,949	-	-	269,934

Summary of Net Present Value of Future Net Revenue of Oil and Gas Reserves as of December31, 2015

	Before Future Income Tax Expenses(8) Discounted at					Unit Value Before Tax at 10%
	0%	5%	10%	15%	20%	$/Mcf
(US$'000)						
Proved						
Developed Producing	393,687	294,629	229,225	184,596	153,197	1.45
Developed Non Producing	-	-	-	-	-	-
Undeveloped	168,112	114,690	79,423	55,503	38,878	1.13
Total Proved	561,798	409,319	308,648	240,100	192,075	1.35
Probable	92,805	65,853	48,823	37,732	30,302	1.19
Total Proved plus Probable	654,603	475,172	357,471	277,832	222,377	1.32

	After Future Income Tax Expenses(8) Discounted at				
	0%	5%	10%	15%	20%
(US$'000)					
Proved					
Developed Producing	393,687	294,629	229,225	184,596	153,197
Developed Non Producing	-	-	-	-	-
Undeveloped	168,112	114,690	79,423	55,503	38,878
Total Proved	561,798	409,319	308,648	240,100	192,075
Probable	92,805	65,853	48,823	37,732	30,302
Total Proved plus Probable	654,603	475,172	357,471	277,832	222,377

Notes:

1. The crude oil and natural gas reserves estimates presented in the McDaniel Report have been based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the Canadian Oil and Gas Evaluation (the "COGE" Handbook"). A summary of those definitions is presented below.
2. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.
3. Reserves are classified according to the degree of certainty associated with the estimates:
   (a) 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.
   (b) 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.
   (c) 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.
   (d) Other criteria that must also be met for the categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.
4. Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:
   (a) 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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
   (b) 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.
   (c) 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.
   (d) Undeveloped reserves are those reserves expected to be recovered from known 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.
5. The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:
   (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
   (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
   (c) at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

   Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5of the COGE Handbook.
6. "Company Gross Reserves" are the total of the Company's working and/or royalty interest share after Tanzania Petroleum Development Corporation ("TPDC") back-in and before deduction of royalties owned by others. It represents the Company's percentage working interest in the property gross reserves.
7. "Company Net Reserves" are the total of the Company's working and/or royalty interest share after deducting the amounts attributable to royalties and Profit Gas owned by others, and represent the Company's share of total Cost Gas and Profit Gas.
8. See "Tax Horizon" for details of tax treatment.
9. There are no state royalties in the Songo Songo Production Sharing Agreement ("PSA").
10. In the McDaniel Report, it has been assumed that TPDC will exercise its right to 'back in' to the field development associated with the SS-N well to earn a 20% increase in the profit share for the production emanating from these wells, the "back-in" rights are assumed to be a carried interest. McDaniel has taken the view that this 'back in' right should be treated as a TPDC working interest and therefore the Gross Property reserves have been adjusted for the volumes of natural gas that are allocated to TPDC for their working interest share. The average effective TPDC working interest in proved plus probable reserves over the life of the licence is 1%, or a total of 3,907 MMcf. The outcome of any final agreement on TPDC future back-in rights may lead to a change in the economic terms of the PSA, but cannot be estimated at this time.
11. The separation of the downstream assets was raised by the Ministry Energy and Mines ("MEM") in the National Natural Gas Policy issued in 2013, which contemplates TPDC as monopoly aggregator and distributor of gas. In the context of the gas policy, TPDC and MEM have indicated that they wish the Company to unbundle the downstream distribution

business in Tanzania. The potential unbundling of the downstream business will be addressed at such time as there is a conflict between new legislation and the Company's right under the PSA. The provisions of the PSA are such that the Company is to be kept economically whole if any legislation affects the Company's economic benefits under the PSA.

12. During the third quarter of 2015, The Petroleum Act, 2015, (the "Act") was passed into law by Presidential decree. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and as well consolidates and puts in place a single, effective and comprehensive legal framework for regulating the oil and gas industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory (PURA). The mid and downstream petroleum as well as gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority (EWURA). The bill also confers upon on TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in the petroleum operations as well as mid and downstream natural gas activities. The bill vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC does not extend to mid and downstream petroleum supply operations. The Company is uncertain regarding the potential impact on its business in Tanzania. The Act does provide grandfathering provisions upholding the rights of the Company under the PSA as it was signed prior to the passing of the Act. However, it is still unclear how the provisions of the Act will be interpreted and implemented regarding upstream and downstream activities.

Total Future Net Revenue – (Undiscounted) as of December 31, 2015

(US$'000)	Revenue[1]	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Total Proved Reserves	828,192	-	163,878	102,516	-	561,798	-	561,798
Total Proved plus Probable	1,052,769	-	186,003	212,163	-	654,603	-	654,603

Note:

1. Revenue is net of Additional Profits Tax which is a form of royalty.

Future Net Revenue by Product Type as of December 31, 2015

(US$'000)	Future Net Revenue Before Future Income Tax Expenses Discounted at 10%	Net Unit Value Before Income Taxes Discounted at 10% ($/Mcf)
Proved		
Light and Medium Crude Oil[1]	-	-
Natural Gas Liquids		
Conventional Natural Gas[2]	308,648	1.35
Proved plus Probable		
Light and Medium Crude Oil[1]	-	-
Natural Gas Liquids		
Conventional Natural Gas[2]	357,471	1.32

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas.
3. Unit values are based on net reserve volumes.

Pricing Assumptions – Forecast Prices, Costs and Gas Sales

McDaniel employed the following gas sales, pricing and inflation rate assumptions as of 31 December 2015 in estimating the Company's reserves data using forecast prices and costs. The Company received an average conventional natural gas price of US$4.49/Mcf in 2015.

		Songo Songo gas prices		
	Brent crude	Proved	Proved plus probable	Annual inflation %
Year	US$/bbl	US$/Mcf	US$/Mcf	
2016	47.50	3.99	4.03	2
2017	56.20	4.10	4.27	2
2018	65.00	4.06	4.27	2
2019	71.70	4.08	4.28	2
2020	75.80	4.18	4.44	2
2021	80.10	4.30	4.63	2
2022	84.40	4.43	4.82	2
2023	89.10	4.56	4.98	2
2024	90.80	4.60	4.98	2
2025	92.60	4.67	4.95	2
2026	94.40	4.96	4.96	2

The price of gas for the Industrial sector is based on a formula related to heavy fuel oil prices and includes caps and floors. This has been reflected in the above pricing.

The price of natural gas for the Power sector is set by reference to a base price of $1.87/MMBTU in 2008 escalated at 2% per annum plus an estimation of the Songas transportation tariff as determined by the energy regulator, Energy and Water Utility Regulatory Authority ("EWURA"). The base price of the gas to the power sector increased to US$2.50/MMBTU on 1 July 2012 the equivalent of US$2.76/MMBTU after the annual 2% escalation pursuant to the terms of the long term power agreements.

It has been assumed that once the new National Natural Gas Infrastructure Project ("NNGIP") Gas Processing Plant on Songo Songo Island is commissioned (first half of 2016), that gas sales to TANESCO will be made via both the NNGIP and Songas Infrastructures. The Company will be connecting the SS-10, SS-11 and SS-12 wells to the NNGIP Infrastructure. Any new TANESCO delivery points will be supplied via the NNGIP infrastructure subject to well deliverability constraints. The Company has been in discussions with TPDC with regards to a new Gas Sales Agreement. It has been assumed that volumes up to 37 MMBTU supplied to TANESCO power plants (via either infrastructure) will be priced according to the Portfolio Gas Supply Agreement ("PGSA") well head price, US$2.76 MMBTU on 1 July 2012 (escalating 2% per annum), with volumes in excess of 37 MMBTU priced at US$3.50 MMBTU on 1 January 2016 (escalating 2% per annum) exclusive of any processing and transportation tariff. Sales made via the Songas infrastructure will be at the TANESCO plant gate with sales made via the NNGIP infrastructure being made at the wellhead. There is no guarantee that this proposed price will be realized and as such there could be further adjustments to the Company's proved plus probable net present value of future revenue once the negotiations are finalised and a new gas sales agreement is signed with TPDC.

The price of natural gas sold to Wazo Hill is based on the contracted prices as set out in the Amendment Agreement No1 dated May 2014 to the 2008 gas sales agreement with Tanzania Portland Cement Company plus an estimation of the Songas transportation tariff as determined by the energy regulator, EWURA.

The decline in the gas price in 2016 is a result of the lower Brent crude price which has the impact of lowering the gas price received from industrial customers. The industrial contracts have caps and floors with regards to gas prices.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of the Company's total gross working interest proved and proved plus probable reserves as at 31 December 2015 against such reserves as at 31 December 2014.

	Conventional Natural Gas (MMcf)		
	Proved	**Probable**	**Proved plus Probable**
Reserves at 31 December 2014	**450,403**	**54,004**	**504,407**
Extensions	-	-	-
Improved recovery	-	-	-
Technical revisions(1)	(65,269)	(4,879)	(70,148)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic factors	-	-	-
Production	(17,311)	-	(17,311)
Reserves at 31 December 2015	**367,823**	**49,125**	**416,948**

Note:

1. During the course of 2015 no significant geological or geophysical data has been acquired on or close to the Songo Songo field that might allow a re-assessment of the volumetric gas initially in place and reserves. The technical revisions are because the gas sales forecast prior to license expiry are expected to be lower.

On a gross Company basis there has been an 18% decline in Songo Songo's proved Additional Gas reserves to the end of the license period with total Additional Gas production of 17.3 Bcf during the year. There has been a 17% decline in the proved plus probable Additional Gas reserves on a gross Company life of license basis from 504.4 Bcf to 419.9 Bcf. The 14% decline in proved plus probable Additional Gas reserves (before 2015 production) is primarily due to a decline in the Company's forecast for Power demand as a consequence of: (i) slower than anticipated growth in the electricity demand in Tanzania; (ii) slower displacement of other sources of power generation; and (iii) the gas on gas competition now faced by the Company. In order to commission the NNGIP gas processing plant in Mtwara in September 2015, the Company, under a Government of Tanzania directive, was requested to allow connection to the NNGIP Infrastructure of two TANESCO power plants previously supplied under the PGSA contract, these power plants are currently being supplied by a third party.

UNDEVELOPED RESERVES

The following table sets forth the undeveloped reserves for the years ended 31 December 2013, 2014, and 2015.

	As of December 31, 2015 Conventional Natural Gas	
Proved Undeveloped		Booked (MMcf)
2013	-	170,750
2014	-	166,756
2015	-	121,896

Probable Undeveloped		Booked (MMcf)
2013	-	36,132
2014	-	60,173
2015	-	36,484

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

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable).

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.

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.

Proved Undeveloped Reserves

Proved undeveloped reserves have decreased slightly due to lower expected demand which has delayed the requirement for an additional well and decreased the undeveloped gas produced during the license period. The proved undeveloped reserves require the SS-12 well to be completed and tied into the NNGIP infrastructure. The SS-12 well was completed in February 2016 and is planned to be tied into the NNGIP infrastructure in 2017. In addition the recovery of the proved undeveloped reserves requires the installation of full field compression in 2019. The timing of the SS-12 tie in and full field compression is driven by the expected demand by the power sector for Additional Gas.

Probable Undeveloped Reserves

Probable undeveloped reserves were assigned for the development of areas of the pool that are further away from well control than assigned in the proved reserves case. The decrease in 2015 is for same reason the proved undeveloped reserves have decreased.

The recovery of the probable undeveloped reserves, require the drilling of a new vertical well in northern area of the Songo Songo reservoir. The Songo Songo North well is currently planned to be drilled in 2021.

The Company intends to develop the undeveloped reserves by the drilling of new wells as and when required to meet the demand for gas by consumers.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Company's reserves are evaluated by McDaniel, an independent petroleum engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

In the McDaniel Report, it has been assumed that TPDC will exercise its right to 'back in' to the field development associated with the SS-N well to earn a 20% increase in the profit share for the production emanating from these wells, the "back-in" rights are assumed to be a carried interest. McDaniel has taken the view that this 'back in' right should be treated as a TPDC working interest and therefore the Gross Property reserves have been adjusted for the volumes of natural gas that are allocated to TPDC for their working interest share. The outcome of any final agreement on TPDC future back-in rights may lead to a change in the economic terms of the PSA, but cannot be estimated at this time.

The separation of the downstream assets was raised by the Ministry Energy and Mines ("MEM") in the National Natural Gas Policy issued in 2013, which contemplates TPDC as monopoly aggregator and distributor of gas. In the context of the gas policy, TPDC and MEM have indicated that they wish the Company to unbundle the downstream distribution business in Tanzania. The potential unbundling of the downstream business will be addressed at such time as there is a conflict between new legislation and the Company's right under the PSA. The provisions of the PSA are such that the Company is to be kept economically whole if any legislation affects the Company's economic benefits under the PSA.

During the third quarter of 2015, The Petroleum Act, 2015, (the "Act") was passed into law by Presidential decree. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and as well consolidates and puts in place a single, effective and comprehensive legal framework for regulating the oil and gas industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory (PURA). The mid and downstream petroleum as well as gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority (EWURA). The bill also confers upon on TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in the petroleum operations as well as mid and downstream natural gas activities. The bill vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC does not extend to mid and downstream petroleum supply operations. The Company believes the potential impact on its business in Tanzania will not be significant as the PSA was signed prior to passing of the Act and there are grandfathering provisions within the Act upholding the rights of the Company under the PSA.

FUTURE DEVELOPMENT COSTS

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved and probable reserves using forecast prices and costs.

	Future Development Costs	
	Forecast Prices and Costs	
	Proved	**Proved plus Probable**
(US$'000)		
2016	16,424	16,424
2017	30,100	38,474
2018	520	10,144
2019	21,383	32,420
2020	19,700	20,133
Remaining Years	14,388	94,567
Total Undiscounted	102,516	212,163

The 2016 future development costs are associated with the completion of the SS-J (SS-12) development well from an offshore surface location between the SS-5 and SS-7 wells together with the demobilisation the rig and service companies following the completion of the Offshore component of the Phase I of the development programme which included the work-over of SS-5, SS-7 and SS-9 wells. The completion of the Phase I development programme in 2017 includes: (i) the installation of field refrigeration at the Songas gas processing facility; (ii) tie-in the SS-12 well (including the installation of a production platform) to the NNGIP infrastructure; and (iii) the work-over of the SS-3 and SS-4 wells (currently suspended and shut-in respectively) and the recompletion of the SS-10 well with chrome production tubing.

Phase II of the proved plus probable capital expenditure from 2017 onwards includes the installation of compression downstream of the Songas facility.

Phase III of the development programme including the undertaking of a 3D seismic programme over Songo Songo North and Songo Songo West and the drilling and completion of one Songo Songo North well.

The Company does not expect to commit to future development costs until: (i) agreeing commercial terms with TPDC for the supply of gas to the NNGIP regarding the sale of incremental gas volumes from Songo Songo; (ii) TANESCO arrears have been substantially reduced, guaranteed or other arrangements for payment made which are satisfactory to the Company; and (iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any new sales contracts with Government entities.

When the above conditions above are met, and in so doing justify further improving the reliability/capacity of field deliverability, the Company would contemplate undertaking the balance of Phase I Development Programme. The additional costs estimated to be approximately US$30.1 million.

On the 29th October 2015, the Company entered into a loan agreement with the International Finance Corporation, a member of the World Bank Group, for a US$60 million investment in the Company's operating subsidiary, PanAfrican Energy Tanzania Limited ("PAET"). On the 14th December 2015, PAET made an initial drawdown of US$20 million from the available US$60 million. Subsequent to the year-end PAET drew down an additional US$40 million. The Company currently anticipates that there will be sufficient funds from existing cash and ongoing cash flows to fund all phases of the future development costs as outlined above.

Land Holdings

The following table set out the developed and undeveloped land holdings of the Company as at 31 December 2015:

	Developed		Undeveloped		Total	
	Gross[1]	**Net[2]**	**Gross[1]**	**Net[2]**	**Gross[1]**	**Net[2]**
Songo Songo	53,623		-	-	53,623	
Total Tanzania	53,623		-	-	53,623	

Notes:

1. "Gross" refers to the total acres of the property in which Orca Exploration or its subsidiaries have an interest.
2. "Net" refers to the total acres in which Orca Exploration or its subsidiaries have an interest, multiplied by the effective working interest percentage owned therein after taking into account the expected TPDC "back-in" rights.

OIL AND GAS PROPERTIES AND WELLS

The following table summarizes the Company's interest as at 31 December 2015 in wells that are producing and non-producing.

	Producing Wells		Non-Producing Wells	
	Natural Gas		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Songo Songo	**5.0**	**5.0**	**3.0**	**3.0**
Total Tanzania	**5.0**	**5.0**	**3.0**	**3.0**

Producing Wells.

At the year-end there were five producing wells, three offshore wells SS-5, SS-7, SS-9 and two onshore wells SS-10 and SS-11. The SS-10 well drilled in 2007 was tied in to the gas processing plant in January 2011. The SS-11 well was completed in June 2012 and was tied in to the gas processing plant in September 2012. In September 2015, the Company contracted an offshore jack-up rig to workover wells SS-5, SS-7 and SS-9. The SS-5 and SS-9 wells had been suspended because of potential tubing integrity issues since 2010 and 2012 respectively. The workovers were successful and at year all three wells were back on production. After conducting the workovers, the rig spudded well SS-12, in the central part of the field between SS-11 and SS-7, and at December 31, 2015 was drilling above top reservoir. The SS-11 well is currently tied into the Songas Gas Processing Plant via the SS-5 offshore flowline. During 2017 there are plans to add a refrigeration unit which will lower plant pressures and further increase well potentials. Engineering plans for the installation of inlet compression were completed alongside the refrigeration works and will be installed in 2019, depending on the deliveries from the field.

Non-Producing Wells

At year end there were two non-producing wells, SS-3 and SS-4, located onshore and one offshore well, SS-12, being drilled. The offshore well SS-12 was successfully completed in February 2016, encountering the top reservoir approximately 100 meters high to prognosis. The well is currently shut in and is expected to be tied into the NNGIP infrastructure in 2017. The onshore well SS-3 was suspended in 2011 and the SS-4 well was shut in December 2015 following the completion of the three offshore work-overs during the year as the production from the well was no longer required. In 2017 the three onshore wells (SS-3, SS-4 and SS-10) will be worked over to install chrome tubing. The SS-3 well is currently suspended because of potential tubing integrity issues.

Currently, the Company can produce approximately 155 MMscfd from the five wells, SS-5, SS-7, SS-9, SS-10 and S-11. The current Songas infrastructure has a maximum capacity of 102 MMscfd.

Off-Shore Programme

The Off-Shore Programme of the Songo Songo Main Field development programme (the "development programme") included workovers on three existing wells (SS-5, SS-7 and SS-9) and the drilling of one new development well, SS-12. Phase 1 of the development programme also includes the completion of the SS-12 production platform, flowlines and tie-in facilities connecting SS-12 to the NNGIP gas processing facilities and the installation of a refrigeration system at the Songas gas processing facility. The full development programme provides for additional workovers, compression systems and additional infrastructure to ensure all production commitments are met through to the end of the licence in 2026.

The Offshore Programme was designed to: (i) put safe existing suspended and operating production wells; (ii) restore and increase the current productive capacity of the Songo Songo Main Field to ensure the continued delivery of Protected and Additional gas into the existing Songas infrastructure; and (iii) provide additional operational redundancy and deliverability for future additional gas sales.

The Offshore Programme has successfully increased production capacity from approximately 83 MMscfd prior to the Off-Shore Programme to current production capabilities of approximately 155 MMscfd. Upon completion of the platform for SS-12 and the tie-in to production facilities, production capabilities are expected to be in excess of 185 MMscfd. The field is now capable of both filling the existing Songas infrastructure to capacity of approximately 102 MMscfd, as well as providing additional gas volumes to the NNGIP. The Company is currently negotiating terms for the sales agreement to the NNGIP with TPDC. Until the agreement is signed, the Company's production is limited by infrastructure and contractual constraints, producing an average of 88 MMscfd for the fourth quarter of 2015 and is expected to average 94 MMscfd in 2016.

Infrastructure

The Gas Processing Plant on Songo Songo Island is owned by Songas and is operated by the Company on behalf of Songas (on a no loss/no profit basis). The Gas Processing Plant consists of 2 x 35 MMscfd raw gas trains.

In June 2011, the Company installed joule thomson valves at the Gas Processing Plant and subsequently signed a Re-rating Agreement with Songas and TANESCO to increase the gas processing capacity from 90 MMscfd to 110 MMscfd (the plant was re-rated and certified at these rate). This increased the overall capacity of the system to 102 MMcfd with the pipeline diameter being the bottleneck. The Re-Rating Agreement expired on 31 December 2012 and, although it was initially extended to 31 December 2013, no new agreement is currently in place. Without the Re-Rating Agreement, the Gas Processing Plant could be be de-rated to 70 MMcfd (the capacity originally agreed to) if there were any technical or safety reasons to do so however the plant is inspected each year and certified to produce at 110 MMscfd. If the plant was de-rated on the ground of technical or safety reasons this would result in a material reduction in the Company’s sales volumes of Additional Gas.

The gas in transported to Dar-es-Salaam via a 25Km 12-inch offshore pipeline to Somanga Funga landfall then via a 207 km 16-inch onshore pipeline to Ubungo Power Plant and a 16 km 8-inch lateral pipeline to the Wazo Hill cement plant. These pipelines are operated and owned by Songas.

Sales of Additional Gas to the Industrial customers are made via the Company’s low pressure distribution system. There are three pressure reduction stations and two separate connections to the 16-inch high pressure pipeline. Since 2004, the Company has constructed over 50 km of low pressure pipeline in Dar es Salaam and 38 industrial customers were connected and consuming Additional Gas at the end of 2015.

PROPERTIES WITH NO ATTRIBUTED RESERVES

Tanzania

The following table summarizes the gross and net acres of unproved properties in which the Company has an interest and also the number of net acres for which the Company's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Acres	**Net Acres**	**Net Acres Expiring Within One Year**	**Natu**re, cost and timing of work commitments US$'000
Songo Songo	-	-	-	-
Total Tanzania	**-**	**-**	**-**	**-**
Italy – Elsa[(1)]	31,300	4,695	**-**	**-**
Italy – Longastrino[(2)]	34,595	24,216	**-**	**-**
Total Italy	**65,895**	**28,911**	**-**	**-**

Notes:

1. The Company will not earn the right to the acres until the Elsa-2 well has been drilled.
2. The Company has earned the right to the acres but the Italian Government has declined the Company's application to be registered on the licence.

Italy

Elsa

On 30 May 2010, the Company signed an agreement to farm in on the Central Adriatic B.R268.RG Permit offshore Italy. The farm-in commits the Company to fund 30% of the Elsa-2 appraisal well up to a maximum of US$11.5 million to earn a 15% working interest in the permit. Thereafter, the Company will fund all future costs relating to the well and the permit in proportion to its participating interest. The Company has also agreed to pay fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million. Changes in Italian environmental legislation in late 2015, has resulted in the development of this permit being postponed indefinitely. As a consequence no geological or drilling activities will be undertaken by the Company in the future. As at the date of this report, the Company has no further capital commitments in Italy.

Longastrino

During November 2010, Orca Exploration signed an agreement to acquire between 70% and 75% of the Longastrino Block in the Po Basin onshore Italy. This acquisition was Orca Exploration's second entry into Italy during 2010.

The La Tosca well was drilled in 2012 at a total cost to Orca Exploration of US$7.4 million. The well encountered no hydrocarbons and has subsequently been abandoned during the second quarter of 2013.

As a consequence of the refusal by the Italian Government to register the Company's interest in the Longastrino block there will be no further geological or drilling activities undertaken by the Company in the future.

EXPLORATION AND DEVELOPMENT ACTIVITY

The following table summarizes the Company's drilling results for the year ended 31 December 2015. The Company does not have any oil wells, service wells or stratigraphic test wells.

	2015	
Italy	**Gross**	**Net**
Exploration		
Natural Gas	-	-
Suspended	-	-
Dry and Abandoned	_	_
Total Exploration	-	-
Songo Songo - Tanzania		
Development		
Natural Gas	1	1
Suspended	-	-
Dry and Abandoned	-	-
Total Development	1	1
Total	1	1

Tanzania

The SS-J (SS-12) development well was spud in December 2015 and was completed in February 2016. The SS-12 well is a vertical offshore well drilled to a total measured depth of 2,130 metres.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

There are no estimates of well abandonment costs included in the McDaniel Report in arriving at future net revenue:

Under the terms of the PSA, the Company is not currently liable for abandonment and reclamation costs as it is envisaged that the wells will continue to produce after Orca Exploration has relinquished the licence. Whilst there is currently no amendment to the PSA, the Government has stated a desire for the Company to contribute towards an escrow account for future abandonment costs based on a per unit of production basis. The Company will provide for abandonment costs once an agreement is reached with TPDC and the PSA amended accordingly.

TAX HORIZON

Under the terms of PSA, the Company is required to pay Tanzanian income tax, but this is recovered by the Company through the profit sharing arrangements with TPDC. Where income tax is accrued, the Company's revenue will be grossed up by the tax due and the tax will be shown as a tax in the Company's accounts. However, the income tax has no material impact on the cash flows emanating from the PSA and accordingly it has not been identified as a separate cash flow stream in the analysis of the net present values.

The Company does not pay any royalties. However, under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"), an Additional Profits Tax ("APT") is payable at a rate of 25% of the Company's profit share. This rate can increase to 55% of the Company's profit share where all costs have been recovered with an annual return of 35% plus the PPI.

The APT can have a significant impact on the project economics as measured by the net present value of the cash streams emanating under the PSA. Higher revenue in the initial years leads to a rapid payback of the project costs and consequently accelerates the payment of the APT. Therefore, the terms of the PSA rewards the Company for taking higher risks by incurring capital expenditure in advance of revenue generation.

The APT has been netted off against revenue rather than identified as a separate cash flow stream in the analysis of the net present values under both the constant and forecast price cases, as its payment and calculation is determined by the terms of the PSA and is applicable only to reserves within the Songo Songo PSA rather than as income tax expense as are most corporate income taxes.

FORWARD CONTRACTS

It has been assumed that once the NNGIP Gas Processing Plant on Songo Songo Island is commissioned (first half of 2016), that gas sales to TANESCO will be made via both the NNGIP and Songas Infrastructures. The Company will be connecting the SS-10, SS-11 and SS-12 wells to the NNGIP Infrastructure. Any new TANESCO delivery points will be supplied via the NNGIP infrastructure subject to well deliverability constraints. The Company has been in discussions with TPDC with regards to a new Gas Sales Agreement. It has been assumed that volumes up to 37 MMBTU supplied to TANESCO power plants (via either infrastructure) will be priced according to the PGSA well head price, US$2.76 MMBTU on 1 July 2012 (escalating 2% per annum), with volumes in excess of 37 MMBTU priced at US$3.50 MMBTU on 1 January 2016 (escalating 2% per annum) exclusive of any processing and transportation tariff. Sales made via the Songas infrastructure will be at the TANESCO plant gate with sales made via the NNGIP infrastructure being made at the wellhead. There is no guarantee that this proposed price will be realized and as such there could be further adjustments to the Company's proved plus probable net present value of future revenue once the negotiations are finalised and a new gas sales agreement is signed with TPDC.

The sales of Additional Gas to industrial customers are under contracts which contain both caps and floors with regards to gas price for all volumes sold and are benchmarked at a discount to Heavy Fuel Oil the customers, alternative fuel source. The floor prices range from US$8.00/GJ to US$9.58/GJ and the ceilings from US$11.73/GJ to US$18.53/GJ. The price of Brent would have to be in excess of US$75/bbl and US$110/bbl before the floor and ceiling prices were attained respectively. The sales to Industrial customers are currently at the floor price which protects the Company from any reduction in revenue as a result of any further decline in the world energy prices. Whilst many of the sales contracts have been extended to the end of the licence period there is no guarantee that the floor prices will continued to be attained.

All other sales of Additional Gas are against fixed price contracts with annual indexation increases.

COSTS INCURRED

The following table summarizes the Company's property acquisition costs, exploration costs and development costs for the year ended 31 December 2015.

(US$'000)	**Year ended 31 December 2015**
Lease acquisition and retention	-
Geological and geophysical	-
Drilling and completion	35,797
Production equipment	-
Infrastructure	2,358
Capitalized general and administrative	-
Development	-
Decommissioning asset	-
Total	**38,155**
Cost by category	
Acquisition of proved properties	-
Acquisition of unproved properties	-
Exploration costs	-
Development costs	38,155
Other costs	-
Total	**38,155**

FURTHER ANALYSIS OF CAPITAL EXPENDITURES

The tables below summarize the Company's quarterly capital expenditures for the year ended 31 December 2015.

	Quarter ended			
(US$'000)	**31 December 2015**	**30 September 2015**	**30 June 2015**	**31 March 2015**
Property acquisitions and retention	-	-	-	-
Geological and geophysical including drilling and completion and production equipment	23,099	7,578	4,135	984
Development and facilities	1,382	547	275	155
Power development	-	-	-	-
	24,481	8,125	4,410	1,139

PERSONNEL

As at December 31, 2015, the Company had 57 full-time personnel, excluding approximately two consultants and contract personnel who devoted the majority of their time to the Company. In addition the Company employs 37 employees who are recharged to Songas for the operatorship of the gas processing plant.

Location	Number of full time personnel
Tanzania – Head office	57
Tanzania – Songo Songo Island (Operatorship)	37
London – Service office	4
	97

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by McDaniel for the year ended December 31, 2016 in the estimates of future net revenue from proved and proved plus probable reserves disclosed above under the heading "Summary of Net Present Value of Future Net Revenue of Oil and Gas Reserves as of December 31, 2015." All of the Company's production is conventional natural gas and took place in Tanzania.

2016 Forecast Production

(MMcf)	Proved	Proven plus Probable
Songo Songo conventional natural gas	19,775	20,014

PRODUCTION HISTORY

The following tables disclose the Company's quarterly average gross daily production and the Company's net production (after TPDC profit share) for the year ended 31 December 2015.

Average Daily Production

	Quarter Ended			
Production Songo Songo	**31-Dec-15**	**30-Sep-15**	**30-Jun-15**	**31-Mar-15**
Gross Company (MMcfd)	49.7	46.3	44.6	49.1
Net Company (MMcfd)	42.2	34.8	33.8	29.4
Prices US$/Mcf				
Industrials	7.62	7.67	7.45	7.54
Power	3.56	3.62	3.47	3.49
Average prices received	4.51	4.66	4.46	4.34
Tariff	(0.71)	(0.71)	(0.73)	(0.72)
TPDC Profit Gas	(0.59)	(1.08)	(0.90)	(1.45)
Production costs US$/Mcf	(0.18)	(0.22)	(0.15)	(0.31)
Resulting netback US$/Mcf	3.03	2.65	2.68	1.86

Production Volume by Field

The following table discloses for each important field, and in total, the Company's gross production volumes for the year ended 31 December 2015 for each product type.

(MMcf)	**Conventional Natural Gas**
Songo Songo gas field	17,311