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 Orca Exploration Report”) dated 28 April 2015. This statement of reserves data and other oil and gas information (this "Statement") uses the information provided in the McDaniel Orca Exploration Report. All financial information in this Statement is in US dollars. This Statement was prepared on 30 April 2015 and is effective 31 December 2014.

The McDaniel Orca Exploration Report evaluated, as at 31 December 2014, Orca Exploration Group Inc.’s (the “Company” or “Orca Exploration”) Tanzanian natural gas reserves for the period to the end of its licence in October 2026. The tables below are a summary of the natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Orca Exploration Report utilising forecast price and cost assumptions. The tables summarize the data contained in the McDaniel Orca Exploration 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 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 Orca Exploration 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

	Company Gross Reserves			Company Net Reserves		
	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas
	Mbbl	*Mbbl*	*MMcf*	*Mbbl*	*Mbbl*	*MMcf*
Proved						
Developed Producing	-	-	283,646	-	-	193,991
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	166,757	-	-	88,871
Total Proved	-	-	450,403	-	-	282,862
Probable	-	-	54,004	-	-	37,365
Total Proved plus Probable	-	-	504,407	-	-	320,227

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

	Before Future Income Tax Expenses[8] and Discounted at				
	0%	**5%**	**10%**	**15%**	**20%**
(US$'000)					
Proved					
Developed Producing	397,990	274,294	195,891	144,326	109,229
Developed Non-Producing	-	-	-	-	-
Undeveloped	302,816	233,518	182,865	145,113	116,464
Total Proved	700,806	507,812	378,756	289,439	225,694
Probable	97,791	60,287	38,411	25,385	17,492
Total Proved plus Probable	798,597	568,099	417,167	314,824	243,186

	After Future Income Tax Expenses[8] and Discounted at				
	0%	**5%**	**10%**	**15%**	**20%**
(US$'000)					
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Notes:

1. The crude oil and natural gas reserves estimates presented in the McDaniel Orca Exploration 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 PSA.

10. In the McDaniel Orca Exploration Report, it has been assumed that TPDC will exercise its right to 'back in' to the field development associated with the new wells SS-12 and SS-N 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 4.8%, or a total of 25,276 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. In response to a Notice of Dispute delivered by the Company, in March 2014, TPDC retracted its claim that the Company had over-recovered or otherwise approximately US$21 million in Cost Gas revenue, which in the opinion of management has exonerated the Company of allegations made by Parliament. Accordingly, the Company continues to rely upon its rights under the existing PSA and has initiated notices of dispute to resolve any remaining issues. Management has no current intention to resume any negotiations on any matters raised by the GNT ,(TPDC back in rights, profit sharing arrangements and the unbundling of the downstream assets) as it is now clear that these negotiations were promulgated under incorrect assumptions.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

Additional Information Concerning Future Net Revenue – (Undiscounted)

(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	1,128,139	-	167,356	251,827	-	700,805	-	700,805
Total Proved plus Probable	1,306,036	-	172,343	326,947	-	798,597	-	798,597

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

Future Net Revenue by Production Group

(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[2]	378,756	1.34
Proved plus Probable		
Light and Medium Crude Oil[1]	-	-
Natural Gas[2]	417,167	1.30

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.

Pricing Assumptions – Forecast Prices, Costs and Gas Sales

McDaniel employed the following gas sales, pricing and inflation rate assumptions as of 31 December 2014 in estimating the Company's reserves data using forecast prices and costs. The Company received an average gas price of US$4.76/Mcf in 2014.

Year	Brent crude US$/bbl	Songo Songo gas prices Proved US$/Mcf	Songo Songo gas prices Proved plus probable US$/Mcf	Annual inflation %
2015	70.00	3.92	3.93	2
2016	77.60	4.27	4.32	2
2017	82.60	4.45	4.47	2
2018	87.60	4.57	4.60	2
2019	92.00	4.68	4.73	2
2020	96.60	4.79	4.86	2
2021	98.50	4.89	4.97	2
2022	100.50	4.97	5.08	2
2023	102.50	5.05	5.19	2
2024	104.60	5.21	5.34	2
2025	106.60	5.40	5.51	2
2026	108.80	5.51	5.63	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 the gas sold to TANESCO from 1 July 2016 will be made via the new National Natural Gas Infrastructure Project ("NNGIP") and as such 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) exclusive of any processing and transportation tariff. The PGSA agreement provides for a 150% well head price escalation for gas sales over 37 MMBTU per day.

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 2015 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 2014 against such reserves as at 31 December 2013.

	Gross Associated and Non-Associated Natural Gas (Bcf)		
	Proved	**Probable**	**Proved plus Probable**
Reserves at 31 December 2013	**475.7**	**51.6**	**527.3**
Extensions	-	-	-
Improved recovery	-	-	-
Technical revisions[1]	(5.9)	2.4	(3.5)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic factors	-	-	-
Production	(19.4)	-	(19.4)
Reserves at 31 December 2014	**450.4**	**54.0**	**504.4**

1. During the course of 2014 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 GIIP and reserves.

On a Gross Company basis there has been a 5% decline in Songo Songo's 1P Additional Gas reserves to the end of the license period with total Additional Gas production of 19.4 Bcf during the year. There has been a 4% decline in the 2P Additional Gas reserves on a Gross Company life of license basis from 527.3 Bcf to 504.4 Bcf. The 1% decline in 2P Additional Gas reserves (before 2014 production) is a consequence of a 1% increase in TPDC effective working interest from 2014 due to the marginal increase in production emanating from the planned SS-12 well.

UNDEVELOPED RESERVES

The following table sets forth the undeveloped reserves for the years ended 31 December 2011, 2012, 2013 and 2014.

	As of December 31, 2014 Natural Gas	
Proved Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
Prior to 2011	79,308	79,308
2011	19,099	152,794
2012	-	149,210
2013	-	170,750
2014	-	166,756

Probable Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
Prior to 2011	18,912	18,912
2011	-	22,379
2012	-	25,453
2013	-	36,132
2014	-	60,173

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.

Proved Undeveloped Reserves

Proved undeveloped reserves have decreased slightly due to decreased offtake rates associated with the delay in the plant expansion.

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 increase in 2012 is due to an increase in the proved plus probable recovery factor compared to 2011.

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 response to a Notice of Dispute delivered by the Company, in March 2014, TPDC retracted its claim that the Company had over-recovered or otherwise approximately US$21 million in Cost Gas revenue, which in the opinion of management has exonerated the Company of allegations made by Parliament. Accordingly, the Company continues to rely upon its rights under the existing PSA and has initiated notices of dispute to resolve any remaining issues. Management has no current intention to resume any negotiations on any matters raised by the GNT (such as TPDC back in rights, profit sharing arrangements and the unbundling of the downstream assets) as it is now clear that these negotiations were promulgated under incorrect assumptions.

In the McDaniel Orca Exploration Report, it has been assumed that TPDC will exercise its right to ‘back in’ to the field development associated with the new wells SS-12 and SS-N 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.

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)		
2015	106,350	106,350
2016	38,964	38,964
2017	3,121	3,121
Remaining Years	103,392	178,512
Total Undiscounted	251,827	326,947

The offshore component of the Company's Phase I Songo Songo field development, planned for 2015 to 2017, consists of the work-over of SS-5, SS-9 and SS-7 wells, the drilling of a SS-J (SS-12) development well from an offshore surface location between the SS-5 and SS-7 wells, together with the installation of field refrigeration at the Songas gas processing facility. An onshore component of the Phase I development is planned to follow the offshore programme, which component includes the workover of the SS-3 and SS-4 wells 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 commencement of the offshore capital programme in 2015/2016 is dependent upon (i) the conclusion of financing arrangements with the International Finance Corporation ("IFC"); and (ii) TANESCO continuing to pay for current gas deliveries. It is expected that the satisfaction with TANESCO payment performance will be a condition precedent to the Company being able to draw funds from the IFC.

The delivery of gas to the NNIGP will commence after (i) the conclusion of commercial terms with TPDC or other buyers; (ii) the TANESCO long term receivables being brought up to date, guaranteed or other arrangements for payment satisfactory to the Company; (iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any sales contracts with Government entities.

Land Holdings

The following table set out the developed and undeveloped land holdings of the Company as at 31 December 2014:

	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 2014 in wells that are producing and non-producing.

	Producing Wells		Non-Producing Wells	
	Natural Gas		Natural Gas	
	Gross	Net	Gross	Net
Songo Songo	**4.0**	**4.0**	**3.0**	**3.0**
Total Tanzania	**4.0**	**4.0**	**3.0**	**3.0**

Producing Wells.

There are currently four producing wells, one offshore SS-7 well and three onshore SS-4, 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. The SS-4 well has been in production since August 2004. All four wells are tied into the Songas Gas Processing Plant located on Songo Songo Island. The SS-11 well is currently tied into the Songas Gas Processing Plant via the SS-5 offshore flowline.

Non-Producing Wells

There are three non producing wells SS-5 (offshore) , SS-9 (offshore) and SS-3 well (onshore). The offshore wells SS-5 and SS-9 were suspended in 2011 and 2012 respectively. The SS-3 well was suspended in 2011. The suspended wells are planned to be the subject of a workover programme in 2015 to 2016 as described above.

Currently, the Company can produce approximately 94 MMcfd from four producing wells, SS-4, SS-7, SS-10 and S-11. The current infrastructure has a maximum capacity of 102 MMcfd. There will, however, be no redundant capacity in the facility or pipeline until the suspended wells SS-3, SS-5 and SS-9 are worked over and recompleted and/or additional wells can be drilled in the field and facilities expanded. A loss or material reduction in the production of any given well will have a material adverse effect on the total production of the Company.

Infrastructure

The Gas Processing Plant on Songo Songo Island is owned by Songas and is operated by Orca Exploration Group 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 signed a Re-rating Agreement with Songas and TANESCO to increase the gas processing capacity from 90 MMscfd to 110 MMscfd. 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, Songas may de-rate plant capacity to 70 MMcfd (the capacity originally agreed to), which 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 37 industrial customers were connected and consuming Additional Gas at the end of 2014

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	Nature, cost and timing of work commitments US$'000
Songo Songo	-	-	-	-
Total Tanzania	**-**	**-**	**-**	**-**
Italy – Elsa(i)	31,300	4,695	-	-
Italy – Longastrino(ii)	34,595	24,216	-	-
Total Italy	**65,895**	**28,911**	**-**	**-**

Notes

(i) The Company will not earn the right to the acres until the the Elsa-2 well has been drilled.

(ii) The Company has earned the right to the acres but its interest has currently not been registered on the licence

Italy

Elsa

On 30 May 2010, the Company signed an agreement with Petroceltic International plc ("Petroceltic") to farm in on Petroceltic's 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 Petroceltic fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million.

Petroceltic was due to spud the Elsa-2 well prior to 31 October 2010, but the Italian government passed a decree, following the blowout of the Macondo well in the U.S., that prevented the drilling in the Italian seas within five nautical miles of the coastline and within 12 nautical miles around the perimeter of protected Marine Parks. In view of this, Petroceltic suspended the permit until such time as the Ministry of Environment issued a decree of environmental compatibility for the drilling program.

On 26 June 2012, Legislative Decree 83/2012 (the "Decree") was approved by both houses of the Italian Parliament with no substantial modifications. On 12th August, the Decree became law following publication in the Italian Official Journal. The new law modifies restrictions on offshore oil and gas exploration and production originally introduced by DLGS 128/2010 in August 2010. The well is expected to be drilled following finalisation of an environmental impact study currently expected in the second half of 2015. Orca will not be liable to any costs associated with the drilling of Elsa-2 until a rig contract is signed.

Longastrino

During November 2010, Orca Exploration signed an agreement with Northern Petroleum plc. 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.

EXPLORATION AND DEVELOPMENT ACTIVITY

The following table summarizes the Company's drilling results for the year ended 31 December 2014

	2014	
Italy	**Gross**	**Net** (1)
Exploration		
Natural Gas	-	-
Suspended	-	-
Dry and Abandoned	_	_
Total Exploration	-	-
Songo Songo - Tanzania		
Development		
Natural Gas	-	-
Suspended	-	-
Dry and Abandoned	-	-
Total Development	-	-
Total	-	-

Tanzania

No activity.

Italy

No activity.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

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

Under the terms of the PSA, Orca Exploration 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 the Production Sharing Agreement ("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.

COSTS INCURRED

The following table summarizes the Company's property acquisition costs, exploration costs and development costs for the year ended 31 December 2014.

	Year ended 31 December 2014
(US$'000)	
Lease acquisition and retention	-
Geological and geophysical	-
Drilling and completion	913
Production equipment	-
Infrastructure	133
Capitalized general and administrative	-
Development	-
Decommissioning asset	-
Total	**1,046**
Cost by category	
Acquisition of proved properties	-
Acquisition of unproved properties	-
Exploration costs	-
Development costs	1,046
Other costs	-
Total	**1,046**

Further analysis of capital expenditures

The tables below summarize the Company's quarterly capital expenditures for the year ended 31 December 2014.

(US$'000)	**Quarter ended**			
	31 December 2014	**30 September 2014**	**30 June 2014**	**31 March 2014**
Property acquisitions and retention	-	-	-	-
Geological and geophysical including drilling and completion and production equipment	522	273	9	109
Development and facilities	193	12	(270)	198
Power development	-	-	-	-
	715	285	(261)	307

Personnel

As at December 31, 2014, the Company had a full time complement of 53 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	53
Tanzania – Songo Songo Island (Operatorship)	37
London – Service office	4
	94

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by McDaniel for 2015 in the estimates of future net revenue from proved and proved plus probable reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

2015 Forecast Production

(MMcf)	**Proved**	**Proven plus Probable**
Songo Songo natural gas	19,121	19,121

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 2014.

Average Daily Production

	Quarter Ended			
Production Songo Songo	**31-Dec-14**	**30-Sep-14**	**30-Jun-14**	**31-Mar-14**
Gross Company (MMcfd)	48.5	56.9	50.0	57.5
Net Company (MMcfd)	26.6	34.3	37.0	34.5

Prices US$/Mcf				
Industrials	8.24	8.85	9.27	8.11
Power	3.49	3.60	3.65	3.52
Average prices received	4.64	4.91	4.94	4.55
Tariff	(0.71)	(0.70)	(0.68)	(0.72)
TPDC Profit Gas	(1.86)	(1.76)	(1.03)	(1.56)
Production costs US$/Mcf	(0.38)	(0.23)	(0.31)	(0.24)
Resulting netback US$/Mcf	1.69	2.12	2.92	2.03

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 2014 for each product type.

(MMcf)	**Natural Gas**
Songo Songo gas field	19,421