ORCA EXPLORATION GROUP INC.

Evaluation of Natural Gas Reserves
Songo Songo Field - Tanzania
As of December 31, 2013

Detailed Property Report

Prepared For:

Orca Exploration Group Inc.
Barclays House, 5th Floor
Ohio Street
P.O. Box 80139
Dar es Salaam, Tanzania

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue SW
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T2P 3G6

April 2014

ORCA EXPLORATION GROUP INC.
SONGO SONGO FIELD - TANZANIA

TABLE OF CONTENTS

McDaniel
& Associates Consultants Ltd.

April 3, 2014

Orca Exploration Group Inc.
Barclays House, 5th Floor
Ohio Street
P.O. Box 80139
Dar es Salaam, Tanzania

Attention: Mr. Robert S. Wynne, Chief Financial Officer

Reference: **Orca Exploration Group Inc.**
Evaluation of Natural Gas Reserves
For the Songo Songo Field
Detailed Property Report

Dear Sir:

Pursuant to your request, we have prepared an evaluation of the natural gas reserves and the net present values of these reserves for the interests of Orca Exploration Group Inc., hereinafter referred to as the "Company" or "Orca", in the Songo Songo Field of Tanzania as of December 31, 2013.

The future net revenues and net present values presented in this report were calculated using forecast prices and costs based on our opinion of future natural gas prices at December 31, 2013 and were presented in United States Dollars. The reserves estimates and future net revenue forecasts have been prepared in accordance with standards set out in the Canadian National Instrument 51-101 (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGEH).

The Company's share of the natural gas reserves as of December 31, 2013 and the respective net present values assigned to these reserves based on forecast prices and costs were estimated to be as follows:

ESTIMATED COMPANY SHARE OF RESERVES
AS OF DECEMBER 31, 2013 (1)
MMCF

	Proved Producing	Proved Undeveloped	Total Proved	Probable	Proved & Probable	Possible	Proved, Probable & Possible
Natural Gas							
Gross (2)	304,935	170,755	475,691	51,606	527,296	38,130	565,427
Net (3)	212,138	100,428	312,566	36,955	349,521	20,637	370,158

(1) Based on production to the end of the production license.
(2) Gross reserves are defined as the aggregate of the Company interest reserves.
(3) Net reserves are based on Company share of Cost and Profit revenues.

ESTIMATED COMPANY SHARE OF NET PRESENT VALUES AS OF DECEMBER 31, 2013
$1000 U.S. (1) (2) (3) (4)

			Discounted At		
	0%	5%	10%	15%	20%
Proved Producing Reserves	393,578	265,213	186,405	136,004	102,537
Proved Undeveloped Reserves	321,051	237,248	178,739	136,955	106,489
Total Proved Reserves	714,629	502,460	365,144	272,959	209,025
Probable Reserves	91,099	57,141	37,987	26,795	20,014
Total Proved & Probable Reserves	805,729	559,602	403,131	299,754	229,039
Possible Reserves	61,293	42,807	30,871	22,947	17,541
Total Proved & Probable & Possible Reserves	867,021	602,409	434,003	322,701	246,580

(1) Based on "Forecast Prices" at December 31, 2013 (see Price Forecasts in Table 16).
(2) Includes In-Country G&A costs but excludes interest expenses and corporate overhead.
(3) The net present values may not necessarily represent the fair market value of the reserves.
(4) There is no defined income tax system in the Songo Songo PSC. Government share of revenues is through a royalty and Cost Revenue/Profit Revenue fiscal system.

The Company's share of reserves and net present values are presented on a total Company basis in Table 1. A map showing the location of the Songo Songo Field is presented in Figure 1. Tables summarizing the reserves, production and revenues for each of the various reserves classes are presented in Tables 2 to 9. Tables showing the reserves calculations and economic parameters are presented in the Tables 10 to 17 and geological maps for the various reservoirs assigned reserves are presented in Figures 8 to 14. A discussion of the geological interpretation of the field, and the methodology for estimating the reserves and revenue forecasts are presented in the Property Discussion section of this report.

The natural gas reserves estimates presented in this report were based on Orca's share of production during the term of the production license ending October 11, 2026. Although it is likely that Orca's license will be extended, standard evaluation procedures in the oil and gas industry limit the Company share of reserves to the term of the existing license unless there is a clear and established track record of license extensions. A summary of the natural gas reserves and the future revenue forecasts to the end of the license are presented in Tables 1 to 5; however, for comparison, the reserves and future revenue forecasts are also presented to the end of the life of the field in Tables 1, 6, 7, 8 and 9.

In preparing this report, we relied upon certain factual information including ownership, well data, production data, prices, revenues, operating costs, capital costs, contracts, and other relevant data supplied by the Company. The supplied information was only relied upon where in our opinion it appeared reasonable and consistent with our knowledge of the properties however, no independent verification of the information was made. We have also relied upon representations made by the Company as to the completeness and accuracy of the data provided and that no material changes in the performance of the properties has occurred nor is expected to occur, from that which was projected in this report, between the date that the data was obtained for this evaluation and the date of this report, and that no new data has come to light that may result in a material change to the evaluation of the reserves presented in this report.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Orca Exploration Group Inc. and is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Orca Exploration Group Inc. without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

B. H. Emslie, P. Eng.
Senior Vice President

A. Tchernavskikh, P. Geol.
Manager International Geology

BHE/AT:jep
[14-0020]

CERTIFICATE OF QUALIFICATION

I, Bryan Howard Emslie, Petroleum Engineer of 2200, 255 - 5th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of Orca Exploration Group Inc., the report entitled "Orca Exploration Group Inc., Evaluation of Natural Gas Reserves, Songo Songo Field – Tanzania, As of December 31, 2013, Detailed Property Report", dated April 3, 2014; and that I was involved in the preparation of this report.

2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with a Bachelor of Science Degree in Mechanical Engineering, that I am a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of thirty years of experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Orca Exploration Group Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

PROFESSIONAL ENGINEER ALBERTA
BRYAN EMSLIE

B. H. Emslie, P. Eng.
Senior Vice President

Calgary, Alberta
Dated: April 3, 2014

CERTIFICATE OF QUALIFICATION

I, Anatoli V. Tchernavskikh, Petroleum Geologist, of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am the Manager of International Geology of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of Orca Exploration Group Inc., the report entitled "Orca Exploration Group Inc., Evaluation of Natural Gas Reserves, Songo Songo Field – Tanzania, As of December 31, 2013, Detailed Property Report", dated April 3, 2014; and that I was involved in the preparation of this report.

2. That I attended Moscow State University (Russia) in the years 1984 to 1991, graduating with a Honorary Master of Science degree in Geology; that I am a registered Professional Geologist with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of twenty years of experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Orca Exploration Group Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

PROFESSIONAL GEOLOGIST
ANATOLI TCHERNAVSKIKH
ALBERTA

A. V. Tchernavskikh, P. Geol.

Calgary, Alberta
Dated: April 3, 2014

ORCA EXPLORATION GROUP INC.

Evaluation of Natural Gas Reserves
Songo Songo Field - Tanzania
As of December 31, 2013

Property Discussion

INTRODUCTION

Natural gas reserves estimates and their associated net present values were prepared in this report for the interests of Orca Exploration Group Inc. in the Songo Songo Field in Tanzania, East Africa. The reserves were estimated at December 31, 2013 and the revenue forecasts and net present value estimates were calculated using forecast prices and costs using our opinion of future natural gas prices at December 31, 2013 and were presented in United States Dollars. The reserves estimates and future net revenue forecasts have been prepared in accordance with standards set out in the Canadian National Instrument 51-101 (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGEH).

An overview of the Songo Songo Field and a detailed discussion of the methodology employed in arriving at the reserves and net present value estimates are presented in this report.

PROPERTY OVERVIEW

The Songo Songo Field is located both on and slightly offshore Songo Songo Island approximately 15 kilometres offshore of the coast of Tanzania, East Africa and 200 kilometres south of the Tanzanian city of Dar es Salaam (see Figure 1). Natural gas was initially discovered by AGIP in 1974; however, the permit was relinquished to the Tanzania Petroleum Development Corporation (TPDC) after drilling only one well. TPDC then drilled an additional eight wells between 1976 and 1983 resulting in a total of nine wells in the field. Five of those wells are capable of production. Orca then drilled well SS-10 in 2007 and SS-11 in 2012.

Ocelot International Inc. ("Ocelot"), later becoming an affiliate of Orca Exploration Group Inc., entered into an agreement with the TPDC in July 1991 to evaluate the economic viability of developing the field to generate electricity. Ocelot conducted an extensive well test program and minor reconditioning program in 1997 on five of the wells. The results of this testing program and prior technical studies were used to prepare a full field reservoir model. This led to the confirmation of sufficient quantities of natural gas to supply a gas to electricity project and submission of a formal development plan in May 2001.

Gas production from the Songo Songo Field commenced June 2004 and by the end of 2013 approximately 231 Bcf of gas had been produced. Performance to date has been excellent. Production history plots on a well and field basis are presented in the Appendix.

Raw gas is processed through a gas plant on Songo Songo Island then transported through a 25 kilometre pipeline to shore and a 207 kilometre pipeline to Dar es Salaam. The plant was initially certified at 70 MMcfpd but was recently re-certified to bring capacity up to 103 MMcfpd.

The overall processing and transportation capacity from the Songo Songo block is planned to be increased to approximately 210 MMcfpd with the de-rating of the SONGAS plant to 70 MMcfpd and the installation by TPDC of a parallel processing and transportation system consisting of two 70 MMcfpd gas processing trains plus a separate offshore and onshore pipeline system, collectively referred to as the National Natural Gas Infrastructure Project ("NNGIP"), planned to be commissioned by the end of 2015. The combined processing and transportation capacity from Songo Songo could increase to as much as 243 MMcfpd should the existing SONGAS plant maintain its current rated capacity and not be de-rated. TPDC plans to reserve a maximum of 20 MMcfpd capacity in the Songo Songo NNGIP facilities to process and transport gas from the third-party owned and operated North Kilwani Field to the east of the Songo Songo Field.

Ownership of the Songo Songo Gas Project is through a consortium called SONGAS with funding of the project obtained through equity ownership by Globeleq, EIB, TPDC and the Tanzania Electric Supply Company Limited and debt funding through the World Bank and EIB. SONGAS owns five of the wells, the gas processing plant, the pipelines and the power plant, although Orca is the operator of the reserves and gas processing plant on a no gain no loss basis. Gas reserves delivered to five of the six turbines in the Ubungo power generation facility, the Wazo Hill cement plant and about one MMcfpd of local use close to the pipeline are owned by SONGAS, but Orca will be entitled to market reserves on its behalf for additional sales above the dedicated SONGAS volumes.

In February 2012, the Government announced that it was setting up a Government Negotiation Team ('GNT') to discuss a number of issues in relation to the Company's Production Sharing Agreement ('PSA') with the TPDC that was signed in October 2001. This includes, but is not limited to, TPDC back in rights, profit sharing arrangements, the unbundling of the downstream assets, cost recovery and Company's management of the upstream operations. After making submissions to the GNT, the Company commenced discussions in April 2012 and further in July 2012, at which time an agreement in principle was reached on a number of major points to resolve the issues. The GNT completed its mandate, and the responsibility for finalization, documentation and implementation has moved back to Ministry of Energy and Mines ("MEM"). The agreement in principle contemplated completion of this process by the end of 2012 as well as a number of undertakings from TPDC and the Government. As at the date of this report none of undertakings of the Government have been met and none of the issues are resolved. The outcome of the final negotiation may lead to material changes in the economic terms of the PSA, but cannot be estimated at this time.

GEOLOGY

Regional Geology

The Songo Songo Gas Field lies in the southern area of the offshore Tanzanian Coastal Basin. This basin is a seaward thickening sedimentary sequence that may reach thickness in excess of 10 kilometres. Although primarily regarded as mainly a marine Mesozoic – Cenezoic Basin, there may be a significant portion of the basin underlain by considerable thickness of the Permo-Triassic Karroo succession. The Coastal Basin has been viewed as a rifted or Atlantic type continental margin that is dominated by extensional tectonics.

The extensional rift margin was initiated in the Early Jurassic through east-west extension and rifting as Africa started to move away from Asia. The Late Jurassic to Early Cretaceous saw the onset of sea floor spreading as Madagascar continued to move now in a southwards direction from East Africa. Renewed rifting in the mid-Cretaceous (probably Aptian to Albian in age) caused reactivation of pre-existing extensional faults and the development of down to the east tilted fault blocks in the Songo Songo Region. Extension slowed soon after (Albian – Cenomanian) as relative motion between Madagascar and East Africa stopped, and in the Late Cretaceous spreading was initiated further east between Madagascar and India. In the Songo Songo Region the Late Cretaceous to Paleogene was a time of thermal subsidence and a thick succession of dominantly shale and claystone were deposited.

The start of the Miocene was a period of regional differential uplift that increases in magnitude to the west and is probably associated with development of the East African Rift system. In the Late Miocene to Recent, inversion occurred generating the Songo Songo regional high, and the field structure in its current form. Listric faults are formed over the Songo Songo structure with detachment on the base Eocene, and may have developed as a collapse of the growing inversion structure.

Stratigraphy

During the Late Jurassic to Late Cretaceous subsidence of the newly formed rift basin led to the deposition of shallow and deep water marine clastics over a large area. Sediments deposited include organic shales in the Upper Jurassic (penetrated by wells SS-1, SS-5, SS-7 and SS-8), thick shallow marine sands in the Early Cretaceous, and deep water shales with intermittent delta front to turbidite fan and channel fill sands in the Late Cretaceous. Together these form the likely source rocks, thick Neocomian and Cenomanian natural gas reservoirs, and top seal in the Songo Songo Region. Rapid deposition during the Paleocene and early Eocene resulted in progradation of clastic shale wedges over a wide area. As subsidence slowed there was a return to shallow and marginal marine deposition and the Miocene is dominated by fine- to medium-grained sands deposited in these environments during a marine regressive phase. Quaternary coralline limestone and marine sands extend to the surface and reflect little change in the depositional environment during this period compared to the modern environments observed today.

The primary reservoir in the Songo Songo Field is the Lower Cretaceous (Neocomian to Albian) sand sequence. These sands were deposited predominantly in shallow to marginal marine environments, with minor fluvial deposition in the Albian. The depositional environment varies little throughout the section from lower shoreface to upper shoreface to tidal sand flat. There is very little interpreted shale in this high net to gross system, which where present is interpreted to have been deposited in marsh, mudflat or lagoon environments. Reservoir quality is good, although it deteriorates with depth towards the base of the Neocomian.

The uppermost gas reservoir in the Songo Songo Field is the Upper Cretaceous Cenomanian sequence, which consists of a generally thick gross interval of shale interbedded with sands and siltstones of varying thickness. The thickest Cenomanian interval on Songo Songo Field is found in the vicinity of the SS-1 and SS-3 wells, while reservoir quality sand only exists in wells SS-7 and SS-3 in the central area of the field. At SS-1 in the north the Cenomanian sand quality is marginal. The Cenomanian sands are thin to absent over the crest of the Songo Songo structure, in the vicinity of the SS-5, SS-7 and SS-9 wells, due to a combination of overburden structural influence and the disparate location of sands being shed off a delta front to the west or as deeper water turbidites.

The Neocomian – Albian and the Cenomanian reservoirs are overlain by a thick section of Late Cretaceous and Paleogene shales which form an excellent top seal. Although faults are mapped extending from the Neocomian upwards to the surface, as is evident on Songo Songo Field, they do not seem to present a seal risk, since they retain approximately 250 metres gas column in the Songo Songo Field.

The primary source rocks for the Songo Songo Region include the Permo-Triassic Karoo shales (gas) and Jurassic and Lower Cretaceous shales (oil and gas) which could have generated gas immediately beneath and to the east of the region. Cretaceous and Tertiary (Eocene) oil sources have the best chance of still being in the oil window at the present time and may present potential oil source rocks further to the east in deeper water. There are two potential routes for the gas migration – lateral migration from the deeper eastern part of the basin or vertical migration directly from the deeper Karoo and Jurassic sources. There is not enough data available right now to exactly identify gas source rocks.

Songo Songo Field Geology

The Songo Songo gas field is a long linear north to south trending domal structure cut by numerous minor faults and bounded on the east by a major fault with a throw of 200 to 300 feet. There have been several two dimensional ("2D") seismic surveys over the field and the seismic quality was considered to be fair to poor due to the steeply dipping nature of some of the fault blocks and the difficulty of obtaining good data in the variety of surface terrains from deep water to shallow water to onshore terrain.

Orca conducted a detailed geophysical interpretation of the original 2D seismic data in 2002 and prepared an updated structural interpretation. This interpretation was less complex than previous interpretations, with one large north to south fault, cutting the crest of the structure between the SS-5, SS-7 and SS-9 group of wells and the SS-3 and SS-4 wells. Previous studies identified several fault blocks although a review of the new seismic interpretation, RFT data and detailed pressure interference testing conducted in 1997 indicated only the one major north-south fault. Pressure interference testing indicated that this fault is not sealing thus the entire structure is interpreted to have a common gas water contact.

Orca prepared an updated geological model in 2008 incorporating the latest structural mapping of the Top Cenomanian and Top Lower Cretaceous (Neocomian to Albian) reservoirs from an updated 2D seismic interpretation. That model incorporated the reservoir zonation derived from a detailed stratigraphic correlation of well logs and was tied to SS-10 well. The petrophysical parameters were also revised based on evaluation of the comprehensive wireline data acquired in SS-10, the first new data on the field for 25 years.

Following the drilling of the SS-11 well in 2012, an updated geophysical model was prepared for the field. It utilized the reservoir zonation from the previous model, but used a simplified fault model and a new time-depth conversion approach based on the mapped velocities values at wells using a regional bias. The new geological model recognized only the major faults and has fewer compartments inside the field area.

The porosity and permeability correlations were reviewed with a modern CMR log interpretation and core data and established porosity cutoffs. Orca prepared updated detailed petrophysical and geological interpretations which were input into a new Petrel model for the field.

The overall changes in geological model did not materially affect the main and southern area of the field but did increase the pool area and average thickness in the northern area of the field due to changes in the top of the structure resulting in more of the zone being above the gas water contact. No material changes in the petrophysics occurred as a result of the petrophysical update.

The natural gas reserves in this field are contained in a thick sequence of Lower Cretaceous (Neocomian to Albian) age sands interbedded with silts, shales and carbonate layers and an overlying Cenomanian sand/shale sequence.

The top of the Cenomanian section occurs at a depth of approximately 1,635 metres subsea over the crest of the Songo Songo structure in the SS-10 well as shown in Figure 7. The Cenomanian natural gas reservoir reaches a maximum gross thickness of 79 metres in the vicinity of the SS-4 well as shown on Figure 11. The rapid facies changes resulted in a large variation in the thickness of the Cenomanian sand reservoir.

The top of the first Lower Cretaceous reservoir was encountered at a subsea depth of 1,698 metres in the SS-5 well over the crest of the Songo Songo structure while the gas water contact was interpreted to be at a depth of 1,940 metres. The gas water contact was estimated from RFT data since it was not possible to determine from well logs. The relative size of the aquifer is not well defined due to a lack of well data outside of the existing 11 wells.

The Albian-Neocomian section reaches a thickness of over 1,250 metres within the Songo Songo Area. The base of the Neocomian lies conformably on the Jurassic Kipatimu shales. The Neocomian reservoir becomes shalier and poorer quality in the lower part of the Neocomian section, which also coincides with the interpreted base of the gross gas pay interval.

The current geological model subdivided the gross Cenomanian / Neocomian section into 11 individual layers consisting of one Cenomanian layer and 10 Albian-Neocomian layers. All of the layers were interpreted to have a common gas-water contact at a depth of 1,940 metres subsea and only eight of the 10 Neocomian layers were structurally high enough to be within the gas column. For mapping purposes, the nine gas bearing layers were grouped into four layers referred to as the Cenomanian, the N-10 to N-6, N-5 and N-4 to N-1. Structure maps for the top of the Cenomanian and the Albian-Neocomian 10, Neocomian 5 and four layers are presented in Figures 7 to 10 and gross gas thickness maps for each of the four layers in Figures 11 to 14.

Estimates of the Original Gas-in-Place and Petrophysical Parameters

The original gas-in-place ("OGIP") estimates for the Songo Songo Field were based on the four gross gas pay maps in Figures 11 to 14 and the reservoir parameters in Table 10. Separate OGIP estimates were prepared for the Proved Producing ("PDP"), Total Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") reserves categories to reflect the drainage areas under the projected development and the respective confidence levels in the geological mapping. The northern area of the N10 to N6 pool (the area north of the faults to the south of SS-1) was separated from the main area of the pool because of the lack of existing wells in the northern area and the less confidence in the quality of the reservoir in that area.

The OGIP estimate for the Cenomanian Unit was based on 50 percent of the mapped OGIP in the PDP reserves case, 75 percent in the 1P case, 100 percent in the 2P case and 125 percent in the 3P case to reflect the uncertainty over where the zone is present. No proved reserves were assigned to the northern area of the N10 to N6 pool due to the very limited well control. The OGIP estimates for the northern area of the N10 to N6 pool were based on 25 percent of the mapped OGIP in the 2P reserves case and 50 percent in the 3P case. The OGIP for the main area of the N10 to N6 pool and all other pools was based on 100 percent of the mapped OGIP.

A summary of the petrophysical parameters by layer is presented in Table 10.

RESERVES ESTIMATES

The natural gas reserves estimates for the Songo Songo Field were based on volumetric estimates. A summary of the petrophysical parameters, original gas in place ("OGIP") estimates and the recovery factors for each of the four layers are summarized in Table 10. The reserves were classified into Proved Producing ("PP"), Proved Undeveloped ("PUD"), Total Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") classes as defined in the Reserves Classification section of this report. A summary of various reservoir and fluid properties is also presented in Table 11.

The total field natural OGIP was estimated to be some 1,381, 1,555 and 1,729 Bcf on a 1P, 2P and 3P reserves basis respectively, based on the methodology for estimating the OGIP described above. Natural gas shrinkage is expected to be relatively low at one percent as the reservoir contains a sweet dry gas with a condensate ratio of only 0.6 bbl per MMcf. All of the condensate reserves are owned by TPDC.

In addition to volumetric estimates of the OGIP, material balance estimates were also prepared. There has been very detailed, accurate pressure data recorded on most of the wells since they started producing although it is still somewhat early in the life of the field to determine the strength of the aquifer with only about 15 percent of the 2P OGIP produced to date.

The total structure volume indicates that the aquifer volume is significantly larger than the gas volume thus the reservoir would very likely have a moderate water drive. A numerical reservoir simulation was conducted by Orca which supports the view that the aquifer would provide pressure support to the gas pool although due to the very large size of the aquifer and the medium reservoir permeability, there would be a significant pressure gradient occurring throughout the reservoir with the lowest pressures near the producing wells.

The water drive effects make it very difficult to rely upon material balance calculations at this time. In our opinion, the volumetric method of estimating the OGIP is the most reliable method at this time and given the well control in the central area of the field where the majority of the OGIP is located, should provide confident estimates of the OGIP.

The recovery factors will depend on the extent of the gas water contact movement during the depletion of the gas pool, the reservoir pressure at abandonment and the amount of water coning that would occur in the gas wells which could limit their economic life. The pool is very thick thus water coning is not expected to be significant until very late in the pool life. The water contact movement and reservoir pressures as forecast in the reservoir simulation were analyzed to estimate recovery factors for each pool and reserves category as shown in Table 10. For the most part, overall average recovery factors of 70, 75, 77.5 and 80 percent for the PP, 1P, 2P and 3P reserves cases respectively were assigned to the Neocomian pools in the main area of the field with somewhat lower recovery factors for the northern area of the N10 to N6 pool since only one production well was forecast to be drilled in that area.

Only a portion of the technically recoverable reserves from the field are owned by Orca. Orca is entitled to only those "Additional" volumes in excess of the "Protected" volumes dedicated to SONGAS. A breakdown between the Additional and Protected sales gas reserves was based on year by year production forecasts and is summarized at the bottom of Table 10.

In addition, the Additional production volumes during the term of the license, to October 11, 2026, were classified as Company owned reserves. Although it is likely that Orca's license will be extended, standard evaluation procedures in the oil and gas industry limit the Company share of reserves to the term of the existing license unless there is a clear and established track record of license extensions. A summary of the reserves to the end of the license as well as to the end of the life of the field are presented in Table 1.

RESERVES CLASSIFICATION

The natural gas reserves estimates presented in this report have been based on the Canadian reserves definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the COGE Handbook. A summary of those definitions is presented below.

Reserves Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates

- **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.
- **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

- **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.

- **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.

- **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.

- **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.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

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:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- 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

- 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 the COGE Handbook.

PRODUCTION FORECASTS AND DEVELOPMENT PLANS

Production forecasts for the Additional Gas sales in the PP, 1P, 2P and 3P reserves categories were prepared for the Songo Songo Field in Tables 2 to 9. A graphical presentation of the production forecasts for the PP, 1P, 2P and 3P reserves categories is also presented in Figures 2 to 6.

Terms of the SONGAS agreement call for natural gas sales to five of the six turbines in the Ubungo power generation facility, the Wazo Hill Cement Plant and about one MMcfpd of local use close to the pipeline to be owned by the SONGAS consortium (referred to as the Protected Volumes) with any volumes above this amount to be owned by Orca (referred to as Additional Volumes). The Protected Volume contract has a 20 year term from the commencement of production then all subsequent sales will be owned by Orca. The max day production rate for the Protected Volumes is approximately 45.1 MMcfpd of sales gas. The Protected Volume load factor is forecast at 82.5 percent resulting in a remaining Protected Volume of approximately 144 Bcf of sales gas to the end of the 20 year term.

The SONGAS agreement requires that the max day rate for the Protected Volume sales to the Ubungo and cement plants to be maintained throughout the 20 year period. Although the deliverability from the existing wells is well above the 45.1 MMcfpd max day requirement, Orca must drill additional wells in the future to allow for Additional Volume sales to new markets.

Orca's Additional Volumes are comprised of industrial contracts and sales to power generation facilities in Dar es Salaam. Orca was selling gas to 31 industrial gas customers in Dar es Salaam in 2013. Additional industrial markets are being pursued by Orca which will likely result in the Additional Volumes steadily increasing over the next few years. Production rates for the industrial sales averaged approximately 6.3 MMcfpd in 2013 and are forecast to reach 8.5 MMcfpd by 2018 in the 2P case. Production rates for the Wazo Hill cement plant averaged approximately 5.65 MMcfpd in 2013 and are forecast to reach 8.0 MMcfpd by 2018 in the 2P case.

Orca's sales to the power sector averaged approximately 49.2 MMcfpd in 2013 and are forecast to rise to 116 MMcfpd by 2016 in the 2P case as new gas fired power generation facilities are added.

The PP reserves case was based on production rates that can be processed by the existing gas plant while the 1P, 2P and 3P reserves cases included a plant expansion that is expected to be completed at the end of 2015.

Production rates for all of the reserves cases forecast the total Additional Volume sales to be in the range of 54 to 56 MMcfpd in 2014 and 2015. The 2P and 3P cases assume that the production rates increase at the beginning of 2016 to 170 MMcfpd in the 2P case and 175 MMcfpd in the 3P case following the workover of several wells and the gas plant expansion. The 1P case assumes a slightly delayed startup of the gas plant in mid-2016 with the rates increasing to 170 MMcfpd. The PP case includes several workovers in 2015 but not the gas plant expansion so the rates increase slightly to approximately 60 MMcfpd starting in 2016. Production forecasts for the total field average sales gas rates for each reserves category are shown graphically in Figures 2 to 6.

One proved undeveloped location was forecast to be drilled in the main area of the field in 2015 and one probable undeveloped location in the north area of the field in 2020. Two new processing trains and plant inlet compression were forecast to be installed by the end of 2015. All of the gas plant and compression expenditures were assumed to be paid by SONGAS or another third party so Orca would pay a processing fee. A summary of the expenditures is presented in Tables 13 to 16.

REVENUE FORECASTS

The net present values of the natural gas reserves assigned to the Songo Songo Field were based on future production and revenue analyses. All of the revenues and costs forecast in this report are presented in US Dollars.

Orca currently owns a 100 percent interest in all of the Additional Volumes; however, TPDC has an option to participate in the drilling of any new wells for 5 to 20 percent of the cost of the wells in return for an additional 5 to 20 percent higher profit revenues on the allocated production to each well. It was assumed that TPDC would exercise its option for 20 percent on all new wells although Orca has advised that under the terms of the PSC that TPDC is not entitled to participate in the SS-10 and SS-11 wells. TPDC will assume obligations for all operating and capital costs associated with their share of production for each well in which it backs into and be entitled to cost recovery, so this participation was treated as a working interest. The net result is that Orca's field average working interest in the Additional Volumes over the life of the reserves is approximately 96 percent.

As discussed in the reserves section of this report, Orca was only assigned reserves representing its share of the Additional Volumes during the term of the production license in all reserves cases. Future revenue forecasts and net present value estimates were prepared for comparison purposes for both the revenues to the end of the license term in Tables 2 to 5 and to the end of the field economic life in Tables 6 to 9.

Future natural gas revenues were based on forecasts of the industrial, Wazo Hill and power market sales volumes and the respective price forecasts for each market. A summary of the Songo Songo industrial and power gas price forecast is presented in Table 17.

The fiscal regime for Songo Songo is detailed in Table 12. Government share of revenues is through a royalty and cost revenue/profit revenue fiscal system and there is no defined income tax system. Operating and capital costs were based on estimates provided by the Company and are summarized in Tables 12 to 16. All of the revenue calculations were presented at the inlet to the Songo Songo gas plant. Operating expenses are incurred for the well and field gathering system, a company owned gas distribution system in Dar es Salaam, a regulator fee, marketing expenses and G&A costs. Capital cost estimates were provided by the Company and are comprised of new wells, wellhead compression and maintenance capex.

Table 1

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only
Summary of Reserves and Net Present Values
Forecast Price Case as of December 31, 2013

Summary of Reserves (1), (3)

	Natural Gas Reserves - To End of License			Natural Gas Reserves - To End of Field Life		
Reserve Category	Property Gross (2) MMcf	Company Gross (2) MMcf	Company Net (2) MMcf	Property Gross (2) MMcf	Company Gross (2) MMcf	Company Net (2) MMcf
Proved Producing Reserves	304,935	304,935	212,138	573,515	573,515	381,619
Proved Undeveloped Reserves	183,587	170,755	100,428	79,890	62,336	39,627
Total Proved Reserves	488,523	475,691	312,566	653,405	635,851	421,246
Probable Reserves	58,707	51,606	36,955	126,531	113,489	75,857
Proved Plus Probable Reserves	547,229	527,296	349,521	779,935	749,340	497,103
Possible Reserves	39,831	38,130	20,637	124,061	118,500	68,954
Proved + Probable + Possible	587,061	565,427	370,158	903,996	867,841	566,057

Summary of Company Share of Net Present Values - Forecast to End of License (3)

	$M US Dollars - Unrisked				
Reserve Category	0.0%	5.0%	10.0%	15.0%	20.0%
Proved Producing Reserves	393,578	265,213	186,405	136,004	102,537
Proved Undeveloped Reserves	321,051	237,248	178,739	136,955	106,489
Total Proved Reserves	714,629	502,460	365,144	272,959	209,025
Probable Reserves	91,099	57,141	37,987	26,795	20,014
Proved Plus Probable Reserves	805,729	559,602	403,131	299,754	229,039
Possible Reserves	61,293	42,807	30,871	22,947	17,541
Proved + Probable + Possible	867,021	602,409	434,003	322,701	246,580

Summary of Company Share of Net Present Values - Forecast to End of Field Life (3)

	$M US Dollars - Unrisked				
Reserve Category	0.0%	5.0%	10.0%	15.0%	20.0%
Proved Producing Reserves	919,598	492,749	291,275	186,990	128,478
Proved Undeveloped Reserves	71,671	129,441	129,285	113,096	94,470
Total Proved Reserves	991,269	622,190	420,560	300,087	222,948
Probable Reserves	239,214	117,720	65,144	39,849	26,638
Proved Plus Probable Reserves	1,230,483	739,910	485,704	339,936	249,585
Possible Reserves	35,753	30,870	25,515	20,565	16,488
Proved + Probable + Possible	1,266,236	770,780	511,219	360,501	266,073

(1) Company Gross reserves are based on Orca's working interest share of the property gross additional reserves (excluding protected volumes). Company Net reserves are based on Orca's share of total Cost and Profit Revenues.
(2) Additional Volumes Only (Excludes Protected Volumes).
(3) Only the reserves and net present values to end of license were included at the corporate level.
(4) There is no defined corporate income tax for this property. Government share of revenue is through a Cost Revenue/Profit Revenue fiscal sytem.

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Proved Producing Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Additional Gas Sales Only: Annual Volume MMcf	Additional Gas Sales Only: Avg Field Gas Price US$/Mcf	Additional Gas Sales Only: Gross Field Sales Rev. US$M
2014	4	37.21	41.98	6.58	0.37	5.93	92.07	54.86	20,025	4.07	81,459
2015	6	37.21	42.33	6.91	0.38	6.23	93.06	55.85	20,386	4.12	84,021
2016	7	37.21	45.72	7.00	0.40	6.54	96.87	59.66	21,777	4.15	90,297
2017	7	37.21	45.37	7.00	0.42	6.87	96.87	59.66	21,777	4.17	90,777
2018	7	37.21	45.01	7.00	0.44	7.21	96.87	59.66	21,777	4.23	92,095
2019	7	37.21	44.70	7.00	0.47	7.50	96.87	59.66	21,777	4.31	93,777
2020	7	37.21	44.67	7.00	0.49	7.50	96.87	59.66	21,777	4.39	95,707
2021	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.49	97,680
2022	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.57	99,613
2023	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.67	101,633
2024	7	21.70	60.17	7.00	0.50	7.50	96.87	75.17	27,436	4.95	135,741
2025	7	-	81.87	7.00	0.50	7.50	96.87	96.87	35,358	5.21	184,284
2026	7	-	81.87	7.00	0.50	7.50	96.87	96.87	27,512	5.32	146,270
2027											
2028											
Rem.											
Total		143,729	237,073	32,464	2,140	33,257	448,665	304,935	304,935		1,393,356

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,654	0.73	2,460	30,955	400	200	350	32,049	61,094	32,049	-	49,411
2015	15,220	0.75	2,536	72,114	400	200	350	81,516	63,016	63,016	18,500	21,005
2016	12,890	0.59	2,693	26,894	400	200	350	27,450	67,723	45,950	-	44,347
2017	13,139	0.60	2,747	265	400	200	350	28,247	68,083	28,247	-	62,529
2018	13,404	0.62	2,801	271	400	200	350	28,807	69,072	28,807	-	63,288
2019	13,680	0.63	2,857	11,317	400	200	350	36,579	70,333	36,579	-	57,198
2020	13,964	0.64	2,915	11,543	400	200	350	34,644	71,780	34,644	-	61,063
2021	14,248	0.65	2,973	11,774	400	200	350	29,395	73,260	29,395	-	68,285
2022	14,533	0.67	3,032	12,010	400	200	350	29,975	74,710	29,975	-	69,638
2023	14,824	0.68	3,093	12,250	400	200	350	30,567	76,225	30,567	-	71,066
2024	15,772	0.57	3,155	12,495	400	200	350	31,821	101,806	31,821	-	103,920
2025	17,017	0.48	3,218	311	400	200	350	20,946	138,213	20,946	-	163,338
2026	13,506	0.49	2,554	247	311	156	272	16,618	109,703	16,618	-	129,653
2027												
2028												
Rem.												
Total	186,851	0.61	37,034	202,445	5,111	2,556	4,472	428,613		428,613		964,743

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,608	32,249	27,176	59,425	17,114	30,955	950	2,601	7,804	7,804	7,441
2015	20,386	18,093	63,016	11,553	74,569	17,756	72,114	950	-	(16,252)	(8,448)	(14,087)
2016	21,777	17,061	46,350	24,391	70,741	15,582	26,894	950	1,669	25,646	17,198	20,208
2017	21,777	15,075	28,447	34,391	62,839	15,885	265	950	11,434	34,303	51,501	24,573
2018	21,777	15,090	29,007	34,809	63,816	16,206	271	950	11,597	34,792	86,293	22,657
2019	21,777	15,847	36,779	31,459	68,238	16,538	11,317	950	9,858	29,575	115,868	17,509
2020	21,777	15,570	34,844	33,585	68,429	16,878	11,543	950	9,764	29,293	145,161	15,766
2021	21,777	14,971	29,595	37,557	67,152	17,221	11,774	950	9,302	27,905	173,066	13,653
2022	21,777	14,970	30,175	38,301	68,476	17,565	12,010	950	9,488	28,463	201,529	12,660
2023	21,777	14,968	30,767	39,086	69,853	17,917	12,250	950	9,684	29,052	230,582	11,748
2024	27,436	18,024	32,021	57,156	89,177	18,926	12,495	950	14,202	42,605	273,186	15,661
2025	35,358	21,294	21,146	89,836	110,982	20,235	311	950	22,372	67,115	340,301	22,429
2026	27,512	16,567	16,773	71,309	88,082	16,060	247	739	17,759	53,278	393,578	16,186
2027												
2028												
Rem.												
Total	304,935	212,138	431,169	530,609	961,777	223,885	202,445	12,139	129,730	393,578		186,405

Table 3

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Total Proved Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.98	6.58	0.37	5.93	92.07	54.86	20,025	4.07	81,459
2015	6	37.21	42.33	6.91	0.38	6.23	93.06	55.85	20,386	4.12	84,021
2016	8	37.21	82.50	7.00	0.40	6.54	133.65	96.44	35,202	4.29	151,180
2017	8	37.21	116.80	7.00	0.42	6.87	168.30	131.09	47,849	4.42	211,383
2018	8	37.21	116.44	7.00	0.44	7.21	168.30	131.09	47,849	4.50	215,114
2019	8	37.21	116.13	7.00	0.47	7.50	168.30	131.09	47,849	4.58	219,256
2020	8	37.21	116.10	7.00	0.49	7.50	168.30	131.09	47,849	4.68	223,695
2021	8	37.21	116.09	7.00	0.50	7.50	168.30	131.09	47,849	4.77	228,228
2022	8	37.21	104.68	7.00	0.50	7.50	156.89	119.68	43,685	4.84	211,504
2023	8	37.21	80.89	7.00	0.50	7.50	133.10	95.89	35,000	4.87	170,516
2024	8	21.70	81.05	7.00	0.50	7.50	117.76	96.05	35,059	5.03	176,251
2025	8	-	83.25	7.00	0.50	7.50	98.25	98.25	35,863	5.21	187,021
2026	8	-	69.72	7.00	0.50	7.50	84.72	84.72	24,060	5.29	127,188
2027											
2028											
Rem.											
Total		143,729	420,661	32,464	2,140	33,257	632,252	488,523	488,523		2,286,815

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,654	0.73	2,529	32,205	400	200	350	33,368	61,094	33,368	-	48,091
2015	15,220	0.75	2,608	104,616	400	200	350	114,090	63,016	63,016	51,074	21,005
2016	13,990	0.40	3,620	26,894	400	200	350	29,678	113,385	80,752	-	70,428
2017	15,248	0.32	4,907	531	400	200	350	32,782	158,537	32,782	-	178,601
2018	15,556	0.33	5,005	541	400	200	350	33,432	161,335	33,432	-	181,681
2019	15,874	0.33	5,105	11,593	400	200	350	41,297	164,442	41,297	-	177,959
2020	16,202	0.34	5,207	11,825	400	200	350	39,456	167,772	39,456	-	184,239
2021	16,531	0.35	5,311	12,061	400	200	350	34,303	171,171	34,303	-	193,924
2022	16,505	0.38	5,050	12,302	400	200	350	34,258	158,628	34,258	-	177,246
2023	16,070	0.46	4,370	12,548	400	200	350	33,388	127,887	33,388	-	137,127
2024	16,510	0.47	3,944	12,799	400	200	350	33,653	132,188	33,653	-	142,597
2025	17,127	0.48	3,356	622	400	200	350	21,505	140,266	21,505	-	165,516
2026	13,253	0.55	2,297	493	311	156	272	16,355	95,391	16,355	-	110,833
2027												
2028												
Rem.												
Total	202,742	0.42	53,510	239,032	5,111	2,556	4,472	497,566		497,566		1,789,249

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,447	32,318	26,450	58,768	17,184	32,205	950	2,107	6,322	6,322	6,028
2015	20,386	18,093	63,016	11,553	74,569	17,828	104,616	950	-	(48,826)	(42,504)	(42,322)
2016	34,193	27,657	81,152	37,626	118,778	17,810	26,894	950	2,779	70,345	27,841	55,431
2017	46,479	29,065	32,982	95,418	128,400	20,155	531	950	26,691	80,073	107,914	57,360
2018	46,479	29,071	33,632	97,063	130,696	20,561	541	950	27,161	81,483	189,397	53,064
2019	46,479	29,604	41,497	95,074	136,571	20,979	11,593	950	25,762	77,287	266,684	45,756
2020	46,479	29,537	39,656	98,430	138,086	21,409	11,825	950	25,976	77,927	344,610	41,940
2021	46,479	28,955	34,503	103,604	138,108	21,842	12,061	950	25,814	77,441	422,051	37,890
2022	42,434	26,675	34,458	94,694	129,152	21,556	12,302	950	23,586	70,758	492,809	31,473
2023	33,997	21,931	33,588	73,260	106,849	20,440	12,548	950	18,228	54,683	547,492	22,112
2024	34,055	21,888	33,853	76,183	110,036	20,454	12,799	950	18,958	56,874	604,366	20,907
2025	34,836	21,119	21,705	88,427	110,132	20,483	622	950	22,019	66,058	670,424	22,075
2026	23,371	14,324	16,510	59,213	75,723	15,550	493	739	14,735	44,205	714,629	13,430
2027												
2028												
Rem.												
Total	475,691	312,566	498,872	956,995	1,455,866	256,251	239,032	12,139	233,815	714,629		365,144

Table 4

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Proved + Probable Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.67	6.74	0.37	6.07	92.07	54.86	20,025	4.10	82,013
2015	6	37.21	41.68	7.25	0.40	6.53	93.06	55.85	20,386	4.18	85,158
2016	8	37.21	115.85	7.79	0.43	7.02	168.30	131.09	47,849	4.39	210,294
2017	8	37.21	114.71	8.37	0.46	7.55	168.30	131.09	47,849	4.48	214,251
2018	8	37.21	114.09	8.50	0.50	8.00	168.30	131.09	47,849	4.56	218,230
2019	8	37.21	114.06	8.50	0.54	8.00	168.30	131.09	47,849	4.65	222,523
2020	9	37.21	114.02	8.50	0.58	8.00	168.30	131.09	47,849	4.75	227,081
2021	9	37.21	113.97	8.50	0.62	8.00	168.30	131.09	47,849	4.84	231,802
2022	9	37.21	113.93	8.50	0.67	8.00	168.30	131.09	47,849	4.94	236,581
2023	9	37.21	113.88	8.50	0.72	8.00	168.30	131.09	47,849	5.05	241,530
2024	9	21.70	105.06	8.50	0.75	8.00	144.01	122.31	44,641	5.18	231,444
2025	9	-	114.02	8.50	0.75	8.00	131.27	131.27	47,913	5.36	256,695
2026	9	-	93.57	8.50	0.75	8.00	110.82	110.82	31,474	5.45	171,642
2027											
2028											
Rem.											
Total		143,729	470,751	38,238	2,692	35,548	690,959	547,229	547,229		2,629,244

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,704	0.73	2,456	32,205	400	200	350	33,344	61,510	33,344	-	48,669
2015	15,327	0.75	2,532	104,616	400	200	350	114,121	63,868	63,868	50,253	21,289
2016	15,202	0.32	4,671	26,894	400	200	350	31,740	157,720	81,992	-	128,301
2017	15,674	0.33	4,764	7,121	400	200	350	39,656	160,688	39,656	-	174,595
2018	16,034	0.34	4,859	6,495	400	200	350	39,718	163,672	39,718	-	178,512
2019	16,368	0.34	4,956	19,708	400	200	350	49,757	166,892	49,757	-	172,765
2020	16,759	0.35	5,056	68,133	400	200	350	96,170	170,311	96,170	-	130,911
2021	17,115	0.36	5,157	12,061	400	200	350	34,733	173,852	34,733	-	197,070
2022	17,478	0.37	5,260	12,302	400	200	350	35,441	177,436	35,441	-	201,141
2023	17,852	0.37	5,365	12,548	400	200	350	36,166	181,148	36,166	-	205,365
2024	18,045	0.40	4,682	12,799	400	200	350	35,927	173,583	35,927	-	195,517
2025	18,881	0.39	4,354	622	400	200	350	24,256	192,521	24,256	-	232,438
2026	14,472	0.46	2,917	493	311	156	272	18,194	128,732	18,194	-	153,449
2027												
2028												
Rem.												
Total	213,912	0.39	57,028	315,998	5,111	2,556	4,472	589,221		589,221		2,040,022

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,421	32,294	26,768	59,062	17,160	32,205	950	2,187	6,561	6,561	6,255
2015	20,386	18,093	63,868	11,709	75,578	17,859	104,616	950	-	(47,848)	(41,287)	(41,474)
2016	46,479	34,343	82,392	68,545	150,937	19,872	26,894	950	10,613	92,607	51,320	72,973
2017	46,479	29,733	39,856	93,278	133,133	20,438	7,121	950	26,156	78,468	129,788	56,211
2018	46,479	29,663	39,918	95,370	135,288	20,893	6,495	950	26,738	80,213	210,001	52,237
2019	46,479	30,589	49,957	92,300	142,257	21,324	19,708	950	25,069	75,206	285,207	44,524
2020	45,656	34,783	96,370	68,702	165,072	21,815	68,133	950	18,544	55,631	340,838	29,941
2021	45,656	28,559	34,933	103,422	138,355	22,271	12,061	950	25,768	77,304	418,142	37,823
2022	45,656	28,558	35,641	105,559	141,199	22,738	12,302	950	26,302	78,906	497,048	35,097
2023	45,656	28,555	36,366	107,775	144,141	23,217	12,548	950	26,856	80,569	577,617	32,579
2024	42,596	26,759	36,127	102,607	138,735	22,728	12,799	950	25,564	76,693	654,310	28,192
2025	45,718	27,333	24,456	121,984	146,440	23,235	622	950	30,408	91,225	745,535	30,486
2026	30,032	18,131	18,349	80,530	98,879	17,389	493	739	20,064	60,193	805,729	18,287
2027												
2028												
Rem.												
Total	527,296	349,521	590,527	1,078,549	1,669,076	270,940	315,998	12,139	264,270	805,729		403,131

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of License
Forecast of Production and Revenues
Proved + Probable + Possible Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.37	6.90	0.38	6.22	92.07	54.86	20,025	4.12	82,567
2015	6	37.21	41.01	7.59	0.42	6.84	93.06	55.85	20,386	4.23	86,321
2016	8	37.21	119.71	8.35	0.46	7.52	173.25	136.04	49,656	4.42	219,723
2017	8	37.21	118.08	9.18	0.51	8.27	173.25	136.04	49,656	4.52	224,284
2018	8	37.21	116.98	10.00	0.56	8.50	173.25	136.04	49,656	4.63	229,959
2019	8	37.21	116.93	10.00	0.62	8.50	173.25	136.04	49,656	4.72	234,515
2020	9	37.21	116.86	10.00	0.68	8.50	173.25	136.04	49,656	4.82	239,381
2021	9	37.21	116.80	10.00	0.75	8.50	173.25	136.04	49,656	4.92	244,440
2022	9	37.21	116.72	10.00	0.82	8.50	173.25	136.04	49,656	5.03	249,568
2023	9	37.21	116.64	10.00	0.90	8.50	173.25	136.04	49,656	5.13	254,901
2024	9	21.70	132.05	10.00	0.99	8.50	173.25	151.55	55,314	5.29	292,406
2025	9	-	130.97	10.00	1.00	8.50	150.47	150.47	54,921	5.44	299,040
2026	9	-	118.42	10.00	1.00	8.50	137.92	137.92	39,171	5.56	217,659
2027											
2028											
Rem.											
Total		143,729	502,337	43,723	3,238	37,762	730,790	587,061	587,061		2,874,765

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,754	0.74	2,165	32,205	400	200	350	33,103	61,925	33,103	-	49,464
2015	15,437	0.76	2,232	104,616	400	200	350	113,931	64,741	64,741	49,190	21,580
2016	15,515	0.31	4,239	26,894	400	200	350	31,621	164,792	80,810	-	138,912
2017	16,072	0.32	4,323	7,121	400	200	350	39,613	168,213	39,613	-	184,671
2018	16,656	0.34	4,410	6,495	400	200	350	39,891	172,469	39,891	-	190,068
2019	17,010	0.34	4,498	19,708	400	200	350	49,941	175,886	49,941	-	184,574
2020	17,424	0.35	4,588	68,133	400	200	350	96,368	179,536	96,368	-	143,014
2021	17,804	0.36	4,680	12,061	400	200	350	34,945	183,330	34,945	-	209,495
2022	18,195	0.37	4,773	12,302	400	200	350	35,670	187,176	35,670	-	213,898
2023	18,598	0.37	4,869	12,548	400	200	350	36,415	191,176	36,415	-	218,486
2024	19,608	0.35	4,966	12,799	400	200	350	37,774	219,305	37,774	-	254,633
2025	20,132	0.37	4,399	622	400	200	350	25,553	224,280	25,553	-	273,487
2026	15,663	0.31	3,201	493	311	156	272	19,669	163,244	19,669	-	197,990
2027												
2028												
Rem.												
Total	222,869	0.38	53,343	315,998	5,111	2,556	4,472	594,494		594,494		2,280,271

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,372	32,053	27,205	59,258	16,919	32,205	950	2,296	6,889	6,889	6,568
2015	20,386	18,093	64,741	11,869	76,610	17,669	104,616	950	-	(46,625)	(39,737)	(40,414)
2016	48,234	35,125	81,210	74,214	155,424	19,753	26,894	950	12,153	95,673	55,937	75,389
2017	48,234	30,657	39,813	98,660	138,473	20,396	7,121	950	27,502	82,505	138,442	59,103
2018	48,234	30,583	40,091	101,544	141,635	21,066	6,495	950	28,281	84,843	223,285	55,252
2019	48,234	31,496	50,141	98,609	148,750	21,508	19,708	950	26,646	79,937	303,223	47,325
2020	47,380	35,600	96,568	75,054	171,621	22,012	68,133	950	20,131	60,394	363,617	32,505
2021	47,380	29,473	35,145	109,943	145,088	22,484	12,061	950	27,398	82,195	445,812	40,216
2022	47,380	29,472	35,870	112,254	148,124	22,968	12,302	950	27,976	83,928	529,740	37,331
2023	47,380	29,469	36,615	114,661	151,277	23,467	12,548	950	28,578	85,734	615,473	34,667
2024	52,780	32,462	37,974	133,631	171,605	24,574	12,799	950	33,320	99,961	715,434	36,746
2025	52,404	31,089	25,753	143,526	169,279	24,532	622	950	35,794	107,382	822,816	35,885
2026	37,376	22,267	19,824	103,905	123,730	18,864	493	739	39,888	63,745	886,561	19,366
2027												
2028												
Rem.												
Total	565,427	370,158	595,799	1,205,075	1,800,874	276,212	315,998	12,139	309,963	886,561		439,939

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Proved Producing Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.98	6.58	0.37	5.93	92.07	54.86	20,025	4.07	81,459
2015	6	37.21	42.33	6.91	0.38	6.23	93.06	55.85	20,386	4.12	84,021
2016	7	37.21	45.72	7.00	0.40	6.54	96.87	59.66	21,777	4.15	90,297
2017	7	37.21	45.37	7.00	0.42	6.87	96.87	59.66	21,777	4.17	90,777
2018	7	37.21	45.01	7.00	0.44	7.21	96.87	59.66	21,777	4.23	92,095
2019	7	37.21	44.70	7.00	0.47	7.50	96.87	59.66	21,777	4.31	93,777
2020	7	37.21	44.67	7.00	0.49	7.50	96.87	59.66	21,777	4.39	95,707
2021	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.49	97,680
2022	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.57	99,613
2023	7	37.21	44.66	7.00	0.50	7.50	96.87	59.66	21,777	4.67	101,633
2024	7	21.70	60.17	7.00	0.50	7.50	96.87	75.17	27,436	4.95	135,741
2025	7	-	81.87	7.00	0.50	7.50	96.87	96.87	35,358	5.21	184,284
2026	7	-	81.87	7.00	0.50	7.50	96.87	96.87	35,358	5.32	187,988
2027	7	-	81.87	7.00	0.50	7.50	96.87	96.87	35,358	5.42	191,723
2028	7	-	81.87	7.00	0.50	7.50	96.87	96.87	35,358	5.53	195,579
Rem.									190,017	6.00	1,140,488
Total		143,729	445,448	60,560	4,147	63,360	717,245	573,515	573,515		2,962,864

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,654	0.73	2,460	30,955	400	200	350	32,049	61,094	32,049	-	49,411
2015	15,220	0.75	2,536	72,114	400	200	350	81,516	63,016	63,016	18,500	21,005
2016	12,890	0.59	2,693	26,894	400	200	350	27,450	67,723	45,950	-	44,347
2017	13,139	0.60	2,747	265	400	200	350	28,247	68,083	28,247	-	62,529
2018	13,404	0.62	2,801	271	400	200	350	28,807	69,072	28,807	-	63,288
2019	13,680	0.63	2,857	11,317	400	200	350	36,579	70,333	36,579	-	57,198
2020	13,964	0.64	2,915	11,543	400	200	350	34,644	71,780	34,644	-	61,063
2021	14,248	0.65	2,973	11,774	400	200	350	29,395	73,260	29,395	-	68,285
2022	14,533	0.67	3,032	12,010	400	200	350	29,975	74,710	29,975	-	69,638
2023	14,824	0.68	3,093	12,250	400	200	350	30,567	76,225	30,567	-	71,066
2024	15,772	0.57	3,155	12,495	400	200	350	31,821	101,806	31,821	-	103,920
2025	17,017	0.48	3,218	311	400	200	350	20,946	138,213	20,946	-	163,338
2026	17,358	0.49	3,282	317	400	200	350	21,357	140,991	21,357	-	166,631
2027	17,705	0.50	3,348	-	400	200	350	21,453	143,792	21,453	-	170,271
2028	18,059	0.51	3,415	-	400	200	350	21,874	146,684	21,874	-	173,705
Rem.	212,209	1.12	20,183	-	4,800	2,400	4,200	237,192		237,192		903,295
Total	438,676	0.76	64,708	202,515	10,800	5,400	9,450	713,872		713,872		2,248,992

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,608	32,249	27,176	59,425	17,114	30,955	950	2,601	7,804	7,804	7,441
2015	20,386	18,093	63,016	11,553	74,569	17,756	72,114	950	-	(16,252)	(8,448)	(14,087)
2016	21,777	17,061	46,350	24,391	70,741	15,582	26,894	950	1,669	25,646	17,198	20,208
2017	21,777	15,075	28,447	34,391	62,839	15,885	265	950	11,434	34,303	51,501	24,573
2018	21,777	15,090	29,007	34,809	63,816	16,206	271	950	11,597	34,792	86,293	22,657
2019	21,777	15,847	36,779	31,459	68,238	16,538	11,317	950	9,858	29,575	115,868	17,509
2020	21,777	15,570	34,844	33,585	68,429	16,878	11,543	950	9,764	29,293	145,161	15,766
2021	21,777	14,971	29,595	37,557	67,152	17,221	11,774	950	9,302	27,905	173,066	13,653
2022	21,777	14,970	30,175	38,301	68,476	17,565	12,010	950	9,488	28,463	201,529	12,660
2023	21,777	14,968	30,767	39,086	69,853	17,917	12,250	950	9,684	29,052	230,582	11,748
2024	27,436	18,024	32,021	57,156	89,177	18,926	12,495	950	14,202	42,605	273,186	15,661
2025	35,358	21,294	21,146	89,836	110,982	20,235	311	950	22,372	67,115	340,301	22,429
2026	35,358	21,292	21,557	91,647	113,204	20,640	317	950	22,824	68,473	408,774	20,802
2027	35,358	21,264	21,653	93,649	115,302	21,053	-	950	23,325	69,974	478,748	19,326
2028	35,358	21,263	22,074	95,538	117,612	21,474	-	950	23,797	71,391	550,139	17,925
Rem.	190,017	122,229	239,592	496,812	736,405	232,392	-	11,400	123,153	369,459	919,598	63,004
Total	573,515	381,619	719,272	1,236,946	1,956,217	503,385	202,515	25,650	305,070	919,598		291,275

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Total Proved Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.98	6.58	0.37	5.93	92.07	54.86	20,025	4.07	81,459
2015	6	37.21	42.33	6.91	0.38	6.23	93.06	55.85	20,386	4.12	84,021
2016	8	37.21	82.50	7.00	0.40	6.54	133.65	96.44	35,202	4.29	151,180
2017	8	37.21	116.80	7.00	0.42	6.87	168.30	131.09	47,849	4.42	211,383
2018	8	37.21	116.44	7.00	0.44	7.21	168.30	131.09	47,849	4.50	215,114
2019	8	37.21	116.13	7.00	0.47	7.50	168.30	131.09	47,849	4.58	219,256
2020	8	37.21	116.10	7.00	0.49	7.50	168.30	131.09	47,849	4.68	223,695
2021	8	37.21	116.09	7.00	0.50	7.50	168.30	131.09	47,849	4.77	228,228
2022	8	37.21	104.68	7.00	0.50	7.50	156.89	119.68	43,685	4.84	211,504
2023	8	37.21	80.89	7.00	0.50	7.50	133.10	95.89	35,000	4.87	170,516
2024	8	21.70	81.05	7.00	0.50	7.50	117.76	96.05	35,059	5.03	176,251
2025	8	-	83.25	7.00	0.50	7.50	98.25	98.25	35,863	5.21	187,021
2026	8	-	69.72	7.00	0.50	7.50	84.72	84.72	30,922	5.29	163,463
2027	8	-	55.71	7.00	0.50	7.50	70.71	70.71	25,808	5.34	137,869
2028	8	-	40.60	7.00	0.50	7.50	55.60	55.60	20,294	5.37	108,932
Rem.									111,918	6.04	676,204
Total		143,729	538,257	54,531	3,717	56,900	797,134	653,405	653,405		3,246,095

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,654	0.73	2,529	32,205	400	200	350	33,368	61,094	33,368	-	48,091
2015	15,220	0.75	2,608	104,616	400	200	350	114,090	63,016	63,016	51,074	21,005
2016	13,990	0.40	3,820	26,894	400	200	350	29,678	113,385	80,752	-	70,428
2017	15,248	0.32	4,907	531	400	200	350	32,782	158,537	32,782	-	178,601
2018	15,556	0.33	5,005	541	400	200	350	33,432	161,335	33,432	-	181,681
2019	15,874	0.33	5,105	11,593	400	200	350	41,297	164,442	41,297	-	177,959
2020	16,202	0.34	5,207	11,825	400	200	350	39,456	167,772	39,456	-	184,239
2021	16,531	0.35	5,311	12,061	400	200	350	34,303	171,171	34,303	-	193,924
2022	16,505	0.38	5,050	12,302	400	200	350	34,258	158,628	34,258	-	177,246
2023	16,070	0.46	4,370	12,548	400	200	350	33,388	127,887	33,388	-	137,127
2024	16,510	0.47	3,944	12,799	400	200	350	33,653	132,188	33,653	-	142,597
2025	17,127	0.48	3,356	622	400	200	350	21,505	140,266	21,505	-	165,516
2026	17,033	0.55	2,952	634	400	200	350	21,019	122,597	21,019	-	142,444
2027	16,913	0.66	2,513	-	400	200	350	19,825	103,401	19,825	-	118,043
2028	16,744	0.83	2,016	-	400	200	350	19,160	81,699	19,160	-	89,772
Rem.	198,738	1.78	12,362	-	4,800	2,400	4,200	215,900		215,900		460,304
Total	438,916	0.67	71,055	239,172	10,800	5,400	9,450	757,116		757,116		2,488,979

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,447	32,318	26,450	58,768	17,184	32,205	950	2,107	6,322	6,322	6,028
2015	20,386	18,093	63,016	11,553	74,569	17,828	104,616	950	-	(48,826)	(42,504)	(42,322)
2016	34,193	27,657	81,152	37,626	118,778	17,810	26,894	950	2,779	70,345	27,841	55,431
2017	46,479	29,065	32,982	95,418	128,400	20,155	531	950	26,691	80,073	107,914	57,360
2018	46,479	29,071	33,632	97,063	130,696	20,561	541	950	27,161	81,483	189,397	53,064
2019	46,479	29,804	41,497	95,074	136,571	20,979	11,593	950	25,762	77,287	266,684	45,756
2020	46,479	29,537	39,656	98,430	138,086	21,409	11,825	950	25,976	77,927	344,610	41,940
2021	46,479	28,955	34,503	103,604	138,108	21,842	12,061	950	25,814	77,441	422,051	37,890
2022	42,434	26,675	34,458	94,694	129,152	21,556	12,302	950	23,586	70,758	492,809	31,473
2023	33,997	21,931	33,588	73,260	106,849	20,440	12,548	950	18,228	54,683	547,492	22,112
2024	34,055	21,888	33,853	76,183	110,036	20,454	12,799	950	18,958	56,874	604,366	20,907
2025	34,836	21,119	21,705	88,427	110,132	20,483	622	950	22,019	66,058	670,424	22,075
2026	30,036	18,410	21,219	76,101	97,320	19,985	634	950	18,938	56,813	727,237	17,260
2027	25,069	15,554	20,025	63,065	83,090	19,425	-	950	15,679	47,036	774,273	12,991
2028	19,713	12,542	19,360	47,961	67,321	18,760	-	950	11,903	35,708	809,981	8,965
Rem.	108,713	76,499	218,300	245,917	464,217	211,100	-	11,400	60,429	181,288	991,269	29,630
Total	635,851	421,246	761,266	1,330,825	2,092,092	509,971	239,172	25,650	326,029	991,269		420,560

Table 8

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Proved + Probable Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate Rate MMcfpd	Total Field Gas Rate MMcfpd	Additional Gas Sales Only: Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.67	6.74	0.37	6.07	92.07	54.86	20,025	4.10	82,013
2015	6	37.21	41.68	7.25	0.40	6.53	93.06	55.85	20,386	4.18	85,158
2016	8	37.21	115.85	7.79	0.43	7.02	168.30	131.09	47,849	4.39	210,294
2017	8	37.21	114.71	8.37	0.46	7.55	168.30	131.09	47,849	4.48	214,251
2018	8	37.21	114.09	8.50	0.50	8.00	168.30	131.09	47,849	4.56	218,230
2019	8	37.21	114.06	8.50	0.54	8.00	168.30	131.09	47,849	4.65	222,523
2020	9	37.21	114.02	8.50	0.58	8.00	168.30	131.09	47,849	4.75	227,081
2021	9	37.21	113.97	8.50	0.62	8.00	168.30	131.09	47,849	4.84	231,802
2022	9	37.21	113.93	8.50	0.67	8.00	168.30	131.09	47,849	4.94	236,581
2023	9	37.21	113.88	8.50	0.72	8.00	168.30	131.09	47,849	5.05	241,530
2024	9	21.70	105.06	8.50	0.75	8.00	144.01	122.31	44,641	5.18	231,444
2025	9	-	114.02	8.50	0.75	8.00	131.27	131.27	47,913	5.36	256,695
2026	9	-	93.57	8.50	0.75	8.00	110.82	110.82	40,451	5.45	220,597
2027	9	-	74.12	8.50	0.75	8.00	91.37	91.37	33,350	5.55	184,937
2028	9	-	62.40	8.50	0.75	8.00	79.65	79.65	29,073	5.64	164,062
Rem.									161,306	6.39	1,030,909
Total		143,729	637,584	70,697	5,556	66,098	923,665	779,935	779,935		4,058,106

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,704	0.73	2,456	32,205	400	200	350	33,344	61,510	33,344	-	48,669
2015	15,327	0.75	2,532	104,616	400	200	350	114,121	63,868	63,868	50,253	21,289
2016	15,202	0.32	4,671	26,894	400	200	350	31,740	157,720	81,992	-	128,301
2017	15,674	0.33	4,764	7,121	400	200	350	39,656	160,688	39,656	-	174,595
2018	16,034	0.34	4,859	6,495	400	200	350	39,718	163,672	39,718	-	178,512
2019	16,368	0.34	4,956	19,708	400	200	350	49,757	166,892	49,757	-	172,765
2020	16,759	0.35	5,056	68,133	400	200	350	96,170	170,311	96,170	-	130,911
2021	17,115	0.36	5,157	12,061	400	200	350	34,733	173,852	34,733	-	197,070
2022	17,478	0.37	5,260	12,302	400	200	350	35,441	177,436	35,441	-	201,141
2023	17,852	0.37	5,365	12,548	400	200	350	36,166	181,148	36,166	-	205,365
2024	18,045	0.40	4,682	12,799	400	200	350	35,927	173,583	35,927	-	195,517
2025	18,881	0.39	4,354	622	400	200	350	24,256	192,521	24,256	-	232,438
2026	18,600	0.46	3,749	634	400	200	350	23,383	165,448	23,383	-	197,214
2027	18,331	0.55	3,153	-	400	200	350	21,884	138,703	21,884	-	163,053
2028	18,305	0.63	2,803	-	400	200	350	21,508	123,047	21,508	-	142,554
Rem.	266,117	1.65	17,524	-	6,000	3,000	5,250	289,642		289,642		741,267
Total	520,793	0.67	81,340	316,139	12,000	6,000	10,500	927,444		927,444		3,130,661

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,421	32,294	26,768	59,062	17,160	32,205	950	2,187	6,561	6,561	6,255
2015	20,386	18,093	63,868	11,709	75,578	17,859	104,616	950	-	(47,848)	(41,287)	(41,474)
2016	46,479	34,343	82,392	68,545	150,937	19,872	26,894	950	10,613	92,607	51,320	72,973
2017	46,479	29,733	39,856	93,278	133,133	20,438	7,121	950	26,156	78,468	129,788	56,211
2018	46,479	29,663	39,918	95,370	135,288	20,893	6,495	950	26,738	80,213	210,001	52,237
2019	46,479	30,589	49,957	92,300	142,257	21,324	19,708	950	25,069	75,206	285,207	44,524
2020	45,656	34,783	96,370	68,702	165,072	21,815	68,133	950	18,544	55,631	340,838	29,941
2021	45,656	28,559	34,933	103,422	138,355	22,271	12,061	950	25,768	77,304	418,142	37,823
2022	45,656	28,558	35,641	105,559	141,199	22,738	12,302	950	26,302	78,906	497,048	35,097
2023	45,656	28,555	36,366	107,775	144,141	23,217	12,548	950	26,856	80,569	577,617	32,579
2024	42,596	26,759	36,127	102,607	138,735	22,728	12,799	950	25,564	76,693	654,310	28,192
2025	45,718	27,333	24,456	121,984	146,440	23,235	622	950	30,408	91,225	745,535	30,486
2026	38,597	23,303	23,583	103,498	127,081	22,349	634	950	25,787	77,361	822,896	23,502
2027	31,822	19,414	22,084	85,570	107,654	21,484	-	950	21,305	63,915	886,812	17,652
2028	27,741	17,104	21,708	74,812	96,521	21,108	-	950	18,616	55,847	942,658	14,022
Rem.	153,915	105,893	292,642	389,017	681,659	283,642	-	14,250	95,942	287,825	1,230,483	45,682
Total	749,340	497,103	932,194	1,650,916	2,583,110	602,133	316,139	28,500	405,855	1,230,483		485,704

Orca Exploration Group Inc.

Table 9

Songo Songo Field Tanzania - Additional Volumes Only - To End of Field Life
Forecast of Production and Revenues
Proved + Probable + Possible Reserves
Forecast Price Case as of December 31, 2013

Property Gross Share of Production and Revenues (Additional Gas Share Only)

								Additional Gas Sales Only			
Year	Producing Well Count	Protected Gas Rate MMcfpd	Power Gas Rate MMcfpd	Industrial Gas Rate MMcfpd	CNG Gas Rate MMcfpd	Wazo Hill Rate MMcfpd	Total Field Gas Rate MMcfpd	Daily Rate MMcfpd	Annual Volume MMcf	Avg Field Gas Price US$/Mcf	Gross Field Sales Rev. US$M
2014	4	37.21	41.37	6.90	0.38	6.22	92.07	54.86	20,025	4.12	82,567
2015	6	37.21	41.01	7.59	0.42	6.84	93.06	55.85	20,386	4.23	86,321
2016	8	37.21	119.71	8.35	0.46	7.52	173.25	136.04	49,656	4.42	219,723
2017	8	37.21	118.08	9.18	0.51	8.27	173.25	136.04	49,656	4.52	224,284
2018	8	37.21	116.98	10.00	0.56	8.50	173.25	136.04	49,656	4.63	229,959
2019	8	37.21	116.93	10.00	0.62	8.50	173.25	136.04	49,656	4.72	234,515
2020	9	37.21	116.86	10.00	0.68	8.50	173.25	136.04	49,656	4.82	239,381
2021	9	37.21	116.80	10.00	0.75	8.50	173.25	136.04	49,656	4.92	244,440
2022	9	37.21	116.72	10.00	0.82	8.50	173.25	136.04	49,656	5.03	249,568
2023	9	37.21	116.64	10.00	0.90	8.50	173.25	136.04	49,656	5.13	254,901
2024	9	21.70	132.05	10.00	0.99	8.50	173.25	151.55	55,314	5.29	292,406
2025	9	-	130.97	10.00	1.00	8.50	150.47	150.47	54,921	5.44	299,040
2026	9	-	118.42	10.00	1.00	8.50	137.92	137.92	50,343	5.56	279,738
2027	9	-	98.77	10.00	1.00	8.50	118.27	118.27	43,168	5.67	244,836
2028	9	-	74.56	10.00	1.00	8.50	94.06	94.06	34,331	5.79	198,937
Rem.									228,265	6.72	1,534,970
Total		143,729	729,416	89,804	7,846	76,930	1,047,725	903,996	903,996		4,915,587

Property Gross Share of Cost and Profit Revenues (Additional Gas Share Only)

Year	Operating Costs US$M	Operating Costs US$/Mcf	Aband. Costs US$M	Capital Costs US$M	Training Fund US$M	Marketing Fee US$M	Corporate Social Resp. Fee US$M	Total Eligible Costs US$M	Cost Recovery Limit US$M	Cost Revenues US$M	Cost Bal. at End of Year US$M	Profit Revenues US$M
2014	14,754	0.74	2,165	32,205	400	200	350	33,103	61,925	33,103	-	49,464
2015	15,437	0.76	2,232	104,616	400	200	350	113,931	64,741	64,741	49,190	21,580
2016	15,515	0.31	4,239	26,894	400	200	350	31,621	164,792	80,810	-	138,912
2017	16,072	0.32	4,323	7,121	400	200	350	39,613	168,213	39,613	-	184,671
2018	16,656	0.34	4,410	6,495	400	200	350	39,891	172,469	39,891	-	190,068
2019	17,010	0.34	4,498	19,708	400	200	350	49,941	175,886	49,941	-	184,574
2020	17,424	0.35	4,588	68,133	400	200	350	96,368	179,536	96,368	-	143,014
2021	17,804	0.36	4,680	12,061	400	200	350	34,945	183,330	34,945	-	209,495
2022	18,195	0.37	4,773	12,302	400	200	350	35,670	187,176	35,670	-	213,898
2023	18,598	0.37	4,869	12,548	400	200	350	36,415	191,176	36,415	-	218,486
2024	19,608	0.35	4,966	12,799	400	200	350	37,774	219,305	37,774	-	254,633
2025	20,132	0.37	4,399	622	400	200	350	25,553	224,280	25,553	-	273,487
2026	20,131	0.40	4,113	634	400	200	350	25,278	209,803	25,278	-	254,459
2027	19,886	0.46	3,598	-	400	200	350	23,884	183,627	23,884	-	220,952
2028	19,472	0.57	2,918	-	400	200	350	22,791	149,203	22,791	-	176,147
Rem.	342,537	1.50	22,168	-	7,200	3,600	6,300	371,905		365,780		1,169,190
Total	609,232	0.67	82,940	316,139	13,200	6,600	11,550	1,018,683		1,012,558		3,903,029

Company Share of Production and Revenues

Year	Gross Ann. Gas Production MMcf	Net Ann. Gas Production MMcf	Cost Revenues US$M	Profit Revenues US$M	Total Revenue Share US$M	Operating & Aband. Costs US$M	Capital Costs US$M	Mark. Fee CSR & Tr. Fund US$M	Additional Profits Tax US$M	Net Revenue After Tax US$M	Cum. Revenue US$M	NPV at 10% US$M
2014	20,025	14,372	32,053	27,205	59,258	16,919	32,205	950	2,296	6,889	6,889	6,568
2015	20,386	18,093	64,741	11,869	76,610	17,669	104,616	950	-	(46,625)	(39,737)	(40,414)
2016	48,234	35,125	81,210	74,214	155,424	19,753	26,894	950	12,153	95,673	55,937	75,389
2017	48,234	30,657	39,813	98,660	138,473	20,396	7,121	950	27,502	82,505	138,442	59,103
2018	48,234	30,583	40,091	101,544	141,635	21,066	6,495	950	28,281	84,843	223,285	55,252
2019	48,234	31,496	50,141	98,609	148,750	21,508	19,708	950	26,646	79,937	303,223	47,325
2020	47,380	35,600	96,568	75,054	171,621	22,012	68,133	950	20,131	60,394	363,617	32,505
2021	47,380	29,473	35,145	109,943	145,088	22,484	12,061	950	27,398	82,195	445,812	40,216
2022	47,380	29,472	35,870	112,254	148,124	22,968	12,302	950	27,976	83,928	529,740	37,331
2023	47,380	29,469	36,615	114,661	151,277	23,467	12,548	950	28,578	85,734	615,473	34,667
2024	52,780	32,462	37,974	133,631	171,605	24,574	12,799	950	33,320	99,961	715,434	36,746
2025	52,404	31,089	25,753	143,526	169,279	24,532	622	950	35,794	107,382	822,816	35,885
2026	48,036	28,618	25,478	133,540	159,019	24,244	634	950	51,264	81,926	904,742	24,889
2027	41,190	24,691	24,084	115,956	140,039	23,484	-	950	63,583	52,022	956,765	14,368
2028	32,758	19,920	22,991	92,442	115,432	22,391	-	950	50,650	41,441	998,206	10,405
Rem.	217,806	144,937	369,180	613,591	982,771	364,705	-	17,100	332,936	268,030	1,266,236	40,984
Total	867,841	566,057	1,017,708	2,056,698	3,074,406	692,172	316,139	31,350	768,509	1,266,236		511,219

Orca Exploration Group Inc.
Songo Songo Field Tanzania - Total Protected and Additional Volumes
Natural Gas Reserve Summary
Effective December 31, 2013

Table 10

	Cenomanian	Neocom. North Units 10-6	Neocom. Main Units 10-6	Neocom. Main Unit 5	Neocom. Main Unit 4-1	Total
Gross Rock Volume, Ac-ft	326,304	746,791	1,300,807	281,564	119,932	2,775,398
Net to Gross Ratio, frac.	0.211	0.84	0.84	0.59	0.88	
Porosity, %	21.0	20.0	20.0	18.0	19.0	
Water Saturation, %	34.0	28.0	28.0	36.0	28.0	
Reservoir Pressure, psia	2,770	2,770	2,770	2,770	2,770	
Reservoir Temperature, deg F	203	203	203	203	203	
Compressibility Factor	0.93	0.93	0.93	0.93	0.93	
Original Gas-in-Place, Bcf	66.5	629.8	1,097.1	133.4	100.7	2,027.5
Proved Producing Reserves						
Portion of Mapped OGIP Classified as Proved, %	50	-	100	100	100	
Original Gas-in-Place, Bcf	33.3	-	1,097.1	133.4	100.7	1,364.4
Recovery Factor, %	70.0	-	70.0	70.0	70.0	70.0
Original Recoverable Raw, Bcf	23.3	-	767.9	93.4	70.5	955.1
Cumulative Recovery, Bcf						230.6
Remaining Recoverable Raw, Bcf						724.5
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						717.2
Total Proved Reserves						
Portion of Mapped OGIP Classified as Proved, %	75	-	100	100	100	
Original Gas-in-Place, Bcf	49.9	-	1,097.1	133.4	100.7	1,381.1
Recovery Factor, %	75.0	-	75.0	75.0	75.0	75.0
Original Recoverable Raw, Bcf	37.4	-	822.8	100.1	75.5	1,035.8
Cumulative Recovery, Bcf						230.6
Remaining Recoverable Raw, Bcf						805.2
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						797.1
Proved Non-Producing Reserves, Bcf						79.9
Proved + Probable Reserves						
Portion of Mapped OGIP Classified as 2P, %	100	25	100	100	100	
Original Gas-in-Place, Bcf	66.5	157.5	1,097.1	133.4	100.7	1,555.2
Recovery Factor, %	80.0	50.0	77.5	77.5	77.5	74.8
Original Recoverable Raw, Bcf	53.2	78.7	850.2	103.4	78.0	1,163.6
Cumulative Recovery, Bcf						230.6
Remaining Recoverable Raw, Bcf						933.0
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						923.7
Probable Reserves, Bcf						126.5
Proved + Probable + Possible Reserves						
Portion of Mapped OGIP Classified as 3P, %	125	50	100	100	100	
Original Gas-in-Place, Bcf	83.2	314.9	1,097.1	133.4	100.7	1,729.2
Recovery Factor, %	80.0	50.0	80.0	80.0	80.0	74.5
Original Recoverable Raw, Bcf	66.5	157.5	877.7	106.7	80.5	1,288.9
Cumulative Recovery, Bcf						230.6
Remaining Recoverable Raw, Bcf						1,058.3
Gas Shrinkage, %						1.0
Remaining Recoverable Sales, Bcf						1,047.7
Possible Reserves, Bcf						124.1
Reserves Summary, Sales Bcf						
Protected Volumes						
Proved						143.7
Proved Plus Probable						143.7
Proved Plus Probable Plus Possible						143.7
Additional Volumes						
Proved						653.4
Proved Plus Probable						779.9
Proved Plus Probable Plus Possible						904.0

Note - This table above includes protected and additional gas volumes to end of field life

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Reservoir and Fluid Properties
Effective December 31, 2013

Zone	Cenomanian & Neocomian
Lithology	Sandstone
Pool Area of N1 Layer, acres	6,090
Depth to Top of Structure, ft	5,450
Depth to Gas Water Contact, ft	6,364
Maximum Gross Gas Pay Thickness (from structure map), ft	914
Average Gross Pay, ft	540
Permeability, md	10 to 40 md
Condensate Gas Ratio, bbl/mmcf	0.1 to 0.2
Gross Heating Value, BTU/scf	1,023

Orca Exploration Group Inc.
Songo Songo Field - Tanzania
Summary of Economic Parameters
Effective December 31, 2013

Price Schedule

McDaniel & Associates December 31, 2013 forecast price case

Natural Gas Price Forecast (2014$ - US)

See Table 17

Operating Costs (2014$ - US - Orca Estimates)

Field Operating Expenses	Amount
Wells and Gathering System, $/Year **	425,000
Wells and Gathering System, $/Well-Year **	53,000
Wells and Gathering System, $/Mcf **	0.013
Dar Gas Distribution System, $/Year	1,700,000
Dar Gas Distribution System, $/Mcf (Industrial Sales)	0.690
CNG Distribution System, $/Year	122,000
CNG Distribution System, $/Mcf (CNG Sales)	0.97
Regulator Fee, % of Additional Sales Gross Revenue	1.0%
Municipal Fee, % of Additional Sales Gross Revenue	0.3%
Re-Rating Fee, $/Mcf 70 to 90 MMcfpd	0.30
Re-Rating Fee, $/Mcf > 90 MMcfpd	0.40
G&A (Excluding head office G&A)	6,700,000
Processing Fee, $/Mcf ***	0.59

** Split between protected and additional volumes according to rates.

*** This includes all additional gas sales until 2016 and then excludes the PGSA sales volumes

Capital Costs (2014$ - US)

Year	Gross Amount	Description
Proved Producing Case		
2014	$13,545,000	SS-3, SS-4, SS-5, SS-7, SS-9 Workovers
2015	$58,850,000	SS-3, SS-4, SS-5, SS-7, SS-9 Workovers
2014	$16,000,000	Compression
2015	$8,450,000	Compression
2016	$25,600,000	Compression
2014	$1,050,000	Pipelines & misc. field costs
2015	$2,800,000	Pipelines & misc. field costs
2016	$250,000	Pipelines & misc. field costs
2014	$360,000	Downstream costs
2015	$600,000	Downstream costs
2019 - 2024	$10,000,000 /year	Misc. workovers
2017 - 2027	$250,000	Plant & field maintenance
Proved Undeveloped		
2014	$1,250,000	Drill & tie-in SS-12 Well
2015	$31,865,000	Drill & tie-in SS-12 Well
2017 - 2027	$250,000	Plant & field maintenance
Probable		
2017	$6,210,000	Seismic
2018	$5,500,000	Seismic
2019	$7,350,000	Seismic
2020	$50,000,000	Drill SSN Horizontal Well

See Tables 13 to 16

Abandonment Costs (2014$ - US)

Well Abandonments — $7,500,000 per well based on unit of production basis

Orca Exploration Group Inc.
Songo Songo Field - Tanzania
Summary of Economic Parameters
Effective December 31, 2013

Interests and Fiscal Terms (2014$ - US)

Orca Interest	100 percent prior to TPDC back in
TPDC Back-in	The original PSC stipulated that TPDC would pay their share of the costs on all new wells and future expenses but the actual operation is that Orca has carried TPDC on these costs and so this is what has been assumed in this evaluation
Cost Recovery Balance @ 2013/12/31	$0
State Royalty	Nil
Eligible Costs for Cost Recovery	Operating costs, G&A, workover costs, remaining capital costs, training fund, DMO, financing costs (of cost recovery balance)
Cost Recovery Limit	75 percent of net sales revenue
Profit Revenues	Net sales revenues less Cost Revenues
Contractor share of Profit Revenues	Greater of the cum. production based calc. or rate based calc. Cumulative Production Based Calculation: 0 - 125 Bcf / 25 percent share 125 - 250 Bcf / 30 percent share 250 - 375 Bcf / 35 percent share 375 - 500 Bcf / 40 percent share 500 + Bcf / 55 percent share Rate Based Calculation 0 - 20 MMcf/d / 25 percent share 20 - 30 MMcf/d / 30 percent share 30 - 40 MMcf/d / 35 percent share 40 - 50 MMcf/d / 40 percent share 50+ MMcf/d / 55 percent share
Training Fund	$400,000 / Year
Bonuses	Nil
Hydrocarbon Support Fund	Nil
TPDC Marketing Fee	$200,000/Year
Corporate Social Responsibility Fee	$350,000/Year
Additional Profits Tax	25 percent APT on First Account cash flow balance after allowance for a 25% rate (plus inflation) of return on negative balances. 40 percent APT on Second Account cash flow balance after allowance for a 35% rate (plus inflation) of return on negative balances.
First Account Opening Balance	$0 at December 31, 2013
Second Account Opening Balance	$98,899,394 at December 31, 2013
License Expiry	October 11, 2026

Table 13

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved Producing Reserves
Forecast Price Case as of December 31, 2013

Year	New Wells 2014 US$M	Workovers 2014 US$M	Facility & Downstream 2014 US$M	Field Maint. 2014 US$M	Seismic 2014 US$M	Total Capital 2014 US$M	Total Capital Future $M
2014	-	13,545	17,410	-	-	30,955	30,955
2015	-	58,850	11,850	-	-	70,700	72,114
2016	-	-	25,850	-	-	25,850	26,894
2017	-	-	-	250	-	250	265
2018	-	-	-	250	-	250	271
2019	-	10,000	-	250	-	10,250	11,317
2020	-	10,000	-	250	-	10,250	11,543
2021	-	10,000	-	250	-	10,250	11,774
2022	-	10,000	-	250	-	10,250	12,010
2023	-	10,000	-	250	-	10,250	12,250
2024	-	10,000	-	250	-	10,250	12,495
2025	-	-	-	250	-	250	311
2026	-	-	-	250	-	250	317
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-
Total	-	132,395	55,110	2,500	-	190,005	202,515

Orca Exploration Group Inc.

Table 14

Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Total Proved Reserves

Forecast Price Case as of December 31, 2013

Year	New Wells 2014 US$M	Workovers 2014 US$M	Facility & Downstream 2014 US$M	Field Maint. 2014 US$M	Seismic 2014 US$M	Total Capital 2014 US$M	Total Capital Future $M
2014	1,250	13,545	17,410	-	-	32,205	32,205
2015	31,865	58,850	11,850	-	-	102,565	104,616
2016	-	-	25,850	-	-	25,850	26,894
2017	-	-	-	500	-	500	531
2018	-	-	-	500	-	500	541
2019	-	10,000	-	500	-	10,500	11,593
2020	-	10,000	-	500	-	10,500	11,825
2021	-	10,000	-	500	-	10,500	12,061
2022	-	10,000	-	500	-	10,500	12,302
2023	-	10,000	-	500	-	10,500	12,548
2024	-	10,000	-	500	-	10,500	12,799
2025	-	-	-	500	-	500	622
2026	-	-	-	500	-	500	634
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-
Total	33,115	132,395	55,110	5,000	-	225,620	239,172

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved Plus Probable Reserves
Forecast Price Case as of December 31, 2013

Table 15

Year	New Wells 2014 US$M	Workovers 2014 US$M	Facility & Downstream 2014 US$M	Field Maint. 2014 US$M	Seismic 2014 US$M	Total Capital 2014 US$M	Total Capital Future $M
2014	1,250	13,545	17,410	-	-	32,205	32,205
2015	31,865	58,850	11,850	-	-	102,565	104,616
2016	-	-	25,850	-	-	25,850	26,894
2017	-	-	-	500	6,210	6,710	7,121
2018	-	-	-	500	5,500	6,000	6,495
2019	-	10,000	-	500	7,350	17,850	19,708
2020	50,000	10,000	-	500	-	60,500	68,133
2021	-	10,000	-	500	-	10,500	12,061
2022	-	10,000	-	500	-	10,500	12,302
2023	-	10,000	-	500	-	10,500	12,548
2024	-	10,000	-	500	-	10,500	12,799
2025	-	-	-	500	-	500	622
2026	-	-	-	500	-	500	634
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-
Total	83,115	132,395	55,110	5,000	19,060	294,680	316,139

Orca Exploration Group Inc.
Songo Songo Field Tanzania
Forecast of Capital Costs for Additional Volumes
Proved + Probable + Possible Reserves
Forecast Price Case as of December 31, 2013

Year	New Wells 2014 US$M	Workovers 2014 US$M	Facility & Downstream 2014 US$M	Field Maint. 2014 US$M	Seismic 2014 US$M	Total Capital 2014 US$M	Total Capital Future $M
2014	1,250	13,545	17,410	-	-	32,205	32,205
2015	31,865	58,850	11,850	-	-	102,565	104,616
2016	-	-	25,850	-	-	25,850	26,894
2017	-	-	-	500	6,210	6,710	7,121
2018	-	-	-	500	5,500	6,000	6,495
2019	-	10,000	-	500	7,350	17,850	19,708
2020	50,000	10,000	-	500	-	60,500	68,133
2021	-	10,000	-	500	-	10,500	12,061
2022	-	10,000	-	500	-	10,500	12,302
2023	-	10,000	-	500	-	10,500	12,548
2024	-	10,000	-	500	-	10,500	12,799
2025	-	-	-	500	-	500	622
2026	-	-	-	500	-	500	634
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-
Total	83,115	132,395	55,110	5,000	19,060	294,680	316,139

Table 17

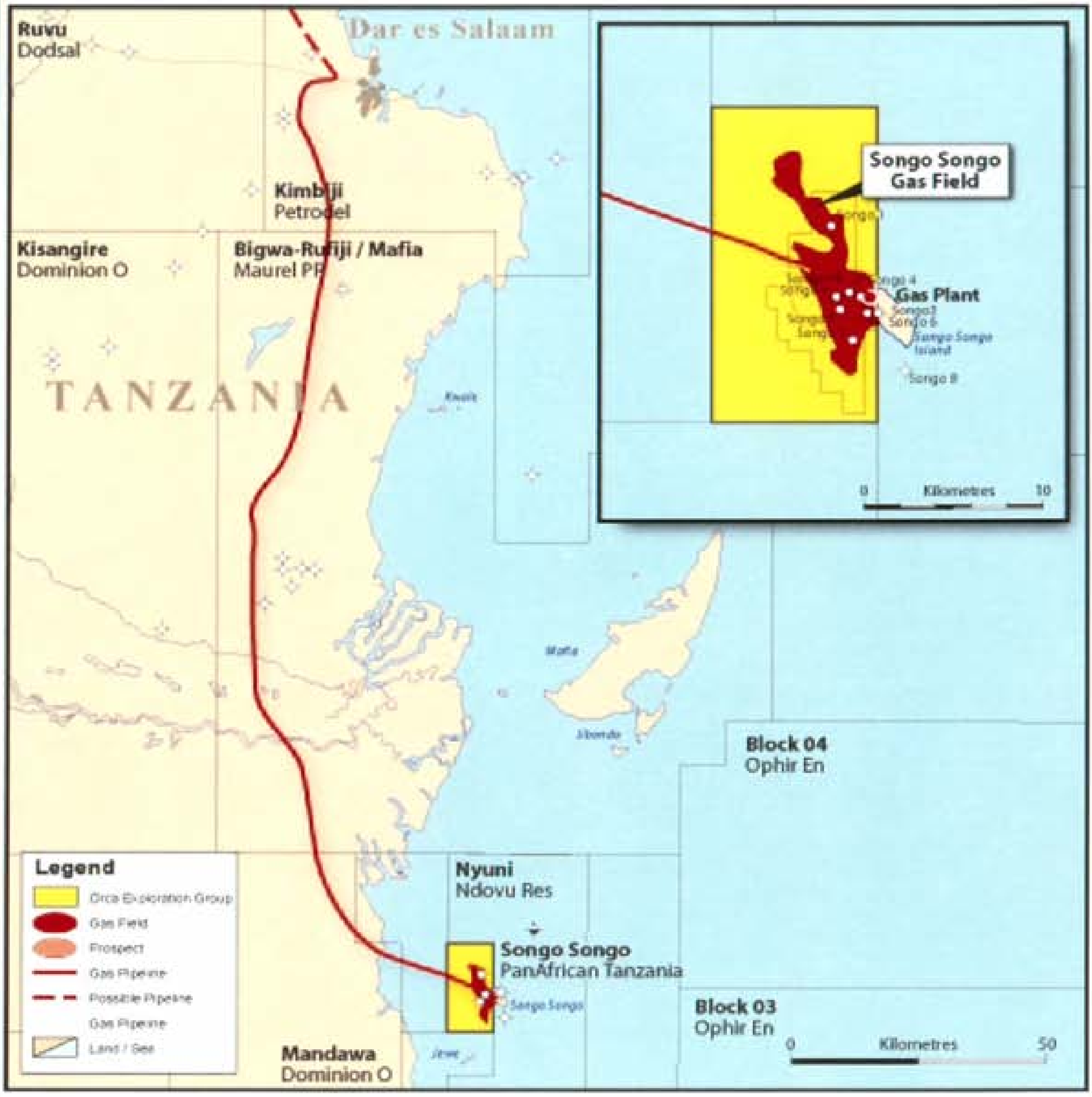
McDaniel & Associates Consultants Ltd.
Summary of Price Forecasts
Effective December 31, 2013

Year	Brent Crude Oil Price $US/bbl	UTG 6 & Power Base Gas Price $US/MMBTU	Power Excess Gas Price $US/MMBTU	Industrial Gas Price $US/MMBTU	Compressed Natural Gas Price $US/MMBTU	Wazo Hill Gas Price $US/MMBTU	Inflation %
2014	105.00	2.84	4.27	10.92	14.60	3.67	2.0
2015	102.50	2.90	4.35	10.66	14.25	3.74	2.0
2016	100.20	2.96	4.44	10.42	13.93	3.82	2.0
2017	97.70	3.02	4.53	10.16	13.58	3.89	2.0
2018	98.00	3.08	4.62	10.19	13.62	3.97	2.0
2019	99.40	3.14	4.71	10.34	13.82	4.05	2.0
2020	101.30	3.20	4.80	10.54	14.08	4.13	2.0
2021	103.40	3.27	4.90	10.75	14.37	4.22	2.0
2022	105.40	3.33	5.00	10.96	14.65	4.30	2.0
2023	107.60	3.40	5.10	11.19	14.96	4.39	2.0
2024	109.70	3.47	5.20	11.41	15.25	4.47	2.0
2025	111.90	3.54	5.30	11.64	15.55	4.56	2.0
2026	114.20	3.61	5.41	11.88	15.87	4.65	2.0
2027	116.40	3.68	5.52	12.11	16.18	4.75	2.0
2028	118.80	3.75	5.63	12.36	16.51	4.84	2.0
2029	121.20	3.83	5.74	12.60	16.85	4.94	2.0
2030	123.50	3.90	5.86	12.84	17.17	5.04	2.0
2031	126.00	3.98	5.97	13.10	17.51	5.14	2.0
2032	128.60	4.06	6.09	13.37	17.88	5.24	2.0
2033	131.10	4.14	6.21	13.63	18.22	5.35	2.0
Thereafter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Pricing Assumptions :

Above prices are field prices referenced at the inlet to the Songo Songo gas plant
Brent price forecast based on the McDaniel & Associates December 31, 2013 price forecast
Gas price for power market sales (UTG 6 & PGSA) based on $2.50/MMbtu in 2008$ plus inflation.
Base gas price is for UTG 6 and PGSA volumes up to 36.8 MMBtu/day
Excess gas price is 150 percent of the base price and is for PGSA volumes above 36.8 MMBtu/day
Gas price for industrial sales based on historical relationship to Brent.
Gas price for CNG sales based on historical relationship to Brent.
Gas price for Wazo Hill sales based on $3.08/GJ in 2008$ plus 2% inflation
All prices are adjusted for a heating value of 1022 btu/scf.

Figure 1



McDaniel

Orca Exploration

Songo Songo field - Tanzania

Location Map

Figure 2

Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Proved Producing Production Forecast

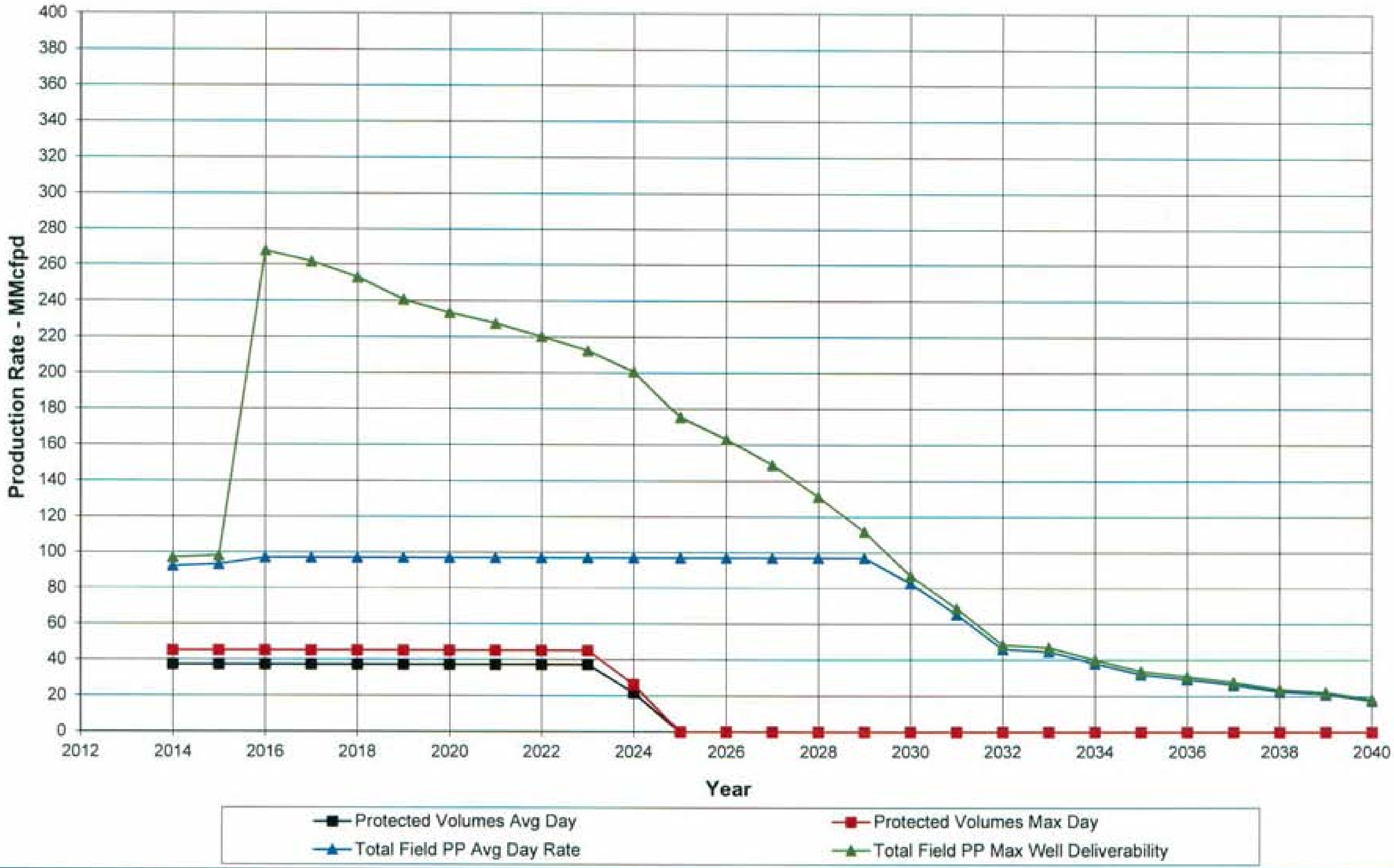
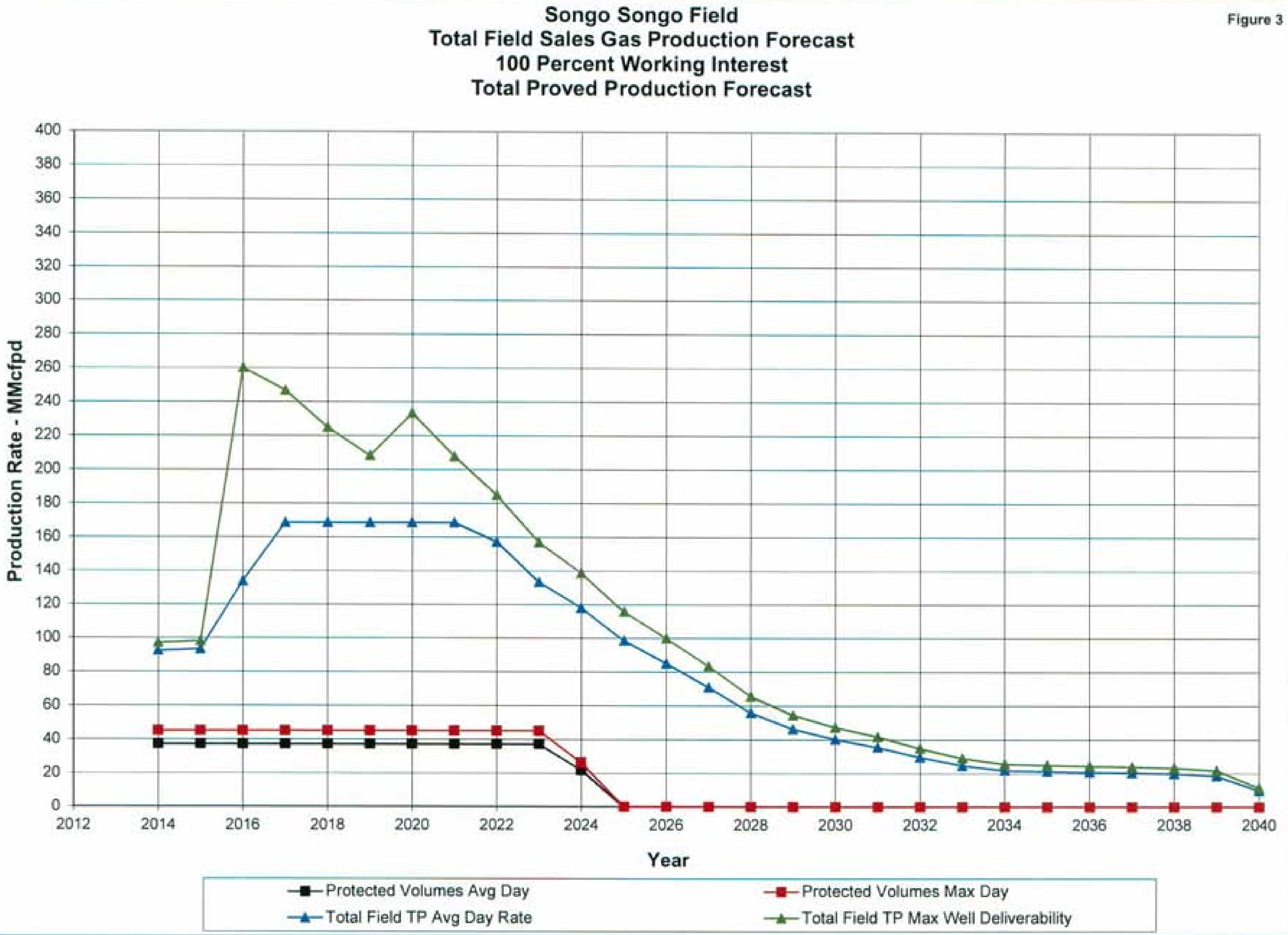
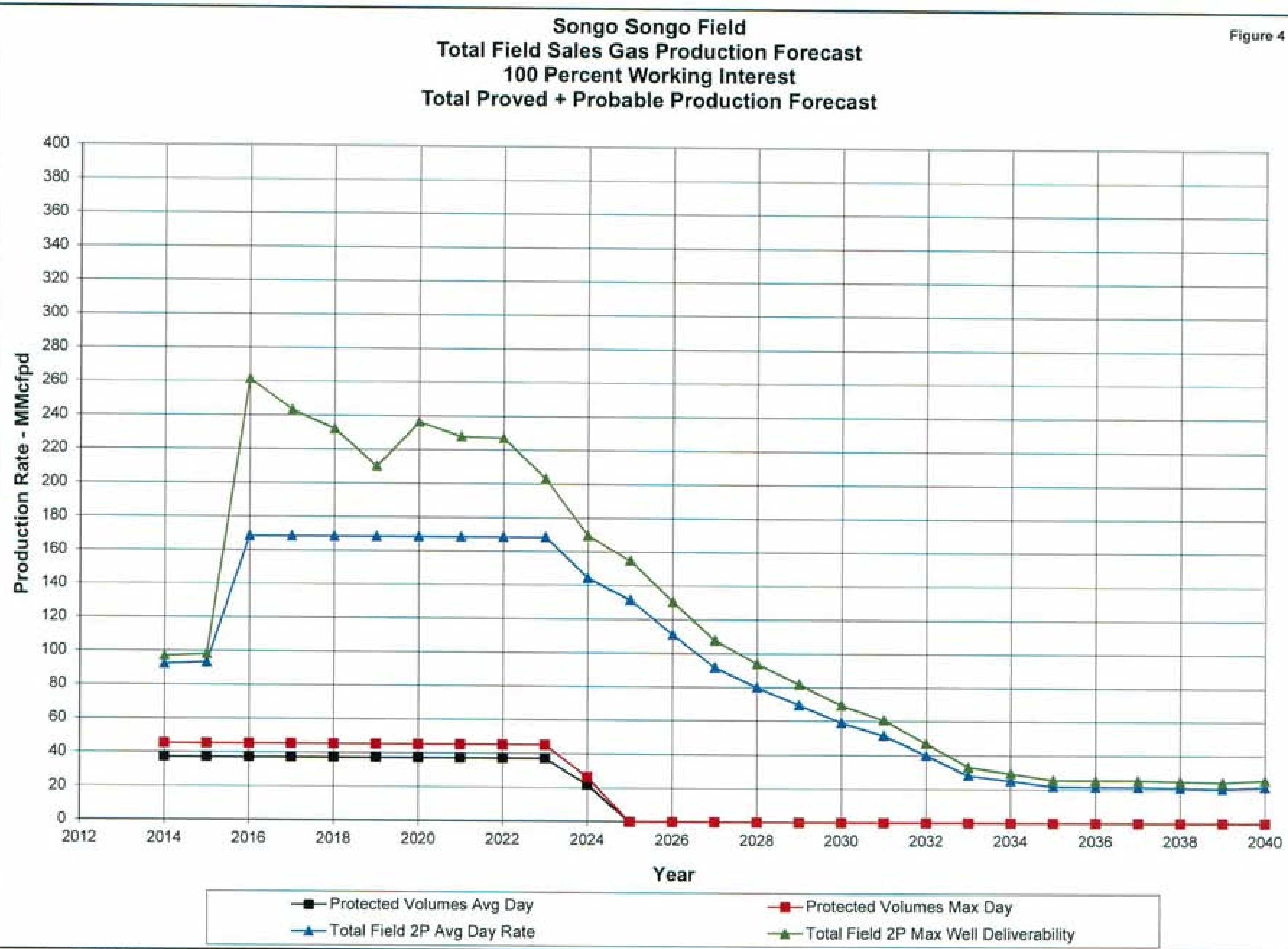


Figure 3



Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Total Proved Production Forecast
Production Rate - MMcfpd
400
380
360
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field TP Avg Day Rate
Total Field TP Max Well Deliverability

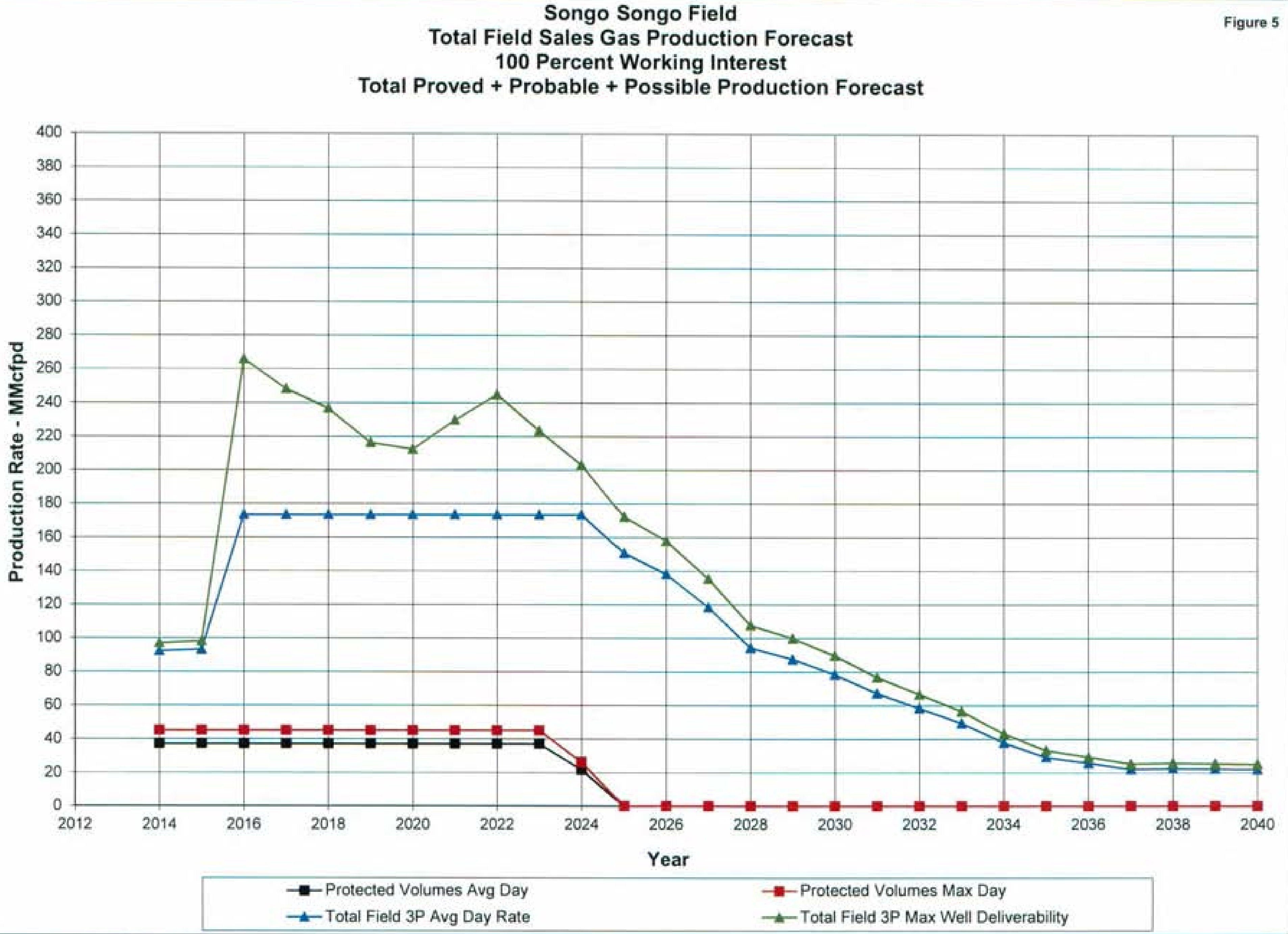
Figure 4



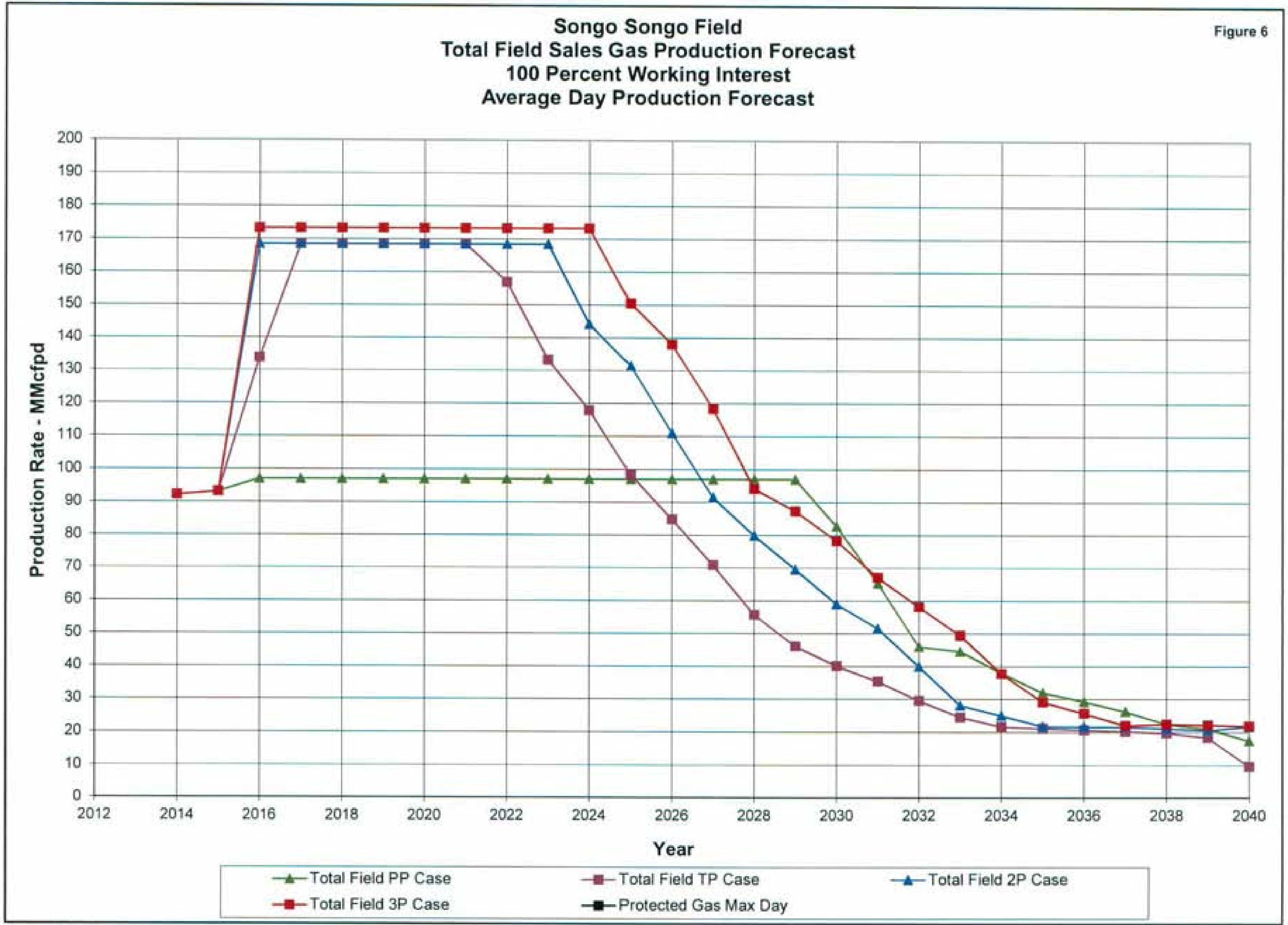
Orca Dec 2013 Reserves Evaluation - Finalb

26/03/2014

Figure 5



Songo Songo Field
Total Field Sales Gas Production Forecast
100 Percent Working Interest
Total Proved + Probable + Possible Production Forecast
Production Rate - MMcfpd
400
380
360
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Protected Volumes Avg Day
Protected Volumes Max Day
Total Field 3P Avg Day Rate
Total Field 3P Max Well Deliverability



Orca Dec 2013 Reserves Evaluation - Finalb

26/03/2014

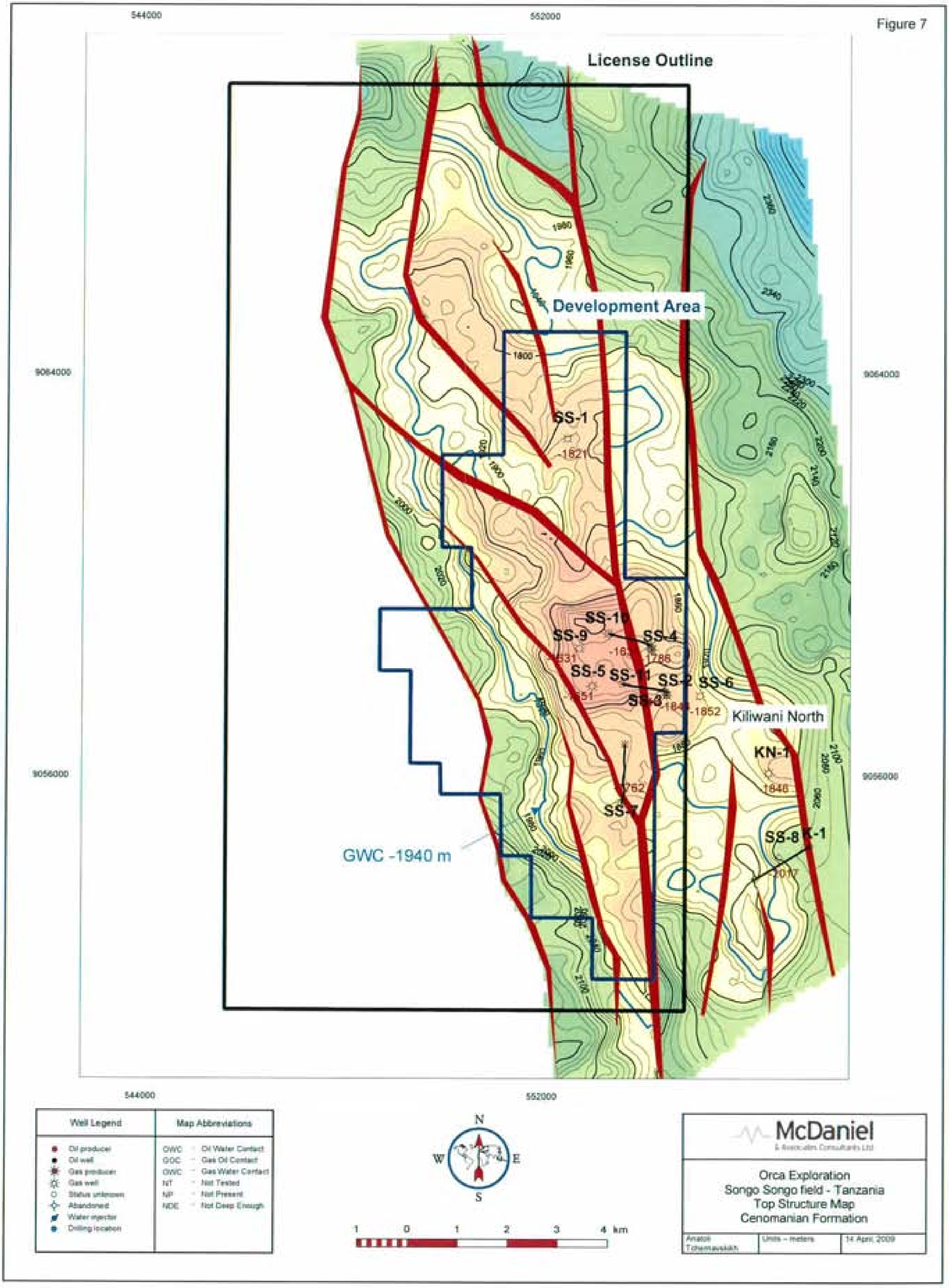
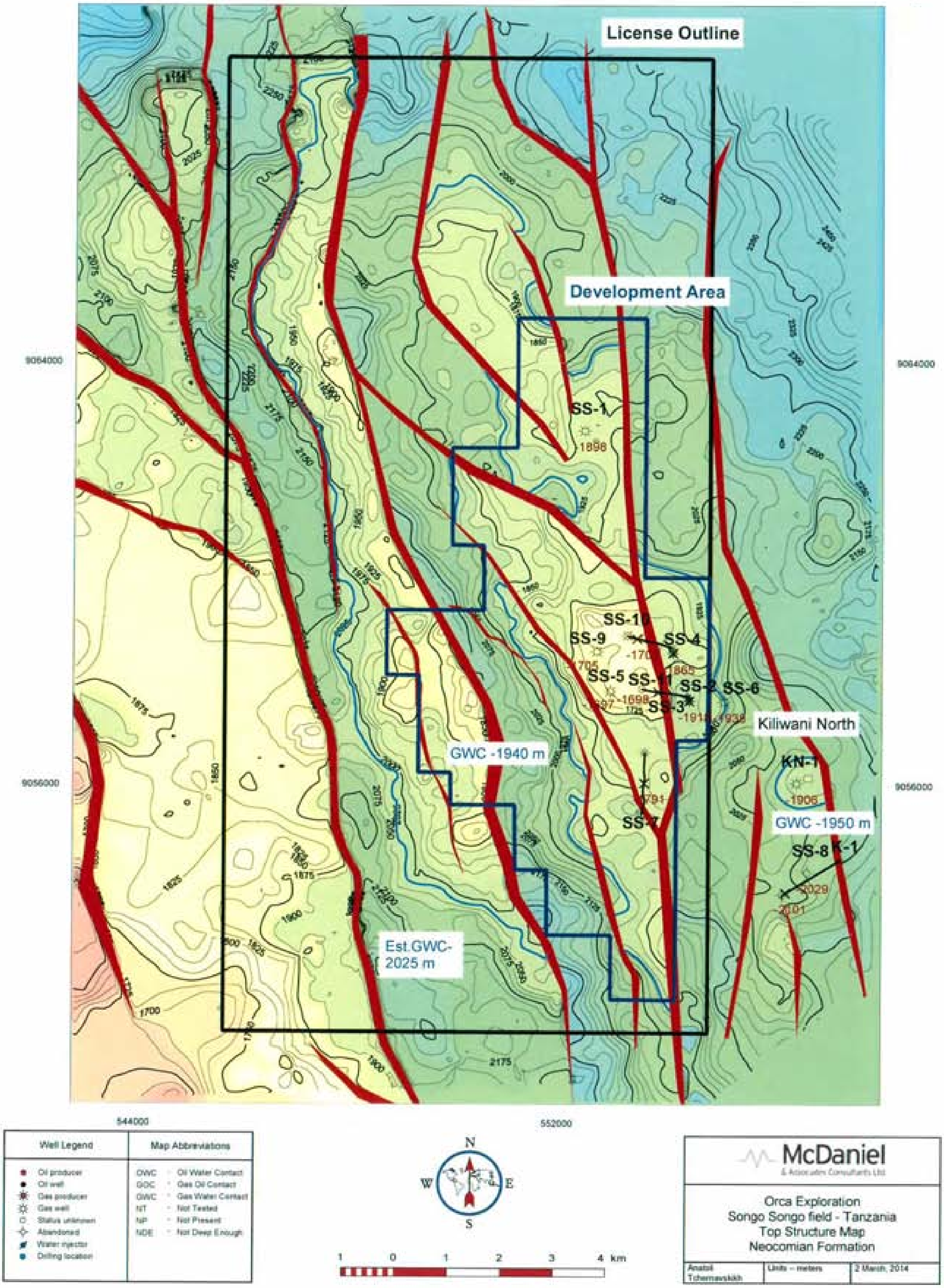


Figure 7
License Outline
Development Area
SS-1
SS-10
SS-9
SS-4
SS-5
SS-11
SS-2
SS-6
SS-3
SS-7
Kiliwani North
KN-1
SS-8
K-1
GWC -1940 m
544000
552000
9064000
9056000
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
S
E
W
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd
Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Cenomanian Formation
Anatoli Tchernavskikh
Units - meters
14 April, 2009

Figure 8


544000
552000
License Outline
Development Area
9064000
9056000
SS-1
1898
SS-10
SS-9
SS-4
SS-5
SS-11
SS-2
SS-6
SS-3
Kiliwani North
KN-1
1906
GWC -1940 m
GWC -1950 m
SS-7
SS-8
K-1
2029
Est.GWC-
2025 m
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
W
E
S
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian Formation
Anatoli Tchernavskikh
Units – meters
2 March, 2014

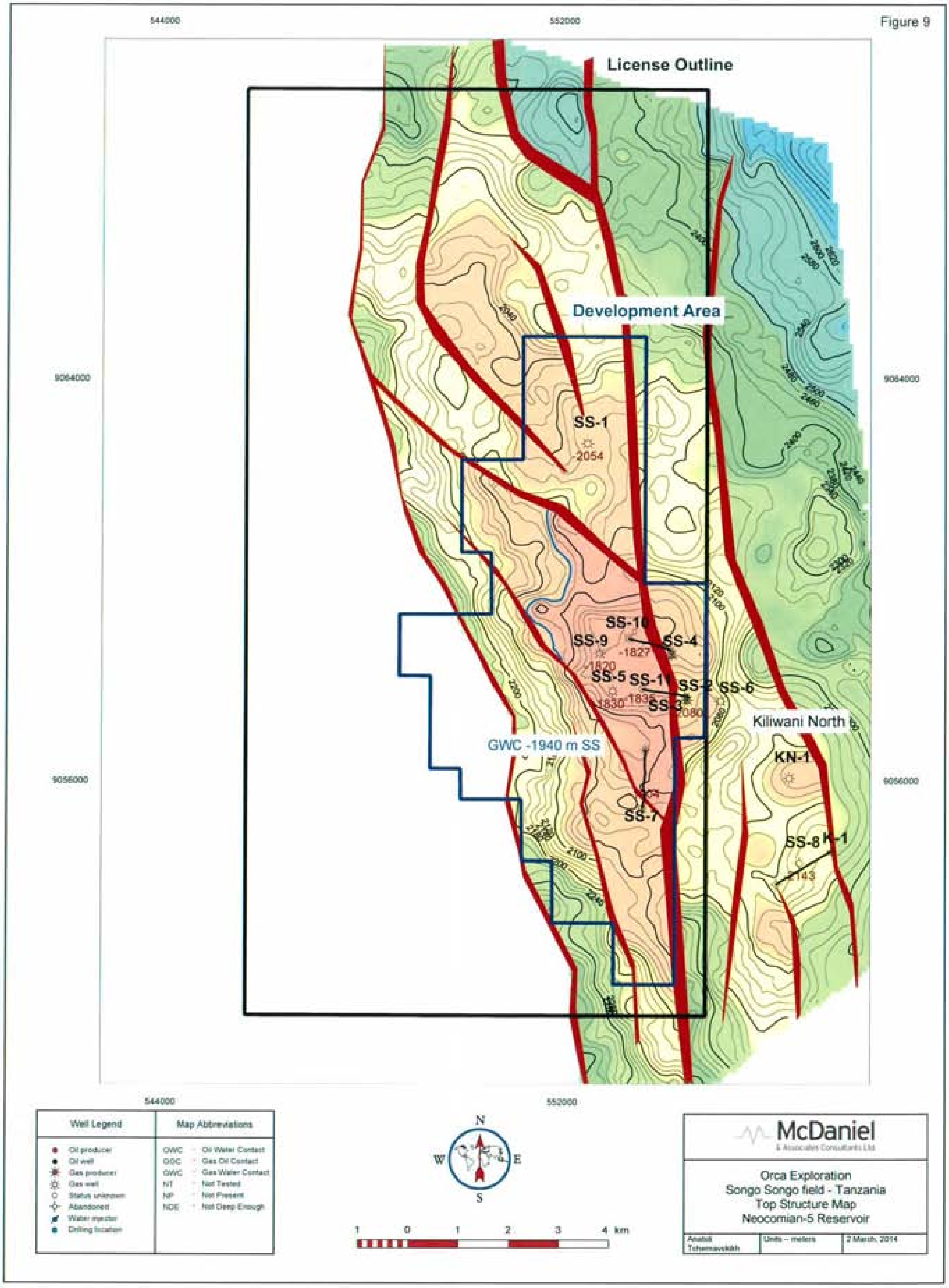
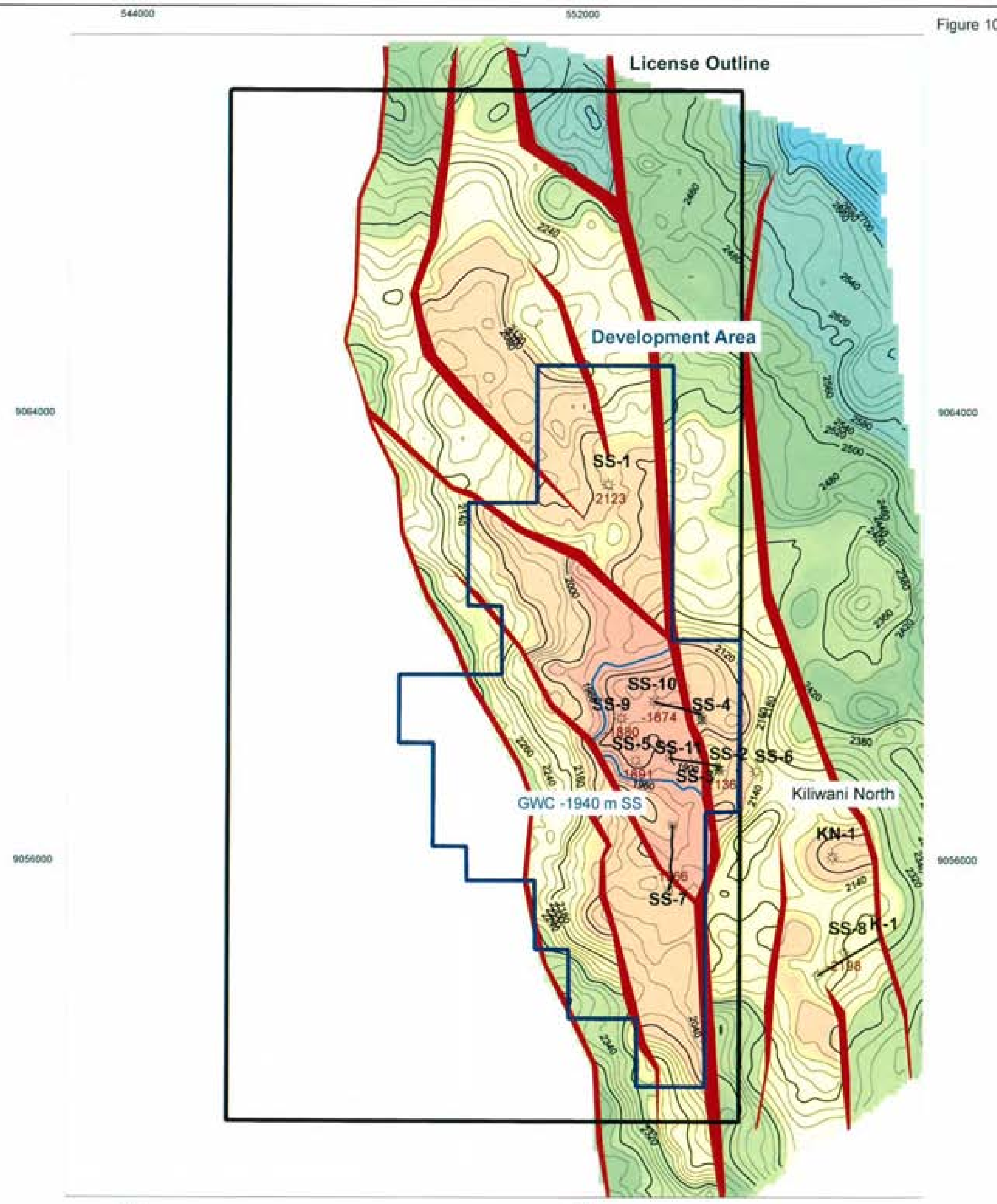
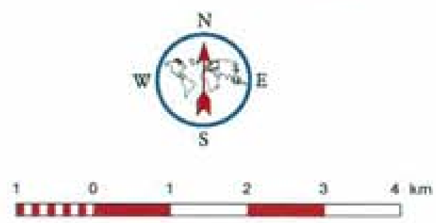


Figure 9
544000
552000
9064000
9056000
License Outline
Development Area
SS-1
-2054
SS-10
SS-9
SS-4
-1827
-1820
SS-5
SS-11
SS-2
SS-6
-1830
SS-3
-2080
Kiliwani North
GWC -1940 m SS
KN-1
SS-7
SS-8
K-1
-2143
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
W
E
S
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian-5 Reservoir
Anatoli Tchernavskikh
Units – meters
2 March, 2014

Figure 10



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil well	GOC - Gas Oil Contact
Gas producer	GWC - Gas Water Contact
Gas well	NT - Not Tested
Status unknown	NP - Not Present
Abandoned	NDE - Not Deep Enough
Water injector	
Drilling location	



McDaniel
& Associates Consultants Ltd

Orca Exploration
Songo Songo field - Tanzania
Top Structure Map
Neocomian-4 Reservoir

Anatoli Tchernavskikh	Units – meters	2 March, 2014

Figure 11

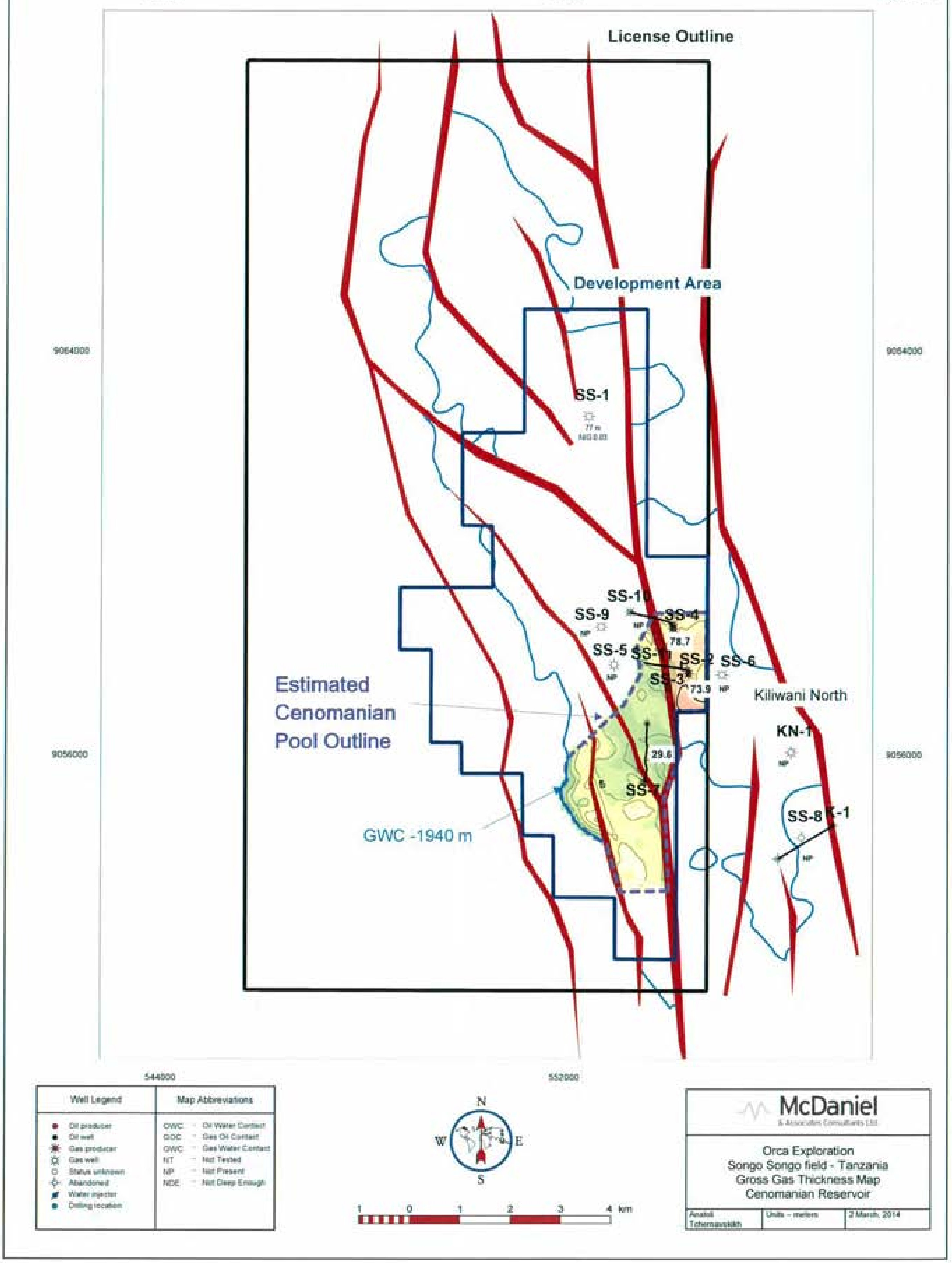
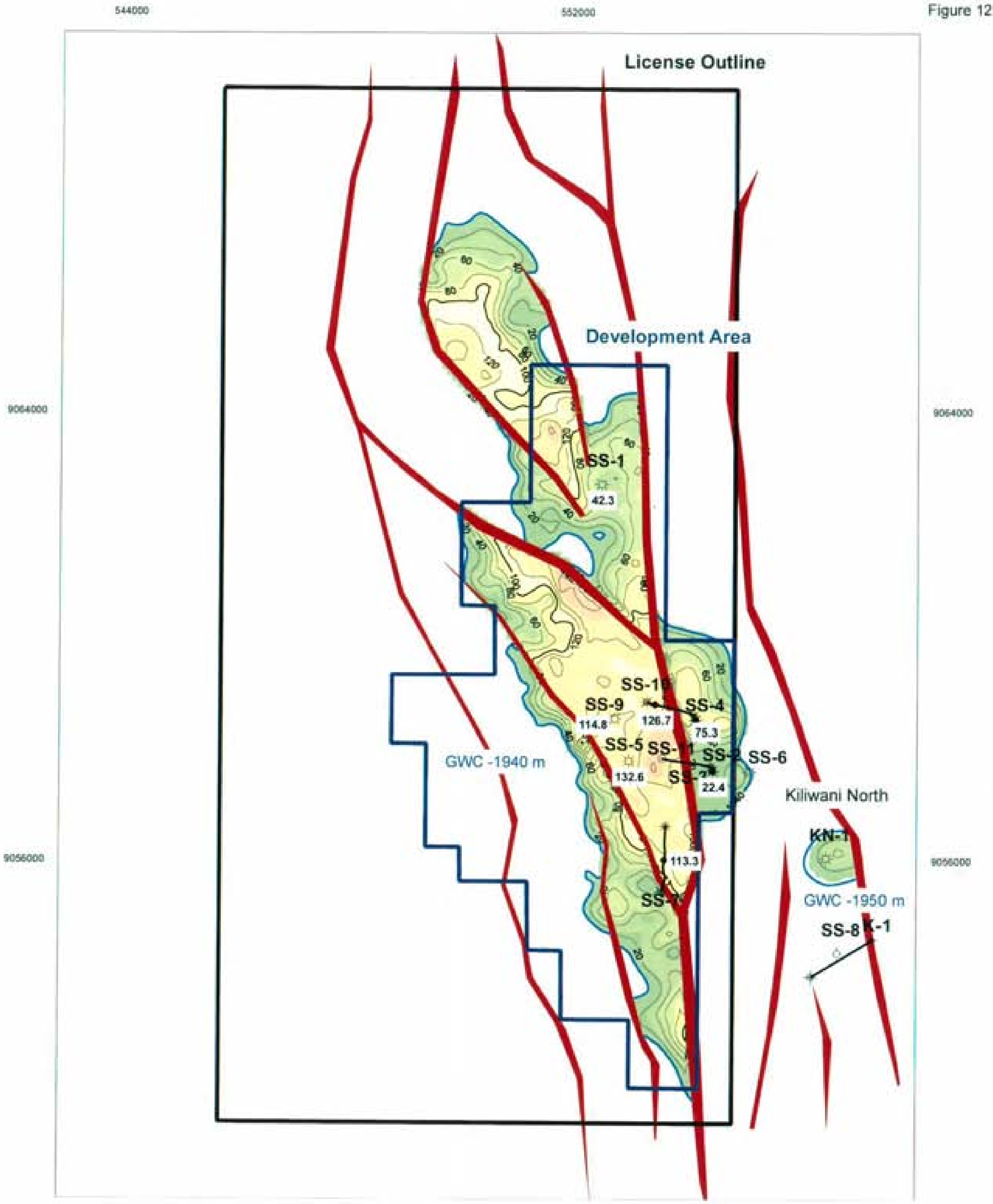
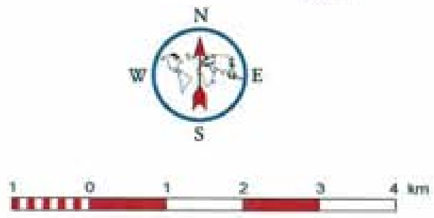

544000
552000
License Outline
Development Area
9064000
9056000
SS-1
SS-10
SS-9
SS-4
78.7
SS-5
SS-11
SS-2
SS-6
SS-3
73.9
Kiliwani North
KN-1
Estimated
Cenomanian
Pool Outline
29.6
SS-7
SS-8
K-1
GWC -1940 m
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
W
E
S
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Cenomanian Reservoir
Anatoli Tchernavskikh
Units – meters
2 March, 2014

Figure 12





Well Legend	Map Abbreviations
Oil producer	OWC : Oil Water Contact
Oil well	GOC : Gas Oil Contact
Gas producer	GWC : Gas Water Contact
Gas well	NT : Not Tested
Status unknown	NP : Not Present
Abandoned	NDE : Not Deep Enough
Water injector	
Drilling location	

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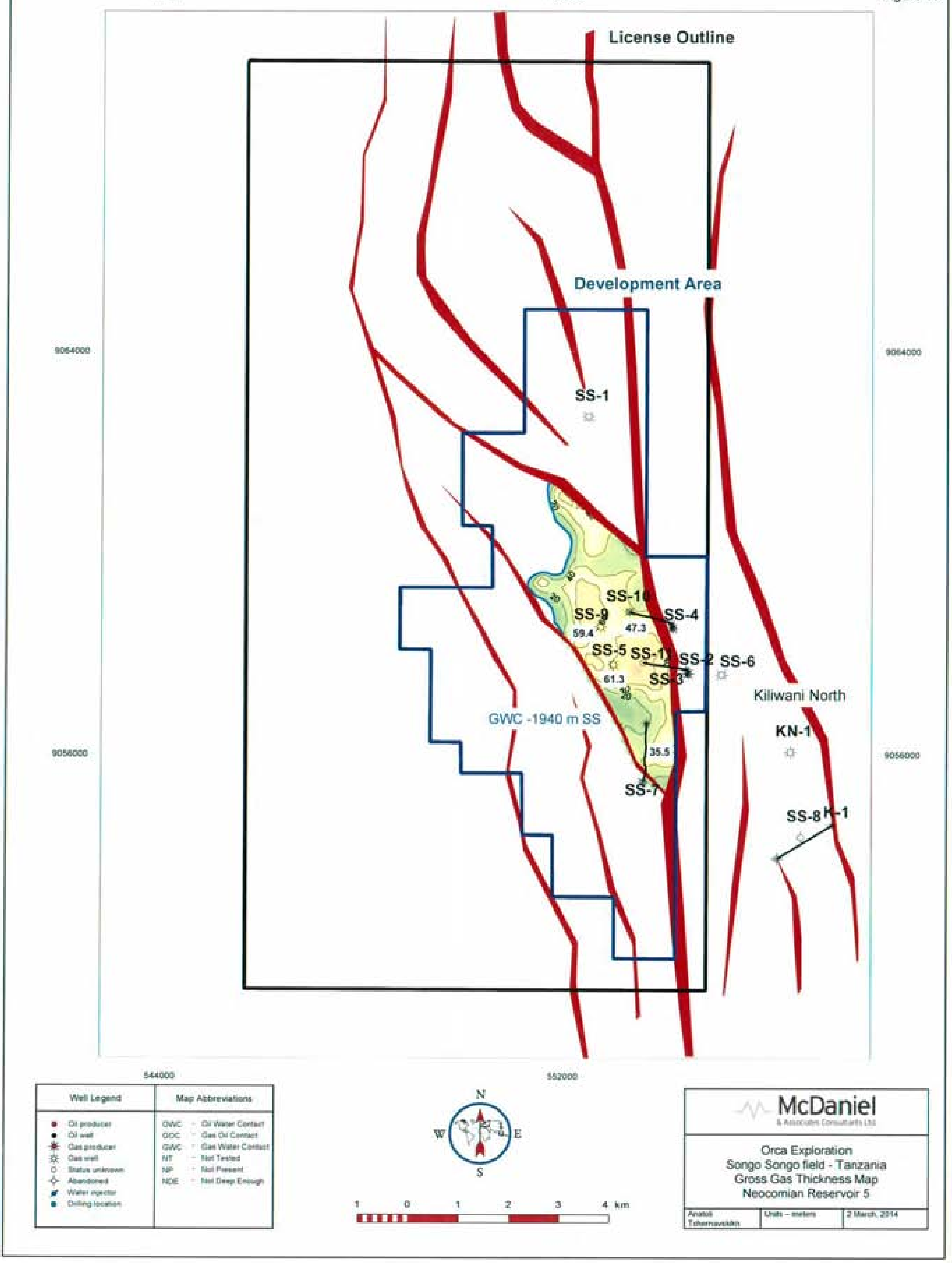
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Neocomian Reservoirs 10-6

Anatoli Tchernavskikh	Units – meters	2 March, 2014

Figure 13


544000
552000
9064000
9056000
License Outline
Development Area
SS-1
SS-10
SS-4
SS-9
59.4
47.3
SS-5
SS-11
SS-2
SS-6
SS-3
61.3
Kiliwani North
GWC -1940 m SS
KN-1
35.5
SS-7
SS-8
K-1
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
W
E
S
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Neocomian Reservoir 5
Anatoli Tchernavskikh
Units – meters
2 March, 2014

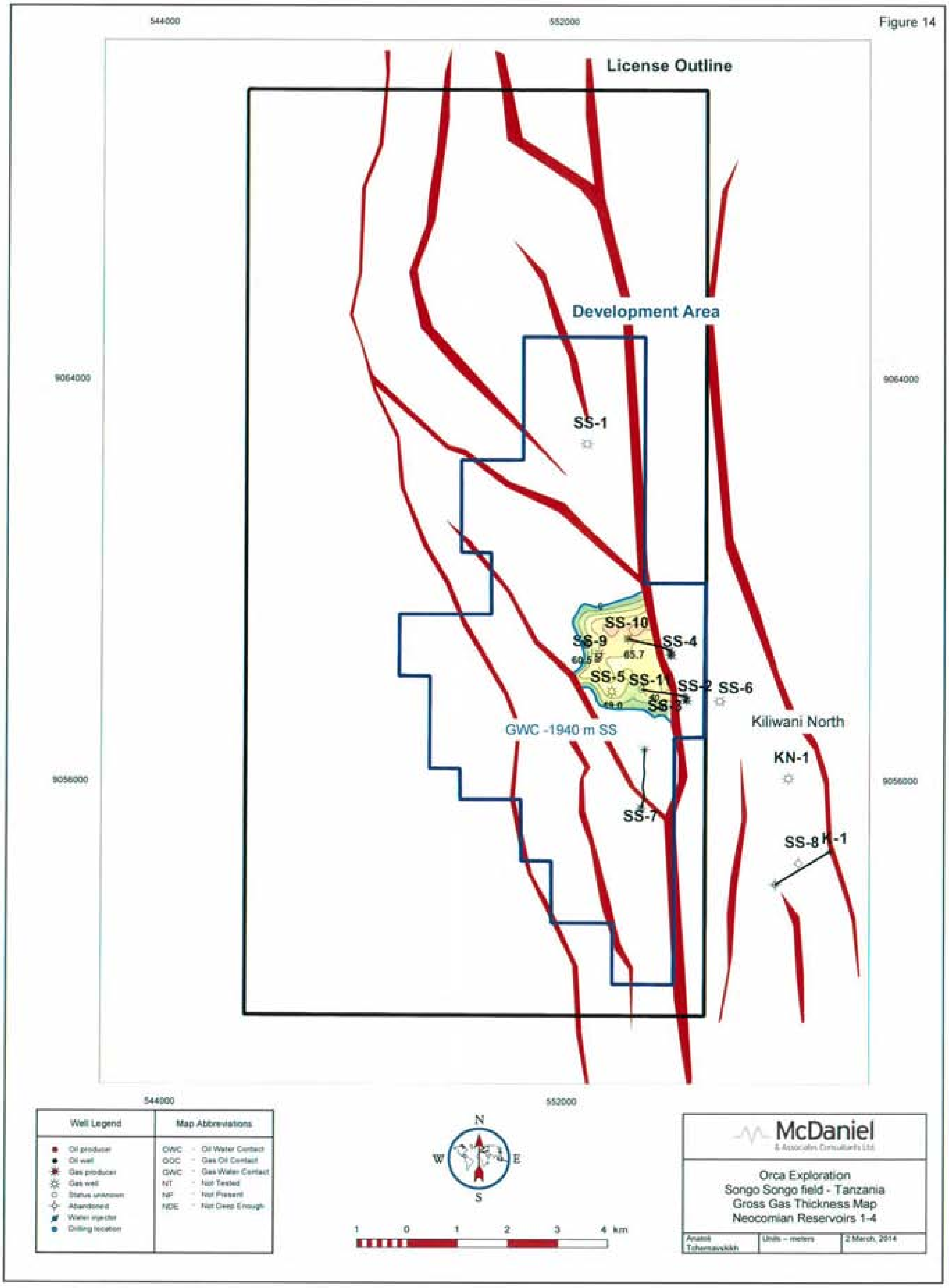
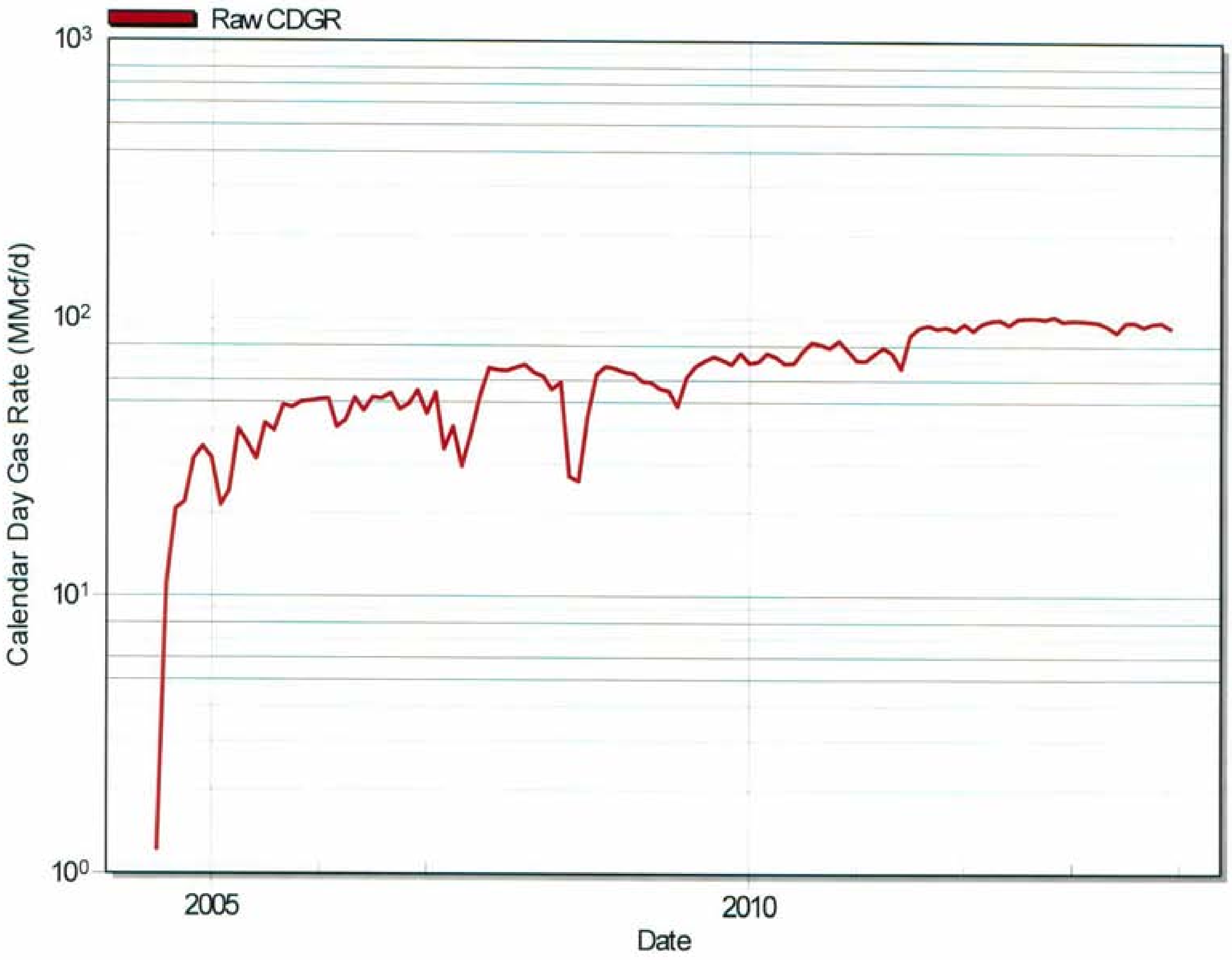
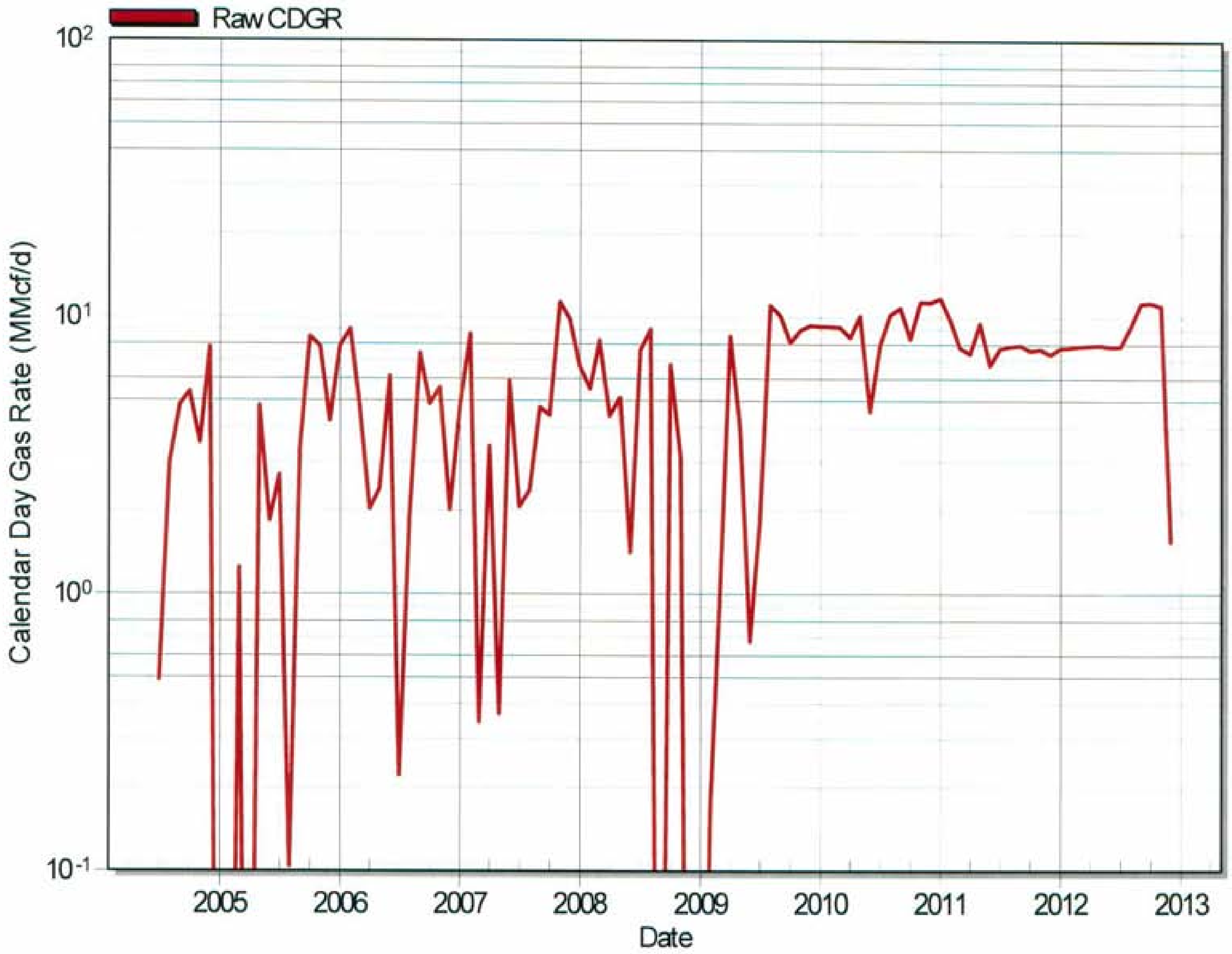


Figure 14
544000
552000
License Outline
Development Area
9064000
9056000
SS-1
SS-10
SS-4
SS-9
60.5
65.7
SS-5
SS-11
SS-2
SS-6
SS-3
GWC -1940 m SS
Kiliwani North
KN-1
SS-7
SS-8
K-1
Well Legend
Oil producer
Oil well
Gas producer
Gas well
Status unknown
Abandoned
Water injector
Drilling location
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
GWC - Gas Water Contact
NT - Not Tested
NP - Not Present
NDE - Not Deep Enough
N
W
E
S
1 0 1 2 3 4 km
McDaniel
& Associates Consultants Ltd.
Orca Exploration
Songo Songo field - Tanzania
Gross Gas Thickness Map
Neocomian Reservoirs 1-4
Anatoli Tchernavskikh
Units – meters
2 March, 2014

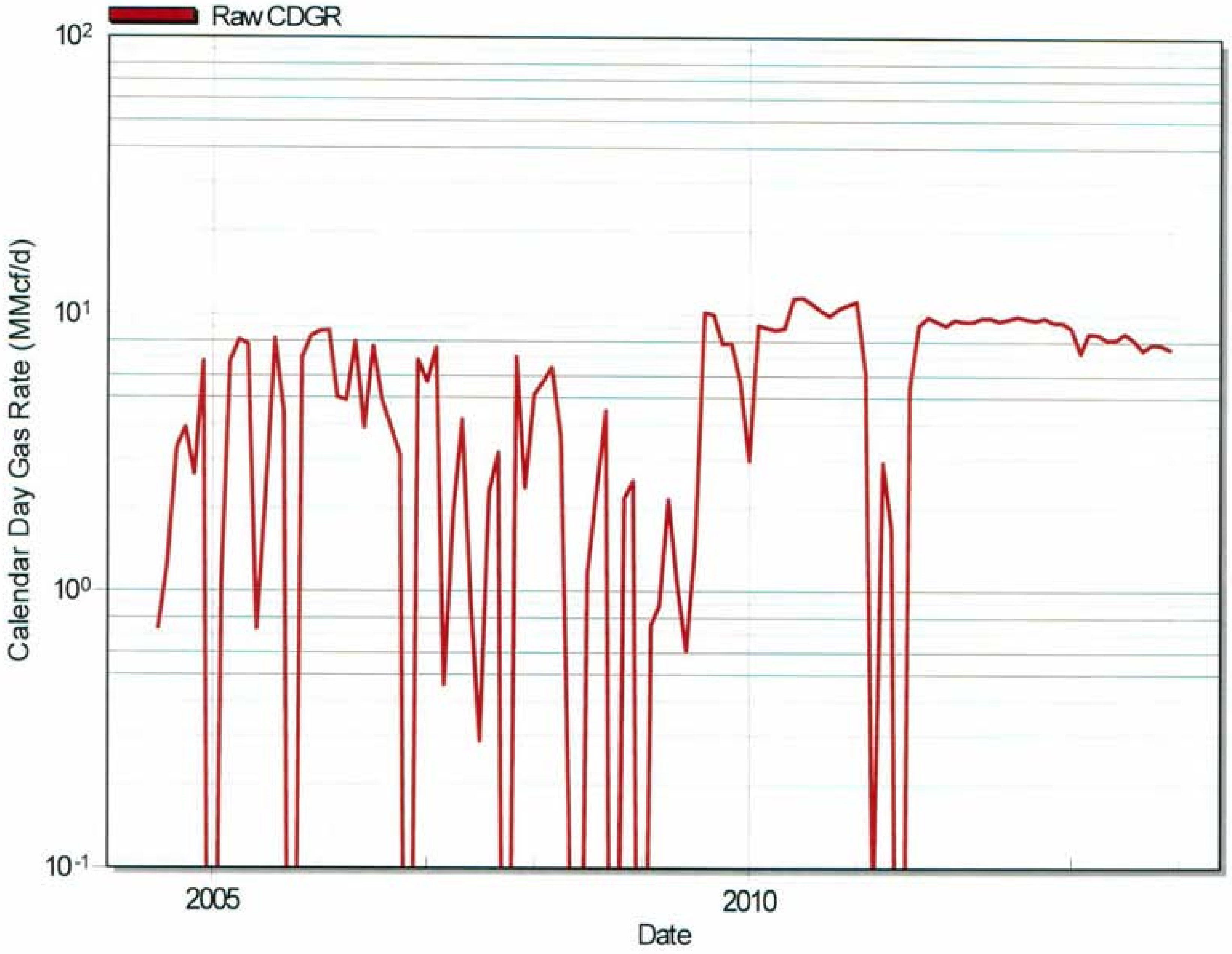
Total Songo Songo Field Production History



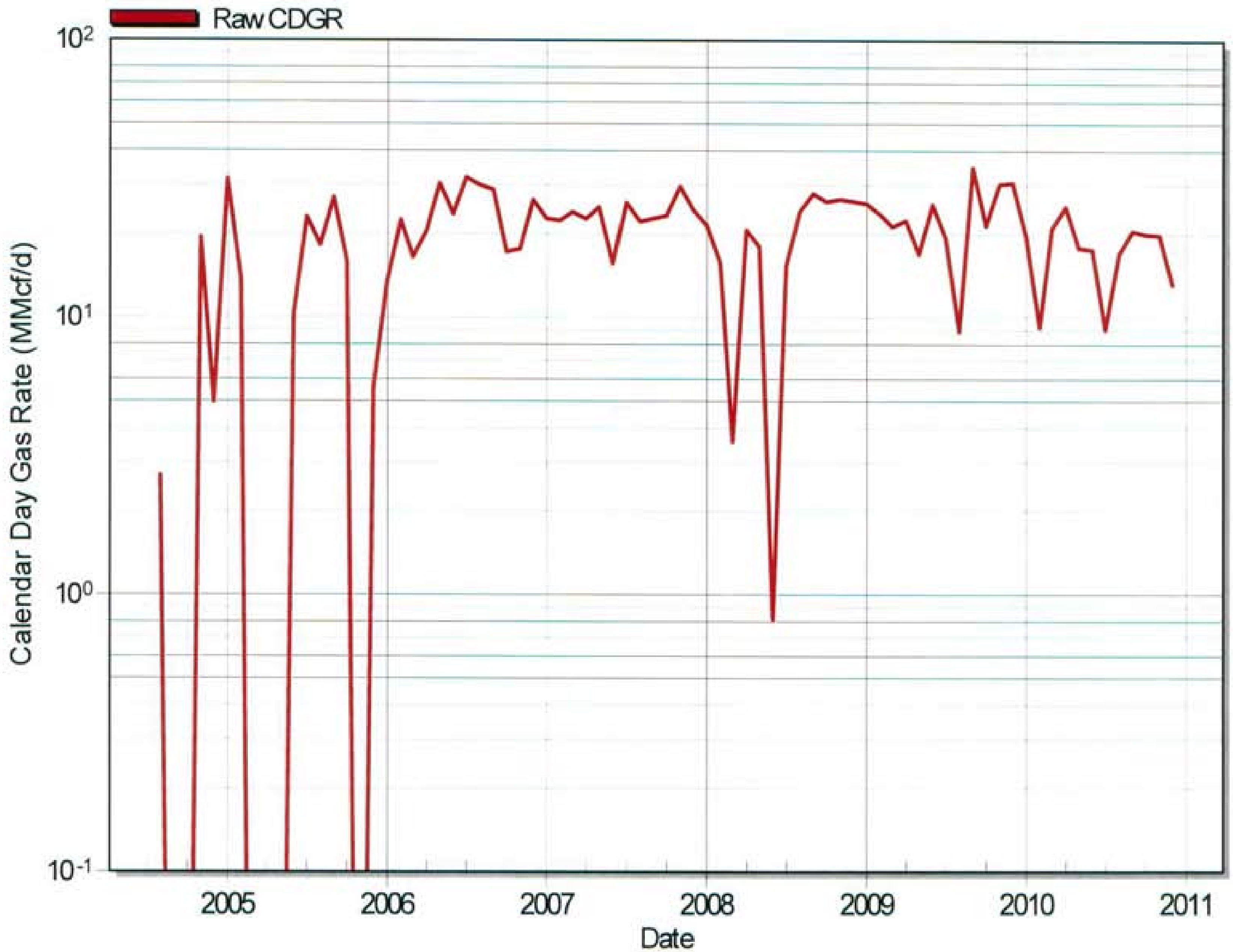
SS-3 Production History



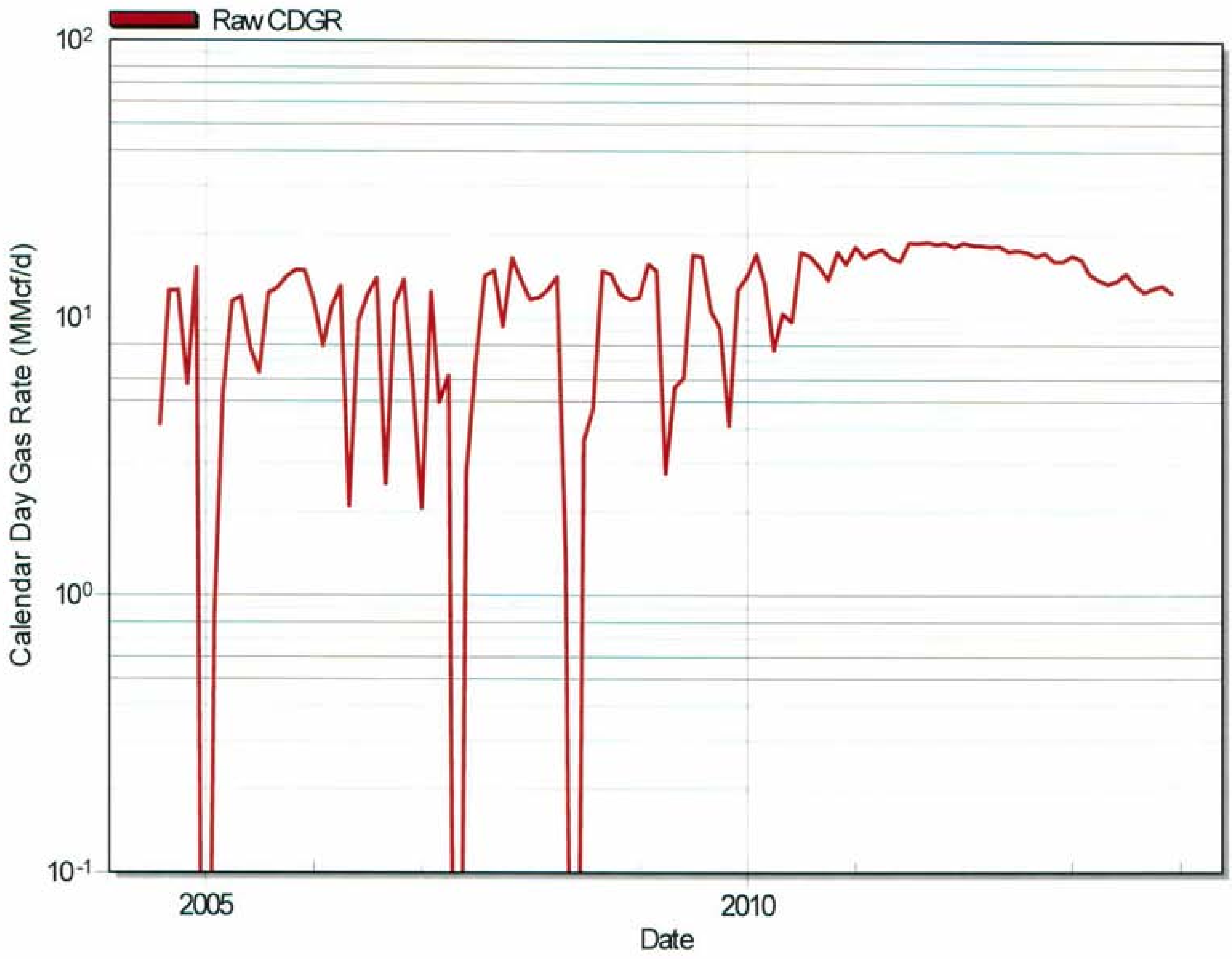
SS-4 Production History



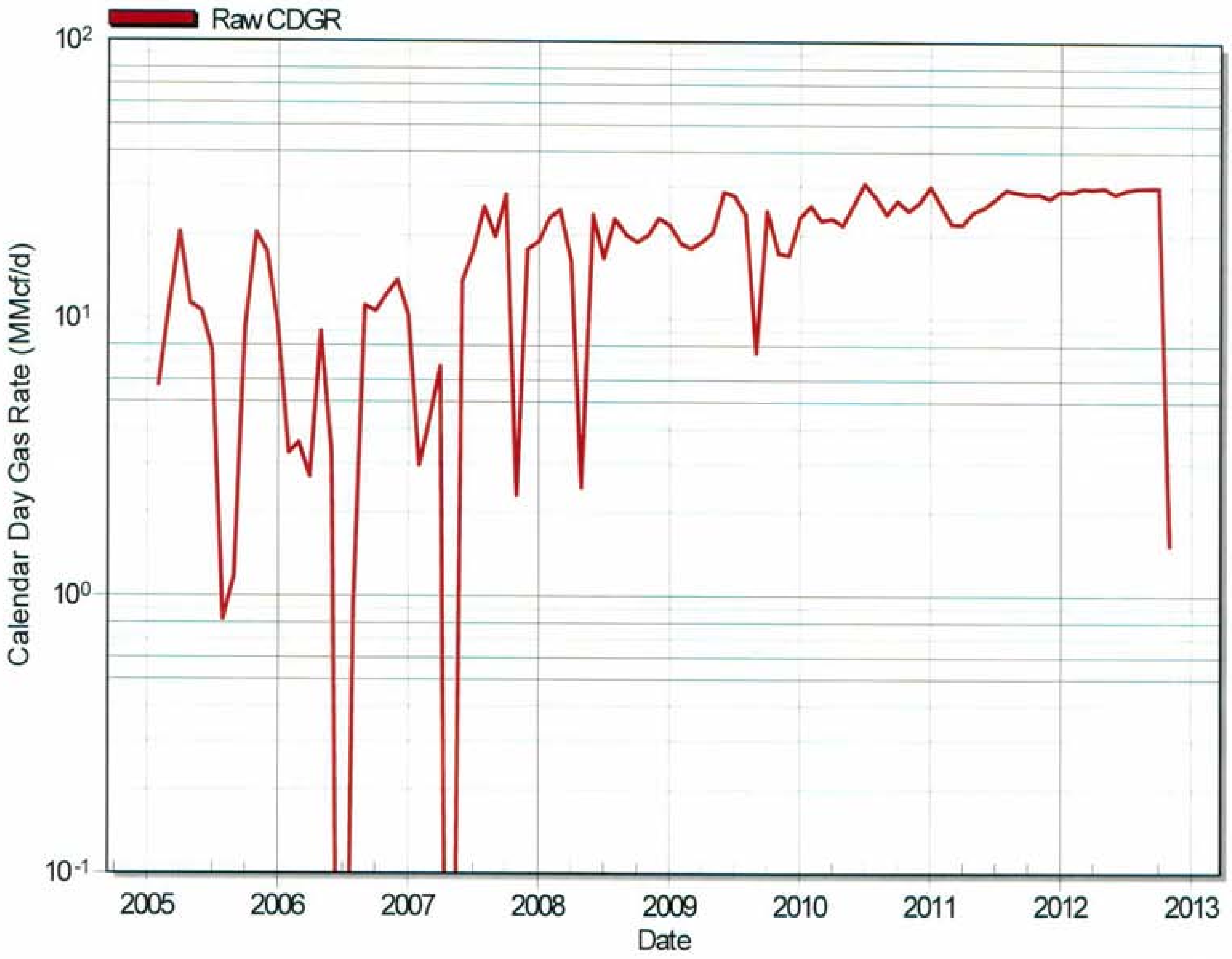
SS-5 Production History



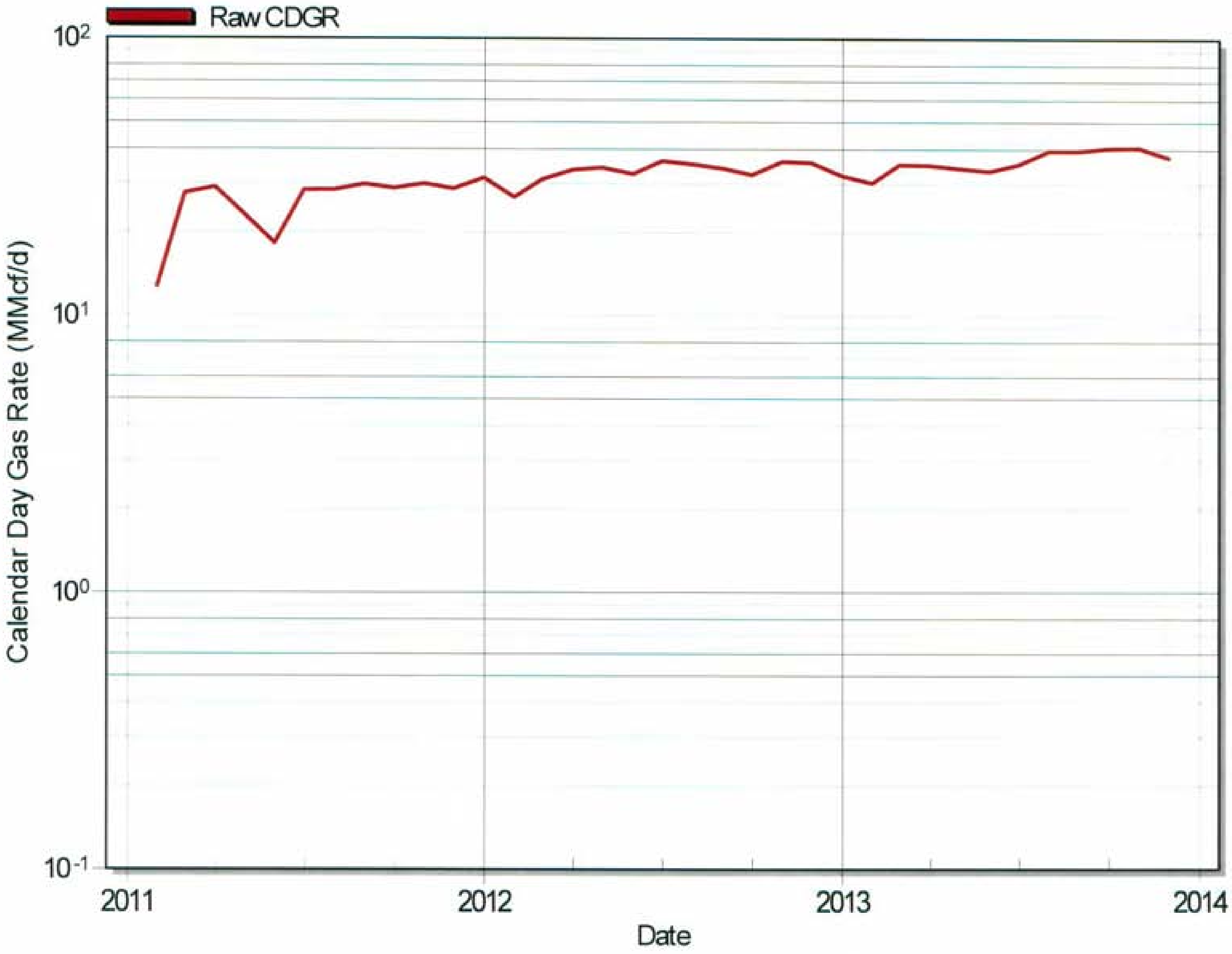
SS-7 Production History



SS-9 Production History



SS-10 Production History



SS-11 Production History