Tanzania and Mozambique Contingent and Prospective Resources Assessment as at August 31, 2013

Prepared for:

Wentworth Resources Limited

And

Panmure Gordon & Co.

Prepared by:

RPS Energy Canada Ltd.

September 27, 2013

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September 27, 2013

Job No. CC00868

Wentworth Resources Limited
3210,, 715 – 5th Avenue SW
Calgary, Alberta Canada T2P 2X6

Attention: Mr. Geoff Bury, Managing Director

Dear Mr. Bury,

Re: Tanzania and Mozambique Contingent and Prospective Resources Assessment, as at August 31, 2013

As requested by Wentworth Resources in the engagement letter dated April 3, 2013 (the "Agreement"), RPS Energy Canada Ltd. ("RPS") has completed an independent resource assessment of Wentworth's interests in the Mnazi Bay Licence in Tanzania and the Rovuma Onshore Block in Mozambique. This is a modified version of the report, wherein at your request, to allow this report to be distributed in the public domain, images of seismic lines in Mozambique have been removed due to confidentiality reasons.

The assessment was divided into three parts:

1. Contingent Resources for the Mnazi Bay and Msimbati fields using available 2D seismic and data from four wells.

2. Prospective Resources for six prospects on the Mnazi Bay Licence resulting from interpretations of 2D seismic lines supplied by Wentworth

3. Prospective Resources for seven prospects on the Rovuma Onshore Block resulting from interpretations of 2D seismic lines supplied by Wentworth

Contingent resources for the Mnazi Bay Licence were derived from volumetrics based on a 3D geological static model which was constructed utilizing the Maurel et Prom 2010 seismic interpretation, calibrated to the horizon tops as identified in the four wells drilled on the licence. The volumes derived from the Petrel model were combined with petrophysical evaluations and well test data from the four wells and have incorporated a range of gas-down-to and gas-water contact depths. Estimates of ultimate technical recovery were derived from a probabilistic analysis of original gas in place.

Wentworth owns 31.94% working interest in the production operations and 39.925% working interest in exploration operations in the Mnazi Bay licence block. The contingent resource volumes are summarized in the following table:

Contingent Resources Mnazi Bay Licence, Tanzania (Bscf) (Unrisked)								
	100% Full Field Values				Wentworth 31.94% Interest			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
Gas Originally in Place	365	892	2,117	1,112	117	285	676	355
Ultimate Recoverable Resources (Raw gas)	271	667	1,594	834	86	213	509	266
Ultimate Recoverable Resources (Sales gas)	260	641	1,532	802	83	205	489	256
Contingent Resources (sales gas)	259	639	1,527	799	83	204	488	255

For the Mnazi Bay Licence prospective resources, RPS has estimated the quantity of undiscovered gas resource that is likely to co-exist within the six identified prospects named Nanguruwe-1, Nanguruwe-West, Nanguruwe-North, Mwambo-1, OSX-1 and OSX-2. The basis of the estimate is the interpreted 2D seismic survey and available well and field data from the area. Consequently there is a wide range of uncertainty in the estimated volume. It should be noted that there is no certainty that any portion of these resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The unrisked probabilistic totals of the five prospects are summarized in the following table:

Mnazi Licence Prospective Resources	100% Full Field Prospective Gas Resources (Unrisked)				Wentworth 39.925% WI Prospective Gas Resources (Unrisked)				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Nanguruwe	23	62	133	72	9.2	25	53	29	17%	Maurel & Prom
Nanguruwe North	14	51	136	66	5.6	20	54	26	17%	Maurel & Prom
Nanguruwe West	138	354	769	415	55	141	307	166	15%	Maurel & Prom
Mwambo	191	369	640	399	76	147	256	159	17%	Maurel & Prom
OSX-1	164	414	847	471	65	165	338	188	23%	Maurel & Prom
OSX-2	61	142	287	161	24	57	115	64	23%	Maurel & Prom
Mnazi Licence - Stochastic Total (Unrisked)(1)(2)	**1064**	**1537**	**2201**	**1596**	**425**	**614**	**879**	**637**	**<<1%**	

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.

For the Rovuma Onshore Block prospective resources, RPS has estimated the quantity of undiscovered gas that is likely to co-exist within seven identified prospect locations. These prospects are consistent with those identified by the operator of the Block, Anadarko, and are named the Tembo, Maroon, Orange, Pink, Scarlet, Teal and Yellow prospects. The basis of the estimates is the interpreted 2D seismic and AVO analysis, together with available well and field data from the area. Consequently there is a wide range of uncertainty in the estimated volume of each prospect. It should be noted that there is no certainty that any portion of these resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The unrisked probabilistic totals of the seven prospects are summarized in the following table:

Rovuma Onshore Licence Total Prospective Resources	100% Full Field Prospective Gas Resources				Wentworth 11.59% WI Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Tembo	143	974	3,419	1,482	17	113	396	172	15%	Anadarko
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,849**	**4,347**	**7,121**	**4,745**	**330**	**504**	**825**	**550**	<<1%	

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.

RPS has also considered the case where the Tembo Prospect contains oil, in which case the unrisked probabilistic totals are summarized in the following table:

Rovuma Onshore Block Total Prospective Resources - Oil Case	100% Full Field Prospective Gas Resources				Wentworth 11.59% WI Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
OIL	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**		
Tembo (Unrisked)	25	192	780	277	3	22	90	32	15%	Anadarko
GAS	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**		
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,194**	**3,100**	**4,428**	**3,234**	**254**	**359**	**513**	**375**	<<1%	

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.

The above results tables present the consolidated results as unrisked probabilistic totals. The likelihood of achieving these results, after consideration of geologic risk, is very remote. In the body of this report, RPS presents fully risked consolidations, which present an expectation of the resource volumes after accounting for geologic risk.

This report is issued by RPS under the appointment by Wentworth Resources Limited and is produced as part of the engagement detailed therein and subject to the terms and conditions of the Agreement. Those terms and conditions contain inter alia restrictions on the use and distribution of information and materials contained in this report.

This report is addressed to Wentworth and the named Third Parties as defined in the Agreement and is only capable of being relied on by Wentworth and the Third Parties under and pursuant to (and subject to the terms of) the Agreement.

Wentworth may disclose the signed and dated report to third parties as contemplated by the purpose detailed in the Agreement but in making any such disclosure Wentworth shall require the third party (including any Third Parties) to accept it as confidential information only to be used or passed on to other persons as Wentworth is permitted to do under the Agreement.

We appreciate the opportunity to conduct this resource assessment for you. We trust that the attached report meets your requirements.

Yours sincerely,
RPS Energy

Brian D. Weatherill, P. Eng.
Reservoir Engineering Specialist
encl.

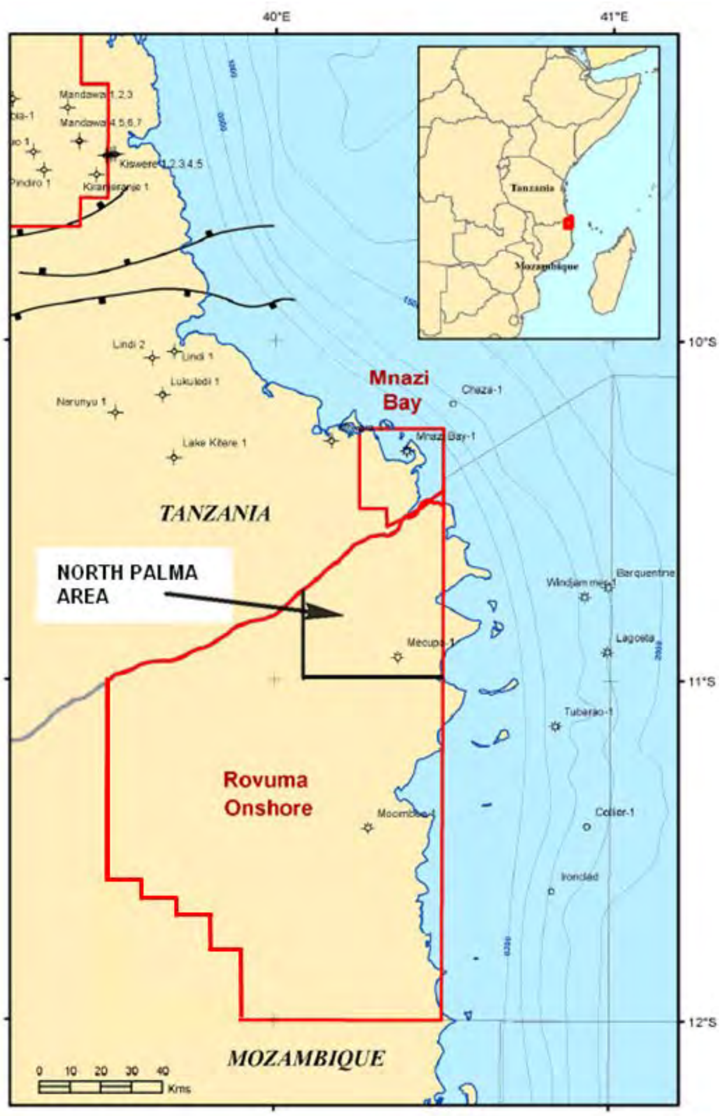
PROFESSIONAL ENGINEER
BRIAN D. WEATHERILL
ALBERTA

PERMIT TO PRACTICE
RPS ENERGY CANADA LTD
Signature
Date 2013-09-27
PERMIT NUMBER: P 4348
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

EXECUTIVE SUMMARY

RPS has reviewed the available data for the Mnazi Bay Concession Area in Tanzania and has evaluated Wentworth's 39.925% (exploration operations) interest in Prospective Resources of six seismically defined prospects on the licence. In addition, RPS has included its evaluation of Wentworth's interest in the Contingent Resources of the Mnazi Bay and Msimbati Gas fields, updating these evaluations to include Wentworth's 31.94% (production operations) working interest and cumulative gas production to August 2013, the effective date of this report.

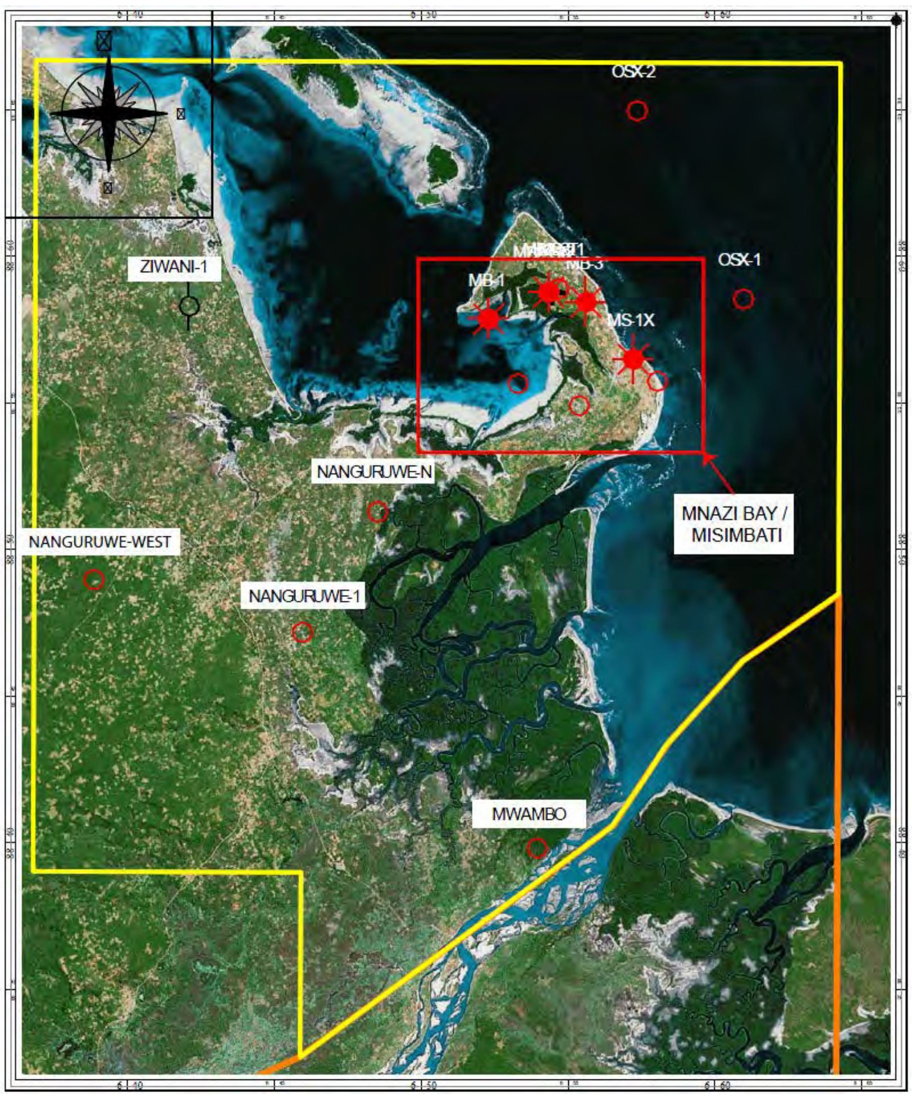
For Wentworth's Mozambique licences, RPS has reviewed the available data for the Rovuma Onshore Block and has evaluated Wentworth's 11.59% working interest in Prospective Resources of seven seismically defined prospects on the block.



Source: Wentworth

Wentworth Resources Inc. (“Wentworth”) owns a 31.94% production operations and 39.925% exploration operations working interest in the 756 km^2 Mnazi Bay concession area in the south-eastern part of Tanzania operated by Maurel & Prom. There are four gas discoveries on the licence, one of which is producing gas with the others completed and shut-in. These wells define the Mnazi Bay and Msimbati gas fields.

The Mnazi Bay concession area (also referred to as the “Mnazi Bay licence” in this report) is shown below with the Mnazi Bay/Msimbati Field and its four wells highlighted in red together with the six prospects evaluated in this report also marked on the map. A development Licence has been issued on the discovery block and eight adjoining blocks comprising the contract area, with an initial term of twenty-five years from October 26, 2006.



Mnazi Bay Licence Area

Source: Base image from Google Earth

RPS reviewed 1658 km of 2D seismic data (103 lines) on the Mnazi Bay licence and 3202 km^2 of 2D seismic data (90 lines) on the onshore Mozambique licence, with the interpretation focus on drill-ready prospects on the subject licence blocks. Additional data reviewed included offsetting well logs and field production histories, details of new competitor discoveries in Mozambique and Tanzania and geological and reservoir information from publically available sources.

These assessments are made in accordance with the London Stock Exchange AIM Rules for Companies (February 2010), AIM Notes for Investing Companies and the AIM Note for Mining and Oil and Gas Companies (June 2009).

Contingent Resources – Mnazi Bay Licence, Tanzania

RPS estimates of Gas Initially In Place and Gas Resources for the Mnazi Bay and Msimbati discoveries are shown in the following tables for the full field (100% Working Interest, unrisked). These estimates are based on the same data used in the RPS evaluation of October 2011. The data from production operations from 2011 to 2013 does not indicate any changes in the Contingent Resource analysis.

Mnazi Bay & Msimbati Resource Estimates - GIIP				
Field	**P90**	**P50**	**Mean**	**P10**
	bscf	bscf	bscf	bscf
Upper & Lower Msimbati	42	122	166	334
Msimbati NE	30	112	161	347
Msimbati NE Extension	7	36	56	125
Upper & Lower Mnazi	210	561	730	1,442
Total	365	892	1,112	2,117

Mnazi Bay & Msimbati Resource Estimates - EUR				
Field	**P90**	**P50**	**Mean**	**P10**
	bscf	bscf	bscf	bscf
Upper & Lower Msimbati	31	91	124	252
Msimbati NE	22	84	121	261
Msimbati NE Extension	5	27	42	93
Upper & Lower Mnazi	156	419	547	1,085
Total	271	667	834	1,594

* Totals determined probabilistically and do not sum arithmetically except at the mean values.

Wentworth's interest in the above Contingent resources is 31.94% of the volumes shown.

Contingent Resources Mnazi Bay Licence, Tanzania (Bscf)								
	100% Field Values				Wentworth 31.94% Interest			
	P_{90}	P_{50}	Mean	P_{10}	P_{90}	P_{50}	Mean	P_{10}
Gas Originally in Place	365	892	1,112	2,117	117	285	355	676
Recoverable Contingent Resources	271	667	834	1,594	86.6	213	266	509

RPS notes that notwithstanding the fact that the resources in the Mnazi Bay field are currently on production, the above volumes have not been classified as reserves. RPS considers the current production operations to be an initial pre-development stage of production operations, implemented to fulfill a licence obligation to supply local area energy needs, but does not, in itself, constitute a commercially viable project, for the purposes of reserves classification. There are several outstanding contingencies on commercial development which would need to be satisfied in order to qualify the project with commercial status and classify the volumes as reserves.

Prospective Resources – Mnazi Bay Licence, Tanzania

On the Mnazi Bay licence area, RPS has estimated the quantity of undiscovered gas resources that are likely to co-exist within the six identified prospect locations, named Nanguruwe, Nanguruwe North, Nanguruwe West, Mwambo, OSX-1, OSX-2. The basis of the estimates is the interpreted 2D seismic survey and available well and field data from the area. Consequently there is a wide range of uncertainty in the estimated volume. It should be noted that there is no certainty that any portion of these resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

To account for geologic risk, the Geological Probability of Success (GPoS) for the prospects is estimated by RPS to be 17% for Nanguruwe, 17% for Nanguruwe West, 15% for Nanguruwe North, 17% for Mwambo and 23% for OSX -1 and OSX -2. With these GPoS values, the individual prospects have been consolidated probabilistically in the summary tables below. The first consolidation shown is the stochastic distribution of resources assuming all prospects are successful. The probability of this occurring is extremely low (<<1%). The second consolidation shows the stochastic distribution of resources assuming at least one of the prospects is successful. This represents the expected value of the success case and has a 92% chance of occurrence. The final distribution shown is the consolidated stochastic distribution of the success and failure case, with at least one successful prospect. This represents the true expected value of the whole portfolio of prospects.

Wentworth owns a 39.925% exploration working interest in the Mnazi Bay licence block. The tables below show Wentworth's share of the in-place volumes and prospective resources. Note that Wentworth's interest is subject to a 20% back-in right in favour of TPDC, in the event of a successful discovery. If this right is exercised for a given field discovery, Wentworth's interests will be reduced to 31.94% of the respective fields volumes.

Mnazi Licence	100% Full Field Gas Initially In Place				GPoS
	P_{90}	P_{50}	P_{10}	Mean	(%)
	Bscf	Bscf	Bscf	Bscf	
Nanguruwe	38	96	202	110	17%
Nanguruwe North	24	85	225	109	17%
Nanguruwe West	239	594	1247	682	15%
Mwambo	298	572	975	612	17%
OSX-1	257	643	1292	723	23%
OSX-2	95	222	434	248	23%
Mnazi Licence - Stochastic Total (Unrisked)(1)(2)	1683	2400	3400	2486	**<<1%**
Mnazi Licence - Stochastic Total(2)	**42**	**357**	**1159**	**501**	**92%**
Mnazi Licence - Stochastic Total Risked(3)				**461**	

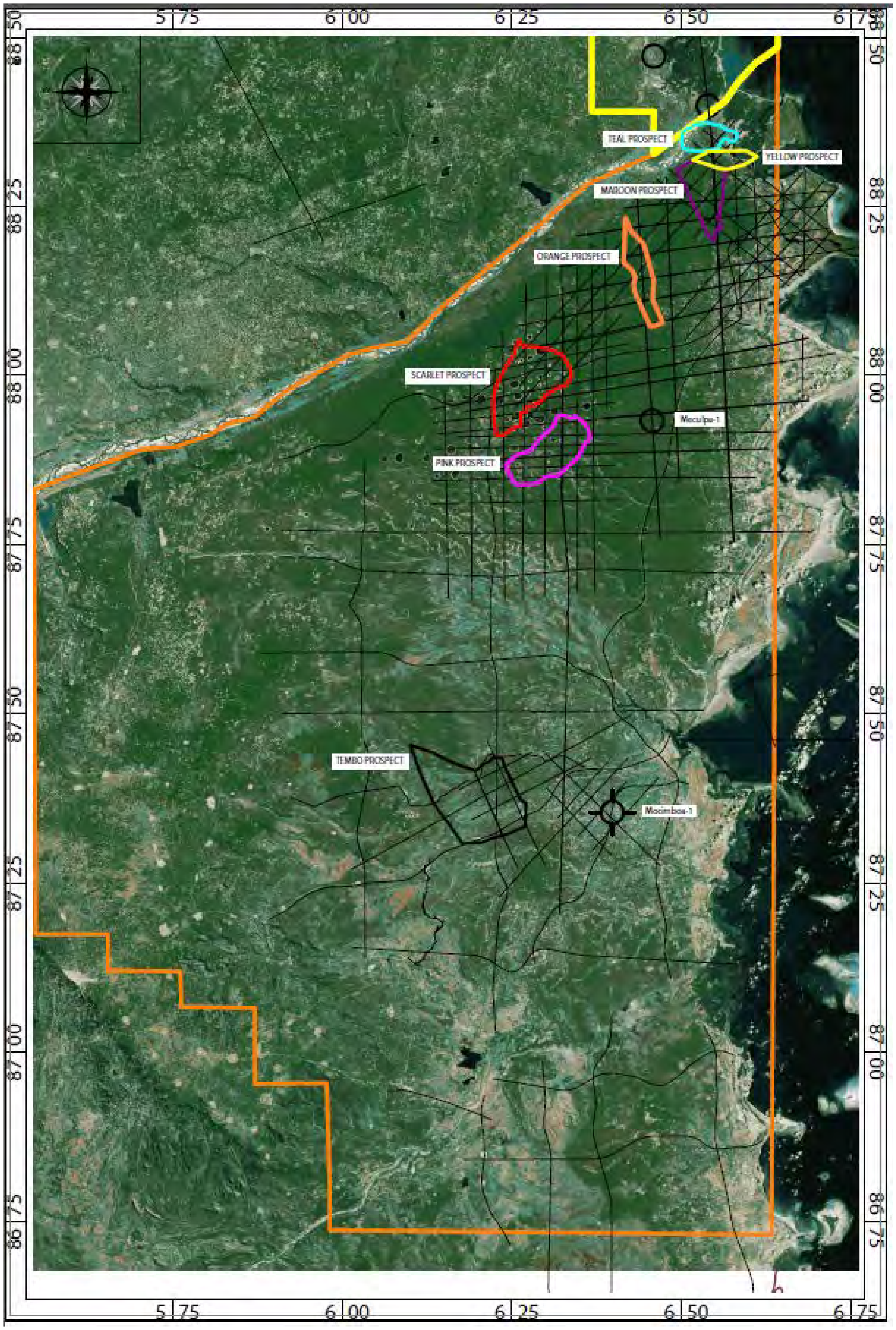
Mnazi Licence Prospective Resources	100% Full Field Prospective Gas Resources (Unrisked)				Wentworth 39.925% WI Prospective Gas Resources (Unrisked)				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Nanguruwe	23	62	133	72	9.2	25	53	29	17%	Maurel & Prom
Nanguruwe North	14	51	136	66	5.6	20	54	26	17%	Maurel & Prom
Nanguruwe West	138	354	769	415	55	141	307	166	15%	Maurel & Prom
Mwambo	191	369	640	399	76	147	256	159	17%	Maurel & Prom
OSX-1	164	414	847	471	65	165	338	188	23%	Maurel & Prom
OSX-2	61	142	287	161	24	57	115	64	23%	Maurel & Prom
Mnazi Licence - Stochastic Total (Unrisked)(1)(2)	**1064**	**1537**	**2201**	**1596**	**425**	**614**	**879**	**637**	**<<1%**	
Mnazi Licence - Stochastic Total(2)	**27**	**228**	**742**	**320**	**11**	**91**	**296**	**128**	**92%**	
Mnazi Licence - Stochastic Total Risked(3)				**294**				**118**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Prospective Resources – Rovuma Onshore Block, Mozambique

Wentworth owns 11.59% production working interest (13.64% during exploration phases) in the Rovuma Onshore Block, together with partners Anadarko (operator, 35.7% production/42.0% exploration)), Maurel et Prom (27.71% production/32.6% exploration), ENH (15% production/0% exploration) and PTT Exploration and Production Public Company Limited (“PTTEP”) (10% production 11.76% exploration). The contract terms on the Block contain obligations for further exploration activity commitments, including 100 km^2 of 3D seismic, subsequently converted to 400 km of 2D seismic, and the drilling of one exploration well. The partners have entered the second phase of exploration activities which will fulfill these commitments, and which will retain the rights to the exploration block through August 2014. One additional exploration well will hold the exploration block through August of 2015.

RPS has evaluated Prospective Resources present within the north-eastern and middle portion of the block, in an area defined by the 2007/2008 and 2012 2D seismic surveys. A map of the location of the area and the seven prospects evaluated in this section of the report is shown below.



Prospective Resources – Rovuma Onshore Block, Mozambique
Source: Google Earth, Consortium Seismic Data

RPS has estimated the quantity of undiscovered gas that is likely to co-exist within the seven identified prospect. RPS believes that if the prospects are hydrocarbon charged, it is most likely that they are gas charged, however there is also a possibility (estimated to be 30-40%) that the Tembo Cretaceous prospect may be oil charged. The basis of the estimates is the interpreted 2D seismic survey and AVO analysis, together with available well and field data from the area. Consequently there is a wide range of uncertainty in the estimated volume. It should be noted that there is no certainty that any portion of these resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The in-place volumes and Prospective Resource volumes are shown below, undiscounted for risk for the individual prospects, with consolidated risk discounted totals for the totals of all prospects.

Rovuma Onshore Block	**100% Full Field**				
	Gas Initially In Place				**GPoS**
	P_{90}	**P_{50}**	**P_{10}**	**Mean**	**(%)**
	Bscf	**Bscf**	**Bscf**	**Bscf**	
Tembo	243	1,643	5,610	2,441	15%
Maroon	882	1,571	2,627	1,679	14%
Orange	105	366	904	453	18%
Pink	376	846	1,816	1,001	22%
Scarlett	353	992	2,471	1,253	22%
Teal	183	356	649	392	15%
Yellow	234	497	942	551	19%
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**4,757**	**7,167**	**11,561**	**7,771**	<<1%
Rovuma Onshore Block - Stoch. Total(2)	**203**	**1,036**	**3,314**	**1,518**	**88%**
Rovuima Onshore Block - Stoch. Total Risked(3)				**1,336**	

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Rovuma Onshore Block	100% Full Field				Wentworth 11.59% WI					
	Prospective Gas Resources				Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Tembo	143	974	3,419	1,482	17	113	396	172	15%	Anadarko
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,849**	**4,347**	**7,121**	**4,745**	**330**	**504**	**825**	**550**	<<1%	
Rovuma Onshore Block - Stoch. Total(2)	**119**	**620**	**2,017**	**919**	**14**	**72**	**234**	**107**	**88%**	
Rovuima Onshore Block - Stoch. Total Risked(3)				**809**				**94**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

RPS considers that although the prospects' hydrocarbons are more likely to be gas than oil. However, there is some possibility that the Tembo prospect may contain oil (estimated by RPS to be about 30% - 40%.) In this case (which we call the "oil case") the consolidated Prospect totals would be as shown in the following tables:

Rovuma Onshore Block - Oil Case	100% Full Field				
	Volumes Initially In Place				GPoS
	P_{90}	P_{50}	P_{10}	Mean	(%)
OIL	**MMstb**	**MMstb**	**MMstb**	**MMstb**	
Tembo (Unrisked)	107	756	2,808	1,205	15%
GAS	**Bscf**	**Bscf**	**Bscf**	**Bscf**	
Maroon	882	1,571	2,627	1,679	14%
Orange	105	366	904	453	18%
Pink	376	846	1,816	1,001	22%
Scarlett	353	992	2,471	1,253	22%
Teal	183	356	649	392	15%
Yellow	234	497	942	551	19%
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**3,667**	**5,123**	**7,198**	**5,329**	<<1%
Rovuma Onshore Block - Stoch. Total(2)	**176**	**870**	**2,465**	**1,147**	**86%**
Rovuima Onshore Block - Stoch. Total Risked(3)				**1,009**	

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Rovuma Onshore Block - Oil Case	100% Full Field Prospective Gas Resources				Wentworth 11.59% WI Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
OIL	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**		
Tembo (Unrisked)	25	192	780	277	3	22	90	32	15%	Anadarko
GAS	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**		
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,194**	**3,100**	**4,428**	**3,234**	**254**	**359**	**513**	**375**	<<1%	
Rovuma Onshore Block - Stoch. Total(2)	**104**	**521**	**1,500**	**694**	**12**	**60**	**174**	**80**	**86%**	
Rovuima Onshore Block - Stoch. Total Risked(3)				**597**				**69**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

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This report is addressed to Wentworth and the named Third Parties as defined in the Agreement and is only capable of being relied on by Wentworth and the Third Parties under and pursuant to (and subject to the terms of) the Agreement.

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Project Title	**Tanzania and Mozambique Prospective Resources Assessment as at August 31, 2013**		
Project Number	CC00868		
	AUTHORS:	Project Manager	Date of Issue
	Brian D. Weatherill	Brian D. Weatherill	September 2013
	Martin Dashwood		
	Kathleen Dorey		
File Location:	RPS Energy Canada Suite 700, 555 – 4th Avenue SW Calgary, Alberta T2P 3E7 Tel:1(403) 265-7226 Fax:1(403) 269-3175 Email: rpscal@rpsgroup.com		

CERTIFICATE OF QUALIFICATION
B.D. Weatherill

I, Brian D. Weatherill, of 3131 Upper Place N.W. Calgary, Alberta T2P 4H2, a Professional Engineer at RPS Energy Canada Ltd., and co-author of a property evaluation (the "Evaluation") dated September 27, 2013 prepared for Wentworth Resources Limited, do hereby certify that:

- I am a Petroleum Engineer employed by RPS Energy Canada Ltd., which prepared a Resource Assessment of the Mnazi Bay, Tanzania assets, the Rovuma Onshore Block in Mozambique and an opinion as to the potential of the Mozambique Rovuma Offshore Area 1 Block assets of Wentworth Resources Limited, as of August 31, 2013.
- I attended the University of British Columbia and that I graduated with a Bachelor of Applied Science Degree Geological Engineering in 1973; that I am a registered Professional Engineer in the Province of Alberta (APEGGA); and that I have in excess of 35 years' experience in Petroleum Engineering relating to Canadian and international oil and gas properties.
- I and my employer are independent of Wentworth and our remuneration is not related in any way to Wentworth's value or any Wentworth financing or capital funding activities.
- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, in Wentworth Resources Limited or any associate or affiliate of the Company.
- The evaluation was prepared based upon information supplied by Wentworth Resources Limited as well as other public data sources.
- I have read and complied with the guidelines issued by the London Stock Exchange's 'AIM Note for Mining and Oil & Gas Companies – June 2009' ("Aim Guidance Note"). I confirm that I fulfill the requirements of a Competent Person and that the sections of this report for which I am responsible have been prepared to a standard expected in accordance with the AIM Guidance Note.
- As of the date of this certificate, I am not aware of any material change since the effective date of the Evaluation and, to the best of my knowledge, information and belief the sections of this report for which I am responsible contain all scientific information that is required to be disclosed to make this report not misleading.

B.D. Weatherill, P. Eng.

CERTIFICATE OF QUALIFICATION
Martin F. Dashwood

I, Martin F. Dashwood, a Professional Geologist at RPS Energy Canada Ltd., and co-author of a property evaluation (the "Evaluation"), dated September 27, 2013, prepared for Wentworth Resources Limited, do hereby certify that:

- I am a Petroleum Geologist employed by RPS Energy Canada Ltd., which prepared a Resource Assessment of the Mnazi Bay Licence, Tanzania assets, the Rovuma Onshore Block in Mozambique and an opinion as to the potential of the Mozambique Rovuma Offshore Area 1 Block assets of Wentworth Resources Limited, as of August 31, 2012.
- I attended University of Reading, U.K. and that I graduated with a Master of Science degree in Sedimentology and it's Applications in 1979, prior to that I attended the Chelsea College, University of London, U.K and received a Bachelor of Science degree in Geology 1980; that I am a registered Professional Geologist in the Province of Alberta (APEGA); and that I have in excess of 30 years' experience in Petroleum Geology relating to Canadian and international oil and gas properties.
- I and my employer are independent of Wentworth and our remuneration is not related in any way to Wentworth's value or any Wentworth financing or capital funding activities.
- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, in Wentworth Resources Limited or any associate or affiliate of the company.
- The evaluation was prepared based upon information supplied by Wentworth Resources Limited as well as other public data sources.
- I have read and complied with the guidelines issued by the London Stock Exchange's 'AIM Note for Mining and Oil & Gas Companies – June 2009' ("Aim Guidance Note"). I confirm that I fulfill the requirements of a Competent Person and that the sections of this report for which I am responsible have been prepared to a standard expected in accordance with the AIM Guidance Note.
- As of the date of this certificate, I am not aware of any material change since the effective date of the Evaluation and, to the best of my knowledge, information and belief the sections of this report for which I am responsible contain all scientific information that is required to be disclosed to make this report not misleading.

Martin F. Dashwood. P. Geol.

CERTIFICATE OF QUALIFICATION
Kathleen Dorey

I, Kathleen Dorey, Consulting Geophysicist of Calgary, Alberta, Canada, am a Professional Geophysicist and Chief Geophysicist of Petrel Robertson Consulting Ltd and co-author of a property evaluation (the "Evaluation"), dated September 27, 2013, prepared for Wentworth Resources Limited, do hereby certify that:

- I am a Professional Geophysicist employed by Petrel Robertson Consulting Ltd., which acted as a subcontractor to RPS in the preparation of a Resource Assessment of the Mnazi Bay, Tanzania and the Rovuma Onshore Block, Mozambique assets and an opinion as to the potential of the Mozambique Rovuma Offshore Area 1 Block assets of Wentworth Resources Limited as of August 31, 2013.
- I attended the University of Western Ontario and that I graduated with a B.Sc. in Geophysics in 1983; that I am a registered Professional Geophysicist in the Province of Alberta (APEGGA); and that I have in excess of 29 years' experience in Geophysical studies relating to Canadian and International oil and gas properties.
- I and my employer are independent of Wentworth and our remuneration is not related in any way to Wentworth's value or any Wentworth financing or capital funding activities.
- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, in Wentworth Resources Limited or any associate or affiliate of the company.
- The evaluation was prepared based upon information supplied by Wentworth Resources Limited as well as other public data sources.
- I have read and complied with the guidelines issued by the London Stock Exchange's 'AIM Note for Mining and Oil & Gas Companies – June 2009' ("Aim Guidance Note"). I confirm that I fulfill the requirements of a Competent Person and that the sections of this report for which I am responsible have been prepared to a standard expected in accordance with the AIM Guidance Note.
- As of the date of this certificate, I am not aware of any material change since the effective date of the Evaluation and, to the best of my knowledge, information and belief the sections of this report for which I am responsible contain all scientific information that is required to be disclosed to make this report not misleading.

Kathleen Dorey, P.Geoph.
Chief Geophysicist

PROFESSIONAL GEOPHYSICIST ALBERTA
KATHLEEN DOREY

INDEPENDENT PETROLEUM CONSULTANT'S CONSENT AND WAIVER OF LIABILITY

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada knows that it is named as having prepared an independent report of the gas resources of the Tanzania and Mozambique properties owned by Wentworth Resources Limited and it hereby gives consent to the use of its name and to the said report. The effective date of the report is August 31, 2013.

In the course of the assessment, Wentworth Resources Limited provided RPS Energy personnel with basic information which included petroleum and licensing agreements, geologic, geophysical and production information, cost estimates, contractual terms and studies made by other parties. Any other engineering or economic data required to conduct the assessment upon which the original and addendum reports are based, was obtained from public literature, and from RPS Energy non-confidential client files and previous technical resource assessment reports on the subject property. The extent and character of ownership and accuracy of all factual data supplied for this assessment, from all sources, has been accepted as represented. RPS Energy reserves the right to review all calculations referred to or included in the said reports and, if considered necessary, to revise the estimates in light of erroneous data supplied or information existing but not made available at the effective date, which becomes known subsequent to the effective date of the reports.

There is considerable uncertainty in attempting to interpret and extrapolate field and well data and no guarantee can be given, or is implied, that the projections made in this report will be achieved. The report and production potential estimates represent the consultant's best efforts to predict field performance within the scope, time frame and budget agreed with the client. Moreover, the material presented is based on data provided by Wentworth Resources Limited. RPS Energy cannot be held responsible for decisions that are made based on this data or reports. The use of this material and reports is, therefore, at the user's own discretion and risk. The report is presented in its entirety and may not be made available or used without the complete content of the reports. RPS Energy liability shall be limited to the correction of any computational errors contained herein.

RPS Energy Group

1.0 INTRODUCTION

1.1 Background and Historical Description

Wentworth Resources Limited ("Wentworth") owns a working interest in two concessions in East Africa; the Mnazi Bay Concession in Tanzania and the Rovuma Onshore Block in Mozambique. (Figure 1-1).

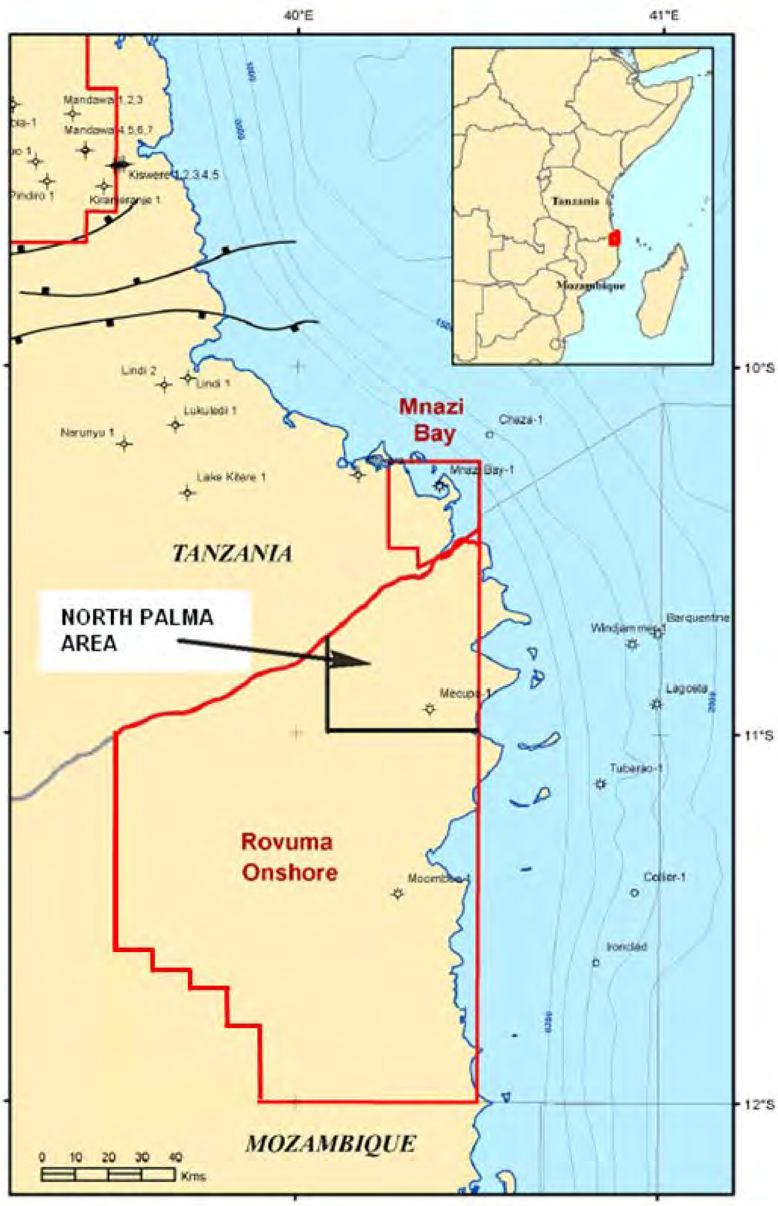

Figure 1-1: Location Map of Wentworth Resources Concessions (formerly Artumas). Mnazi Bay Licence, Rovuma Onshore Block.

Source: Wentworth

Summary Table of Assets

Asset	Operator	Wentworth Interest	Status	Licence Expiry Date	Licence Area	Comments
Mnazi Bay Licence, Tanzania	Maurel and Prom	31.94% production 39.925% exploration	Production, Development and Exploration	October 26, 2031	756 km^2	Small field development currently on production. Additional exploration and development potential
Rovuma Onshore Block, Mozambique	Anadarko	11.59% working interest 13.64% paying interest	Exploration	August 31, 2014	13,500 km^2	In second phase exploration programme

Table 1-1: Summary Table of Assets

The Mnazi Bay Concession is located at approximately 10° 19' South and 40° 23' East, on the south-eastern coast of Tanzania, just north of the border with Mozambique. (Figure 1-2)

In 1982, a gas field (Mnazi Bay) was discovered on the concession by AGIP, who drilled the discovery well Mnazi Bay #1 ("MB-1") on a seismic defined structure. The objective of the well was to identify the stratigraphic column and focus on a Lower Cretaceous oil target. The well was evaluated as having oil and gas in several potential reservoir zones, and was drill stem tested over two Miocene aged zones: the "D" zone flowing over 13 MMscf/d of sweet dry gas, and then the "D" & "E" zones combined, flowing at about 12.5 MMscf/d of dry gas. These tests demonstrated the commercial potential of the discovery. After testing, the well was suspended by AGIP, due to lack of gas markets at the time. The concession was subsequently relinquished by AGIP.

In 2003 Artumas Group Inc. (now Wentworth)[1] held discussions with the Government of Tanzania with the objective of implementing a gas-to-power ("GTP") project as a means of exploiting the potential gas resources. The GTP project was conceptualized as having several components: development of the gas reservoir, by drilling and tie-in of sufficient production wells, a gas pipeline, a gas fired power plant and an upgraded power transmission system for local power distribution. In August 2003 an agreement of intent was struck between the Government of Tanzania, the Tanzanian Petroleum Development Corporation ("TPDC") and Artumas to proceed with the GTP project. In mid-2004, a Production Sharing Agreement ("PSA") on the acreage was executed between the Government of Tanzania, TPDC and Artumas Group & Partners (Gas) Limited ("AG&P"), a wholly owned subsidiary of Artumas, clearing the way for implementation of the project. The agreement concession is comprised of a 756.8 km^2 (75,680 hectare) exploration area, both onshore and offshore (Figure 1-2). The concession PSA is also supported by the Agreement of Intent and several other related agreements with the Government of Tanzania to implement the other aspects of the GTP

[1] In September 2010, Artumas Group Inc. changed its name to Wentworth Resources Limited, as a result of a business combination transaction between the two companies. In this report, RPS uses the name Artumas, where appropriate, in discussion of historical company activities which pre-date the corporate name change.

project. On October 26, 2006 the Tanzanian Ministry of Energy and Minerals granted a development licence to TPDC covering one discovery block and eight adjoining blocks, which comprise the Mnazi Bay Contract Area. The development licence has an initial twenty-five year term, and may be extended under certain conditions.

Figure 1-2: Mnazi Bay Licence Area

In 2005 Artumas initiated a programme of field development and appraisal, activities. This consisted of:

- Reprocessing and reinterpretation of the original 2 D seismic data;
- MB-1 well was re-entered, and re-tested over the D & E sands;
- MB-2 was drilled, logged and tested over the C, D, F, G and I sands;
- MB-3 was drilled, logged and tested over the C, D, F and G sands;
- MS-1X was drilled, logged and tested over the Mnazi Bay F sands, and the Msimbati K1, K2 and K3 sands The acquisition and interpretation of an additional 453 km of marine and transition zone 2D seismic, which lead to the identification of numerous leads and prospects.

In concert with field appraisal activities, Artumas constructed field production facilities and a 27 km, 8” gas pipeline to Mtwara. The production facilities and pipeline are tied in to an associated 18 megawatt electric power generation facility located at Mtwara. The power facility generated first electricity on December 24, 2006, fuelled by gas production from Mnazi Bay. The eventual 30 megawatt facility is expected to use about 10 MMcf/d of gas production from the Mnazi Bay field. As of March 5, 2007, the commissioning of the Mnazi Bay gas processing facility and tie-in connection to the Mtwara area power generating facility was complete.

On July 26, 2010 Artumas Group Inc. completed a business combination with Wentworth Resources Limited (Cayman Islands), a company established to investigate the viability of a methanol and urea project for utilising greater volumes of the Mnazi Bay gas resources.

The Mnazi Bay gas resource properties were most recently evaluated by RPS in October 2011 (RPS Tanzania and Mozambique Resource Report). Since then, the Ziwani-1 well has been drilled by Wentworth and it's partners and proved to be wet in the lower Oligocene zone of interest. The field continues to produce gas at approximately 2 MMcf/d. However, six prospects have now been identified on the Mnazi Bay licence and prospective resources have been assigned to these prospects. The contingent resources from the October 2011 report have been included in this report.

The Prospective Resources for seven prospects in the Rovuma Onshore Block (Mozambique) are also discussed in this report. Wentworth owns 11.59% production working interest (13.64% exploration working interest) in the block and Anadarko Petroleum Inc, is the operator of the block.

The operator is planning to drill two prospects in 2014, the first of which will meet the Phase 2 license commitment requirement. Wentworth has indicated that it intends to participate in these wells. An optional Phase 3 commitment well needs to be drilled by 2015. The second of the two planned wells for 2014 will meet the Phase 3 commitment.

RPS has previously prepared a series of related resource assessment reports listed below:

- May 2005, APA Petroleum Engineering Inc. (now a part of RPS), together with its geological and geophysical associates Petrel Robertson Consulting Limited, prepared a resource assessment report, for the Mnazi Bay gas discovery[1]. The report was based on the MB-1 original discovery well log and test data, and early interpretation of the 2D seismic available at the time. In April 2007, RPS-APA issued an updated resource assessment, with an effective date of December 31, 2006, and included additional data from 233 kilometers of new 2D seismic and drilling wells, MB-2 and MB-3.
- September 2007, the Mnazi Bay April 2007 report was further updated (September 30, 2007 Resource Assessment) to include drilling, logging and testing of MS-1X, updated seismic interpretations and extended well tests on MB-2, MB-3 and MS-1X.
- July 2010, RPS produced an update of the previous Mnazi Bay resource evaluation, which included a review and audit of the Maurel et Prom seismic re-interpretation and re-evaluation of assessed resources.
- November 2010, RPS produced a revised resource assessment report for Mnazi Bay and Msimbati which was based on a new depositional model similar to Maurel and Prom and a seismic re-interpretation carried out by RPS and its geophysical associates Petrel Robertson Consulting Limited. The depositional model (deepwater canyon/slope setting), changes the sand correlations at Mnazi Bay and Msimbati from a simplistic sand to sand correlation to a more stratigraphically complex series of stacked channels. Consequently the C,D and E sands at Mnazi Bay are now called the Lower Sands; the F,G, H and I sands are called the Upper Sands; the K0 sand at Msimbati is referred to

as the Msimbati Lower K Sand and the K1, K2 and K3 sands are referred to as the Msimbati Upper K Sand.

- October 2011, RPS prepared an update of its November 2011 report, and added the Prospective Resources owned by Wentworth on the Rovuma Block, Mozambique as well as the a commentary on the Prospective Resources associated with the Rovuma Basin Offshore Area 1 Block, Mozambique, in which Wentworth held a net profits interest at the time.

This report contains an evaluation of Contingent and Prospective Resources on the aforementioned blocks. The report is divided into three parts:

- Contingent Resources for the Mnazi Bay and Msimbati fields using available 2D seismic and well data
- Prospective Resources for six prospects on the Mnazi Bay Licence resulting from interpretations of 2D seismic lines supplied by Wentworth
- Prospective Resources for seven prospects on the Rovuma Onshore Block resulting from interpretations of 2D seismic lines supplied by Wentworth

1.2 Scope

This evaluation covers the quantity of contingent gas resources and prospective gas resources that are likely to exist in the Tertiary and Cretaceous formations within the Mnazi Bay licence, Tanzania and the Rovuma Onshore Block, Mozambique.

1.3 Data Sources

RPS has based this resource assessment on publically available basin data, data supplied by Wentworth and work previously carried out by RPS, APA and PRCL.

Key data and reports which form the basis of RPS' estimates are as follows:

- Wentworth proprietary 2D seismic data
- Mnazi Bay and Msimbati field - well and production data (five wells).
- Onshore Mozambique – well information from two wells
- Previous RPS, APA and PRCL studies and resource reports
- Public data available from Anadarko Petroleum, ENH and Maurel et Prom and others

In addition, RPS has relied upon, and accepted without independent verification, land and concession term data and information supplied by Wentworth. RPS has conducted a site visit to Wentworth's Mnazi Bay, Tanzania property during 2008. No site visits to the licence areas in Mozambique have been conducted.

Other than references to recent press release information which are contained herein, RPS is not aware of any material change to the resources described herein, from the date that the resources were evaluated to the date of this report.

1.4 Resource Definitions

Resources detailed in this report have been assessed using the Resource definitions as published by the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers[2].

2.0 CONCESSION AREAS

2.1 Mnazi Bay Licence, Tanzania

The Mnazi Bay Concession Area is located in south-eastern Tanzania in the Ruvuma (Rovuma) Basin. The concession area is a 756 square kilometre block that holds Tertiary, Cretaceous and Jurassic hydrocarbon potential (Figure 2-1). The discovered Tertiary aged Mnazi Bay and Msimbati fields and extensions are defined by relatively sparse and variable quality 2D seismic data. Five wells have been drilled on the concession to date: MB-1, MB-2, MB-3 and MS-1X and Ziwani-1. Five Tertiary prospects and one Cretaceous prospect have been identified on the block, Figure 2-2.

2.2 Oil and Gas Occurrences in Coastal Tanzania and NE Mozambique

The coastal region of Tanzania and Mozambique have numerous hydrocarbon discoveries, significant shows and seeps. These are shown in Table 2-1 and Table 2-2 following.

		Hydrocarbon Discoveries		
Discovery		**Area**	**Reservoir**	**Resources**
Tanzania				
Songo Songo	Gas Field	Songo Songo Prod. Licence	Lower Cretaceous	GIIP = 1.433 Bscf (P50)
Kiliwani North - 1		Nyuni Area PSA, Kiliwani North Dev. Licence	Lower Cretaceous	Test 40 MMscf/d, GIIP 45 Bscf (Pmean)
Mkuranga-1	Gas discovery		Upper Cretaceous	< 20 Bscf
Mafia Deep 1	Gas shows	Mafia Exploration Licence	Upper & Lower Cretaceous	Gas column 600 m thick, Potentially large (> 1 Tscf), Not tested
Chewa - 1	Gas discovery	Block 4	Palaeocene	GIIP 826 Bscf
Chaza-1	Gas discovery	Block 1	Miocene	GIIP 123 Bscf (Pmean)
Pweza	Gas discovery	Block 4	Palaeocene	GIIP 2,278 Bscf (Pmean)
Jodari 1	Gas discovery	Block 1	Lower Tertiary & Micocene	Recoverable 4.1 Tscf (Pmean)
Mzia-1	Gas discovery	Block 1	Upper Cretaceous	Estimated GIIP 4 -9 Tscf
Mzia-2	Gas discovery	Block 1	Cretaceous	Test 57 MMscf/d
Ntorya-1	Gas + condensate discovery	Onshore Ruvuma PSA Mtwara Licence	Basal Tertiary / Upper Cretaceous	GIIP 178 Bscf
Zafarani-1	Gas discovery	Block 2		GIIP 6 Tscf
Lavani-1	Gas discovery	Block 2	Paleogene	GIIP 3 Tscf
Lavani-2	Gas discovery	Block 2	Paleogene & Cretaceous	volumes pending
Tangawizi	Gas discovery	Block 2	Tertiary	GIIP 4 -6 Tscf
Mnazi Bay/Msimbati	Gas Fields	Mnazi Bay Prod. Licence	Micocene/Oligocene	GIIP 940 Bscf (2P)
Mozambique				
Windjammer-1	Gas discovery	Area 1, Prosperidade Field	Palaeocene and Oligocene	GIIP 17-30 Tcf
Barquentine - 1	Gas discovery	Area 1, Prosperidade Field	Palaeocene and Oligocene	
Lagosta - 1	Gas discovery	Area 1, Prosperidade Field	Eocene and Oligocene	
Tubarao - 1	Gas discovery	Area 1, Prosperidade Field	Eocene	
Golfinho	Gas discovery	Area 1, Golfino/Atum Field	Oligocene	GIIP 15-35 Tcf
Atum	Gas discovery	Area 1, Golfino/Atum Field	Oligocene	
Orca-1	Gas discovery	Area 1	Paleocene	

Table 2-1: Hydrocarbon Discoveries, Coastal Tanzania and NE Mozambique

HYDROCARBON SHOWS AND SEEPS		
	Well or Seep Name	**Comment**
Tanzania	Makarawe-1	Tarry bitumens
	Tundaua	Oil seep
	Pemba-5	Oil shows
	Kiwangwa-1	Tarry bitumens
	Kimbiji East-1	Gas shows
	Zanzibar-1	Gas shows
	Tan Can-1	Gas shows
	Okuza Island	Oil shows
	Nyuni Island & well	Oil & gas shows
	Kisangire-1	Oil shows
	Wingayongo	Oil seep
	Wingayongo-1 & -2	30m & 40m of tar sand
	Mandawa Basin wells	Oil shows
	Ruhoi River (5km from Wingayongo)	Oil seep
	Mnazi Bay-1	Oil shows
Mozambique	Mocimboa-1	Oil shows
	Mecupa-1ST1	Gas Shows
	Ironclad-1 (offshore)	Oil shows
	Msimbati Island	Oil Seeps
	Pemba, Ponte Uifondo	Oil Seeps

Table 2-2: Shows and Seeps, Coastal Tanzania and NE Mozambique

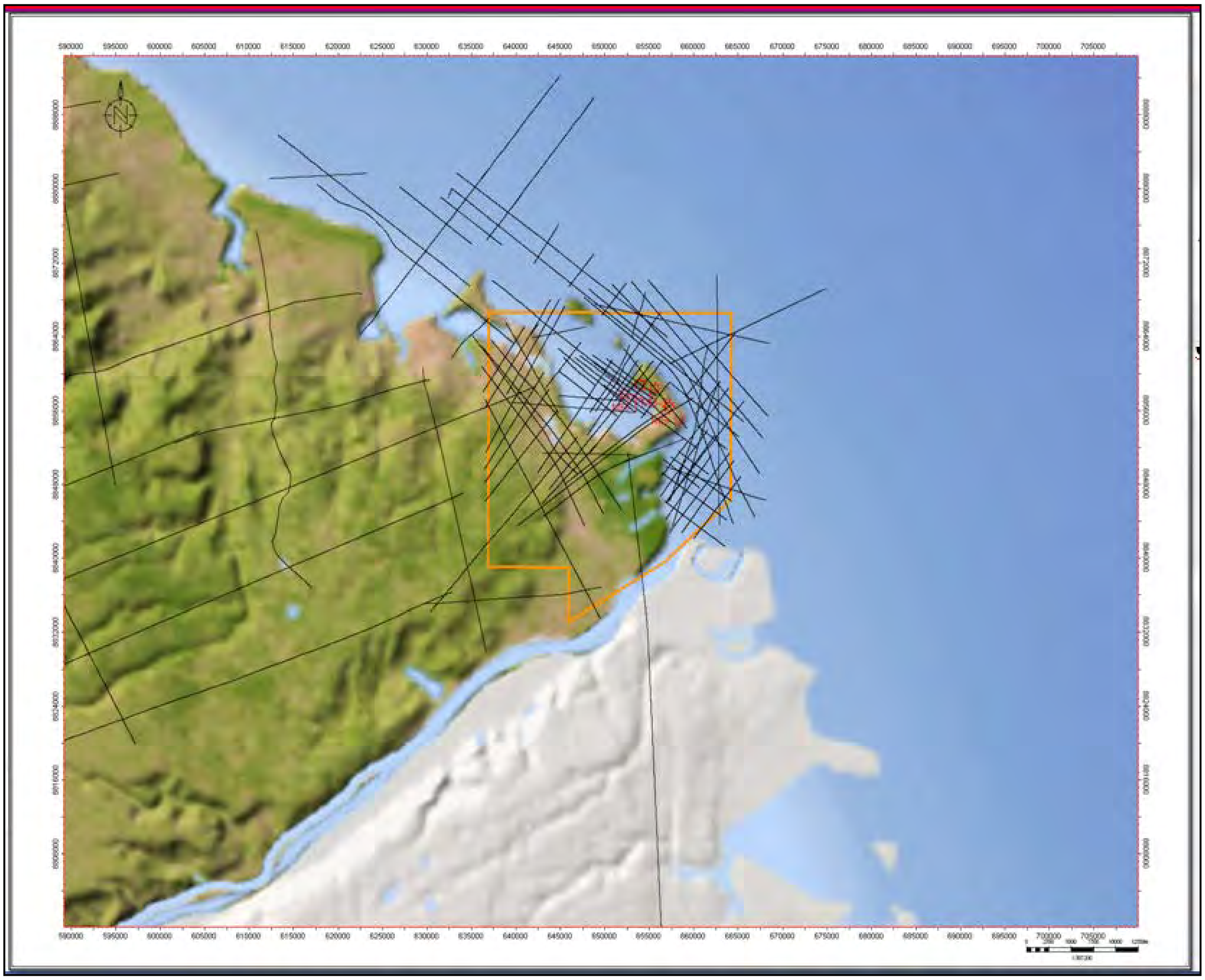

Figure 2-1: Mnazi Bay Concession, Tanzania

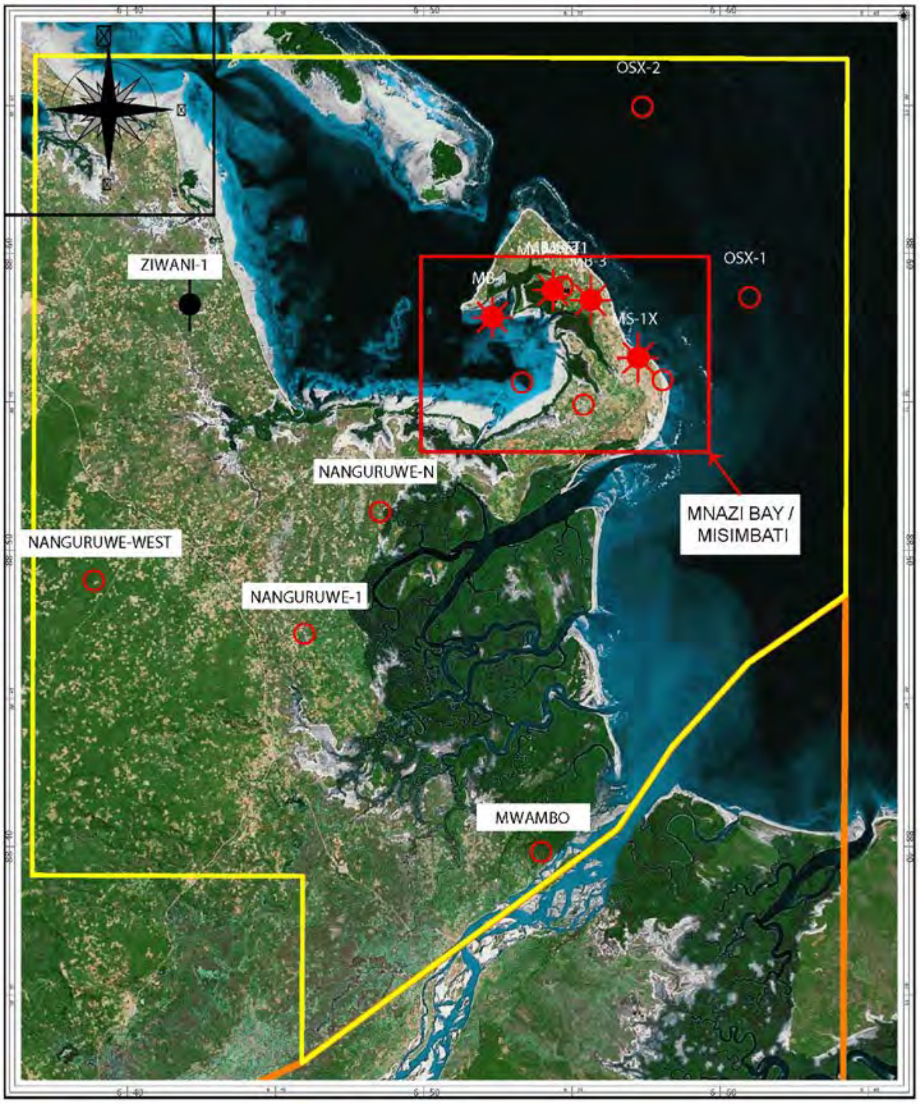

Figure 2-2: Mnazi Bay showing Mnazi Bay/Msimbati Fields and six new prospects

2.2.1 Wentworth Interests and Burdens

Wentworth owns a 31.94% working interest in petroleum operations other than exploration on the Mnazi Bay Licence block together with operator Maurel and Prom 48.06% and TPDC 20%.

Wentworth also owns a 39.925% working interest in exploration operations on the block, together with Maurel et Prom's 60.075% working interest. Wentworth's interest is subject to a provision of a back-in right, held by TPDC whereby, upon an oil or gas discovery, TPDC may back-in with a 20% interest. If TPDC should exercise this right, Wentworth's interest in the discovery would decrease to a 31.94% interest. Wentworth's working interests represent the interest in field gross recoverable volumes, not net entitlements after application of royalty or equivalent deductions.

In addition, Wentworth retains full ownership of a $35.2 million (as of June 30, 2013) receivable from TPDC, resulting from TPDC's election to participate in the Mnazi Bay and Msimbati gas field discoveries in 2006, representing TPDC share of past costs. Wentworth also retains an option to transfer a further 5% working interest per well in exchange for other party's payment for up to two appraisal wells on the block.

Production operations on the development licence area are governed by the Production Sharing Agreement, executed in 2004. This agreement is a cost recovery form of agreement and contains detailed cost recovery and profit sharing arrangements and production royalty payment obligations.

2.2.2 Mnazi Bay Licence Block Exploration History

The Mnazi Bay gas field was discovered in 1982 by AGIP. The first well Mnazi Bay #1 ("MB-1") tested gas from the Miocene formation at rates of 13 mmcf/d. After testing, the well was suspended by AGIP, due to lack of gas markets at the time. The concession was subsequently relinquished by AGIP. The licence was acquired by Artumas (now Wentworth) in 2004. In 2005, following reprocessing and acquisition of additional 2D seismic data, the MB-1 well was re-entered and three gas discovery wells were drilled, MB-2, MB-3 and MS-1X. Two additional seismic programs were shot in 2007 and 2008 by Artumas (now Wentworth). This has allowed the Mnazi Bay interpretation model to be refined and extended through the whole concession area. Numerous exploration leads and five Tertiary prospects have been identified across the licence.

A full description of the historical background of the block is outlined in section 1.1 of this report

2.3 Rovuma Onshore Block, Mozambique

The Rovuma Onshore Area Block is situated in north-eastern Mozambique and is adjacent to the Mnazi Bay concession, the depositional environment is part of the same deltaic complex identified at Mnazi Bay (Note: Rovuma Basin in Mozambique is spelled as "Ruvuma" in Tanzania, and in this report RPS has used the spelling as appropriate in context). The Rovuma Onshore Block is a 13,500 square kilometre concession which abuts the Area 1 Offshore Block. In 2007/2008, 640 km of 2D seismic was acquired in the north-east portion of the Onshore Block, referred to as the North Palma Area, bringing the total amount of seismic on the block to 1834 km of data (41 lines) .In 2012, another 1068 kms (31 lines) of 2D seismic data was acquired by Anadarko and it's partners to further delineate prospects in this area. (Figure 2-3 and Figure 2-4).

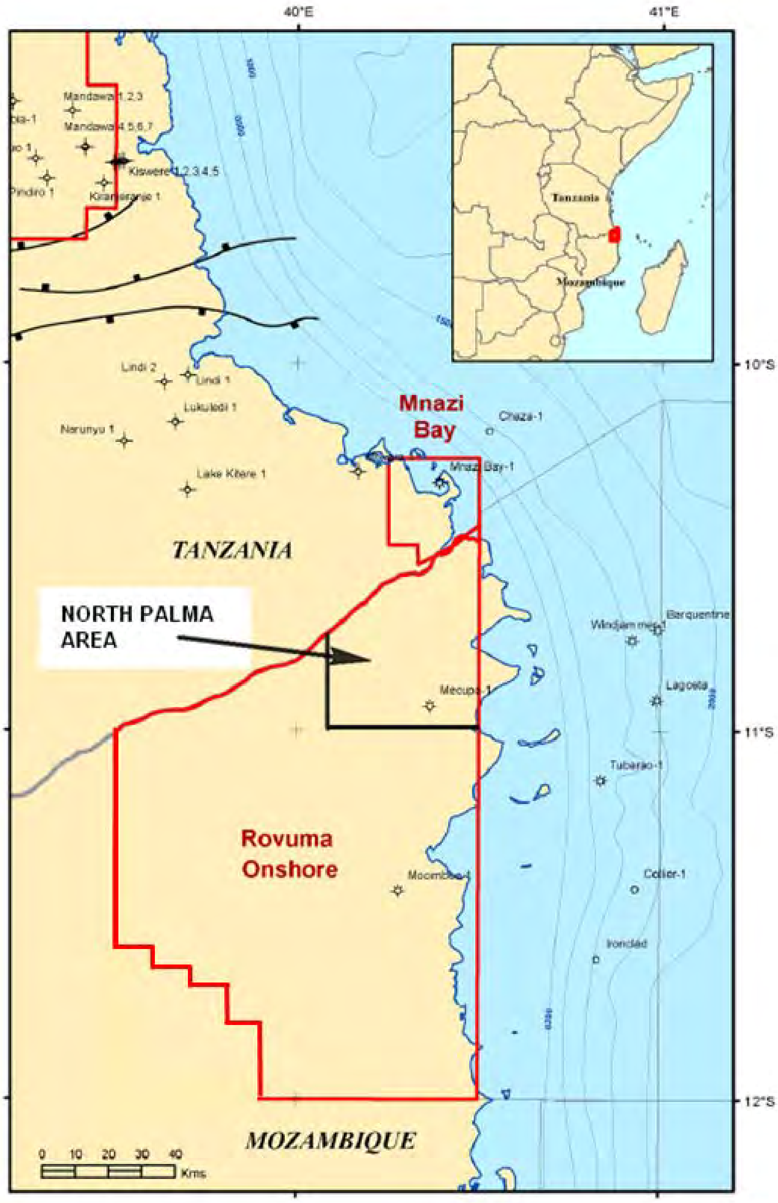

Figure 2-3: Rovuma Onshore Block, Mozambique

Source: Wentworth

2.3.1 Wentworth Interests and Burdens

Wentworth currently owns 11.59% working interest (13.64% paying interest) in the Rovuma Onshore Block, together with partners Anadarko (operator, 35.70%), Maurel et Prom (27.71%), ENH (15%) and PTT Exploration and Production Public Company Limited ("PTTEP") (10%). The contract terms on the Block contain obligations for further exploration activity commitments, with a second phase consisting of shooting 100 km^2 of 3D seismic, subsequently converted to 400 km of 2D seismic, and the drilling of one exploration well. The partners have entered into the second phase of exploration activities which will fulfill these commitments, and will retain the rights to the exploration block until September 2014. Wentworth has indicated that the acquisition of 1016 km of 2D seismic in 2012 fulfilled the seismic requirement of the second licensing phase. A third commitment phase consisting of the drilling of an additional well is required by 2015.

Wentworth's working interests represent the interest in field gross recoverable volumes, not net entitlements after application of royalty or equivalent deductions.

2.3.2 Block Exploration History

The first prospect identified on the block using the new data, the Mecupa-1 well, was drilled in Q4 2009 and encountered excellent Tertiary reservoir sands and indications of gas. Anadarko indicates it has identified seven prospects in the north-eastern and central portion of the block.

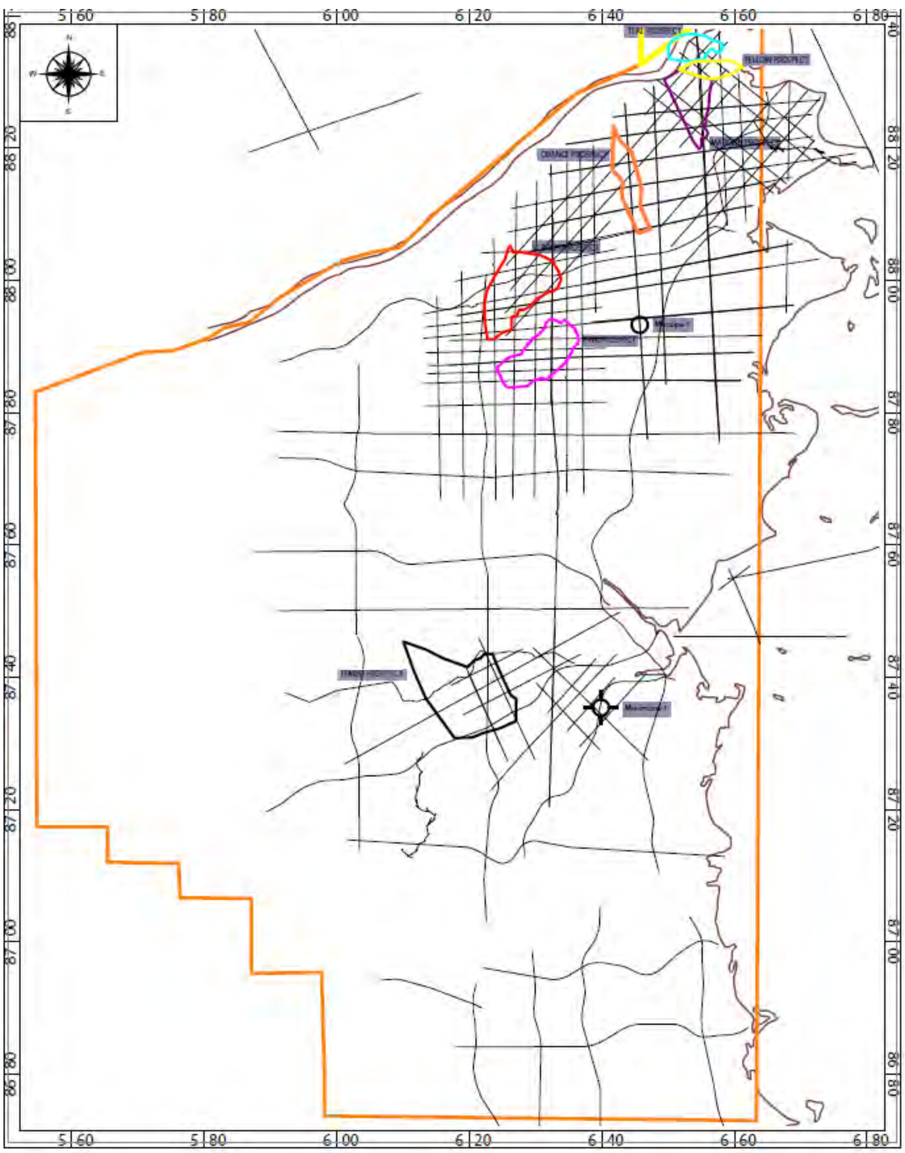

Figure 2-4: Prospects North Palma and Central Area, Onshore Block, Mozambique

3.0 REGIONAL GEOLOGY AND PETROLEUM SYSTEM

3.1 Regional Geological Setting

The Mnazi Bay Licence area in Tanzania and the Rovuma Onshore Block in Mozambique are located in the northern part of the Ruvuma ("Rovuma" in Mozambique) Basin which straddles the border between Tanzania and Mozambique. It is one of numerous basins along the east coast of Africa, formed when the paleo-continent of Gondwana rifted apart during the Permian, Triassic and early Jurassic. Locally, the rifting associated with the formation of the Ruvuma Basin led to the separation of the island of Madagascar from the main body of Africa.

Figure 3-1: Location Map Ruvuma Basin

The basin contains Triassic and lower Jurassic syn-rift sediments overlain by thick drift sequences. The depositional environment is dominantly clastic with the exception of some mid-Jurassic carbonates. Early Jurassic restricted marine deposits and continental sediments along the basin margins are overlain by a transgressive-regressive sequence estimated to be as much as 7-8 km thick at the coast. In response to the early uplift and doming that preceded rifting of the modern-day East African Rift System, the Ruvuma River delta and submarine channel system began to form during the Oligocene. The passive margin sequence was succeeded by a massive influx of eastward prograding clastic sediments from Mid-Tertiary to Recent. The position of the Ruvuma Delta depocenter was constrained by fault block rotation and basin subsidence during the Tertiary, with the early centre located towards the northern part of the Rovuma Basin. These sediments have been subjected to intensive gravity driven deformation, shale diaparism and slumping. The Ruvuma Delta complex comprises of a thick, eastwardly prograding wedge of rapidly deposited clastic sediments which extends eastward into canyon/channel sediments, forming a complex network of stacked channel sandstones. Resources are contained in this Tertiary interval, primarily in the Miocene and Oligocene.

The stratigraphy in the area is shown on the following chart:

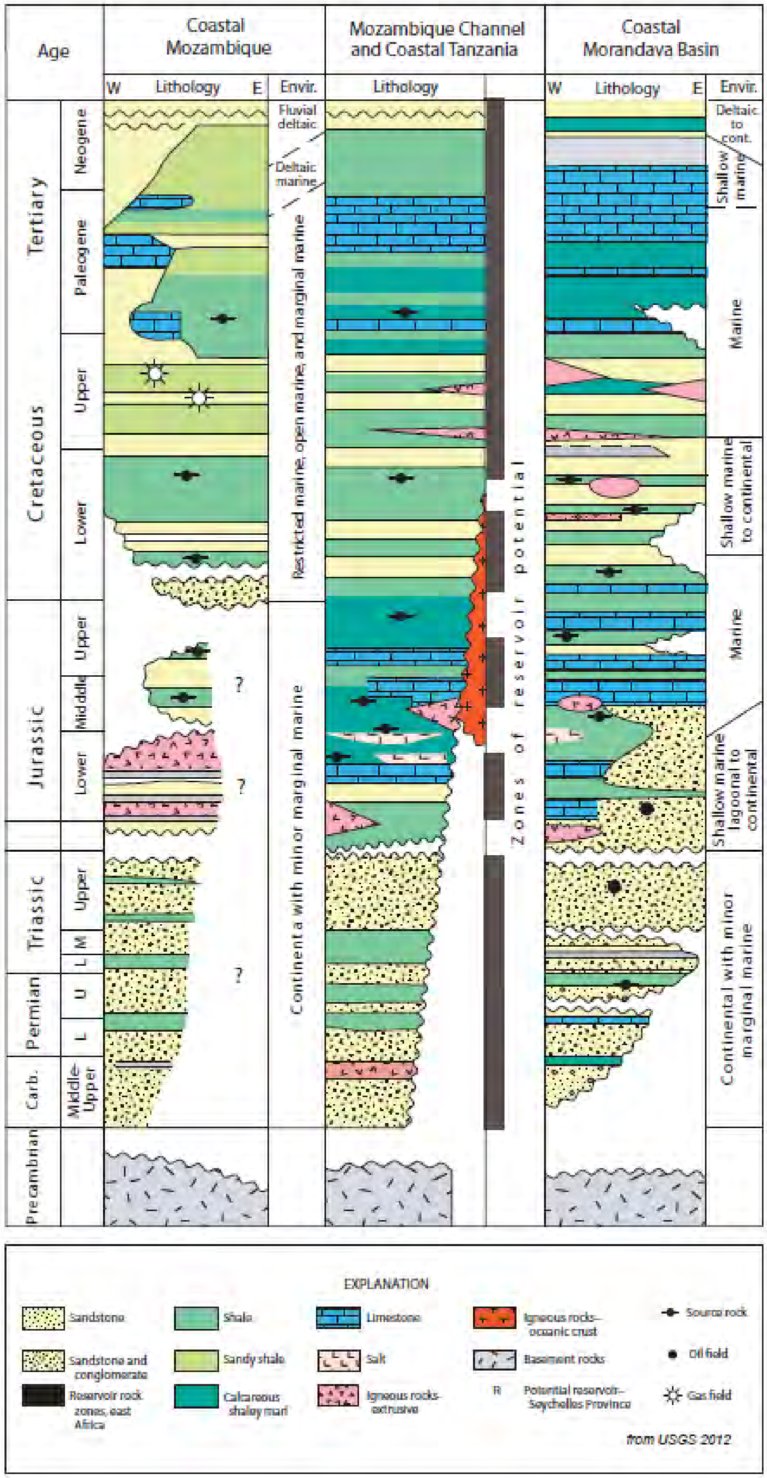

Figure 3-2: Stratigraphic Chart [3]

3.2 Tertiary Depositional Environments

The Tertiary sequence in the Mnazi Bay area is situated within the canyon slope setting (Figure 3-3); these turbidite canyon-fill deposits contain sandstones which provide good reservoirs and shales which provide stratigraphic traps. Onshore Mozambique Tertiary deposits are fluvial deltaic deposits and marine shelf deposits (Figure 3-4), which make excellent reservoirs. In Offshore Area 1, Tertiary sediments consist of channel and deepwater fan deposits, which contain excellent quality reservoir sands; hydrocarbons are trapped on toe thrust structures. (Figure 3-3 and Figure 3-4).

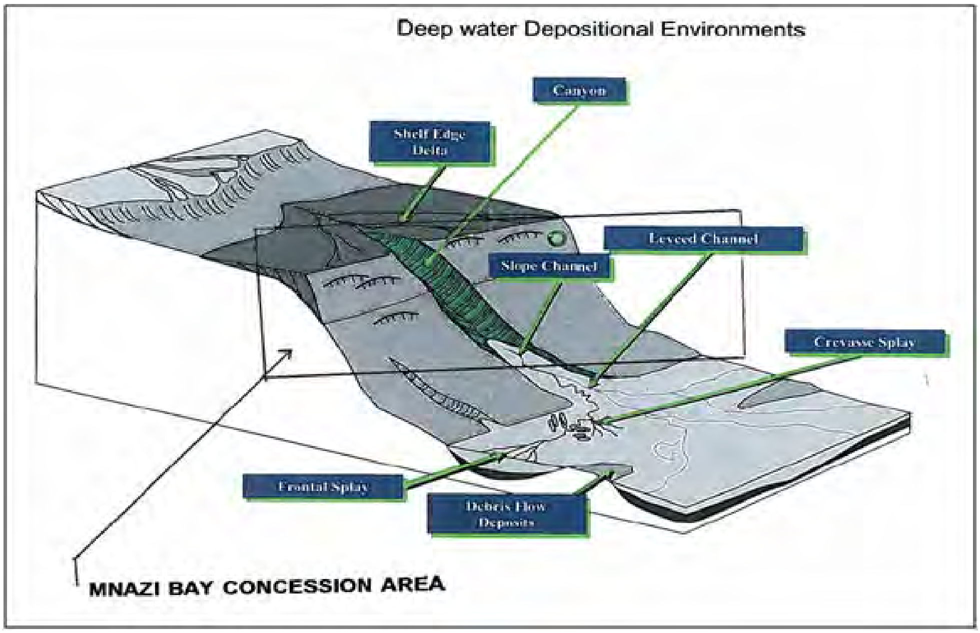

Figure 3-3: Tanzania Tertiary Deposition - Canyon Slope Setting

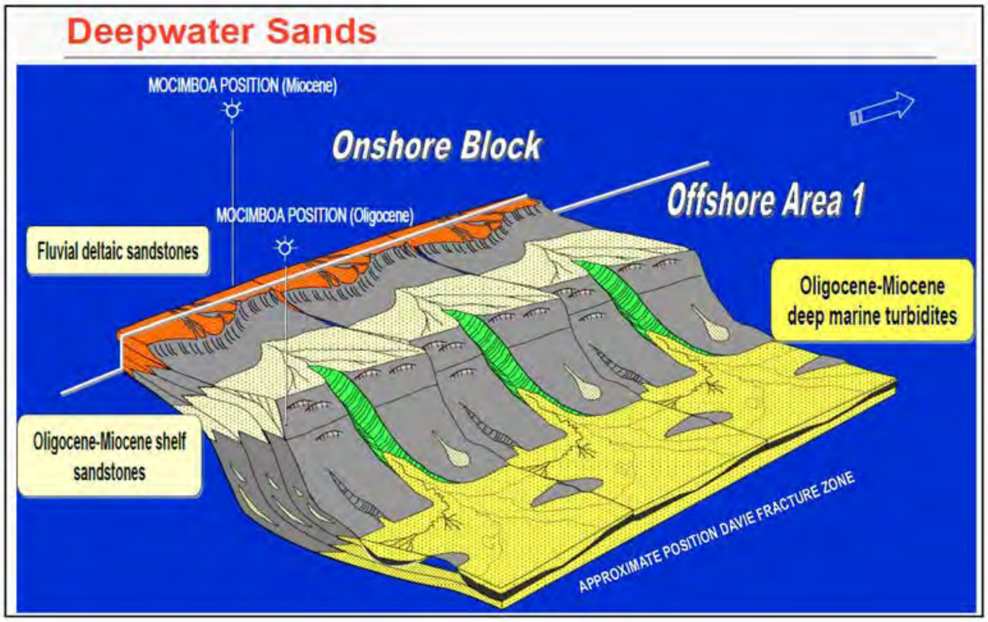

Figure 3-4: Mozambique Tertiary Deposition. Onshore Block: Fluvial-Deltaic and Marine Shelf Sandstone.

Offshore Area 1: Deep Marine Turbidites and Fans

Source: Cove Investor Presentation (May 2011)

Figure 3-5 below shows the correlation between three wells on-shore Tanzania and on-shore Mozambique demonstrating the Upper and Lower Tertiary depositional cycles across the Ruvuma (Rovuma) Basin.

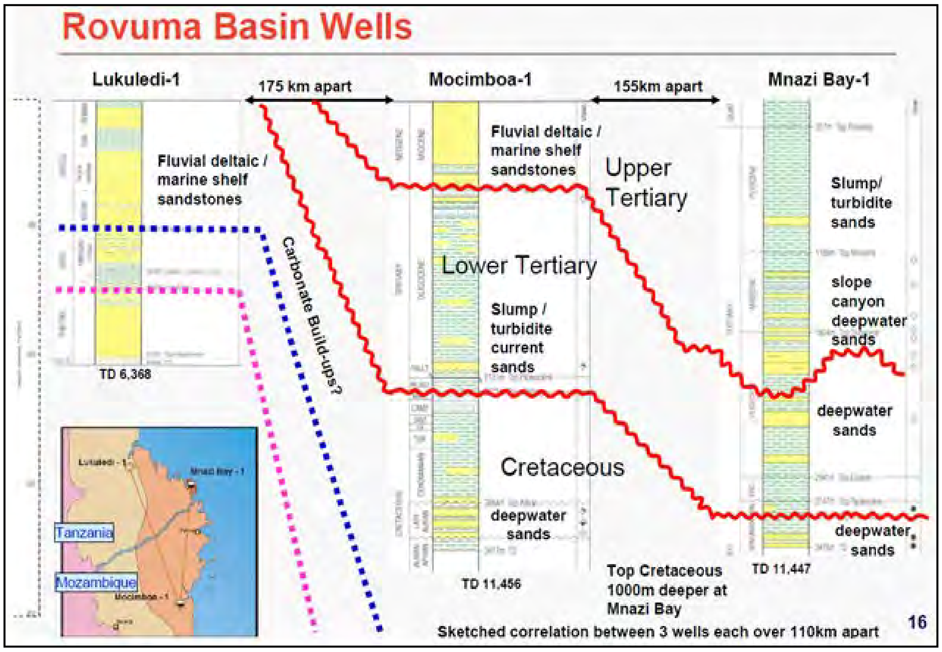

Figure 3-5: Cross Section across On-Shore Tanzania and Mozambique Showing Upper and Lower Tertiary Environments and Reservoir/Seal Pairs

Source: Cove Investor Presentation (May 2011)

3.3 Tertiary Stratigraphy

The new prospects on the Mnazi Bay licence and the Mnazi Bay and Msimbati fields lie at the northern end of the Ruvuma Basin. The Ruvuma basin contains a shallow deltaic through deep slope and deep water fan succession. Reliable correlations within such successions are difficult, as channelized, laterally-discontinuous reservoir sandstones, deposited in shallow deltaic through to deep slope settings, generally lack unique, correlatable characteristics. The Pliocene, Miocene, Oligocene and Eocene deposits on the Mnazi Bay licence are all thought to be deposited as deep-water continental slope deposits consisting of channels within submarine canyons and turbidite current sediments. The submarine canyons are filled with channel sands and slump deposits (shales).

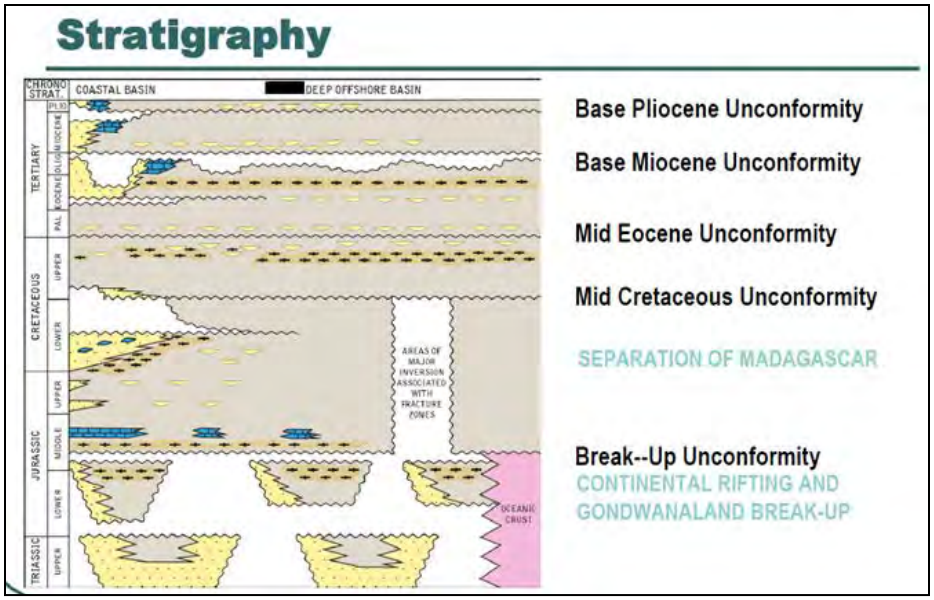

Figure 3-6: Evolution of the Ruvuma Basin with Stratigraphic Units

Source: Artumas Internal Presentation

3.4 Cretaceous Stratigraphy

An Early Cretaceous regression resulted in Lower Cretaceous deposition dominated by continental clastics on the western flank of the basin in the Maconde Formation passing laterally to shallow marine deposits to the east. The Maconde Formation consists of fluvial conglomerates and feldspathic quartz sandstones with associated fine grained interbedded clastic facies.

These terrestrial deposits pass into Aptian-Albian aged shallow marine fluvio-deltaic clastics, intraslope channels and basin floor submarine fan complexes. Based on modern analogues the stratigraphic architecture in different portions of the submarine fan complex is expected to vary based on position on the slope. In an upslope position the primary facies include mass-transport deposits and sand or mud-filled channels. The mid slope setting is characterized by sand-filled channels and levees passing laterally into fine grained marine mudstones. On the basin floor the facies include sandstone lobes as well as very fine grained interbedded sandstones and siltstones. The most distal and lateral fan positions include thin sandy channels, tabular sandstone beds and laminated mudstone. This distal setting is anticipated to have the lowest net:gross sand ratios.

The Upper Cretaceous is characterized by marine fine grained clastics, micaceous and pyritic shales, fossiliferous lime mudstone and dolomite deposited in a range of restricted and open marine settings. The formational nomenclature given to this post-Albian marine succession is the upper Domo Shales and overlying Grudja Formation in the Mozambique coast and channel area but it is unclear whether this terminology extends into the Ruvuma Basin.

3.5 Ruvuma Basin - Source Rocks, Maturity and Migration Paths

Only a small number of wells have been drilled in the Ruvuma Basin to date, consequently the main potential source rock sequences have yet to be intersected in the subsurface. Data from recent discoveries on the Offshore Area 1 Block are not available. Analogues from other East African margin basins have been used to describe the source rock potential of the Ruvuma Basin. Known source rocks, along the East African margin, range from Permo-Triassic through

Jurassic to possibly Cenozoic age. The source for the Mnazi Bay and Msimbati gas discoveries is thought to be the regionally extensive mature Jurassic source rocks.

Results of 1D basin modeling from across the Ruvuma Basin indicate that peak oil generation for mid-Jurassic source rocks was during early-mid Cretaceous times, while remaining potential source rocks in the Late Jurassic, Cretaceous and younger sections, which saw major hydrocarbon generation and expulsion during the Eocene, Oligocene, and Recent epochs. The latter is triggered by the initiation of the Late-Tertiary to Recent East African Rift Valley system which resulted in subsidence and a major heating phase pulse throughout the Ruvuma Basin.

3.6 Structure

Two episodes of deformation dominate the structural history of the Ruvuma Basin. During rifting, a NNE-SSW trending system of horsts and grabens developed, affecting pre-Upper Jurassic strata. These strata dip regionally eastward due to loading of the passive margin. Gravitational collapse of passive margin sediments has resulted in the development of a linked shelf-extensional and basinward toe-thrust system. Listric normal faults cut Tertiary strata and sole in a decollement near the top of the Cretaceous. The associated toe-thrust system is located offshore to the east of the Mnazi Bay licence in Tanzania and on the offshore Rovuma block in Mozambique.

Figure 3-7 shows the linked extensional system of roll over anticlines associated with normal listric growth faults, as found in Mnazi Bay and onshore Mozambique, and basinward toe thrust systems which create structural traps for the Tertiary plays in offshore Mozambique.

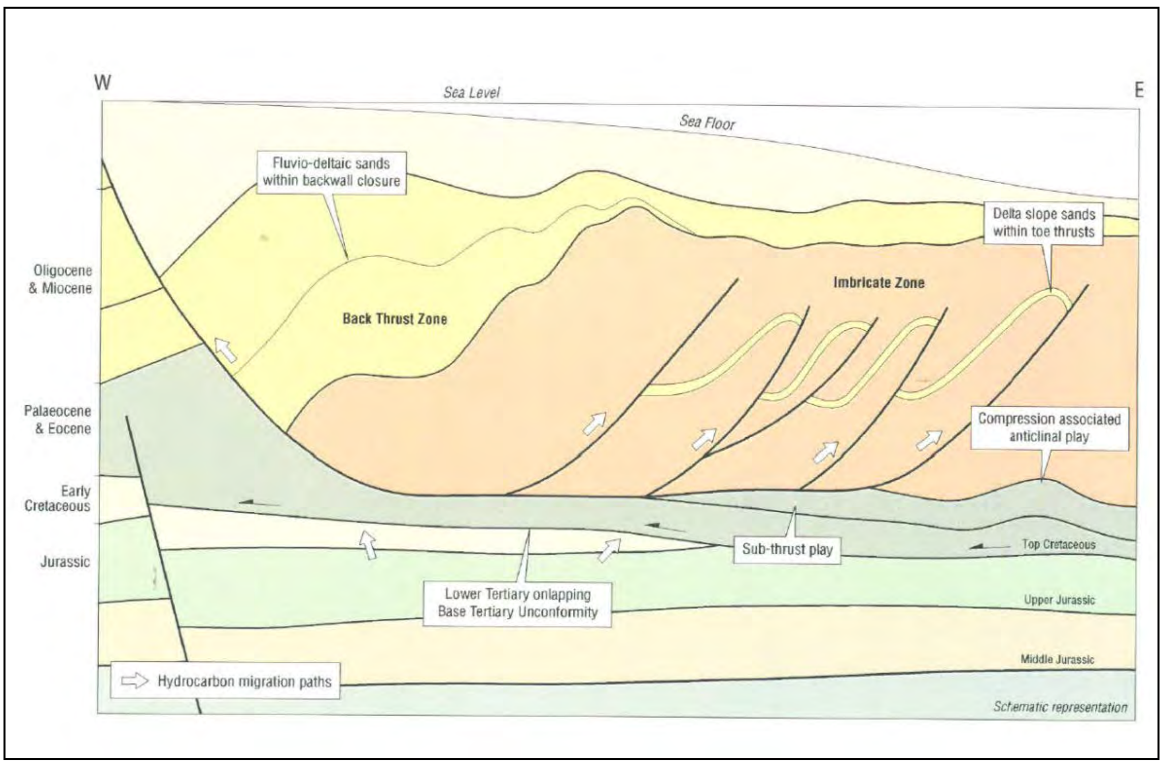

Figure 3-7: Cross Section Showing the Linked Extensional and Basinward Toe Thrust System

Source: Artumas Internal Presentation

Figure 3-8 shows a seimic section from West to East through the Ruvuma (Rovuma) Basin, Tanzania which demonstrates the extensional to toe thrust system.

This figure has been removed due to confidentiality reasons.

Figure 3-8: Near-shore to Deep-water Structural Deformation Style, Ruvuma (Rovuma) Basin Mozambique

Source: Artumas Internal Presentation

4.0 MNAZI BAY & MSIMBATI FIELDS – CONTINGENT RESOURCES

RPS Energy conducted a Contingent Resource assessment report on the Mnazi Bay and Msimbati discoveries on the Mnazi Bay licence in November 2010 (RPS Mnazi Bay and Msimbati Resource Report). The report was based on a new depositional model similar to Maurel et Prom and a seismic re-interpretation carried out by RPS and its geophysical associates Petrel Robertson Consulting Limited. The depositional model (deepwater canyon/slope setting), changes the sand correlations at Mnazi Bay and Msimbati from a simplistic sand to sand correlation to a more stratigraphically complex series of stacked channels. No new activity has been carried out on these fields since the November 2010 report and, based on information from Wentworth, the field continues to produce gas at approximately 1.7 MMcf/d. The Contingent Resource assessment of these fields remains unchanged from the November report due to the very low production rates and no new field data.

4.1 Reservoir Geology

4.1.1 Stratigraphy

Mnazi Bay and Msimbati reservoirs lie at the northern end of the Ruvuma Basin. The Ruvuma basin contains a shallow deltaic through deep slope succession. Reliable correlations within such successions are difficult, as channelized, laterally-discontinuous reservoir sandstones, deposited in shallow deltaic through to deep slope settings, generally lack unique, correlatable characteristics.

Within the reservoir section, several correlation schemes can be envisioned between the MB-1, MB-2, MB-3, and MS-1X wells. The nature of the seismic anomalies at Mnazi Bay, indicate a deep water channel/canyon setting rather than a near shore deltaic environment. The reservoir sands are interpreted to have been deposited on the deepwater continental slope, as offset stacked channel deposits and have been identified as occurring within four Miocene aged channel sequences, the Lower Sand and Upper Sand for the Mnazi Bay reservoir section and the Lower K Sand and Upper K Sand for Msimbati Field (Figure 4-1 and Figure 4-2). The sand units were correlated using seismic and well logs and used channel scour, gas-water contacts and thickness and flooding surfaces to identify the channel sequences.

Four wells at Mnazi Bay, MB-1, MB-2, MB-3 and MS-1X contain gas in the Miocene.

A composite of the logs from the four wells at Mnazi Bay is shown in Figure 4-1 and Figure 4-2.

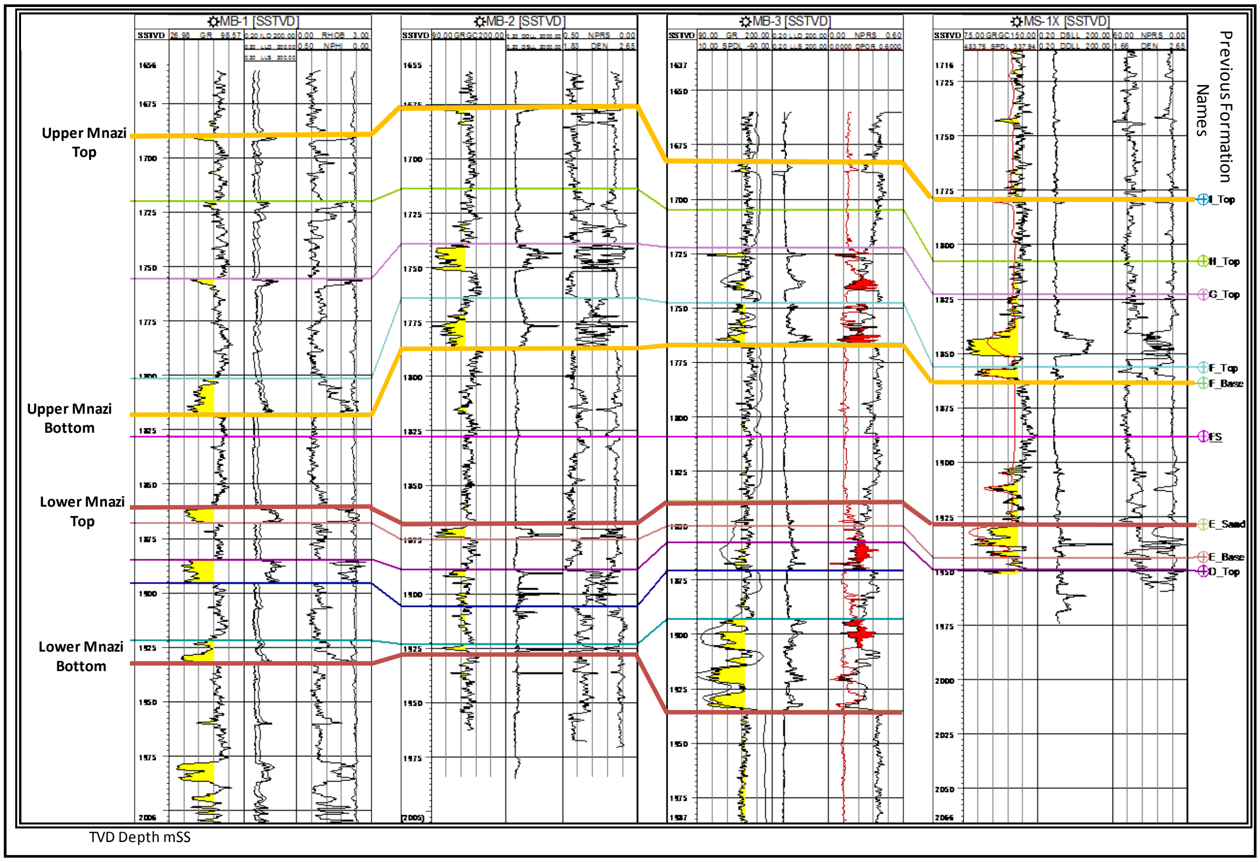

Figure 4-1: Mnazi Bay Stratigraphic Section

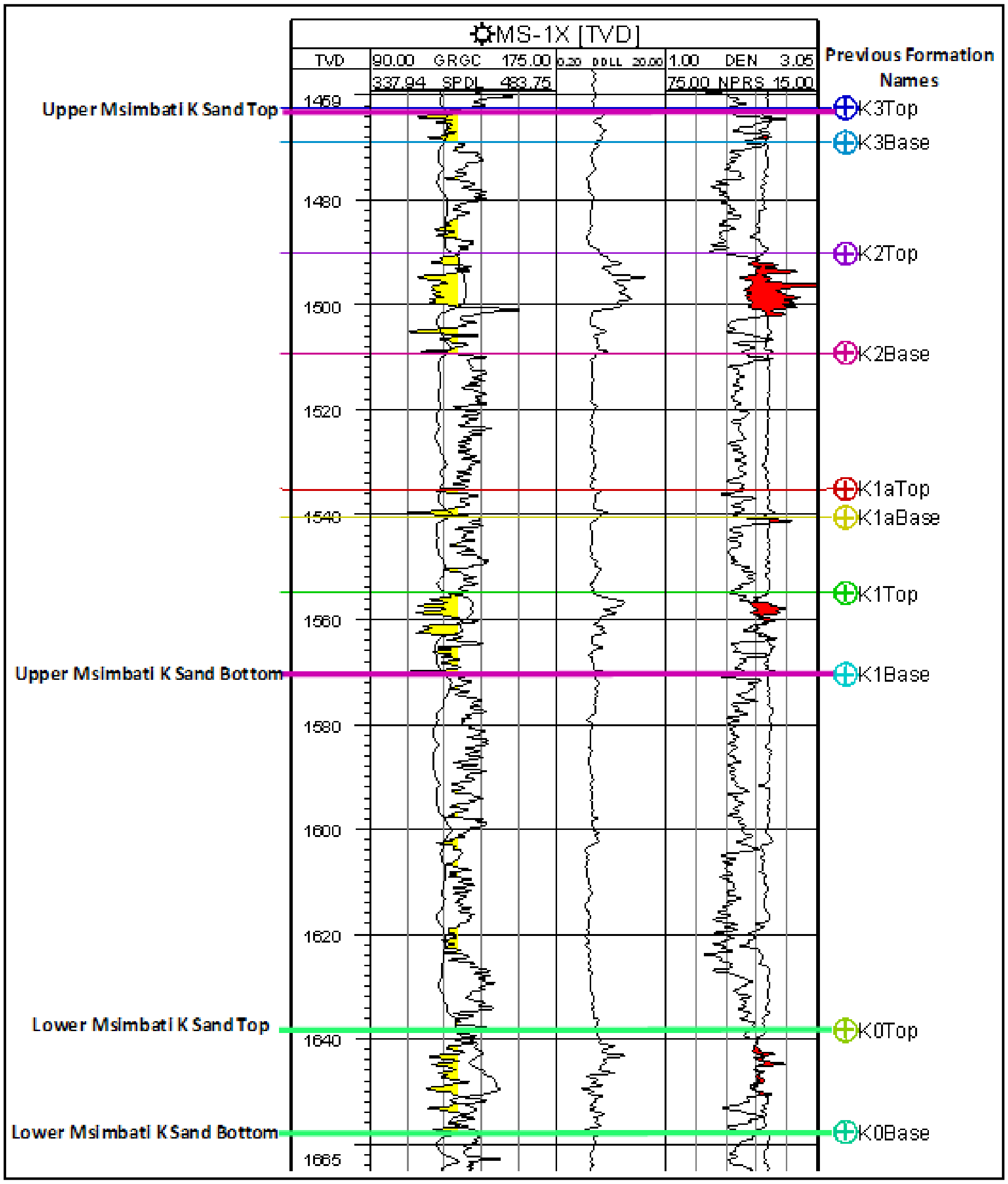

Figure 4-2: Msimbati Field MS-1X K Sands – Stratigraphic Section

4.1.2 Structural Geology

The Mnazi Bay structure lies along the crest of a major roll over anticline associated with an extensional normal listric growth fault. The channel complex cuts into the anticline and is parallel to the fault trend.

A pre-Tertiary unconformity high, as shown in Figure 4-3, at Mnazi Bay/Msimbati may have influenced preferential fairways for the intense channelized slope system during the Oligocene and Miocene.

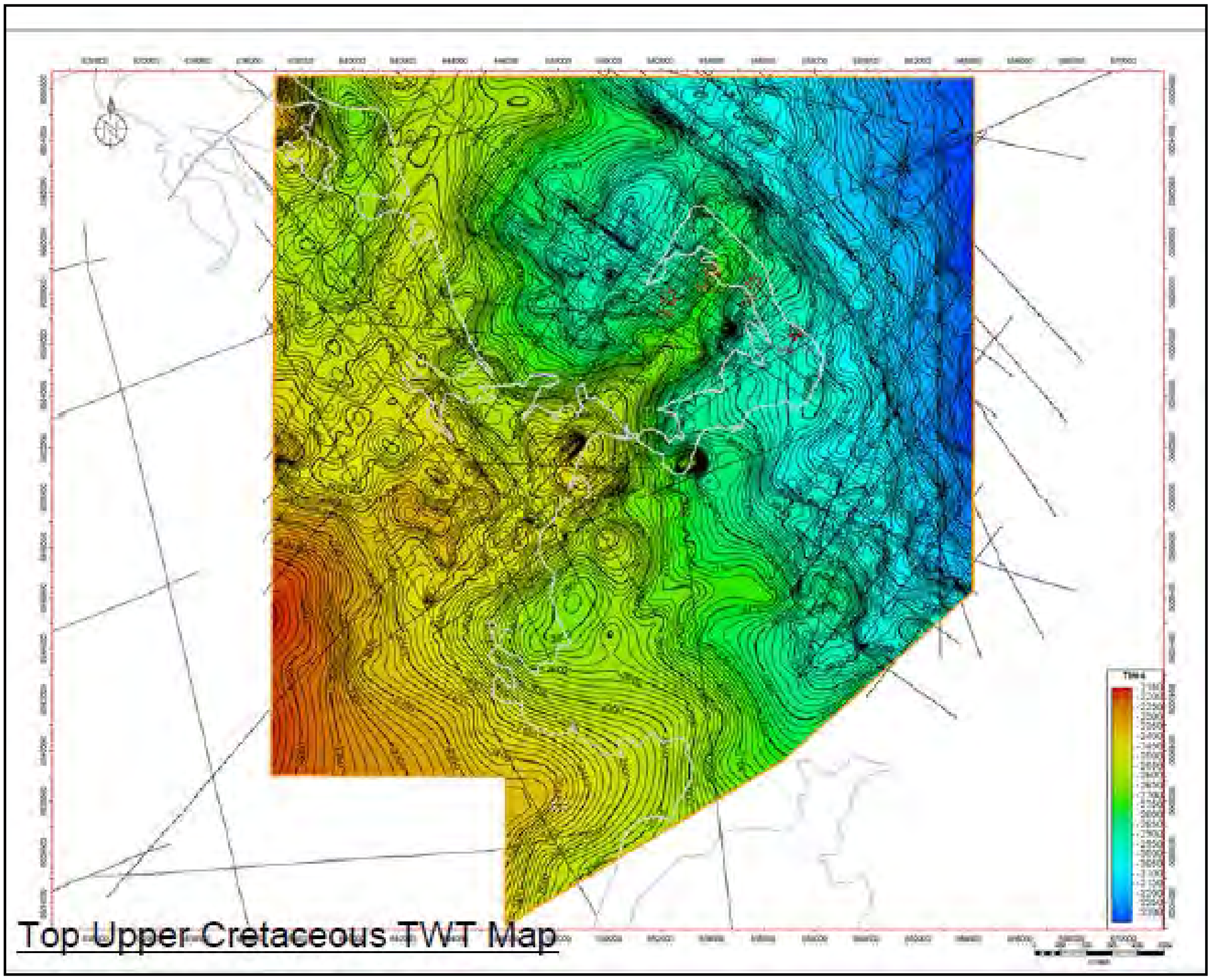

Figure 4-3: Pre-Tertiary Unconformity Surface (Top Upper Cretaceous)

4.1.3 Seismic Interpretation

Mnazi Bay Field

Four horizons have been picked within the Mnazi Bay channel structure, the top of the Upper Sand, base of the Upper Sand, top of the Lower Sand and base of the Lower Sand. In addition, the base of the channel was interpreted from the data set. The lower sand package contains sands which have previously been described as the C, D and E sands, while the upper sand package contains sands previously described as the F, G, H and I sands, all of Mio-Oligocene age. There is a shale interval between the two sand packages.

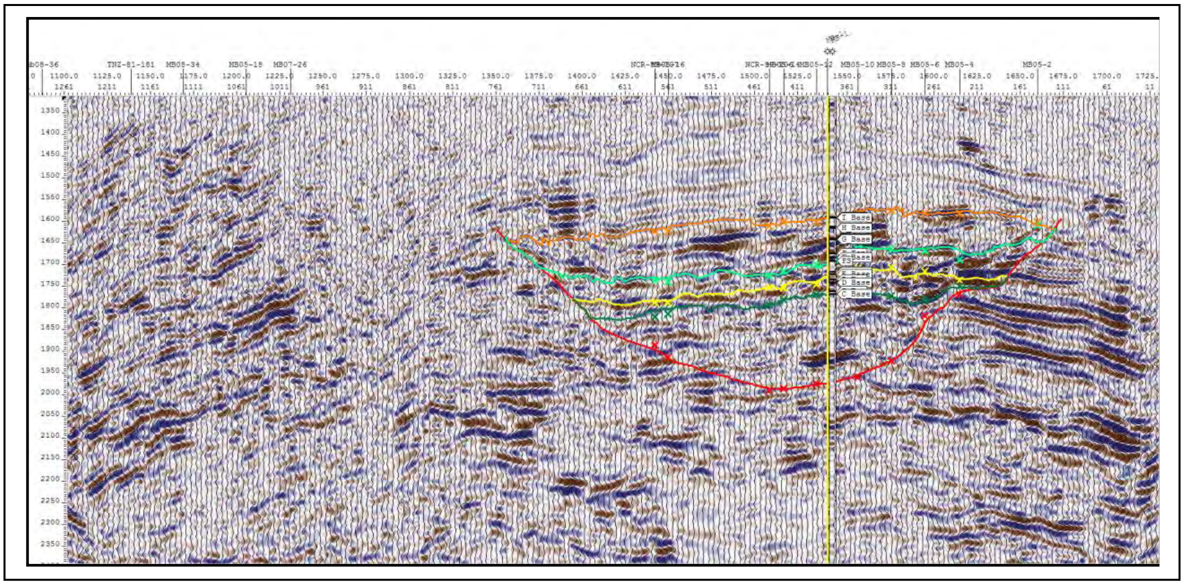

Figure 4-4: Line MB05-9 Showing the Mnazi Bay Channel

Figure 4-4 shows the Mnazi Bay channel feature in red, the upper sand package top in orange, the upper sand package base in light green. The lower sand package top is in yellow, and the lower sand package base is in dark green.

Msimbati Field

Three horizons were picked in the Msimbati channel structure and the base of the channel was interpreted. The horizons picked defined the bounds of an Upper K sand package containing the K3, K2, K1 and K1A sands. The deepest horizon picked defined the top for the lower K0 sand package. The base for the lower K0 sand package occurs within 1 wavelength in the 2D seismic dataset. Therefore only a top was picked to define the lateral extents of the K0 sand and a constant thickness defined by the well data was assumed.

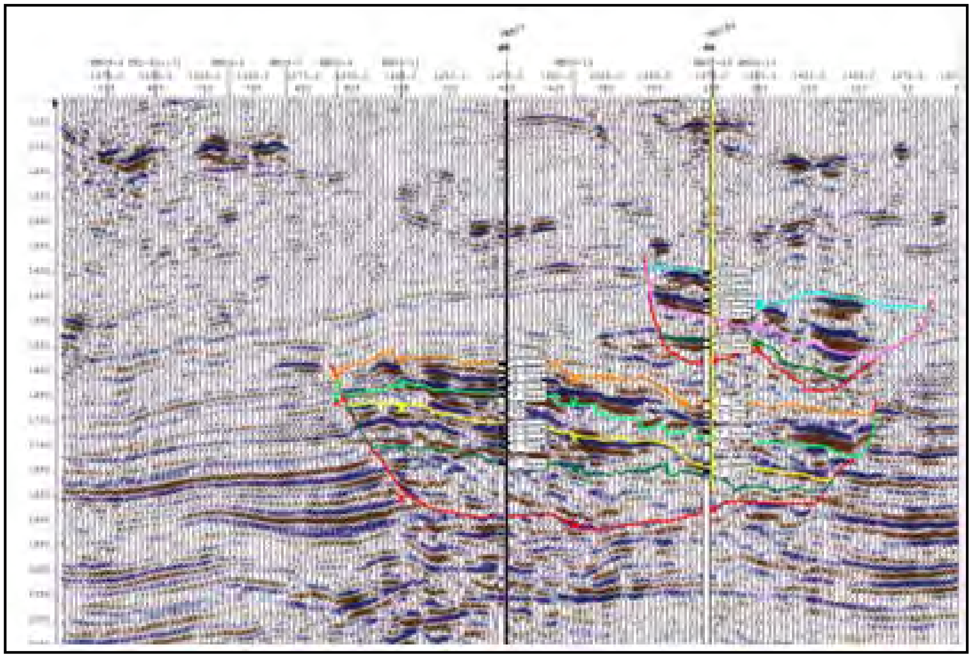

Figure 4-5: Line MB05-2 Showing the Msimbati Channel

Figure 4-5 shows the Msimbati channel feature on the top right of the seismic line. The Upper K sand package top is in light blue, the Upper K sand base in pink and the Lower K sand top in dark green. Base of the channel is in red. The Mnazi Bay channel feature is also shown in this figure and is the deeper of the two channel features.

Msimbati N.E. and N.E. Extension Channel Features

A third channel slope feature, referred to as Msimbati N.E., is present at Mnazi Bay/Msimbati. The channel is interpreted to be connected to the Mnazi Bay channel complex. Msimbati N.E. is a separate channel to the Mnazi Bay and Msimbati channels, deposited in a similar slope setting. It is expected to contain similar sand properties to the other channels and is potentially connected laterally and/or vertically to the Mnazi Bay and Msimbati channels. Figure 4-6, below, illustrates the position of the Msimbati N.E. channel feature and shows how it is juxtapose to the other two channels. As there is no well data for this sand body, only 1 horizon was picked for the top of the channel feature and another horizon for the base.

A fourth channel slope feature, identified as the Msimbati N.E. Extension was likewise mapped, this feature may or may not be connected to Msimbati N.E proper. The imaging of this feature in the transition zone is not as good as the other channel features. The majority of the channel lies down-dip from Msimbati N.E.

Averaged values from the other channel features were used to calculate net pay, porosity, and water saturation values for both the Msimbati N.E. and Msimbati N.E. Extension. See the Petrophysical parameters in this report for further information.

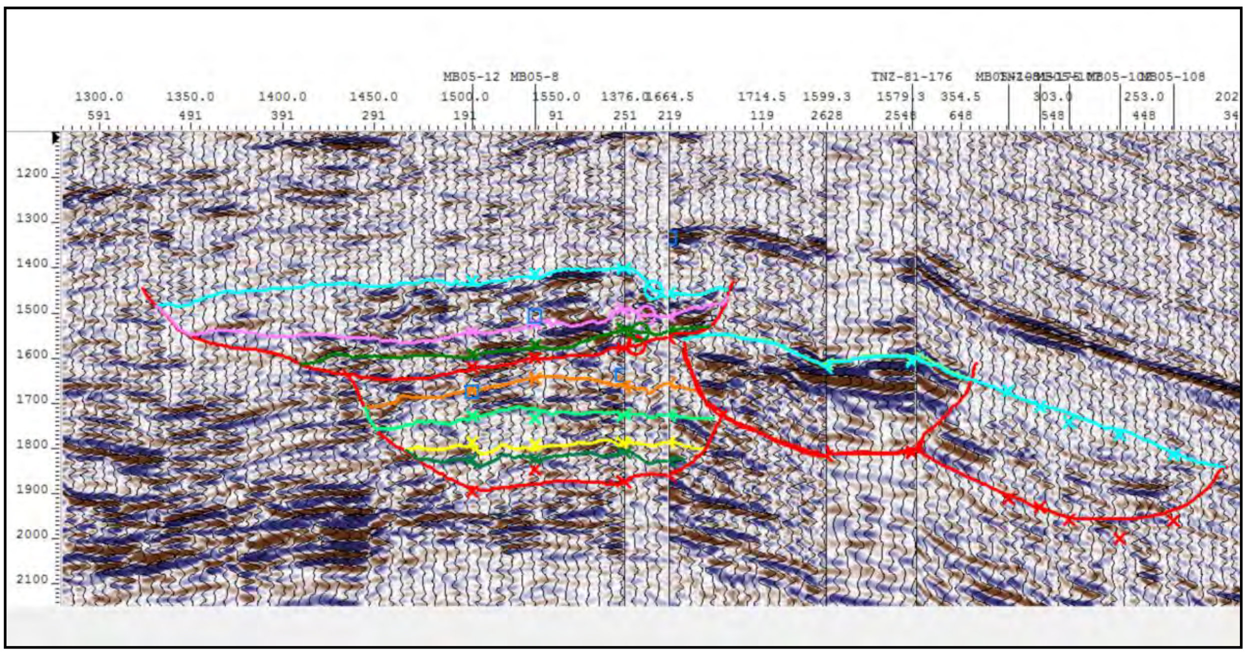

Figure 4-6: Arbitrary Seismic Line Showing Msimbati NE and NE Extension Channel

Figure 4-6 shows the Arbitrary Line; showing the Msimbati NE and NE Extension channel body to the right, with the Mnazi Bay channel on the left (lower body), and with the Msimbati channel overlying it.

4.1.4 Geological Model – Gross Rock Volume

Mnazi Bay

A simple geological/geophysical structural model was constructed using depth grids created by seismic mapping and log data from the four wells MB-1, MB-2, MB-3 and MS-1X. Gross rock volumes were calculated using depth grids created from the seismic mapping from the top and bottom of the mapped sand packages. In order to create the depth grids, the depths from the well control were used in conjunction with the time structures to create a velocity field within the channels.

The following maps were produced:

Mnazi Bay

- Upper Sand Top Structure Map
- Upper Sand Base Structure Map
- Lower Sand Top Structure Map
- Lower Sand Base Structure Map

Msimbati

- Upper K Sand Top Structure Map
- Upper K Sand Base Structure Map
- Lower K Sand Top Structure Map
- Lower K Sand Base Structure Map

Msimbati NE

- Sand Top Structure Map
- Sand Base Structure Map

Msimbati NE Extension

- Sand Top Structure Map
- Sand Base Structure Map

Mnazi Bay

- Upper Sand Isopach
- Lower Sand Isopach

Msimbati

- Upper K Sand Isopach
- Lower K Sand Isopach

Msimbati NE

- Sand Isopach

Msimbati NE Extension

- Sand Isopach

Figure 4-7 and Figure 4-8 are examples of these maps. All maps are included in Appendix 2.

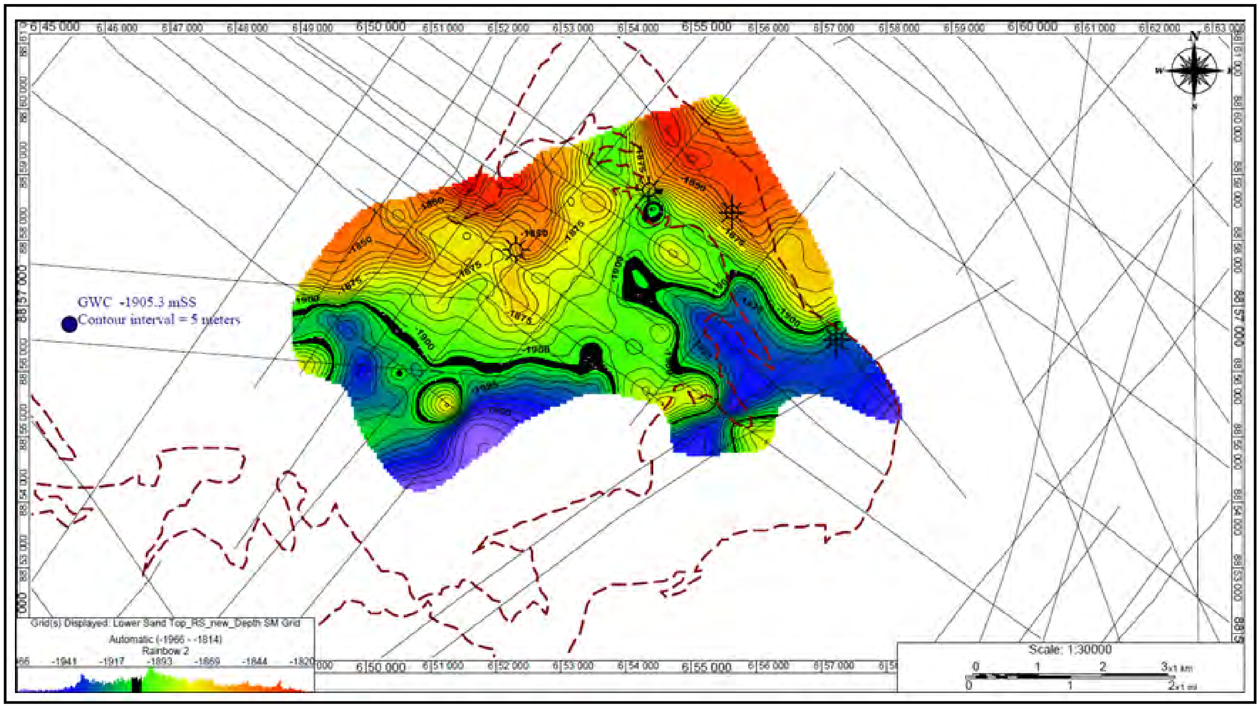

Figure 4-7: Mnazi Bay - Lower Sand Top Structure Map

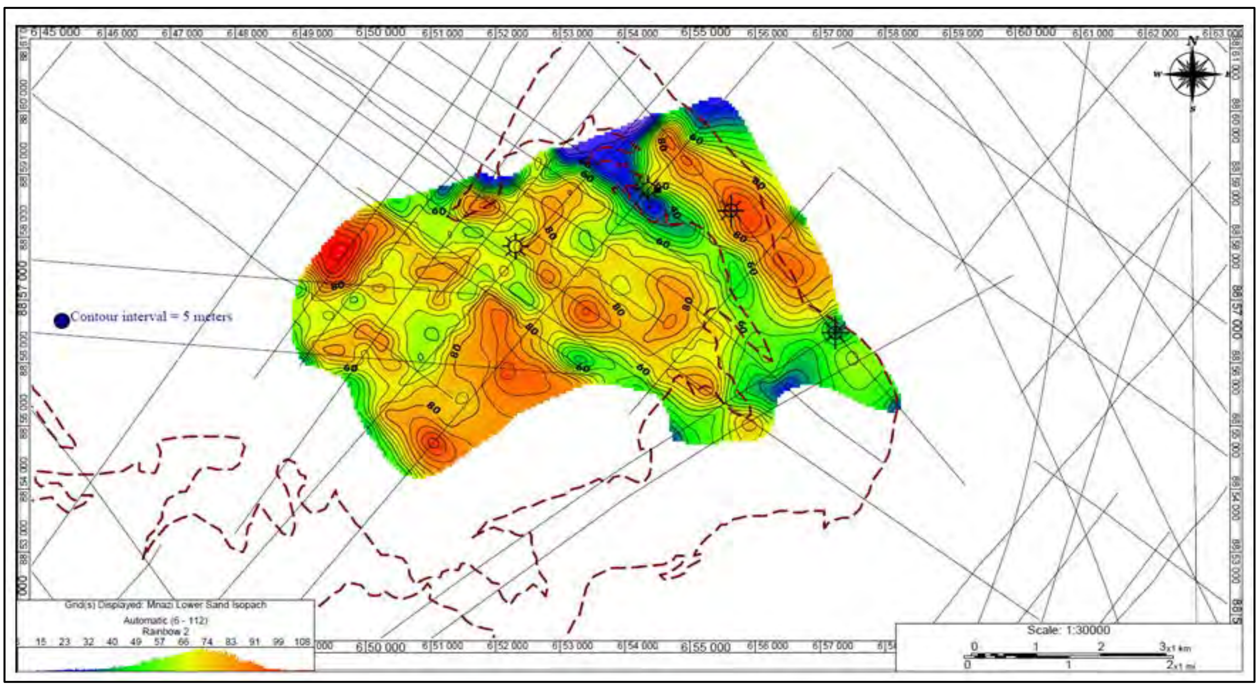

Figure 4-8: Mnazi Bay - Lower Sand Isopach

4.1.5 Petrophysical Analysis

The Mnazi Bay reservoirs have been penetrated by four wells:

- Mnazi Bay #1("MB-1") drilled by AGIP in 1982;
- Mnazi Bay #2 ("MB-2"); drilled by Artumas in 2006;
- Mnazi Bay #3 ("MB-3"); drilled by Artumas in 2006
- Msimbati #1 ("MS-1X"), drilled by Artumas in 2007

Full suites of open-hole logs were run in all wells, including resistivity devices, neutron-density, and borehole-compensated sonic. No core has been acquired. Logs from MB-1, MB-2 and MB-3 and MS-1X were previously evaluated to identify potentially productive intervals, and establish reservoir parameters[4 5 6 7].These same evaluations were used for this study, as the rock properties are deemed reasonable, however, the previous break out of sands (C, D, E etc.) have been amalgamated into the Lower Sands, Upper Sands, Msimbati Lower K Sands and Msimbati Upper K Sands as indicated above. To derive petrophysical parameters for this probabilistic resource analysis, net reservoir thicknesses were calculated for each zone using the following cutoffs:

- $V_{sh} < 0.5$,
- $\Phi_e > 0.08$, and
- $S_w < 0.60$

A composite of the logs from the four wells is shown in Figure 4-1 and Figure 4-2 of Section 4.1. The log evaluation summaries for each well are summarized in Table 4-1.

Mnazi Bay & Msimbati Petrophysical Evaluations Summary

SAND	Well	Top (ft)	Base (ft)		Thickness (ft)	Net Pay (ft)	Net / Gross	Effective Porosity	Water Saturation
Msimbati Upper K Sand									
	Msimbati #1X	4798.23	5152.74	(MD)	354.51	48.50	0.14	0.20	0.37
Msimbati Lower K Sand									
	Msimbati #1X	5375.36	5439.11	(MD)	63.75	14.50	0.23	0.18	0.49
Mnazi Upper Sand									
	Mnazi Bay #1	5588.26	6007.81	(MD)	419.55	33.50	0.08	0.15	0.47
	Mnazi Bay #2	5541.88	5904.85	(TVD)	362.97	93.00	0.26	0.22	0.24
	Mnazi Bay #3	5564.31	5839.06	(MD)	274.75	65.00	0.24	0.25	0.41
	Msimbati #1X	5881.36	6158.40	(MD)	277.04	32.00	0.12	0.18	0.16
Mnazi Lower Sand									
	Mnazi Bay #1	6147.31	6383.32	(MD)	236.01	49.50	0.21	0.15	0.41
	Mnazi Bay #2	6168.54	6368.13	(TVD)	199.58	43.50	0.22	0.17	0.32
	Mnazi Bay #3	6075.36	6392.90	(MD)	317.54	97.00	0.31	0.24	0.46
	Msimbati #1X	6371.64	6545.00	(MD)	173.36	5.50	0.03	0.11	0.27
Msimbati NE									
					510.86	95.08	0.19	0.20	0.38
Msimbati NE Extension									
					510.86	95.08	0.19	0.20	0.38

Table 4-1: Log Evaluation Summary

Statistical properties of the petrophysical analyses were determined for the entire net pay sections of the three wells encountering the classic sands. The average petrophysical properties were calculated based on weighting by net pay and are summarized in Table 4-2.

Average Formation Values			
	Net:Gross	Effective Porosity	Water Saturation
Msimbati Upper K	0.14	0.20	0.37
Msimbati Lower K	0.23	0.18	0.49
Msimbati NE	0.19	0.20	0.38
Msimbati NE Extension	0.19	0.20	0.38
Mnaxi Upper	0.17	0.21	0.31
Mnazi Lower	0.25	0.20	0.42

Table 4-2: Average Formation Values

4.2 Reservoir Fluids

4.2.1 Pressure vs. Depth Relationships

In all four wells, reservoir pressure has been measured and interpreted at various sand depth levels. Initial reservoir pressures in the gas bearing sands generally range from 2900 to 2990 psia. The pressure data set is comprised of RFT test data, MDT test data and DST measured test data. These data allow determination of the in-situ pressure gradients in various sands, both gas bearing and water bearing. Pressure versus depth plots for each of the wells is shown in Figure 4-9 to Figure 4-12. A composite pressure vs. depth plot is shown in Figure 4-9. On each plot the range of pressure gradient derived gas-water contact (“GWC”) depths are shown.

The composite DST, MDT, RFT pressure data suggest that multiple GWC depths are likely prevalent throughout the fields.

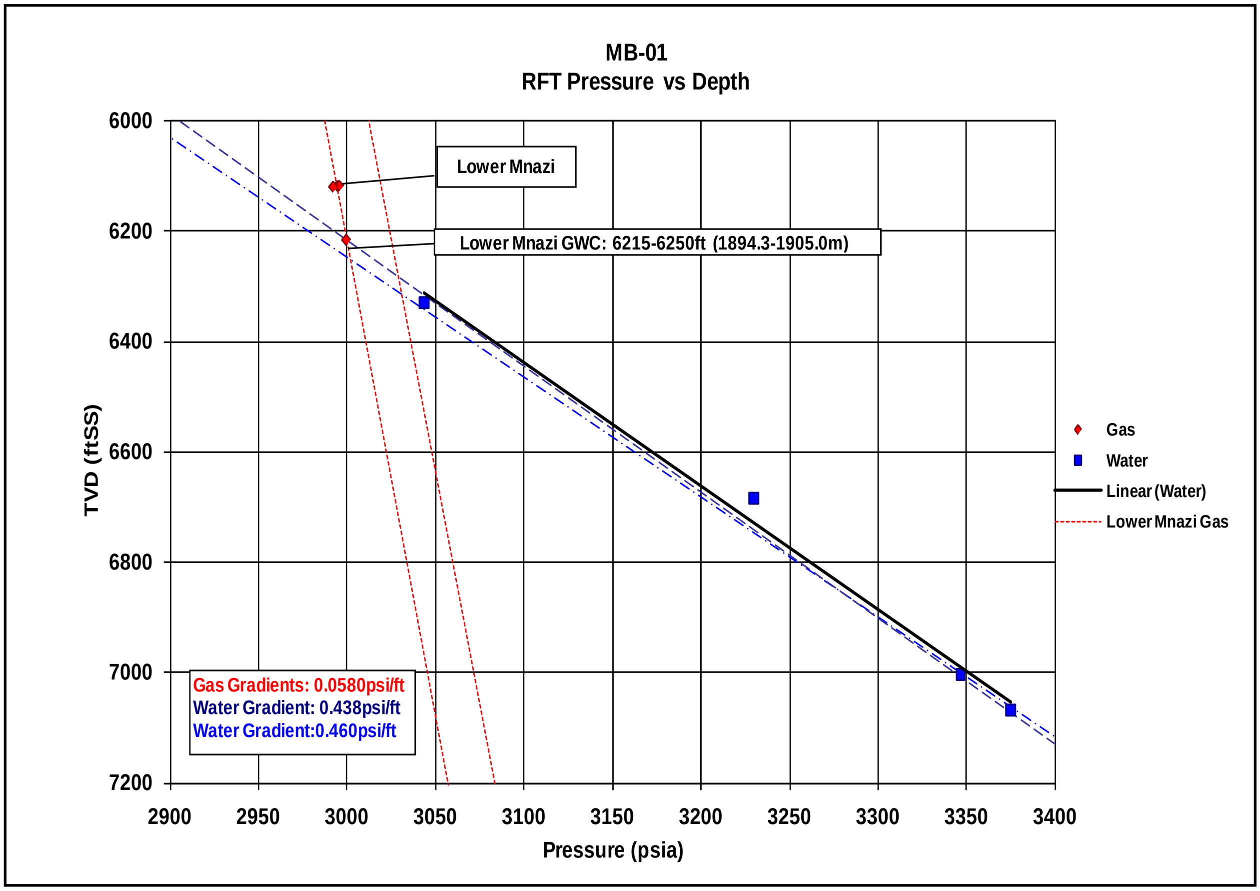

Figure 4-9: MB-01 RFT Pressure vs. Depth

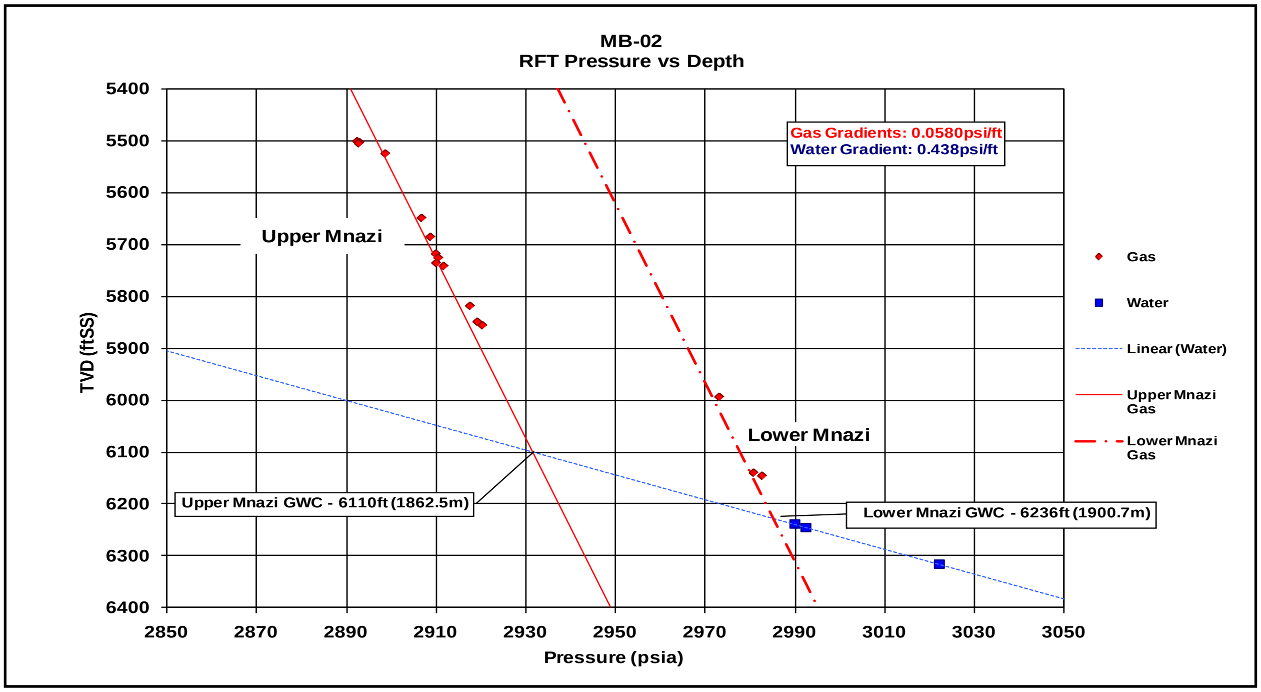

Figure 4-10: MB-02 Pressure vs. Depth

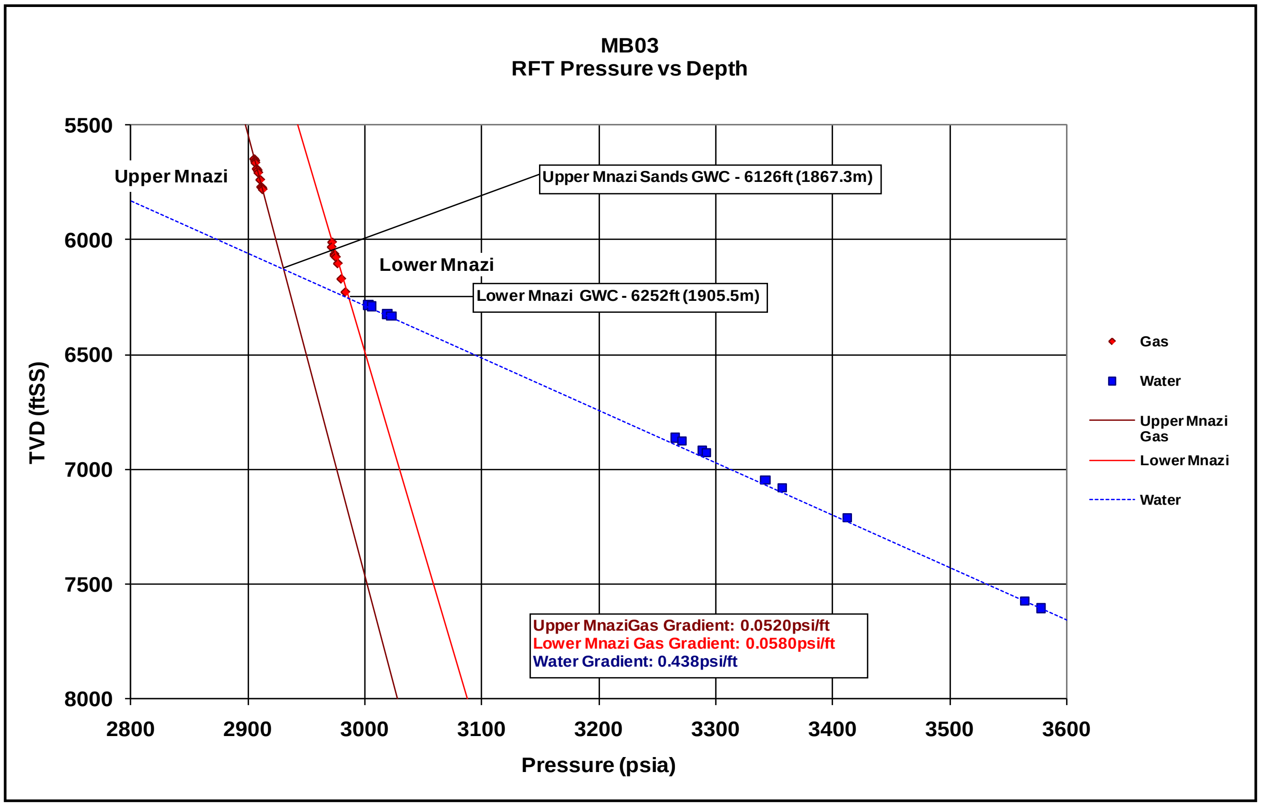

Figure 4-11: MB-03 RFT Pressure vs. Depth

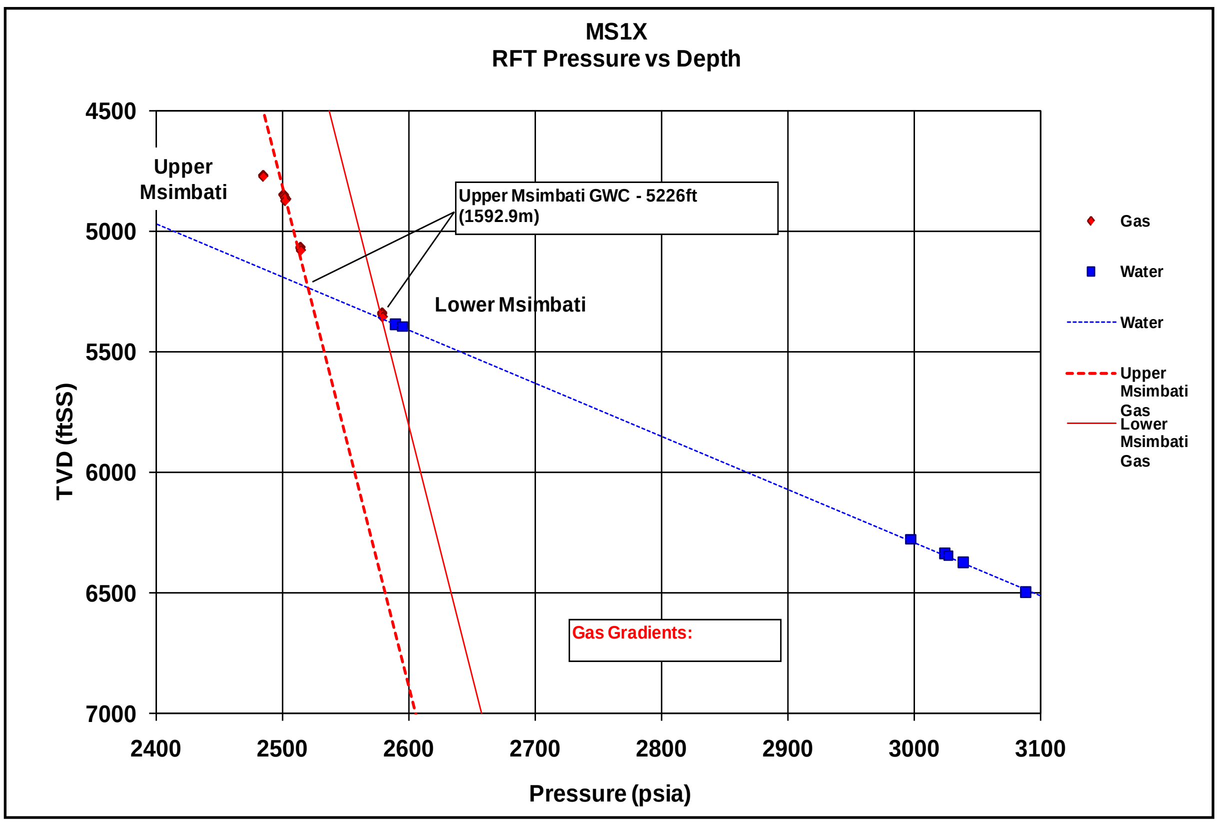

Figure 4-12: MX-1 RFT Pressure vs. Depth

4.2.2 Gas Water Contact Depths

The depths of the gas water contacts ("GWC") in the Mnazi Bay and Msimbati fields have been estimated based on various interpretations of well test data, pressure gradient analyses from repeat formation tester ("RFT") data, and well log interpretation data. Although some uncertainty remains in the estimated GWC depths, it appears that there are two main GWC levels in the classic sands, and two GWC levels in the Upper Msimbati K sands. These sets of GWC levels can be seen on the composite RFT plot shown below:

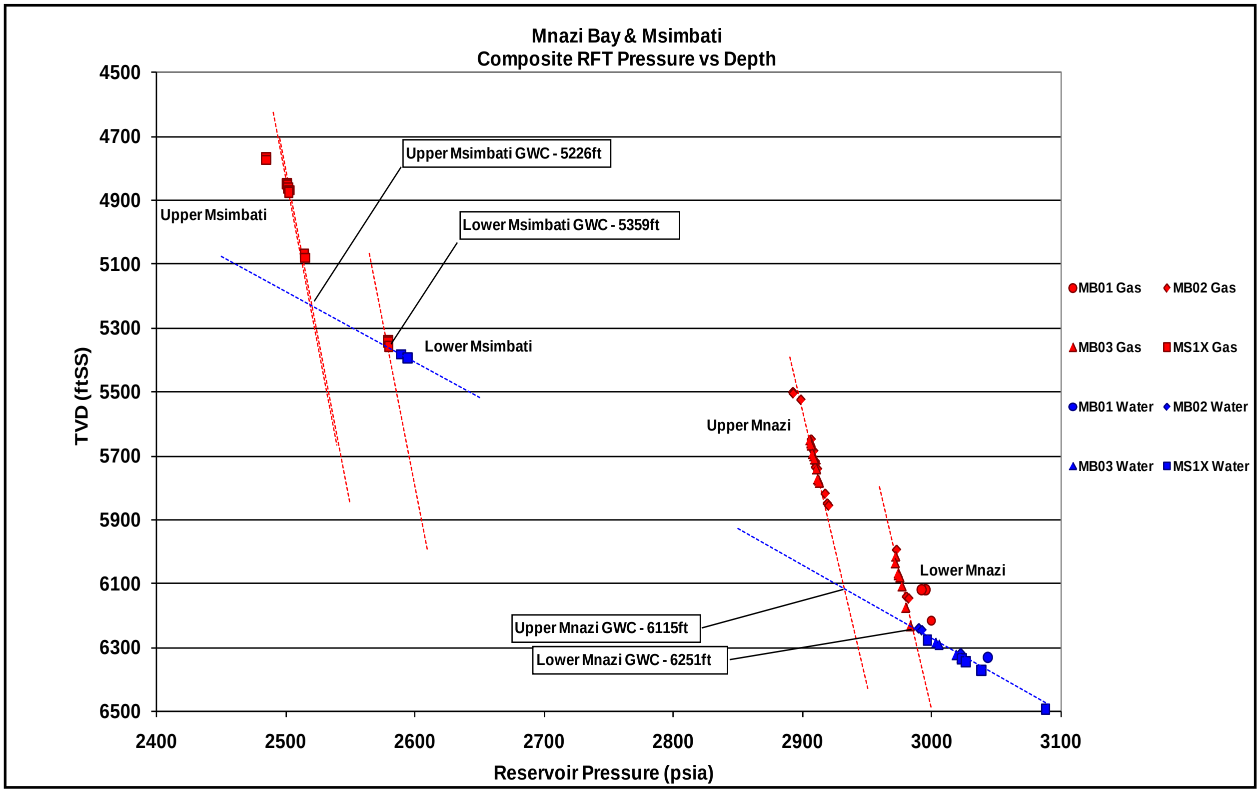

Figure 4-13: Composite RFT Pressure vs. Depth

The data used in determination of GWC depths for the field are summarized in Table 4-3:

Mnazi Bay and Msimbati Gas Fields - all depths listed as subsea depth
Gas Water Contact Depths

	MB#1	MB#2-ST2	MB#3	MS-1X
KB Elevation (ft above msl)	44	43	44	44
GWC Evidence				
Well Logs				U. Msimbati: GWC @ 5358 ftSS (1633.1 mSS)
	No GWC on logs			U. Mnazi: GWC >6074 ftSS (1851.4 mSS) and < -6082 ftSS (-1853.8 mSS)
		L. Mnazi: GWC @ 6249 ftSS (1904.7 mSS)	L. Mnazi: GWC @ 6252 ftSS (1905.6 mSS)	
Test Data				U. Msimbati: tested clean gas to mid point of K1 sands @ 5085 ftSS (1549.9 mSS)
				U. Mnazi: produced clean gas to 6066 ftSS (1848.9 mSS)
	L .Mnazi: tested clean gas to 6218 ftSS (1895.2 mSS)	L. Mnazi: Water and gas produced interval 6214 ftSS to 6253 ftSS (1894 to 1906 mSS)	L. Mnazi: tested clean gas to 6251 ftSS (1905.3 mSS)	
GDT				U. Msimbati: 5082 ftSS (1549.0 mSS)
				L. Msimbati: 5355 ftSS (1632.2 mSS)
	L. Mnazi: 6218 ftSS (1895.2 mSS)	L. Mnazi: 6249 ftSS (1904.7 mSS)	L. Mnazi: 6251 ftSS (1905.3 mSS)	
RFT/MDT Data GWC:				U. Msimbati: 5193 to 5229 ftSS (1583 to 1593.9 mSS)
				L. Msimbati: 5357 ftSS (1632.7 mSS)
		U. Mnazi: 6106 to 6119 ftSS (1861.1 to 1865.1 mSS)	U. Mnazi: 6126 ftSS (1867.3 mSS)	U. Mnazi: n/a
	L. Mnazi: 6215 to 6250 ftSS (1894.3 to 1905.0 mSS)	L. Mnazi: 6236 ftSS (1900.7 mSS)	L. Mnazi: 6252 ftSS (1905.5 mSS)	
Regional Water Gradient	Measured below 6330 ftSS	Measured below 6239 ftSS	Measured below 6288 ftSS	
	P (psia) = (TVDSS (ft) + 623)/2.284	P (psia) = (TVDSS (ft) + 584)/2.284	P (psia) = (TVDSS (ft) + 568)/2.284	P (psia) = (TVDSS (ft) + 333)/2.207

Table 4-3: Gas:Water Contact Data

GWC depths can be interpreted from some of the log evaluations: In MB-1 no GWC is observed directly on the logs, as all of the gas bearing sands occur in the well at depths wholly within either gas or water saturated zones. In the MB-2-ST2 well, an apparent GWC is observed in the Lower Mnazi Bay sands at a depth of -6249 ftSS (-1904.7 mSS) and in the MB-3 well in the Lower Mnazi Bay sands at a depth of -6252 ftSS (-1905.6 mSS). In the MS-1X well, a contact is interpreted in the Lower Msimbati sands at -5358 ftSS (-1633.1 mSS). In the Upper Mnazi Bay sands, the GWC is inferred to lie in a narrow depth range between the bottom of a gas bearing sand at -6074 ftSS (1851.4 mSS) and the top of a water bearing sand at -6082 ftSS (-1853.8 mSS).

Drill stem test ("DST") and production test data are also used to infer GWC depths and/or GWC depth limitations. Production of clean gas is confirmed at the base of the Lower Mnazi Bay sands in MB-1 and MB-3 and the base of the Upper Mnazi Bay sands in MS-1X. This establishes a gas-down-to ("GDT") depth of -6218 ftSS (-1895.2 mSS) and -6251 ftSS (-1905.3 mSS) in each of these two wells respectively.

The GWC depths interpreted from RFT pressure data is more interpretive, and therefore less certain than those from well tests and logs, due to the uncertainties in pressure data measurements and the extrapolation of pressure gradient intersection lines associated with RFT tests. For example, in the case of the Lower Mnazi Bay sands RFT interpreted GWC depth of -6236 ftSS (-1900.7 mSS) in MB-2, this depth is shallower than a clearly defined GWC depth as seen on logs and confirmed by well testing. The interpreted depths and ranges of depths from RFT tests are shown for each of the four wells on Figure 4-13.

Recognizing the inherent uncertainty in the GWC depths, where measured or inferred depths are very similar across different sands, they have been grouped. For the purpose of this resource evaluation, RPS has selected a set of GWC depths as summarized in the Table 4-4. The 'gas down to' (GDT) depth, the maximum depth at which gas was observed, is also shown in the table for reference.

Further, for the purposes of this resource assessment, RPS has assumed that the GWC depths are uniform within each of the respective sands. For the areas outside the Mnazi Bay and Msimbati fields APA/PRCL have included a volumetric case with a distributed GWC as deep as the deepest C sands in the south-west corner of the model, 6251 ftSS (1905.3 mSS), as shallow as 5226.3 ftSS (1593 mSS) and a probable GWC of 6115.4 ftSS (1864 mSS).

Gas:Water Contact								
	Low		Probable		High		Gas Down To	
Formation	(mSS)	(ftSS)	(mSS)	(ftSS)	(mSS)	(ftSS)	(mSS)	(ftSS)
Msimbati Upper K			1593.0	5226.3			1549.0	5082.0
Msimbati Lower K			1633.4	5358.9			1632.2	5354.9
Msimbati NE	1613.2	5292.6	1864.0	6115.4	1905.3	6250.9		
Msimbati NE Extension	1613.2	5292.6	1864.0	6115.4	1905.3	6250.9		
Mnazi Upper			1864.0	6115.4			1851.0	6072.8
Mnazi Lower			1905.3	6250.9			1905.3	6250.9

Table 4-4: Selected Gas:Water Contact

4.2.3 Reservoir Fluid PVT Properties

The reservoir fluid in the Mnazi Bay reservoir is predominantly dry gas. During all tests of the producing zones in each of the four wells, separator gas samples were analyzed on-site using gas chromatographic analysis. These analyses were limited to hydrocarbon components up to nC_5. Further, separator gas and liquid samples were collected during extended well tests, and subject to full compositional lab analyses[8] [9] [10]. The analyses all show the gas to be predominantly (>97.5 mole %) methane, with minor amounts of ethane, propane and butane and minor amounts of nitrogen and carbon dioxide. No H_2S has been measured in any of the samples. Most gas samples showed a specific gravity of about S.G. = 0.57. The on-site samples on Upper Mnazi Bay 5798 – 5812 ftSS, previously referred to as the G sand, indicated ethane concentrations of up to 3.2 mole% and propane concentrations of up to 1 mole % during the first period of flow, however these dropped down to much lower levels after a few hours of flow.

During the drill stem testing, with the exception of the sample from Upper Mnazi Bay, all MB-2-ST2 liquid samples were water. The liquid sample from the Upper Mnazi Bay sand (5798 – 5812 ftSS) in MB-2 contained about 30 cc water and 20 cc oil. The oil was centrifuged and analyzed for hydrocarbon content to C_{37}^{+}, and was calculated to have an atmospheric pressure specific gravity of S.G.= 0.8151, which equates to an oil gravity of 42° API. Note that no measurable oil liquid volumes were reported in the separator during any of the flow tests. A summary of the lab measured compositional gas analyses is shown in Table 4-5.

MB-2 Gas Composition Analysis (Mole %)					
DST #	**1**	**2**	**3**	**4**	**5**
Sand	**Lower Mnazi**		**Upper Mnazi**		
Interval	**6300 - 6340**	**6220 - 6230**	**5920 - 5940**	**5798 - 5812**	**5578 - 5592**
SG	0.6276	0.5661	0.5738	0.5738	0.57
H2	0.07	0	0	0	0
N2	0.19	0.18	0.19	0.19	0.19
CO2	0.28	0.18	0.3	0.24	0.32
H2S	0.02	0	0	0	0
C1	97.98	98.19	98.05	98.11	98.04
C2	1.01	1.01	1.02	1.02	1.02
C3	0.28	0.28	0.28	0.28	0.28
IC4	0.05	0.05	0.05	0.05	0.05
NC4	0.05	0.06	0.06	0.06	0.06
IC5	0.01	0.02	0.01	0.02	0.01
NC5	0.01	0.01	0.01	0.01	0.01
C6	0.02	0.01	0.02	0.01	0.02
C7+	0.03	0.01	0.01	0.01	0
Total	100.0	100.0	100.0	100.0	100.0

Table 4-5: MB-2 Gas Composition

In the series of DST tests on MB-3, the on-site gas analyses indicated slightly richer gas in the Lower Mnazi Bay sands from 6202 – 6251 ftSS, previously referred to as the C sands. These samples showed a specific gravity varying from S.G.= 0.59 up to S.G. = 0.6276, with methane concentration of about 90 mole% and ethane, propane, and butane concentrations of about 6.5%, 2.5% and 1% respectively. The Upper Mnazi Bay sands from 5648 – 5798 ftSS showed methane concentrations of about 96 mole% and ethane concentrations of about 3 mole %. These minor concentrations of heavier hydrocarbon components may account for the reported darker flame color during the testing of this well. A summary of these on-site measured gas analyses is shown in Table 4-6. In this table, the non hydrocarbon components have been added, and the measured hydrocarbon components normalized, using the non hydrocarbon analyse from MB-2-ST2.

MB-3 Gas Composition Analysis (Mole %)				
DST #	**1**	**2**	**3**	**4**
Sand	**Lower Mnazi**		**Upper Mnazi**	
Interval (ft)	**6246-6295**	**6110-6180**	**5795-5842**	**5692-5760**
SG	0.6276	0.5661	0.5738	0.5738
H2	0.01	0	0	0
N2	0.02	0.01	0.63	0.63
CO2	0	0	0	0
H2S	0	0	0	0
C1	89.88	98.37	96.18	96.18
C2	6.62	1.17	3.08	3.08
C3	2.42	0.31	0.01	0.01
IC4	0.43	0.06	0	0
NC4	0.62	0.07	0	0
IC5	0	0	0	0
NC5	0	0.01	0	0
C6	0	0	0.07	0.07
C7+	0	0	0.03	0.03
Total	100.0	100.0	100.0	100.0

Table 4-6: MB-03 Gas Composition

During the extended production testing on all four wells minor volumes of liquid hydrocarbon were produced. The measured producing oil:gas ratios were all too small to be measured on a daily basis, and have been summarized for the duration of each of the extended production tests in Table 4-7:

Extended Well Testing - Fluid Production Summary				
	MB-1	**MB-2**	**MB-3**	**MS-1X**
Formation	Lower Mnazi	Upper Mnazi	Upper Mnazi	Upper Msimbati
Depth (ft SS)	6147.3 - 6263.3	5843 - 5863	5648 - 5714	4889.4 - 4951.5
Test start date	30/04/2005	30/04/2007	09/04/2007	23/05/2007
Test duration (days)	8	16	16	15
Gas Produced (MMscf)	107	180	176	140
Oil Produced (stb)	6	15	14	61
Producing OGR (bbl/mmscf)	0.06	0.08	0.08	0.44
Oil Gravity (°API)	24	25	25	27

Table 4-7: Extended Well Testing Fluid Production Summary

The volume of the liquid hydrocarbons produced was relatively small. For the purposes of this resource evaluation the reservoir fluids are assumed to be gas only, and no resource volumes have been attributed to the potential oil resources.

For the purposes of this analysis, the normalized gas analysis from the series of DST tests on MB-2 is adopted. PVT properties have been calculated, using industry correlations, based on a gas the average gas compositions from the MB-2-ST2 analyses, and an average reservoir temperature of 200°F (93°C). The resulting gas viscosity and formation volume factor is shown in Figure 4-14.

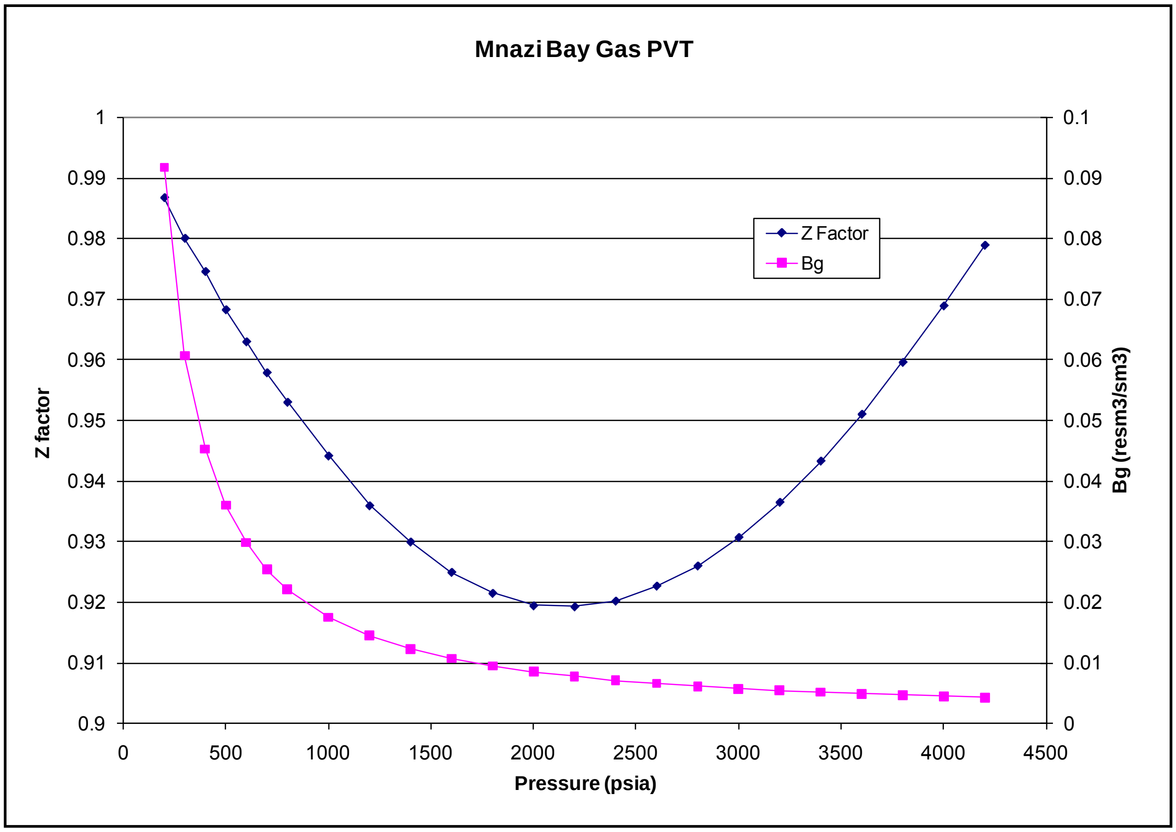

Figure 4-14: Mnazi Bay (MB-02-ST2) Gas PVT

4.3 Well Deliverability Testing

The four Mnazi Bay wells have been flow tested across the evaluated pay sands using standard open hole and cased hole drill stem test techniques. In the MB-1 well, the test was conducted using a production completion across the perforated Lower Mnazi Bay, 6147.3 – 6263.3 ftSS. For the MB-2 and MB-3 wells, the tests were conducted open-hole: the target test zone was isolated using a straddle packer assembly, the well was flowed for varying periods (ranging from 5 to 27 hours) and shut in for pressure build up measurement for periods from 6 to 48 hours. During the flow periods, the gas was flared. Bottom hole pressures, flowing tubing head pressures, separator pressures and gas flow rates were recorded during each of the tests. The flowing and pressure data was analyzed for each test to determine average reservoir pressure, reservoir flow properties and reservoir flow barriers[11] [12] [13].

The following table summarizes the test production rates in each of the wells[14] [15] [16].

Mnazi Bay & Msimbati Drill Stem Test and Extended Well Test Summary Well Test Flow Rate (MMcf/d)											
Sands	**MB#1**		**MB#2-ST2**			**MB#3**			**MS-1X**		
	Depth (ftSS)	DST	**Depth (ftSS)**	DST	EWT	**Depth (ftSS)**	DST	EWT	**Depth (ftSS)**	DST	EWT
Upper Msimbati		-		-	-		-	-	4798.2 - 4820.0	9.2	-
		-		-	-		-	-	4889.41- 4951.5	9.6	9.4
		-		-	-		-	-	5101.8 - 5152.7	9	-
Upper Mnazi		-	5500.5 - 5514.3	7.84	-		-	-		-	-
		-	5717.6 - 5731.4	8.71	-		9.33	11.1		-	-
		-	5838 - 5731.4	8.44	11	5735 - 5812	14.57	-	6040 - 6080	10.1	-
Lower Mnazi	6147.3 - 6172.3	10.5		-	-		-	-		-	-
			6132.4 - 6146.3	8.29	-	6080 - 6150	13.95	-		-	-
		-	6213.6 - 6253.1	1.25	-	6216 - 6265	11.84	-		-	-

Table 4-8: Mnazi Bay & Msimbati Fields Well Test Summary

Further details of the above test interpretations are shown in Table 4-9. All of the above tests were conducted with low sandface pressure drawdown. The tests confirm substantial deliverability potential in each of the wells and each of the reservoir sands.

MB#1

DST#	Sands	Test Interval Top (TVD ftSS)	Test Interval Bottom (TVD ftSS)	Test Interval (ft)	Tested Interval Net Pay (ft)	Sandface Drawdown (psia)	Final Gas Production Rate (MMcf/d)	ϕ (fraction)	Pi (psia)	k_gh mD-ft	AOF MMcf/d
commingled	Lower Mnazi	6,109	6,121	12	39	131	10.5	0.20	2,992	1,638	n/a
	Lower Mnazi	6,188	6,218	30							

MB#2-ST2

DST#	Sands	Test Interval Top (TVD ftSS)	Test Interval Bottom (TVD ftSS)	Test Interval (ft)	Tested Interval Net Pay (ft)	Sandface Drawdown (psia)	Final Gas Production Rate (MMcf/d)	ϕ (fraction)	Pi (psia)	k_gh mD-ft	AOF MMcf/d
5	Upper Mnazi	5,501	5,514	14	6	12.1	7.8	0.18	2,896	671	37
4a	Upper Mnazi	5,718	5,731	14	10	0.2	8.7	0.24	2,914	14,250	280
3	Upper Mnazi	5,838	5,858	20	20	1.5	8.4	0.25	2,922	3,803	225
2	Lower Mnazi	6,132	6,146	14	11	1.0	8.3	0.14	2,986	8,337	113
1	Lower Mnazi	6,214	6,253	40	43	7.7	1.3	0.21	2,997	154	n/a

MB#3

DST#	Sands	Test Interval Top (TVD ftSS)	Test Interval Bottom (TVD ftSS)	Test Interval (ft)	Tested Interval Net Pay (ft)	Sandface Drawdown (psia)	Final Gas Production Rate (MMcf/d)	ϕ (fraction)	Pi (psia)	k_gh mD-ft	AOF MMcf/d
4a	Upper Mnazi	5,648	5,716	68	32	19	9.3	0.26	2,907	8,329	154
3	Upper Mnazi	5,721	5,798	77	30	29	14.6	0.26	2,909	7,212	149
2	Lower Mnazi	6,066	6,136	70	48	49	14.0	0.26	2,973	9,312	133
1	Lower Mnazi	6,202	6,251	49	47	21	11.8	0.23	2,984	34,075	294

MS-1X

DST#	Sands	Test Interval Top (TVD ftSS)	Test Interval Bottom (TVD ftSS)	Test Interval (ft)	Tested Interval Net Pay (ft)	Sandface Drawdown (psia)	Final Gas Production Rate (MMcf/d)	ϕ (fraction)	Pi (psia)	k_gh mD-ft	AOF MMcf/d
4	Upper Msimbati K	4,746	4,771	25	4	420	9.2	0.16	2,478	948	66
3	Upper Msimbati K	4,841	4,866	25	31	11	9.6	0.19	2,498	24,583	222
2	Upper Msimbati K	5,046	5,066	20	15	43	9.0	0.23	2,507	4,263	109
1	Upper Mnazi	6,026	6,066	40	32	12	10.1	0.18	2,912	28,687	372

Table 4-9: Mnazi Bay and Msimbati DST Summary

4.4 Production History

The Mnazi Bay field was put on production beginning in January 2007, and has been more or less continuous ever since. Production has occurred from both the lower and upper zones in MB-01, and since mid 2012 from MB-03. Natural gas produced is processed and pipelined to the town of Mtwara where it is used as the feed stock in an 18 MW natural gas fired generation facility. The production rates are limited to the requirements of the generation facility at Mtwara, currently about 2 MMscf/d. Total field cumulative production as at August 31, 2013 is 3.16 Bscf.

The total field production history is shown on the following chart:

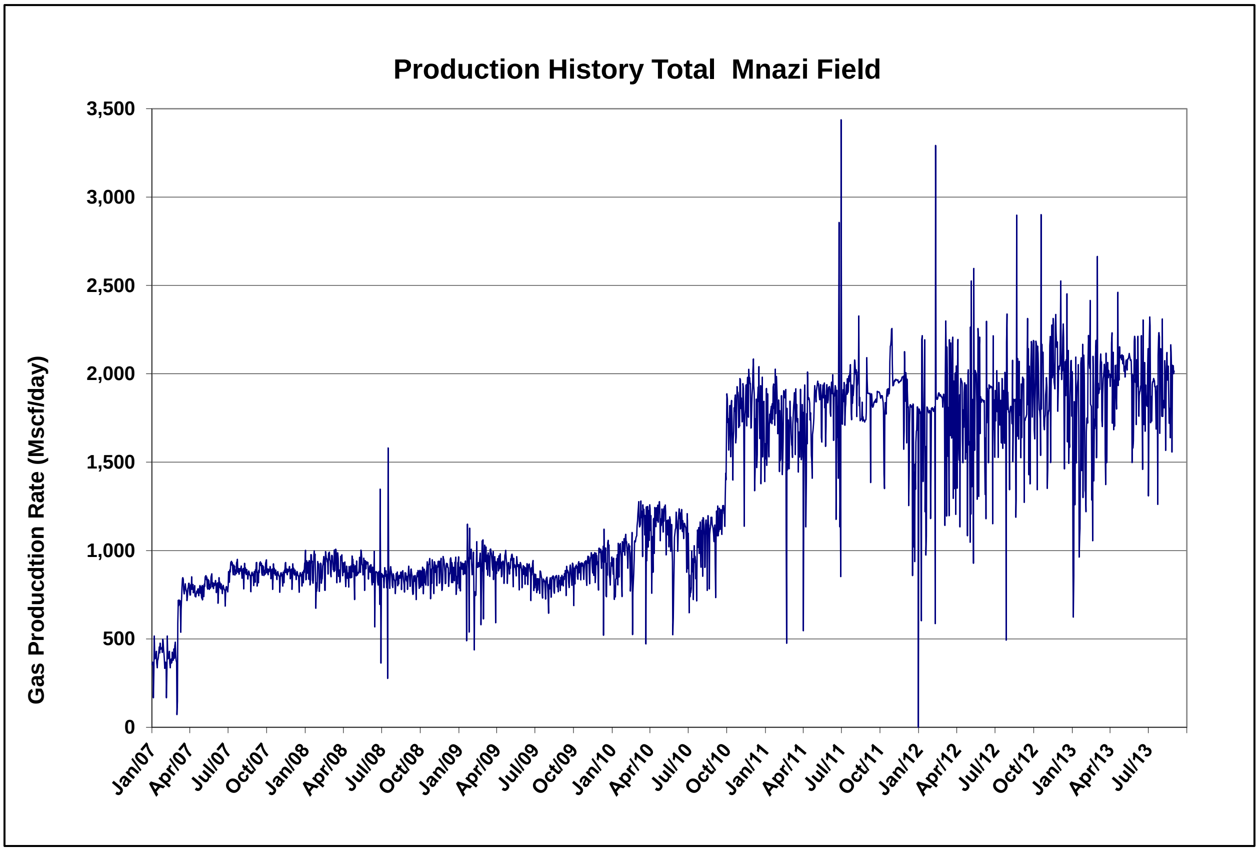

Figure 4-15: Production History Mnazi Bay Gas Field

The well MB-01 was re-entered for the purpose of testing in March 2005. The existing cement and bridge plugs were drilled out and the well perforated in the Upper and Lower Mnazi Bay at the following intervals:

- Lower Mnazi Bay: 6232 – 6262 ftKB (6188 – 6218 ftSS)
- Upper Mnazi Bay:
    - o 6150 – 6170 ftKB (6106 – 6126 ftSS)
    - o 5962 – 5992 ftKB (5918 – 5948 ftSS)
    - o 5803 – 5813 ftKB (5759 – 5769 ftSS)

A dual packer with dual string tubing with sliding sleeves was installed which allows commingled production of the Lower Mnazi Bay (6232 – 6262 ftKB) and Upper Mnazi (6150 – 6170 ftKB), and production from either of the Upper Mnazi Bay intervals (5962 – 5992 ftKB & 5803 – 5813 ftKB). The production data for comingled Lower Mnazi Bay (6232 – 6262 ftKB) and Upper Mnazi Bay (6150 - 6170 ftKB) is shown below:

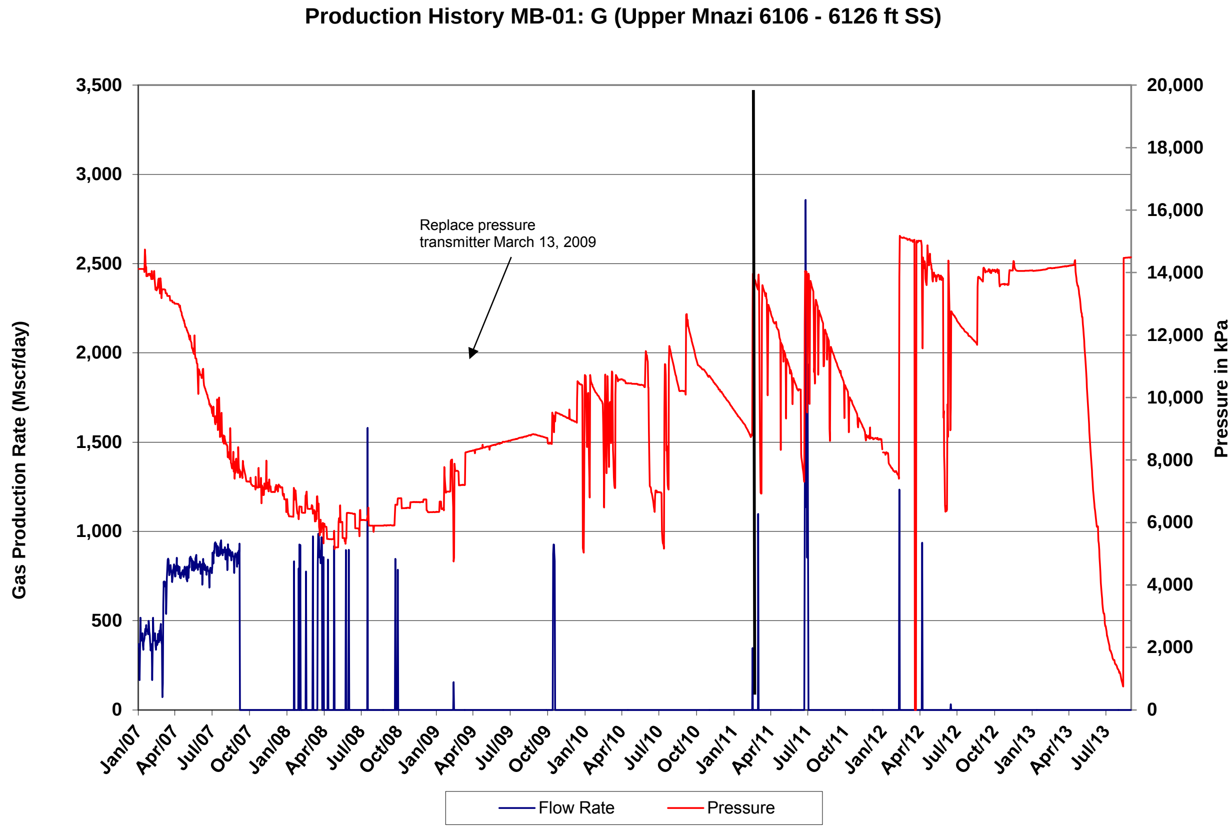

Figure 4-16: Production History MB-01 - Lower Mnazi Bay (6188-6218 ftSS) & Upper Mnazi Bay (6106-6126 ftSS) Commingled

Production from the Upper Mnazi (5759 – 5769 ftSS) zone is shown in the following figure. Note that MB-1 production reported from January to September 2007 was originally recorded and attributed to the comingled Upper and Lower zones. However, during 2013 the operator Maurel and Prom has determined that the recorded producing interval was erroneous due to a mix-up in tubing head labeling, and that production during this period was actually occurring from the Upper Mnazi (5759 – 5769 ftSS) zone, as shown on Figure 4-17 below.

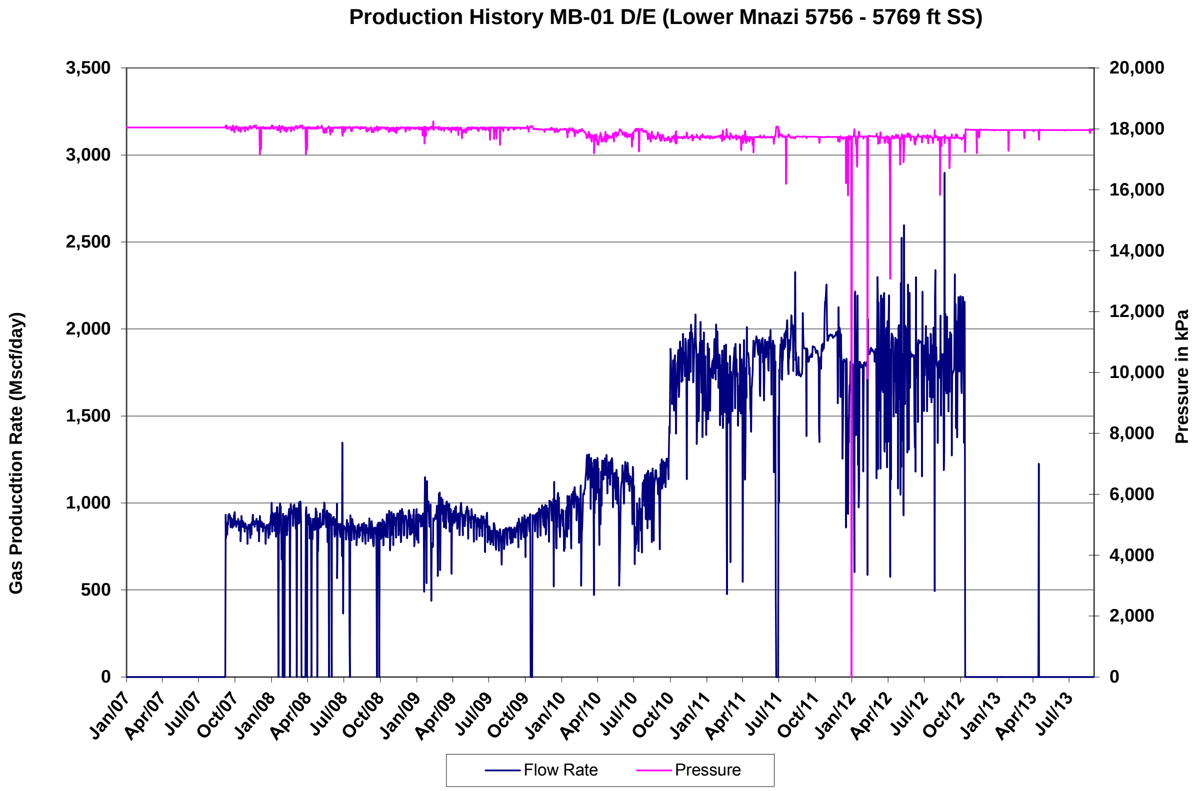

Figure 4-17: Production History MB-01 - Upper Mnazi Bay (5759-5769 ftSS)

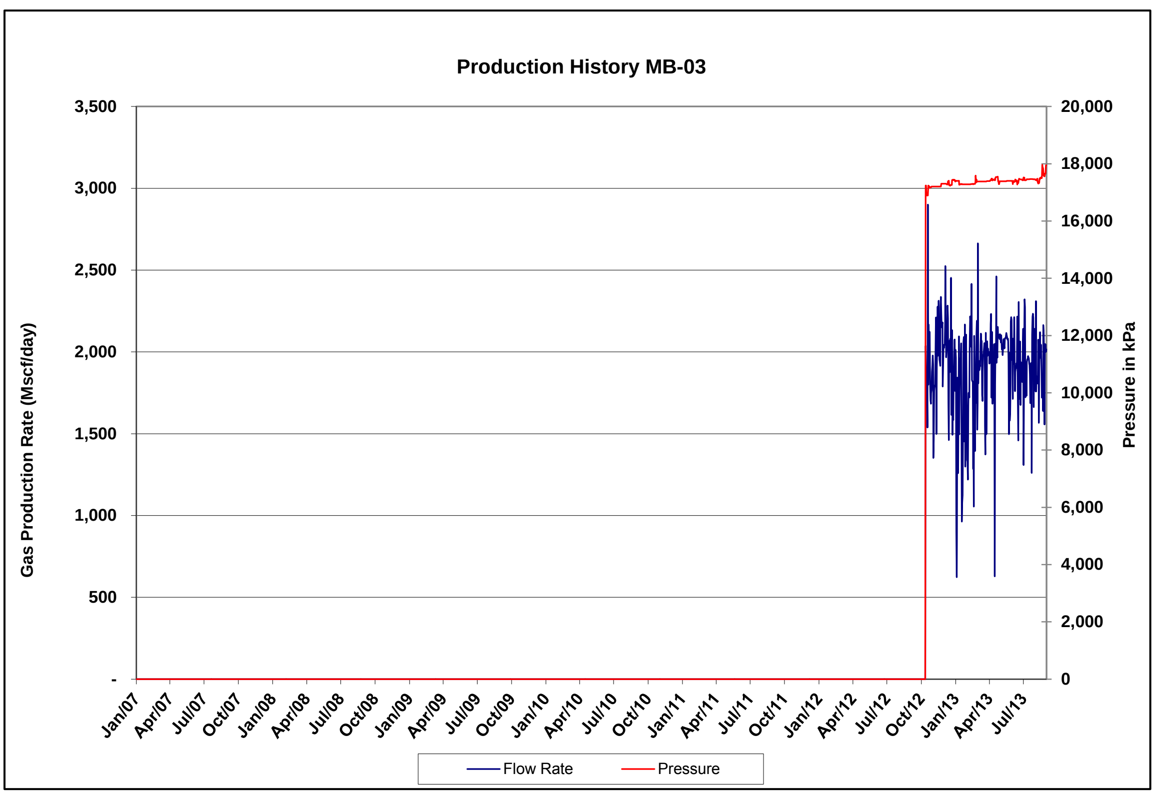

Figure 4-18 Production History MB-03

4.5 Mnazi Bay and Msimbati Resource Base

In carrying out this review, RPS has utilized information and data from Wentworth and has accepted this information and data as presented. The data utilized consists of:

- Seismic interpretation maps and cross sections
- Interpreted well logs and well log evaluations from MB-1, MB-2-ST2, MB-3 and MS-1X.
- DST and production testing reports from MB-1, MB-2-ST2, MB-3 and MS-1X.

RPS has reviewed the aforementioned information, interpretations and data and feels assured that the data is reasonable. However, all data has been accepted as presented and has not undergone due diligence to verify its accuracy.

4.5.1 Resource Determination Methodology

A volumetric probabilistic methodology has been utilized to determine in-place and recoverable resource volumes. The inputs for the probabilistic analysis are comprised of:

- Gross Rock Volumes: determined from the Geostatistical static reservoir model.
- Net/Gross pay ratio: determined by statistical analysis of the log evaluations, by layer, for each of the four wells.
- Porosity: determined by statistical analysis of the log evaluations, by layer for each of the four wells.
- Water Saturation: determined by statistical analysis of the log evaluations, by layer for each of the four wells.
- Gas Formation Volume Factor: determined from gas analysis data from the MB-2 well.
- Recovery Factor: determined by calculated material balance depletion calculations, using assumed reasonable average reservoir abandonment pressures.

4.5.2 Gross Rock Volume

From the 3D static model, the gross rock volume (“GRV”) above fluid contacts for each of the reservoir zones was derived for each zone in both the Mnazi Bay and Msimbati fields. For both the Mnazi Bay and Msimbati fields, it is recognized that some uncertainty in GWC depth remains. A GRV of ±25% was used for the low and high side cases to account for the variation in the GWC and the accuracy of measuring volumes using seismic interpretations. For the Mnazi Bay field, the mapped area of the Mnazi Bay channel down to the GWC depths previously listed were used to define the GRV, most likely case for hydrocarbon in place determination. The low side and high side cases were defined as being ± 25% of the most likely GRV.

For the Msimbati field, the most likely GRV was defined down to the GWC within the Upper and Lower Msimbati sands. The low and high side cases were defined as being ± 25% of the most likely GRV.

The GRV of the Msimbati NE and Msimbati NE Extension fields was defined by using a GWC equivalent to the average GWC of the Upper and Lower Msimbati sands for the low case. The most likely GRV was defined based on a GWC equal to the Upper Mnazi Bay. The high case GRV was defined using a GWC equal to the lower Mnazi Bay.

A summary of the derived gross rock volumes and areas of each layer is shown in:

Volumetrics to GWC			
Formation	Low (e6 m3)	Probable (e6 m3)	High (e6 m3)
Upper Msimbati	1337.2	1782.9	2228.6
Lower Msimbati	3.4	4.5	5.7
Msimbati NE	69.9	1657.2	1726.6
Msimbati NE Extension	0.1	372.2	695.8
Upper Mnazi	3035.7	4047.7	5059.6
Lower Mnazi	405.7	540.9	676.2

Table 4-10: Volumes to Gas:Water Contact

4.5.3 Initial Hydrocarbons in Place

The original gas in place for the Mnazi Bay reservoir accumulation was derived volumetrically, using a probabilistic analysis. A probabilistic simulation was run using the above inputs to define distributions of each of the variables:

- Gross rock volume: A triangular distribution was input, with the P_{50} volumes defined by seismic mapping and log data of the top and bottom of the sand packages of the four wells. The P_{90} was defined as 75% of the P_{50} gross rock volume, and the P_{10} was defined as 125% of the P_{50} value.
- Net Pay to Gross Pay ratio: A lognormal distribution for each of the sand packages was utilized, with the mean value as determined by the petrophysical analysis for each layer, and a standard deviation of 25% of the mean value.
- Water Saturation: A log normal distribution was input for each layer, with the mean and standard deviation as determined from the Petrophysical analysis statistics.
- Gas Formation Volume Factor: A log normal distribution was used, with a mean value for each formation calculated using the PVT analysis of MB-02-ST2 and the initial reservoir pressure at MPP of each formation. B_g varies between 0.005673 in Lower Mnazi Bay to 0.006784 in Upper Msimbati.

The original gas in place estimates, derived from the probabilistic analysis, are shown for the formations and the total of all of the formations in Figure 4-19.

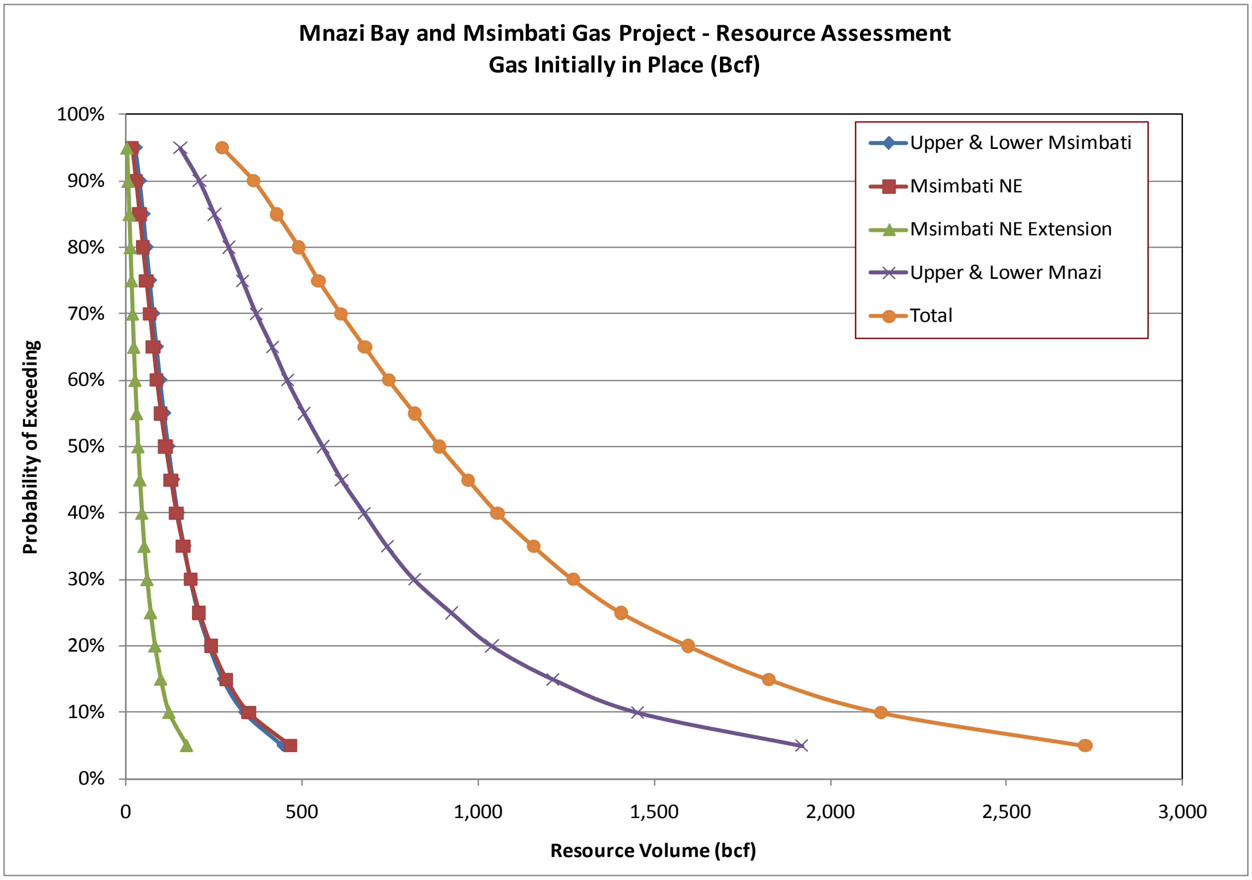

Figure 4-19: Mnazi Bay, Msimbati Resource Assessment - Initial Gas in Place (Bscf)

4.5.4 Technically Recoverable Resources

The volume of gas ultimately recoverable is a function of both technical factors governing the flow rates and gas deliverability of the gas reservoirs and economic factors governing the commerciality of potential gas recovery schemes. The recoverable resource estimates in this report deal only with the technical recovery factors for the whole field, and do not account for the commercial factors which would impact field development limitations and economic limits to ultimate recovery. When economic limits are applied, the volumes may be less than the technical recoverable volumes cited here.

The ultimate technical recovery for the Mnazi Bay gas resources has been estimated using a material balance calculation of reservoir pressure depletion, and assumed final reservoir abandonment pressures.

The material balance based pressure function, for the gas properties of the Mnazi Bay reservoirs is shown on Figure 4-20. Converting this plot to derive recovery factor as a function of abandonment pressure is shown in Figure 4-21. Inspection of the chart shows that for assumed abandonment pressures of about 1,100 psia, 750 psia and 500 psia yields recovery factors of about 65%, 75% and 85% respectively. These material balance derived recovery factors are deemed to be reasonable for the quality of gas sands at Mnazi Bay, and were used to define the triangular distribution inputs for the probabilistic calculation of recoverable resources.

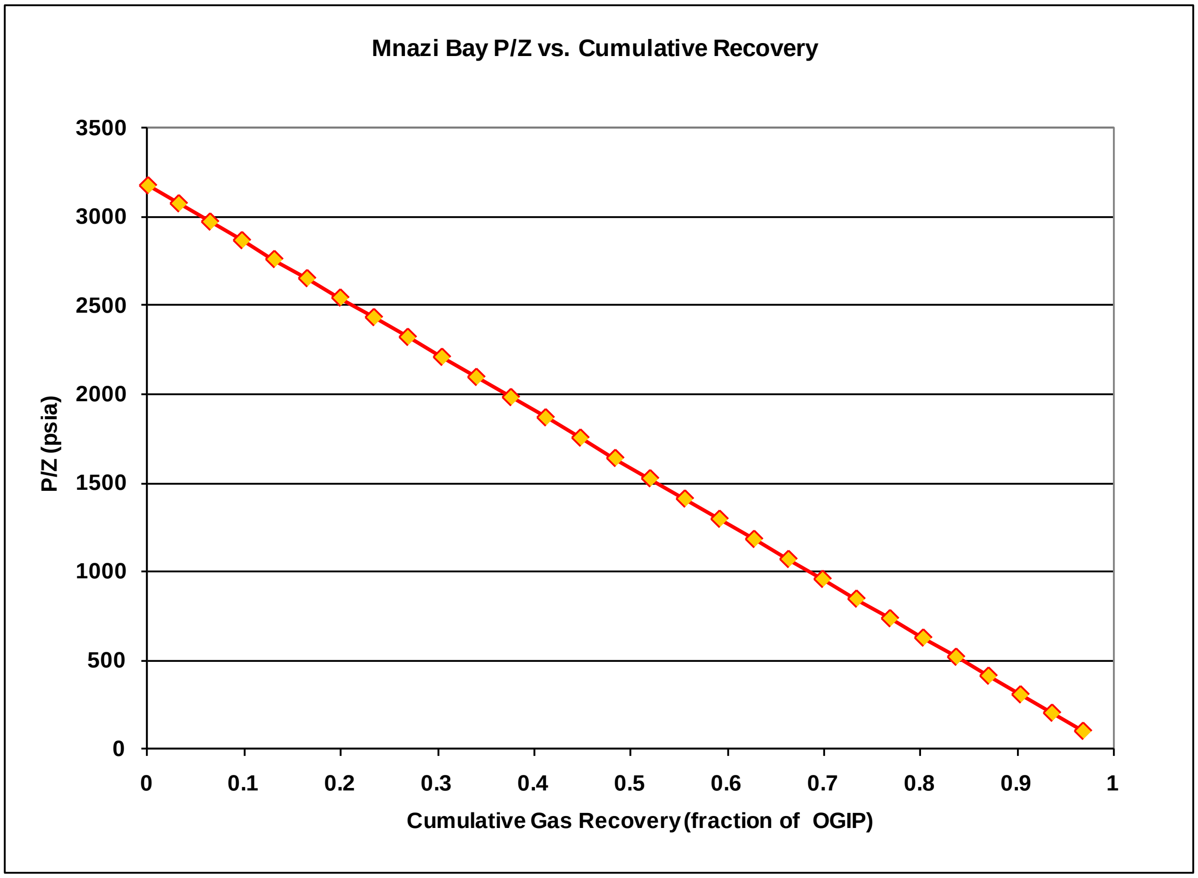

Figure 4-20: Mnazi Bay & Msimbati Cumulative Recovery

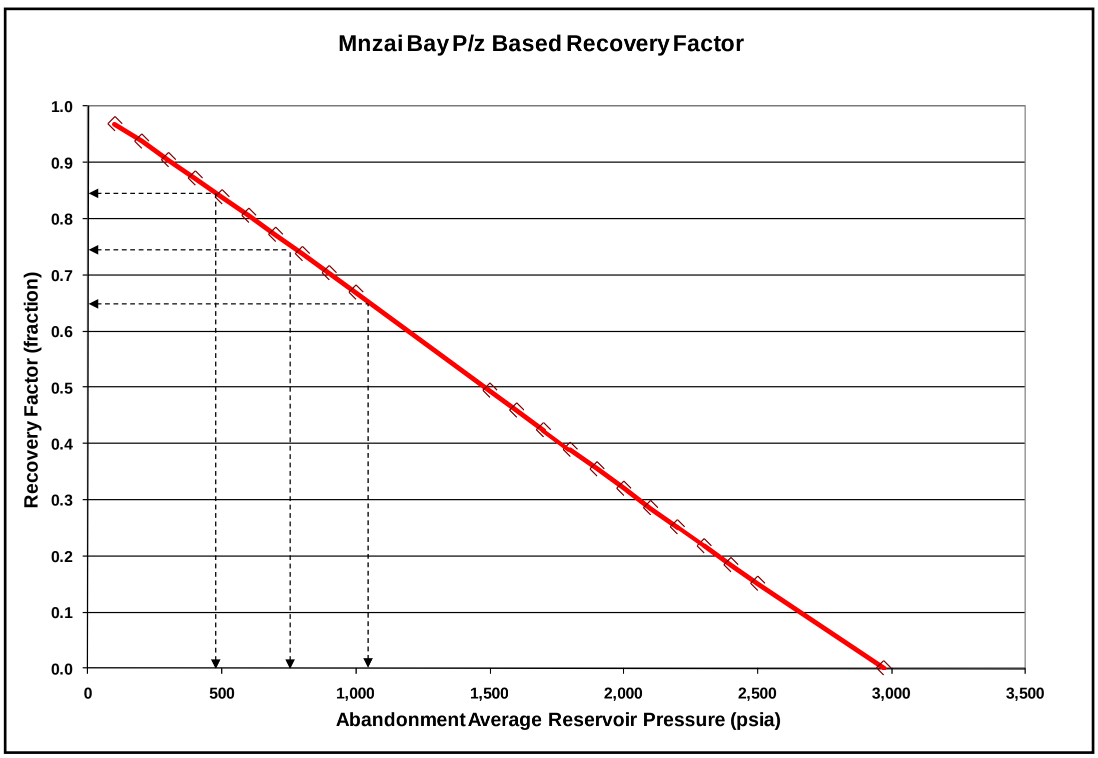

Figure 4-21: Mnazi Bay & Msimbati Recovery Factor

The above inputs were used in a probabilistic simulation, using Latin Hypercube sampling and 20,000 iterations. The resulting distributions of original gas in place and technically recoverable gas are shown in Figure 4-22 and summarized here.

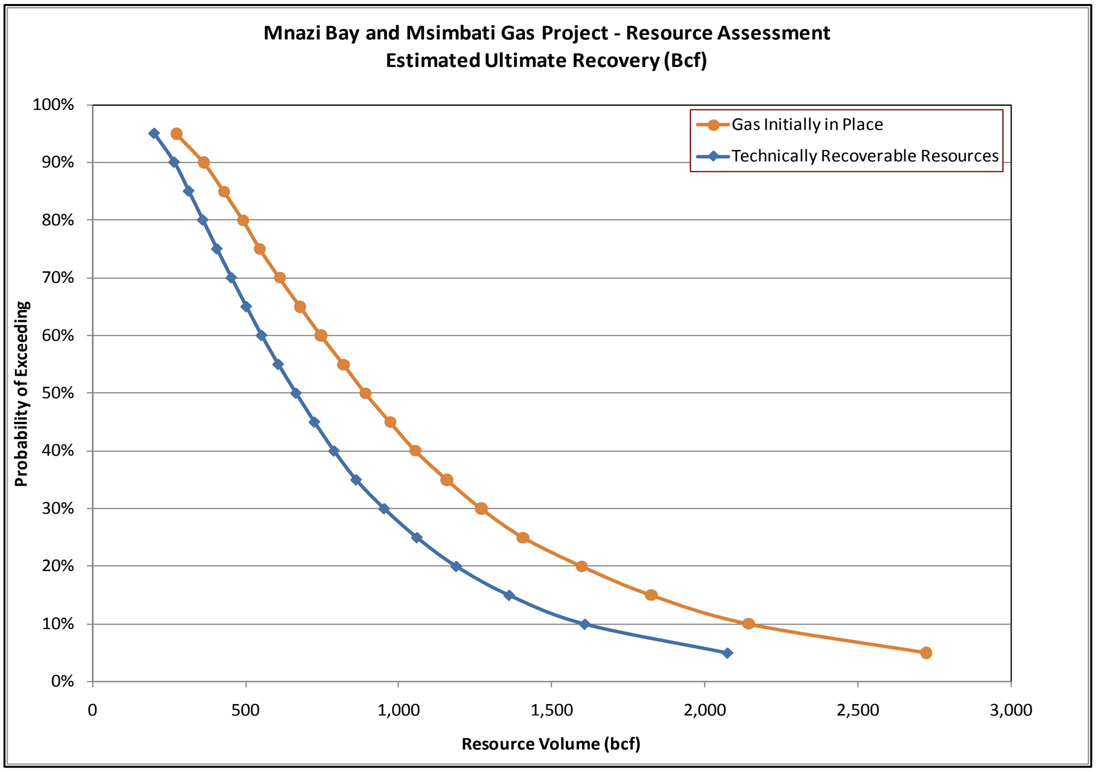

Figure 4-22: Mnazi Bay and Msimbati Gas Project Resource Assessment - Estimated Ultimate Recovery (Bscf)

4.5.5 Resource Classifications

4.5.5.1 Commercially Recoverable Resources

All of the potentially recoverable resource quantities for the Mnazi Bay and Msimbati Gas fields have been designated contingent resources. The resources are listed as contingent resources and not as reserves for several reasons relating to commerciality and relatively limited amount of data currently available as further outlined below.

4.5.5.2 Contingent Resources

Contingent resources are defined as those resource quantities potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.

Estimated ultimate technically recoverable (EUR) resources refers to volumes of hydrocarbons that could potentially be recovered, up to the limits of physics, without relating to any specific development plan or economic conditions and do not relate to any specific potential commercial development. The estimated ultimate recoverable resources referred to in this report are contingent resources.

In this evaluation all of the resources have been categorized as contingent, as at the effective date of this report business contingencies remain to be fulfilled before the resources can be deemed to be commercial. The primary contingency for commercialisation is the development of natural gas markets in the area. However, as activities are ongoing to justify commercial development in the foreseeable future, all contingent resources are classified as "Development Pending".

The volumes, as derived in the aforementioned probabilistic analysis are summarized in Table 4-11:

Mnazi Bay & Msimbati Resource Estimates - GIIP				
Field	P90	P50	Mean	P10
	bscf	bscf	bscf	bscf
Upper & Lower Msimbati	42	122	166	334
Msimbati NE	30	112	161	347
Msimbati NE Extension	7	36	56	125
Upper & Lower Mnazi	210	561	730	1,442
Total	365	892	1,112	2,117
* Totals determined probabilistically and do not sum arithmetically except at the mean values.				

Table 4-11: Mnazi Bay & Msimbati Resource Estimate – Gas Initially in Place

Mnazi Bay & Msimbati Resource Estimates - EUR				
Field	P90	P50	Mean	P10
	bscf	bscf	bscf	bscf
Upper & Lower Msimbati	31	91	124	252
Msimbati NE	22	84	121	261
Msimbati NE Extension	5	27	42	93
Upper & Lower Mnazi	156	419	547	1,085
Total	271	667	834	1,594
* Totals determined probabilistically and do not sum arithmetically except at the mean values.				

Table 4-12: Mnazi Bay & Msimbati Resource Estimate – Estimated Ultimate Recoverable Resource

5.0 MNAZI BAY LICENCE – PROSPECTIVE RESOURCES

RPS has identified six prospects on the Mnazi Bay Licence utilising 2D seismic data supplied by Wentworth. The 2D seismic was interpreted for stratigraphic and structural features in Tertiary and Cretaceous aged sediments. This interpretation was supported by previous assessments in the area completed by Maurel et Prom, Cove Energy and Artumas.

The six prospects are:

- Nanguruwe
- Nanguruwe West
- Nanguruwe North
- Mwambo
- OSX -1
- OSX -2

For ease of comparison, RPS has used the same naming convention as previously adopted by Maurel et Prom and partners for proposed wells and prospects. Five horizons were interpreted across the area of interest to classify the prospects by formation age. These horizons were Pliocene, Miocene, Oligocene, Eocene and Cretaceous. . There are 6 potential well locations identified to date, with each location exhibiting single or stacked Tertiary through to Cretaceous aged prospects (Figure 5-1).

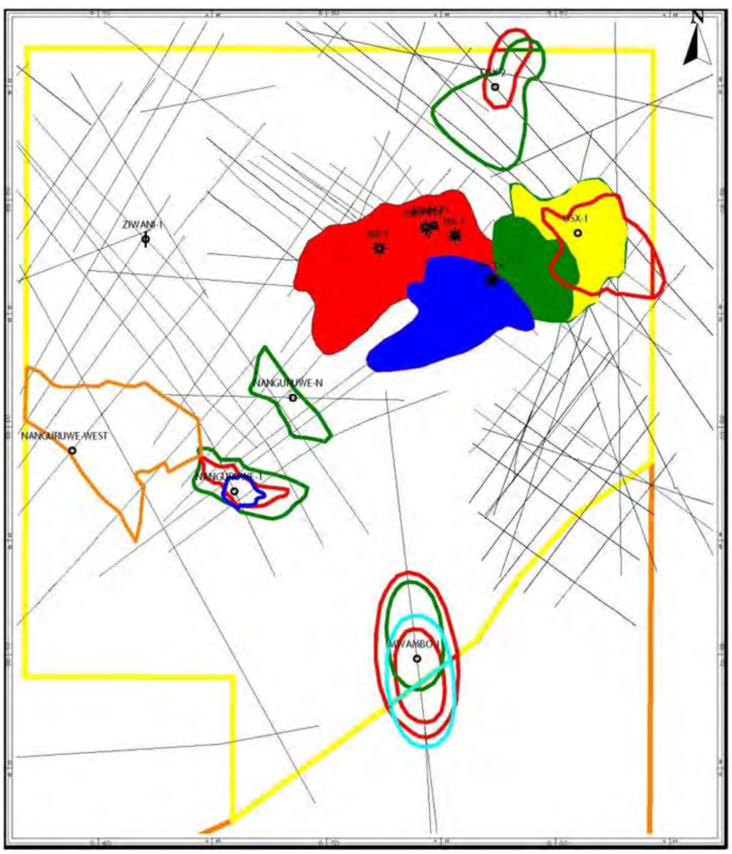

Figure 5-1: Map View of the 6 Prospect Locations

Note: Pliocene prospects are shown as open dark blue, Miocene in red, Oligocene in green, Eocene in light blue and Cretaceous in orange polygons. The Tanzania licence block is in yellow, shoreline is a brown line and Mnazi/Msimbati discoveries are denoted by *the solid filled polygons. In some prospect locations there are multiple Miocene anomalies, and therefore multiple red polygons for the prospect.*

5.1 Seismic Interpretation

Nanguruwe -1

Nanguruwe -1 is an onshore prospect with three stacked structural targets; ST-P-2, ST-M-5 and ST-O-3. A fault system was interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closures. Each prospective horizon was gridded and polygons were drawn in map view (Figure 5-2) to delineate the extents of the isolated closures.

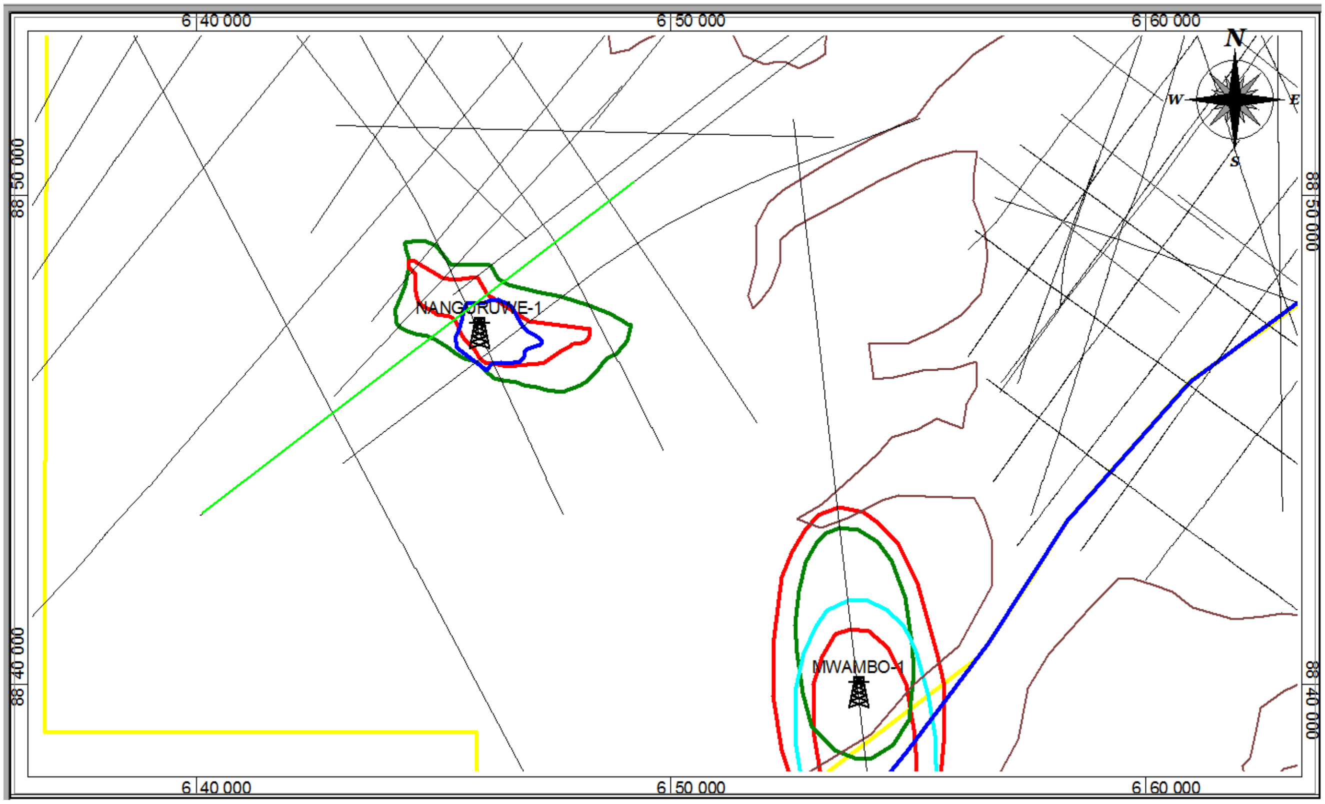

Figure 5-2: Map View of the Nanguruwe -1 Proposed Location.

Note: Pliocene anomalies are shown in dark blue, Miocene in red, and Oligocene in green.

The light green line in Figure 5-2 represents the seismic line shown in Figure 5-3.

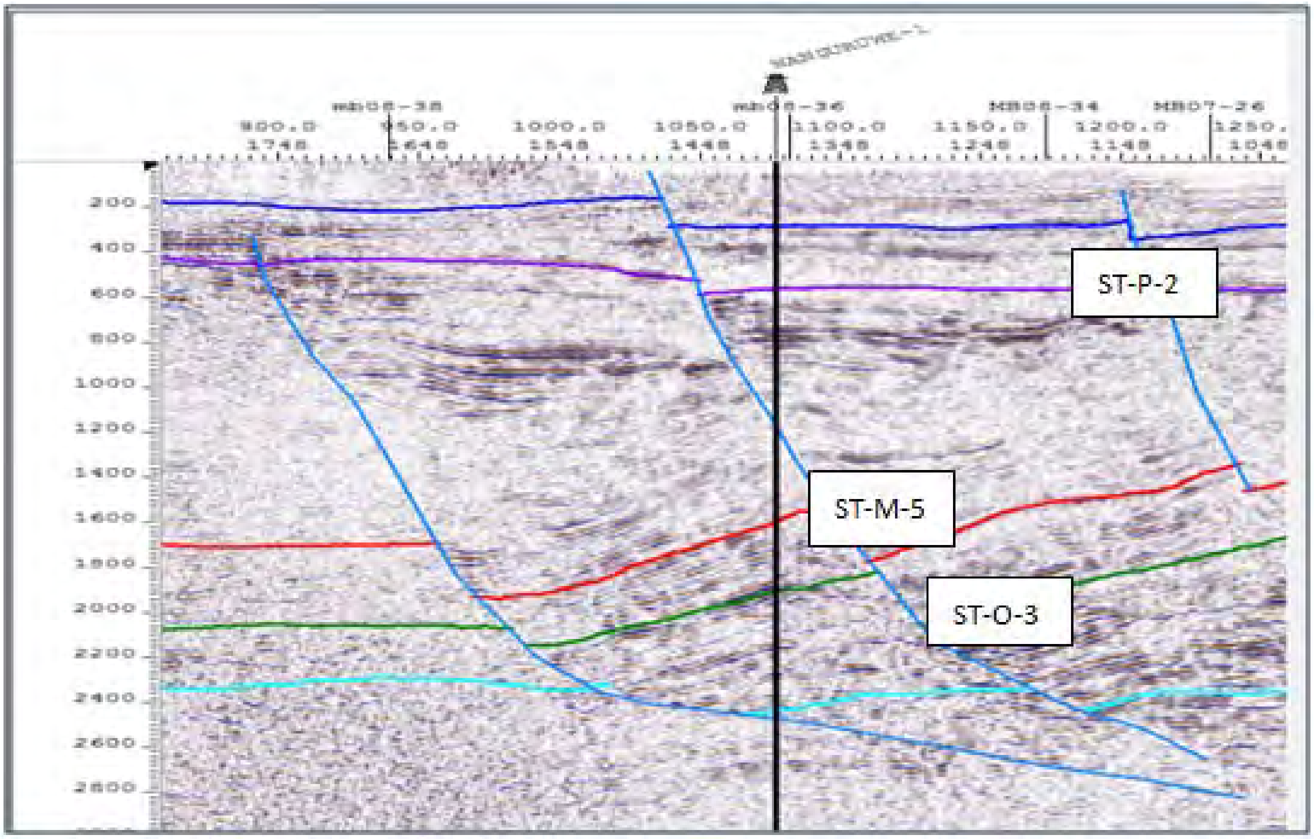

Figure 5-3: Seismic Line through Nanguruwe Prospect

Note: The Pliocene horizon is shown in dark blue, Intra-Pliocene in purple, Miocene in red, Oligocene in green and Eocene in light blue.

Nanguruwe-West

Nanguruwe West is an onshore prospect with a single Cretaceous target. This structural feature is bounded to the west by a north-south trending fault. The top of the structure was interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closures. Polygons are drawn in map view to delineate the extents of the isolated closure.

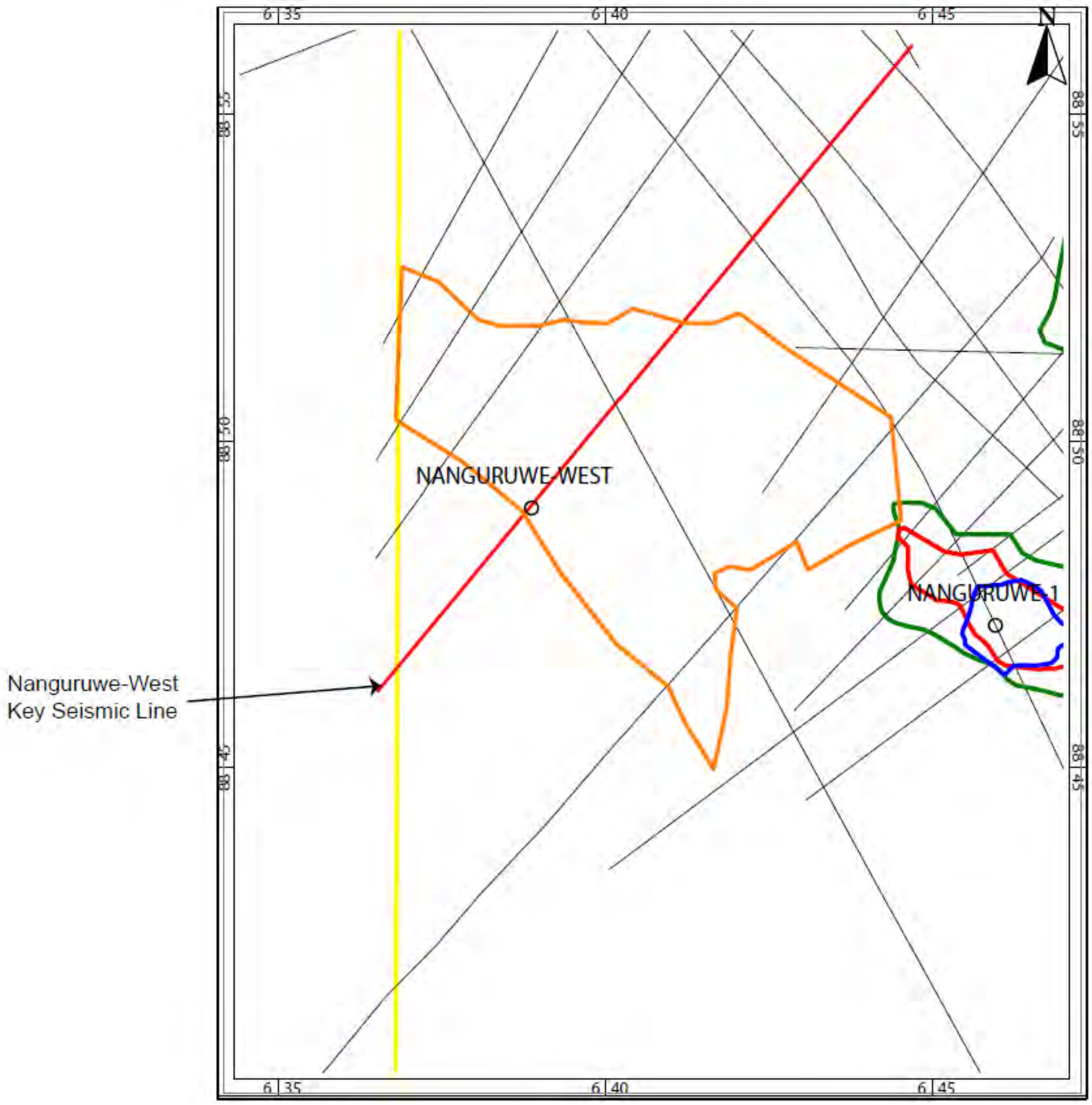

Figure 5-4: Map View of the Nanguruwe - West Cretaceous Prospect and Proposed Location.

The red line in Figure 5-5 shows the location of the seismic line shown in Figure 5-5.

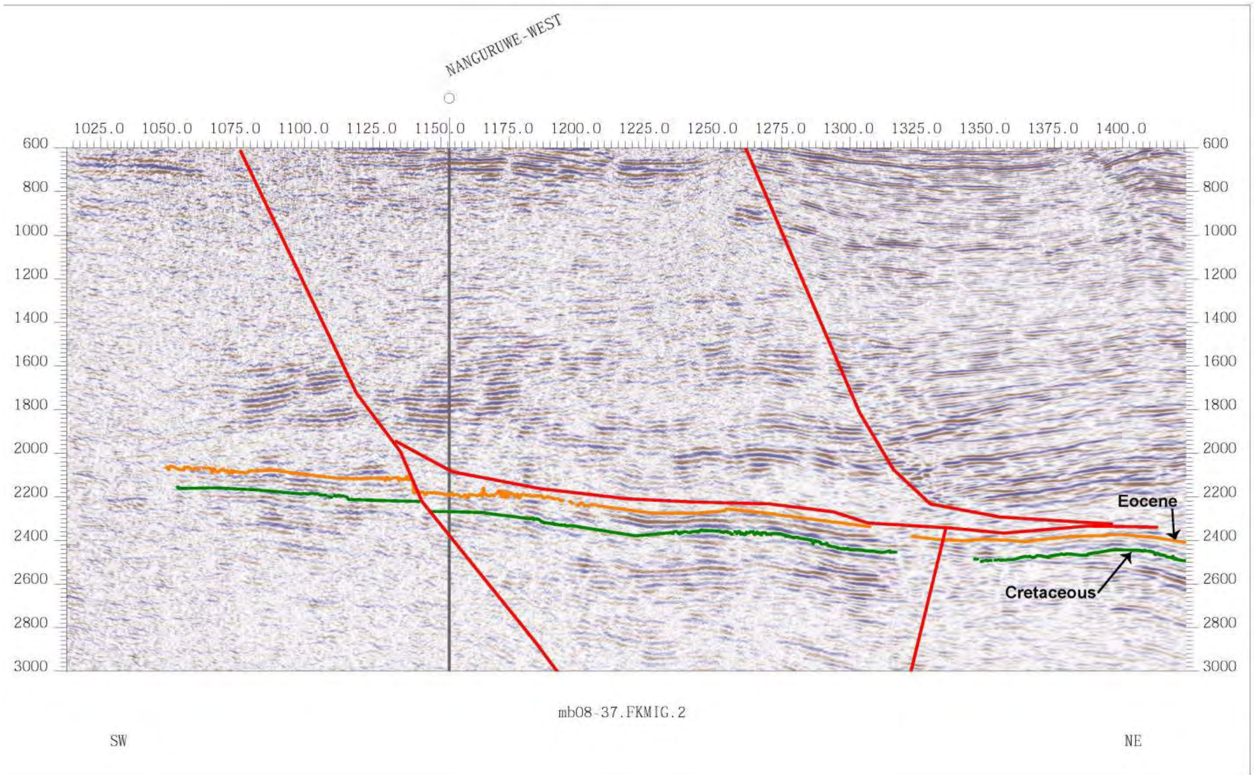

Figure 5-5: Seismic Line through Nanguruwe-West.

Nanguruwe-North

Nanguruwe-North is an Oligocene structural prospect bounded to the east by a northwest-southeast trending fault. The top of the structure was interpreted and the horizon was gridded with the fault to determine the lateral extent of the isolated closures. Polygons are drawn in map view (Figure 5-2) to delineate the extents of the isolated closure.

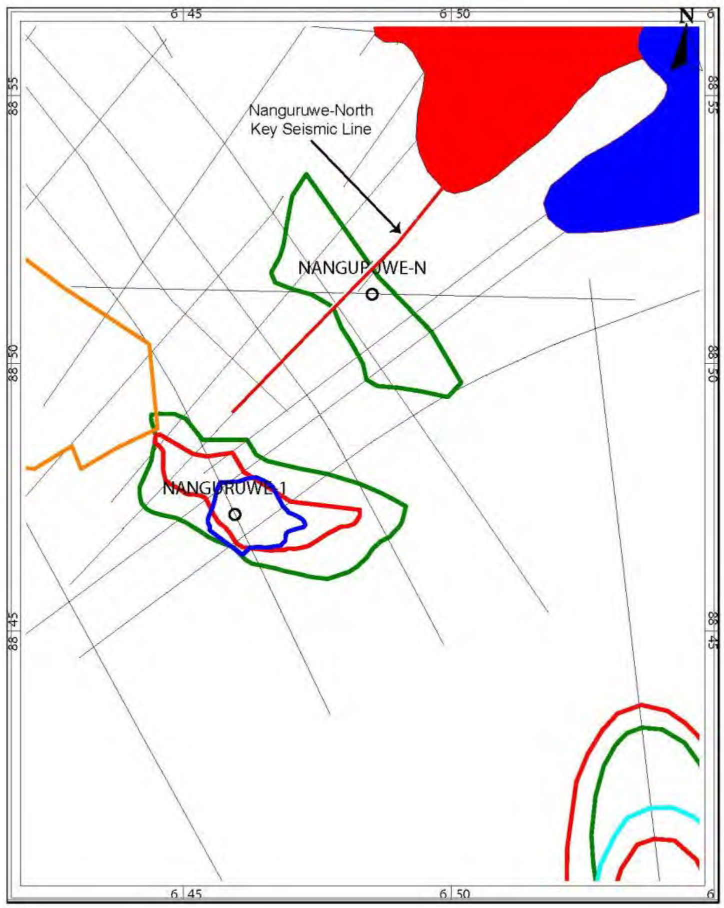

Figure 5-6: Map View of the Nanguruwe-North Proposed Location

Note: Oligocene anomally is shown in green.

The light red line in Figure 5-6 shows the location of the seismic line shown in Figure 5-7.

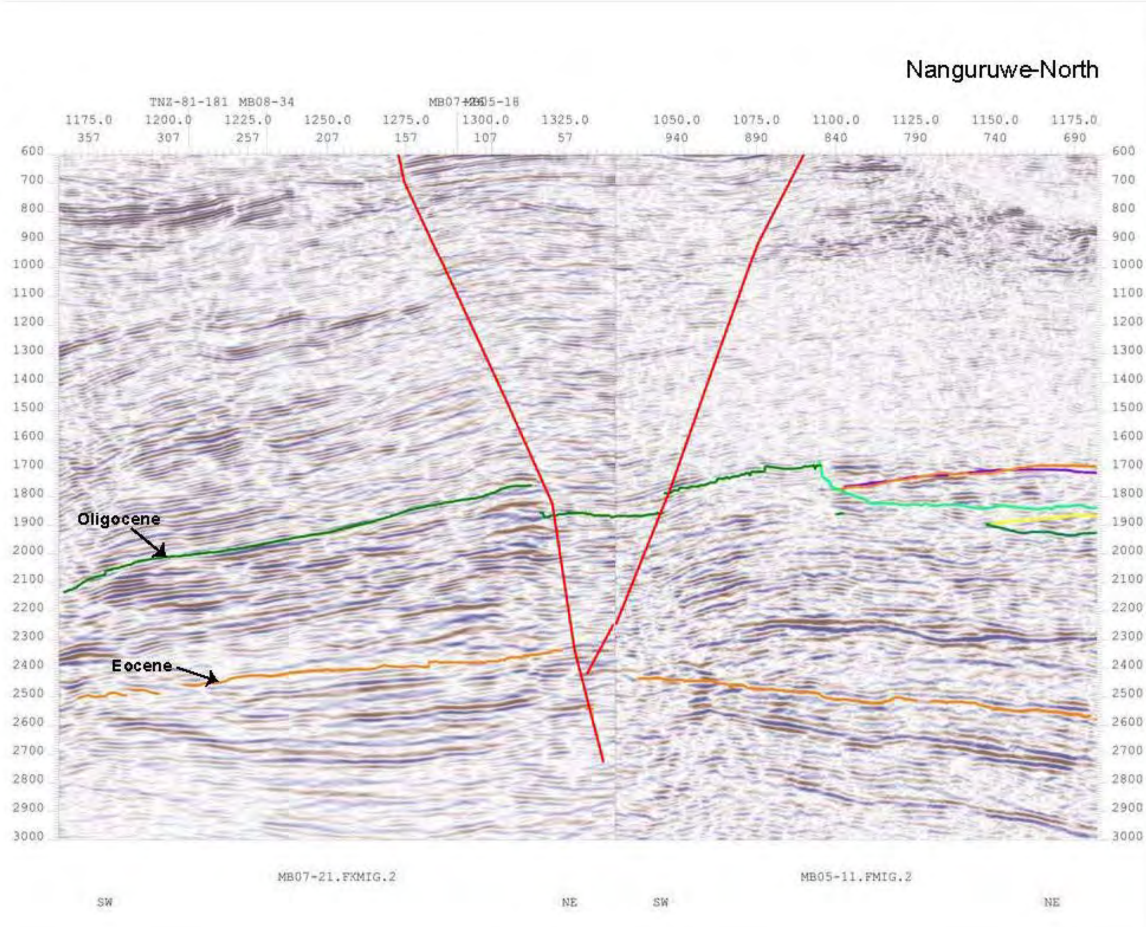

Figure 5-7: Seismic Line through Nanguruwe-North.

Mwambo -1

Mwambo -1 is an onshore prospect with four stacked stratigraphic targets; SG-M-BA-2, SG-M-3, SG-O-4 and SG-E-1. The tops and bases of the stratigraphic features were interpreted based on seismic character and anomalous amplitudes. There was only one seismic line that passed through these sand bodies therefore a best estimate was made of the lateral extents. The channel body width was estimated by halving the length seen on the seismic line (Figure 5-8). There is significant uncertainty in the shape of these sand bodies.

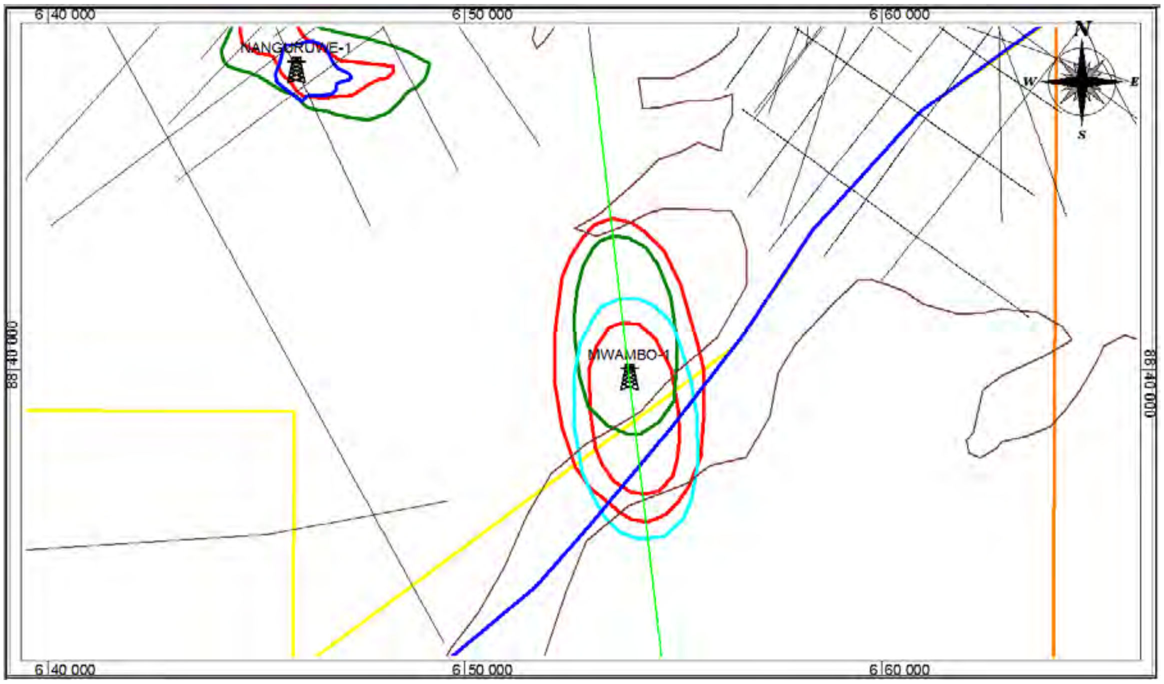

Figure 5-8: Map View of the Mwambo -1 Proposed Location.

Note: Miocene anomalies are shown in red, Oligocene in green and Eocene in light blue.

The light green line in Figure 5-8 represents the seismic line shown in Figure 5-9.

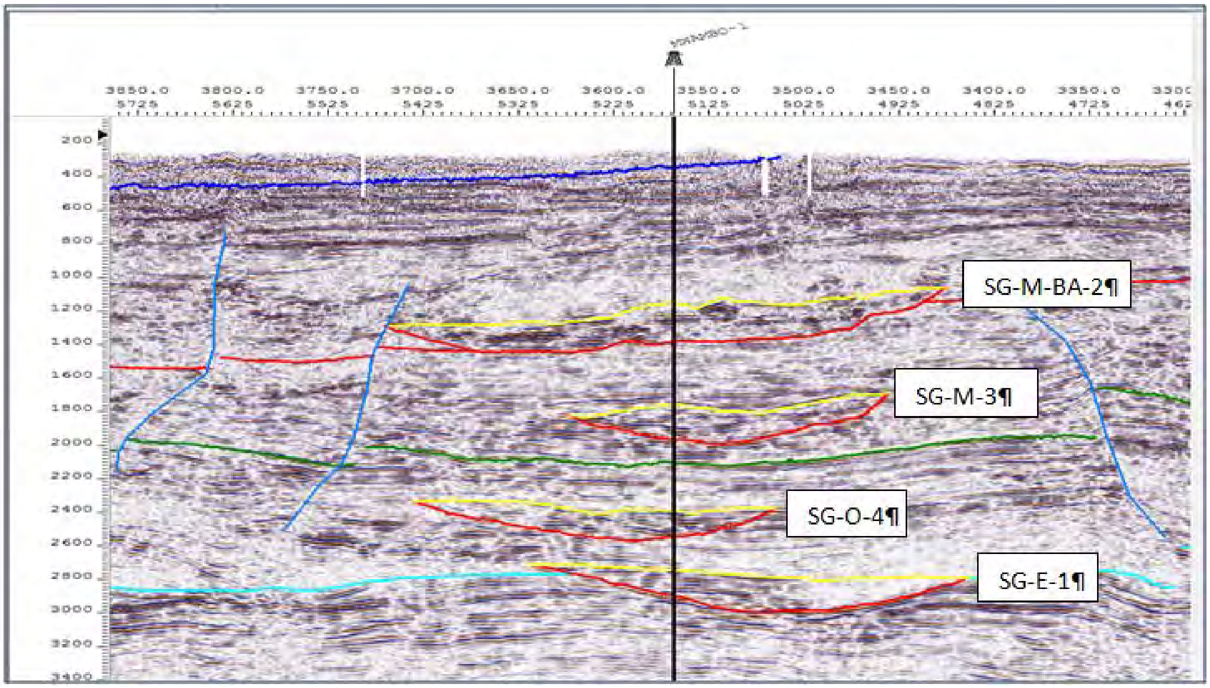

Figure 5-9: Seismic Line through Mwambo -1.

Note: The Pliocene horizon is shown in dark blue, Miocene in red, Oligocene in green and Eocene in light blue. From surface to basement the prospective horizons identified on this section are SG-M-BA-2, SG-M-3, SG-O-4 and SG-E-1.

OSX-1

OSX-1 is an offshore prospect with two stacked stratigraphic targets; SG-M-2 and SG-MSNE. The tops and bases of the stratigraphic features were interpreted based on seismic character and anomalous amplitudes. These interpretations were made on all of the lines in the vicinity and polygons were drawn in map view to delineate the extents of the sand bodies (Figure 5-10).

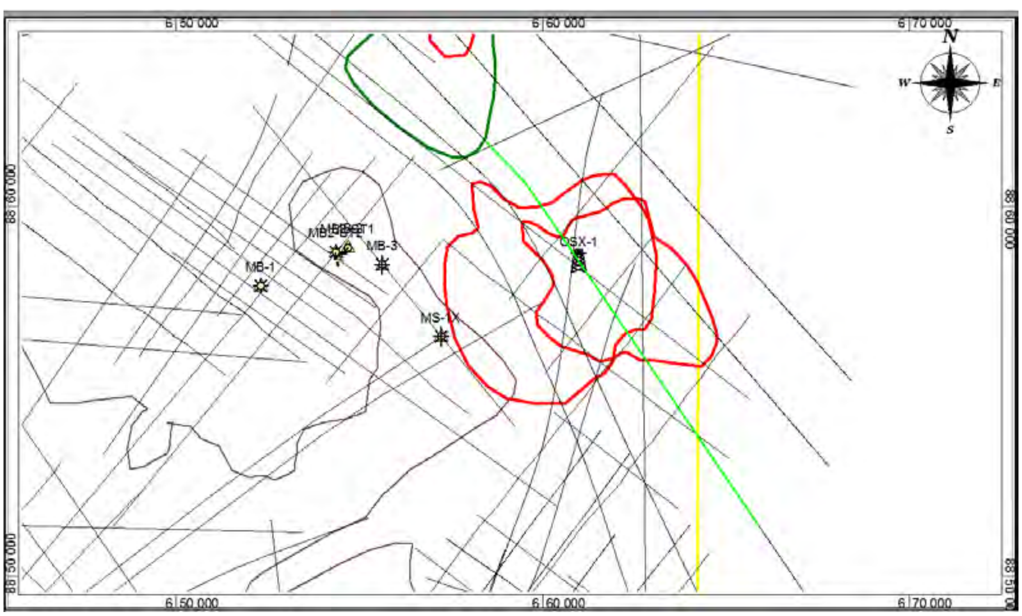

Figure 5-10: Map View of the OSX -1 Proposed Location.

Note: Miocene anomalies are shown in red.

The light green line in Figure 5-10 represents the seismic line shown in Figure 5-11.

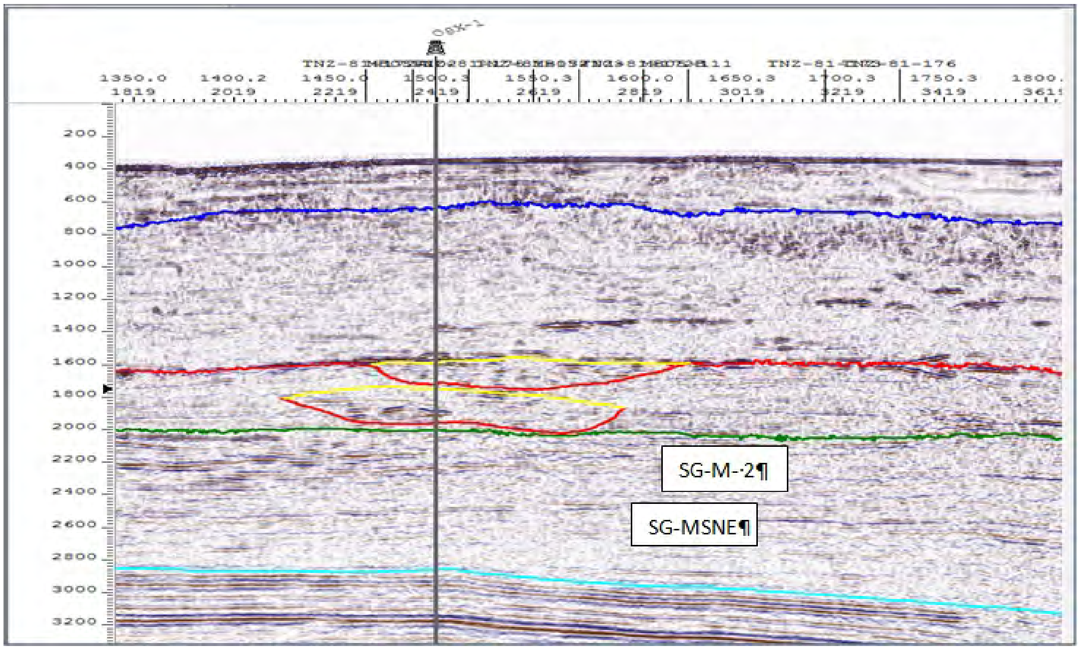

Figure 5-11: Seismic Line through OSX -1.

Note: The Pliocene horizon is shown in dark blue, Miocene in red, Oligocene in green and Eocene in light blue. From surface to basement the prospective horizons identified on this section are SG-M-2 and SG-MSNE.

OSX-2

OSX-2 is an offshore prospect with two stacked stratigraphic targets; SG-M-BA-1 and SG-O-BA-1. The tops and bases of the stratigraphic features were interpreted based on seismic character and anomalous amplitudes. These interpretations were made on all of the lines in the vicinity and polygons were drawn in map view (Figure 5-12) to delineate the extents of the sand bodies.

Figure 5-12: Map View of the OSX-2 Proposed Location

Note: Miocene anomalies are shown in red and Oligocene in green.

The light green line in Figure 5-12 represents the seismic line shown in Figure 5-13.

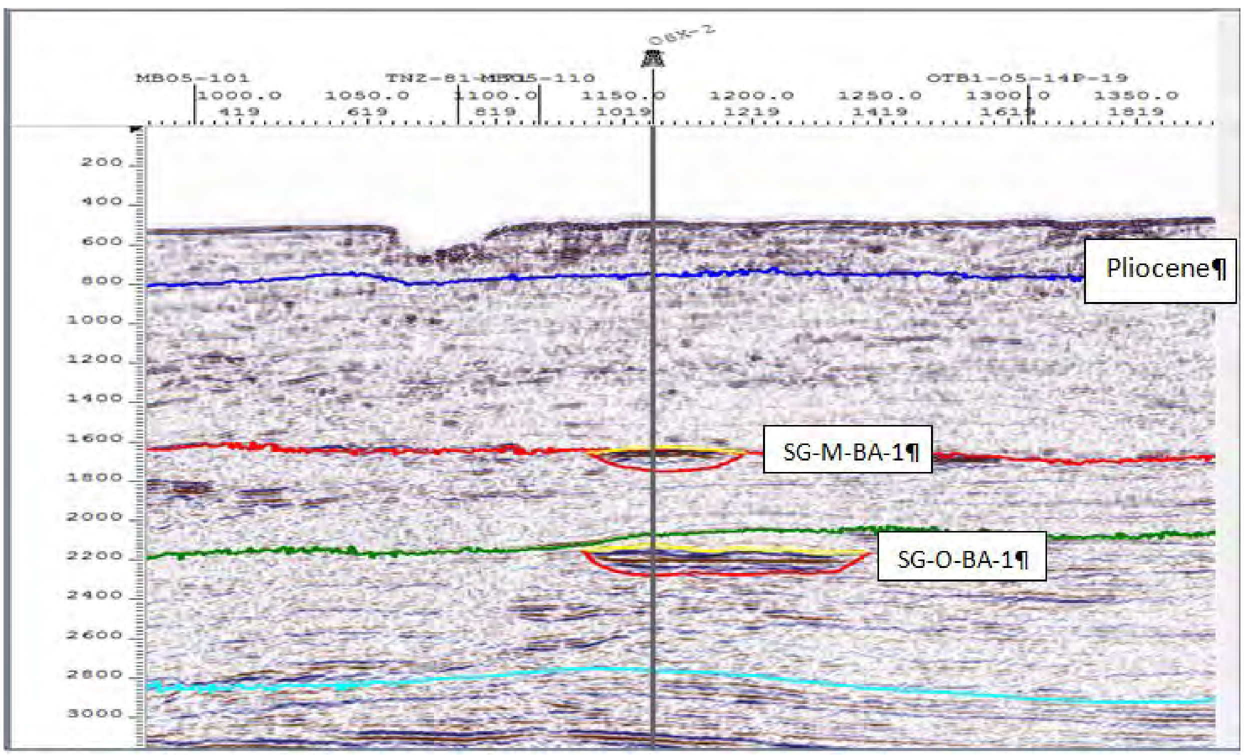

Figure 5-13: Seismic Line through OSX-2

Note: The Pliocene horizon is shown in dark blue, Miocene in red, Oligocene in green and Eocene in light blue. From surface to basement the prospective horizons identified on this section are SG-M-BA-1 and SG-O-BA-1.

5.2 Geological Description

For all prospects, except Nanguruwe-1 and Nanguruwe West the gross rock volumes were estimated using depth grids created from the top and bottom of the interpreted sand packages. A constant velocity depth conversion was used to convert the time surfaces to depth. An average velocity of 2700 m/s was calculated off of the Mnazi bay channel interval from the sonic logs run at the Mnazi Bay wells. The Mnazi channel package straddled the Miocene/Oligocene boundary. A constant velocity of 2700 m/s was therefore used in the depth conversion for all of the Miocene, Oligocene, and Eocene channel packages. On a large scale it is reasonable to assume that velocity increases with depth. For this reason a slightly lower velocity of 2500 m/s was used to depth convert the shallow Pliocene channel packages. This velocity was estimated by extrapolating the low frequency trend of the sonic logs from existing Mnazi Bay wells. The gross rock volumes for the Nanguruwe and Nanguruwe West prospects were generated by the area of closure and thickness method. The thicknesses were derived from Cretaceous control wells in the basin.

For the stratigraphic prospects, the volumes were calculated for each target three times, varying the reservoir fill (oil water contact depth) to be 30%, 50% and 70%, between the minimum and maximum depths of the sand package. The same process was used for the Nanguruwe–1, Nanguruwe West and Nanguruwe West prospects except that the maximum depth was controlled by the spill point of the feature instead of the top and bottom sand package grids. 100% fullness was assumed to be the high case, the most likely case was a fullness of 70% and the low case was a fullness of 50%.

In some cases, the seismic surfaces extended outside the licence boundary. Volumes used for volumetric calculations have been restricted to those within the licence boundary polygon.

Figure 5-14 below is an example of the isopach maps created for a specific prospect. All maps are included in Appendix 3.

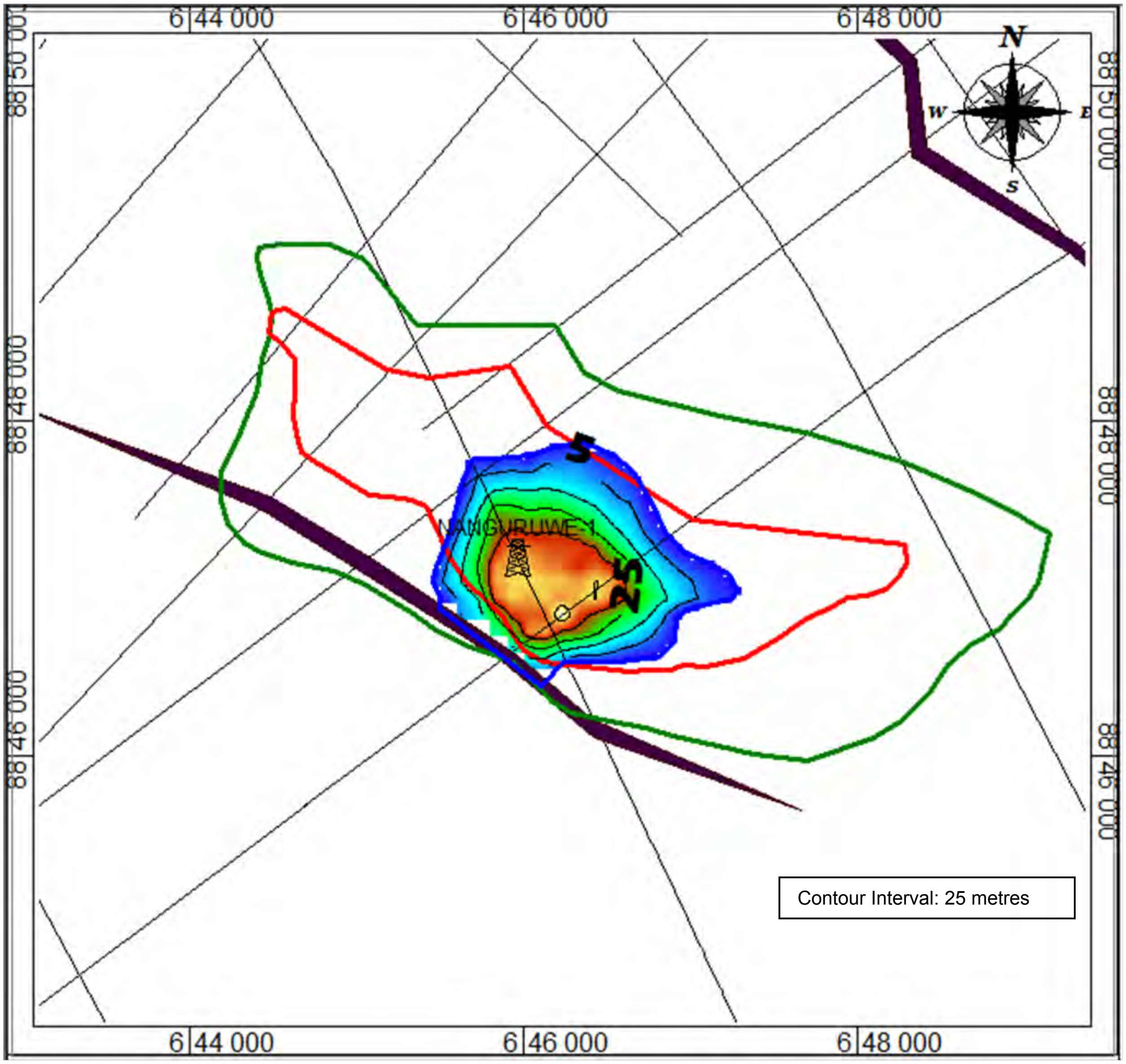

Figure 5-14: Nanguruwe-1 Prospect Isopach Map

5.3 Reservoir Properties

A volumetric probabilistic methodology has been utilized to determine in-place and recoverable resource volumes. The inputs for the probabilistic analysis are comprised of:

- Gross Rock Volumes: determined from the seismic interpretations and in some cases, seismically defined areas and geologically determined thicknesses.
- Net/Gross pay ratio: determined by analysis of the Mnazi Bay log evaluations, together with examples from other Tertiary fields within East Africa to determine a wider range of possible distributions. For the Cretaceous, the pay ratio was defined by the Mocimboa-1 well, in Mozambique.

- Porosity: determined by analysis of the Mnazi Bay log evaluations, together with examples from other Tertiary fields and Cretaceous well control within East Africa to determine a wider range of possible distributions
- Water Saturation: determined by analysis of the log evaluations, by layer for each of the four wells for the Tertiary and by control wells for the Cretaceous
- Gas Formation Volume Factor: determined from gas analysis data from the MB-2 well, adjusted for pressure and temperature gradients
- Recovery Factor: determined using estimates for Mnazi Bay field and also recognizing for a low case that reservoir channel sands in some cases may not be fully connected

The reservoir volume and property inputs for each of the prospects are summarized in the following tables.

Prospect:	Nanguruwe			
Reservoir:	Pliocene			
		P_{90}	Mode	P_{10}
Gross Rock Volume	($10^6 m^3$)	7	14	31
Net/Gross	(%)	12	25	40
Porosity	(%)	16	18	20
S_w	(%)	30	40	55
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0112	0.0109	0.0106
Recovery Factor	(%)	55	70	85

Table 5-1: Nanguruwe - Pliocene Reservoir Properties

Prospect:	Nanguruwe			
Reservoir:	Miocene			
		P_{90}	Mode	P_{10}
Gross Rock Volume	($10^6 m^3$)	25	62	158
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0067	0.0055	0.0049
Recovery Factor	(%)	55	70	85

Table 5-2: Nanguruwe - Miocene Reservoir Properties

Prospect:	Nanguruwe			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	130	315	644
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0048	0.0048	0.0045
Recovery Factor	(%)	55	70	85

Table 5-2: Nanguruwe - Oligocene Reservoir Properties

Prospect:	Nanguruwe West			
Reservoir:	Cretaceous			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	10.4	16.7	23.3
Reservoir Thickness	(m)	180	200	220
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	50
Porosity	(%)	10	15	20
S_w	(%)	40	30	20
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0050	0.0046	0.0043
Recovery Factor	(%)	50	65	80

Table 5-3: Nanguruwe West Cretaceous Reservoir Properties

Prospect:	Nanguruwe North			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	1.1	2.5	4.8
Reservoir Thickness	(m)	80	120	200
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	12	21	30
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0045	0.0043	0.0040
Recovery Factor	(%)	0	0	0

Table 5-4: Nanguruwe North Cretaceous Reservoir Properties

Prospect:	Mwambo			
Reservoir:	Miocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	144	1,021	2,409
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0067	0.0055	0.0049
Recovery Factor	(%)	55	70	85

Table 5-5: Mwambo-1 Miocene Reservoir Properties

Prospect:	Mwambo			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	263	802	1,247
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0048	0.0048	0.0045
Recovery Factor	(%)	55	70	85

Table 5-7: Mwambo-1 Oligocene Reservoir Properties

Prospect:	Mwambo			
Reservoir:	Eocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	305	702	1,026
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0046	0.0045	0.0043
Recovery Factor	(%)	55	70	85

Table 5-8: Mwambo-1 Eocene Reservoir Properties

Prospect:	OSX-1			
Reservoir:	Miocene-1			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	95	645	1,692
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0067	0.0055	0.0049
Recovery Factor	(%)	55	70	85

Table 5-9: OSX-1 Miocene-1 Reservoir Properties

Prospect:	OSX-1			
Reservoir:	Miocene-2			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	884	2,555	4,587
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0067	0.0055	0.0049
Recovery Factor	(%)	55	70	85

Table 5-10: OSX-1 Miocene-2 Reservoir Properties

Prospect:	OSX-2			
Reservoir:	Miocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	75	160	198
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0067	0.0055	0.0049
Recovery Factor	(%)	55	70	85

Table 5-11: OSX-2 Miocene Reservoir Properties

Prospect:	OSX-2			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Gross Rock Volume	($10^6 m^3$)	483	1,035	1,339
Net/Gross	(%)	15	30	50
Porosity	(%)	14	16	20
S_w	(%)	25	40	60
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0048	0.0048	0.0045
Recovery Factor	(%)	55	70	85

Table 5-12: OSX-2 Miocene Reservoir Properties

5.4 Geological Probability of Success

RPS estimate a GPoS (without a commercial cut-off) as the Geological Play Chance multiplied by the Prospect Specific Chance.

The Play Chance, the chance of the play working in the play fairway segment being considered, is estimated using three factors: Source, Reservoir, and Seal. In all cases the assessed chance is the presence and effectiveness of the specified element in the assigned segment of the play fairway. As noted in Section 4 of this report, for the Ruvuma Basin the source is proven to exist and both the reservoir and seal for all four reservoir play styles exist. For the focus area considered (Mnazi Bay – Pliocene, Miocene, Oligocene and Eocene Plays), the Play Chance is therefore taken as 100%.

The overall 'Geological Probability of Success' (GPoS) for a lead or prospect is defined as the product of the Play Chance of Success and each of the lead/prospect location specific risks identified above. Thus, the GPoS is always less than the Play Chance of Success.

Risks which are specific to the prospects within the play can be categorised as follows:

Trap & Timing: chance that a structural / stratigraphic trap exists in a particular location;
Seal: chance that there is an effective top seal in that location;
Charge: chance that the trap is in the hydrocarbon migration path;
Reservoir: chance that reservoir of commercially productive quality exists in the trap.

The prospect-specific chances of success are:

Nanguruwe

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	60%	Faults identified on 2D seismic.
Seal	50%	Reservoir-Seal pairs. Fault required to seal.
Charge	95%	Reservoirs are offset by Mnazi Bay and Msimbati gas discoveries.
Reservoir	60%	Turbidite canyon-fill setting, sands and shale
Total	17%	

Nanguruwe North

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	60%	Faults identified on 2D seismic.
Seal	50%	Reservoir-Seal pairs. Fault must seal.
Charge	95%	Prospects are offset from Mnazi Bay and Msimbati gas discoveries in same reservoir targets.
Reservoir	60%	Turbidite canyon-fill setting, sands and shale as in Mnazi Bay
Total	17%	

Nanguruwe West

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	60%	Faults identified on 2D seismic.
Seal	50%	Reservoir-Seal pairs. Fault must seal.
Charge	95%	Cretaceous petroleum system is proven by the Ntorya-1 discovery, Mocimboa-1 well (gas and oil shows) and successful gas discoveries on and off-shore Tanzania. Access to mature source uncertain.
Reservoir	60%	Turbidite canyon-fill setting, sands and shales. Cretaceous reservoir exists in Likonde-1 well and nearby Ntorya-1 discovery (albeit thin pay zone).
Total	17%	

Mwambo -1

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	35%	P_{10}-P_{90} relies on stratigraphic trap within a channel sandstone, imaged on limited 2D seismic data.
Seal	60%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal..
Charge	95%	Prospects are offset from Mnazi Bay and Msimbati gas discoveries in same reservoir targets.
Reservoir	80%	Turbidite canyon-fill setting, sands and shale as in Mnazi Bay
Total	17%	

OSX -1

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	50%	P_{10}-P_{90} relies on stratigraphic trap within a channel sandstone, offshore seismic data.
Seal	60%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal..
Charge	95%	Reservoirs are offset by Mnazi Bay and Msimbati gas discoveries.
Reservoir	80%	Reservoirs likely, some risk associated with reservoir quality
Total	23%	

OSX -2

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	50%	P_{10}-P_{90} relies on stratigraphic trap within a channel sandstone, offshore seismic data.
Seal	60%	Overlying shales drape over structure. Reservoir-Seal pairs.
Charge	95%	Reservoirs are offset by Mnazi Bay and Msimbati discoveries.
Reservoir	80%	Reservoirs likely, some risk associated with reservoir quality
Total	23%	

5.5 Prospective Resources – Results Summary

The resources for the five prospects at Mnazi Bay have been estimated using a probabilistic volumetric methodology. As these resources are undiscovered, they have been classified as Prospective Resources.

For each individual prospect, the results of the probabilistic assessment are shown below on a whole prospects (100% WI) basis. These are presented in both the un-risked total volumes as well as the consolidated risked volumes in the following tables. Note that the distributions have been derived using probabilistic evaluation, and will not sum arithmetically, except at the mean values.

Mnazi Nanguruwe	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**
Pliocene	0.4	1.4	3.2	1.6	0.3	0.9	2.1	1.0
Miocene	3.6	14	36	18	2.3	9	24	12
Oligocene	21	75	181	90	13	48	118	59
Mnazi Nanguruwe-1 - Stochastic Total(1)	38	96	202	110	23	62	133	72
Mnazi Nanguruwe-1 - Stochastic Total(2)	**1.0**	**19**	**128**	**44**	**0.6**	**12**	**83**	**29**
Mnazi Nanguruwe-1 - Stochastic Total Risked(3)				**19**				**12**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-13: Mnazi Nanguruwe Prospect

Mnazi Nanguruwe-West	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**
Cretaceous	239	594	1,247	682	138	354	769	415
Mnazi Nanguruwe-West - Stochastic Total Risked(3)				**102**				**62**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-15: Mnazi Nanguruwe-West Prospect

Mnazi Nanguruwe-North	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**
Oligocene	24	85	225	109	14	51	136	66
Mnazi Nanguruwe-North - Stochastic Total Risked(3)				**19**				**11**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-16: Mnazi Nanguruwe-North Prospect

Mnazi Mwanbo	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Miocene	49	211	554	266	31	136	364	174
Oligocene	42	154	359	182	27	100	235	119
Eocene	47	144	318	166	29	93	208	109
Mnazi Mwanbo-1 - Stochastic Total(1)	298	572	975	**612**	191	369	640	**399**
Mnazi Mwanbo-1 - Stochastic Total(2)	**51**	**191**	**501**	**242**	**32**	**122**	**326**	**158**
Mnazi Mwanbo-1 - Stochastic Total Risked(3)				**102**				**66**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-17: Mnazi Mwambo Prospect

Mnazi OSX-1	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Miocene1	33	145	386	184	21	94	254	120
Miocene2	122	451	1,083	542	78	289	709	354
Mnazi OSX-1 - Stochastic Total(1)	257	643	1,292	723	164	414	847	471
Mnazi OSX-1 - Stochastic Total(2)	**58**	**286**	**926**	**406**	**37**	**184**	**605**	**265**
Mnazi OSX-1 - Stochastic Total Risked(3)				**162**				**106**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-18: Mnazi OSX-1 Prospect

Mnazi OSX-2	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Miocene	8.7	24	51	27	5.5	16	33	18
Oligocene	69	193	407	219	43	124	267	143
Mnazi OSX-2 - Stochastic Total(1)	95	222	434	248	61	142	287	161
Mnazi OSX-2 - Stochastic Total(2)	**14**	**79**	**340**	**137**	**8.7**	**50**	**221**	**89**
Mnazi OSX-2 - Stochastic Total Risked(3)				**55**				**36**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 5-19: Mnazi OSX-2 Prospect

Wentworth owns a 39.925% working interest in the Mnazi Bay licence area. The following tables show the prospect volumes owned by Wentworth according to their working interest.

Mnazi Licence Prospective Resources	100% Full Field				Wentworth 39.925% WI					
	Prospective Gas Resources (Unrisked)				Prospective Gas Resources (Unrisked)				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Nanguruwe	23	62	133	72	9.2	25	53	29	17%	Maurel & Prom
Nanguruwe North	14	51	136	66	5.6	20	54	26	17%	Maurel & Prom
Nanguruwe West	138	354	769	415	55	141	307	166	15%	Maurel & Prom
Mwambo	191	369	640	399	76	147	256	159	17%	Maurel & Prom
OSX-1	164	414	847	471	65	165	338	188	23%	Maurel & Prom
OSX-2	61	142	287	161	24	57	115	64	23%	Maurel & Prom
Mnazi Licence - Stochastic Total (Unrisked)(1)(2)	**1064**	**1537**	**2201**	**1596**	**425**	**614**	**879**	**637**	**<<1%**	
Mnazi Licence - Stochastic Total(2)	**27**	**228**	**742**	**320**	**11**	**91**	**296**	**128**	**92%**	
Mnazi Licence - Stochastic Total Risked(3)				**294**				**118**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

(Note: The Wentworth working interest applies to the exploration phase of operations on the licence. In the event of a discovery, TPDC has the right to back in for a 20% working interest. If this occurs, Wentworth's interests in the resource volumes will be reduced to 31.94% of the full field volumes. Wentworth's interests are in the gross recoverable volumes and do not represent the net entitlement interests after application of effective royalties.)

Table 5-6: Mnazi Licence Prospective Resources: Full Field and Wentworth Working Interest Consolidated Volumes

6.0 ROVUMA ONSHORE BLOCK, MOZAMBIQUE PROSPECTIVE RESOURCES

6.1 Introduction

(Note: In Mozambique there is a spelling change from Ruvuma to Rovuma, such that Rovuma in Mozambique is the same as Ruvuma in Tanzania)

The Rovuma Onshore Block is situated in the north-eastern portion of Mozambique and is approximately 13,500 km^2 in size. Wentworth owns a 11.59% working interest in the block.

Wentworth acquired a grid of 2D seismic lines across the onshore block through the business combination with Artumas Group and with its partners on the block, has identified numerous leads in the Tertiary and Cretaceous formations.

The 2D seismic was interpreted for stratigraphic and structural features in Tertiary and Cretaceous aged sediments. This interpretation was supported by previous assessments in the area completed by Anadarko, Cove Energy and Artumas.

6.2 Prospective Resources

Interpretation of the recently acquired seismic data and the drilling of the Meculpa-1 well in 2009 has concentrated exploration activity to the north-eastern portion of the block. This area, referred to as the North Palma area, contains prospects and leads within the Tertiary aged Miocene, Oligocene, Eocene, Paleocene formations as well as Cretaceous aged prospects. After interpretation of Wentworth's 2D seismic data and AVO analysis, prospective resources have been assigned by RPS to seven prospects:

- Tembo Prospect
- Maroon Prospect
- Orange Prospect
- Pink Prospect
- Scarlet Prospect
- Teal Prospect
- Yellow Prospect

These prospects have been named to conform with the names used by Anadarko in identifying prospects in its literature. RPS has calculated prospective resource volumes assuming the prospects are charged with gas. RPS believes there is a much higher likelihood of the reservoirs being gas charged as opposed to oil charged, based on:

- The burial history of source rocks is similar to those of Mnazi Bay, which are gas generators,
- Offsetting discoveries at Mnazi Bay and offshore Mozambique were all gas reservoirs, and
- The nearby Mecupa-1 well encountered only gas shows in the Tertiary formations.

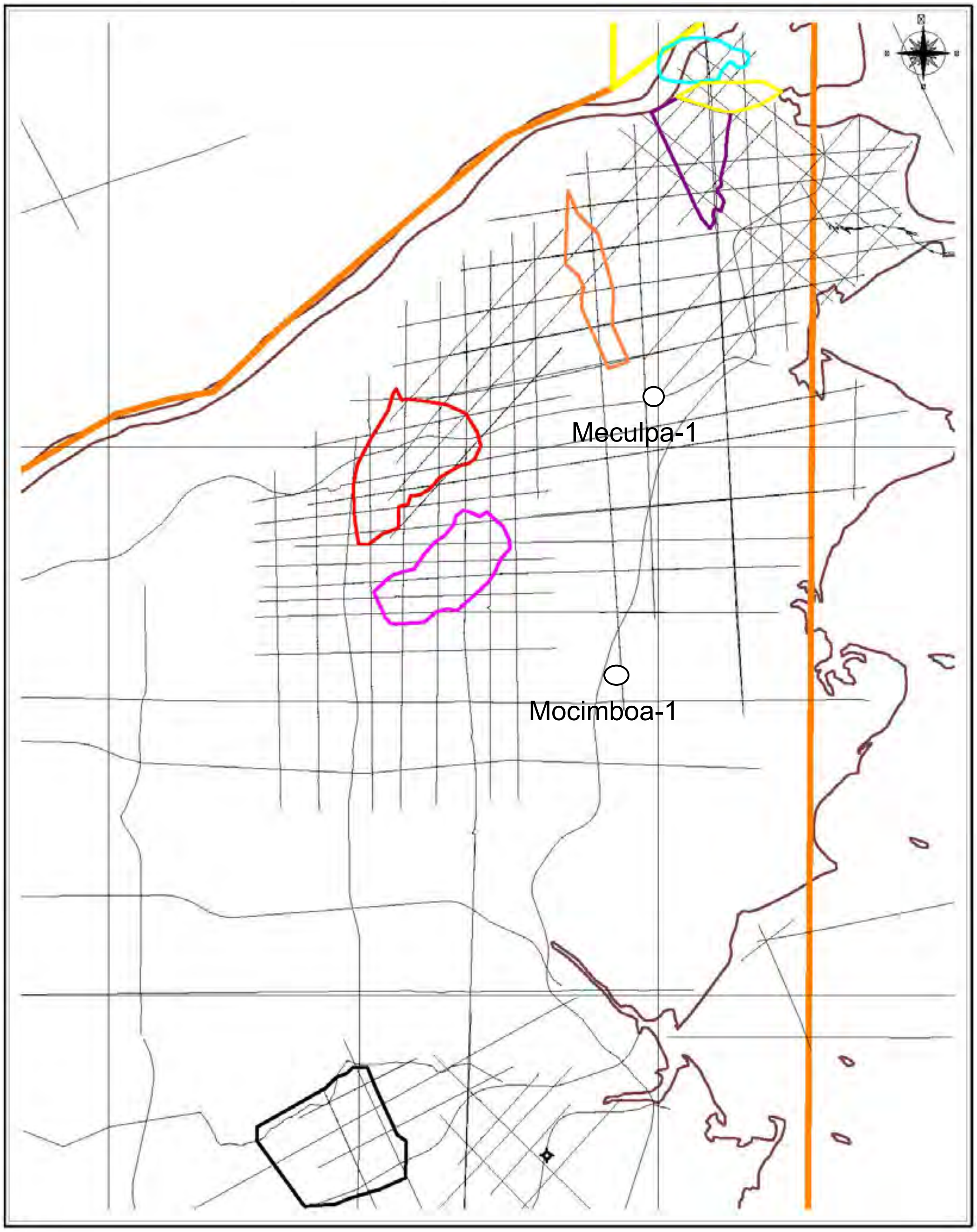

Figure 6-1: Seismic Coverage Map for Onshore Mozambique

Source: Wentworth

6.3 Seismic Interpretation

6.3.1 Tembo Prospect

The Tembo prospect is an onshore prospect with one large stratigraphic target of Cretaceous age. The top and base of the stratigraphic features were interpreted based on seismic character. These interpretations were made on all of the lines in the vicinity and a polygon was drawn in map view to delineate the extents of the Cretaceous deep marine deltaic deposit that was structurally closed against the northwest-southeast trending fault.

The Tembo prospect, if hydrocarbon bearing, is most likely to contain gas. However, there is sufficient evidence of the possibility of the structure being oil charged that RPS has included an oil case in this analysis. The evidence of possible oil charging includes:

- Oil staining and fluorescence in the Upper Cretaceous of the Mocimboa-1 well
- Fluid migration and geochemical work on Cretaceous drill cutting samples from the Mocimboa-1 well indicating positive oil indicators
- Traces of oil in the Cretaceous in Anadarko's offshore Ironclad well
- Regional source rock and geochemical studies indicating oil potential and Jurassic oil prone source rocks

As the offsetting well Mocimboa-1 encountered oil shows, RPS/PRCL have attributed a possibility of the Tembo Prospect being oil filled. For the purposes of this report, RPS/PRCL attribute a probability of oil vs gas fill as:

	P_{90}	P_{50}	P_{10}
Deeper Basinal Setting	30%	40%	50%
Shallower Slope setting	20%	30%	40%

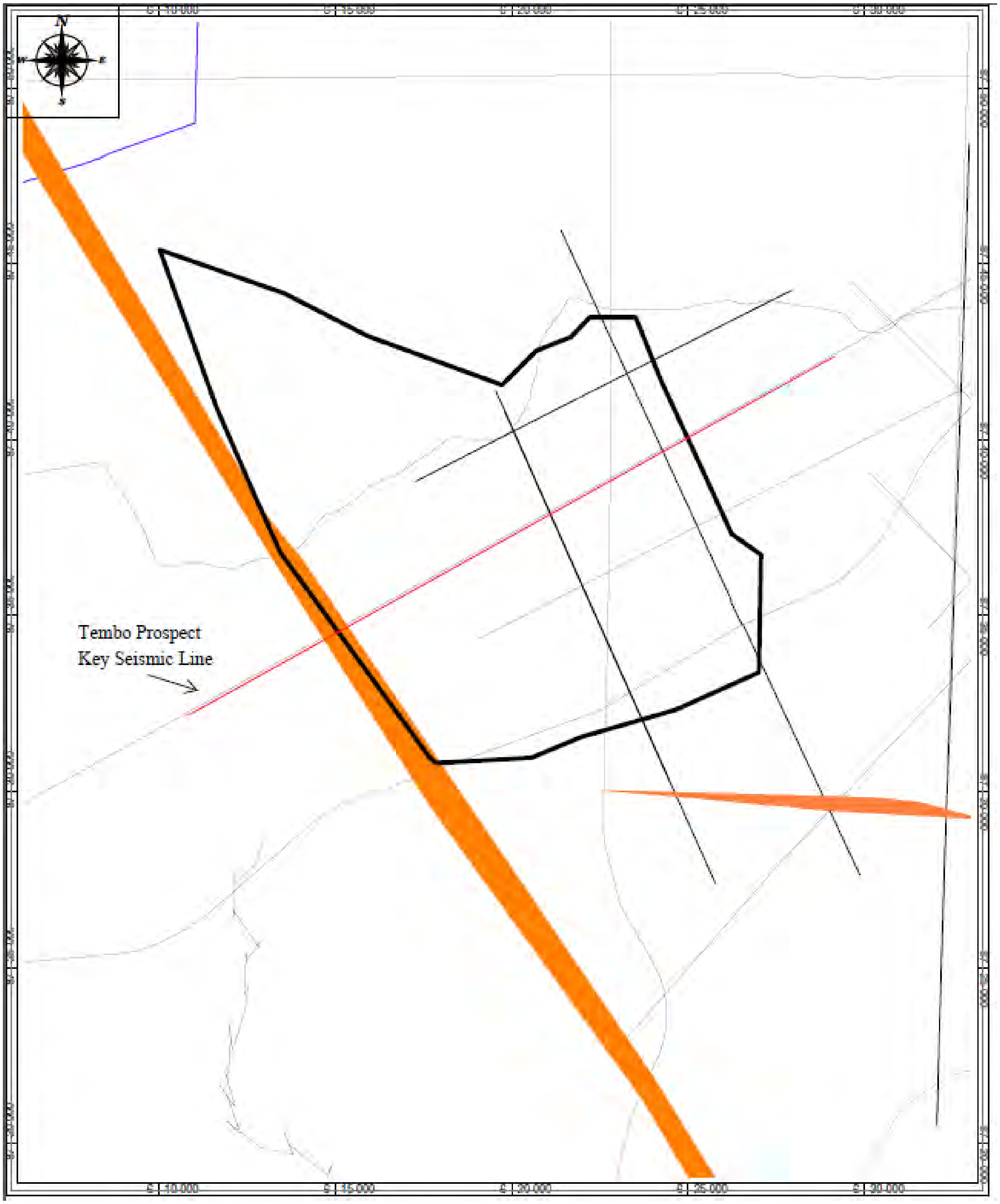

Figure 6-2: Map view of the Tembo Cretaceous Prospect

Note: Tembo prospect outline shown in black. . The red line represents the seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-3: Seismic Line Through the Tembo Prospect

Note: Interpreted faults are represented by red lines.

6.3.2 Maroon Prospect

Maroon is an onshore prospect with three formation targets. The age of these targets are Miocene, Oligocene and Eocene. The horizon interpretations were made on all of the lines in the vicinity and in the case of the Miocene prospect, a polygon was drawn in map view to delineate the extent of the sand body observed on the seismic AVO displays. For these prospects a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closure. In the case of the Miocene, the polygon outlined the closure over the extent of the interpreted sand.

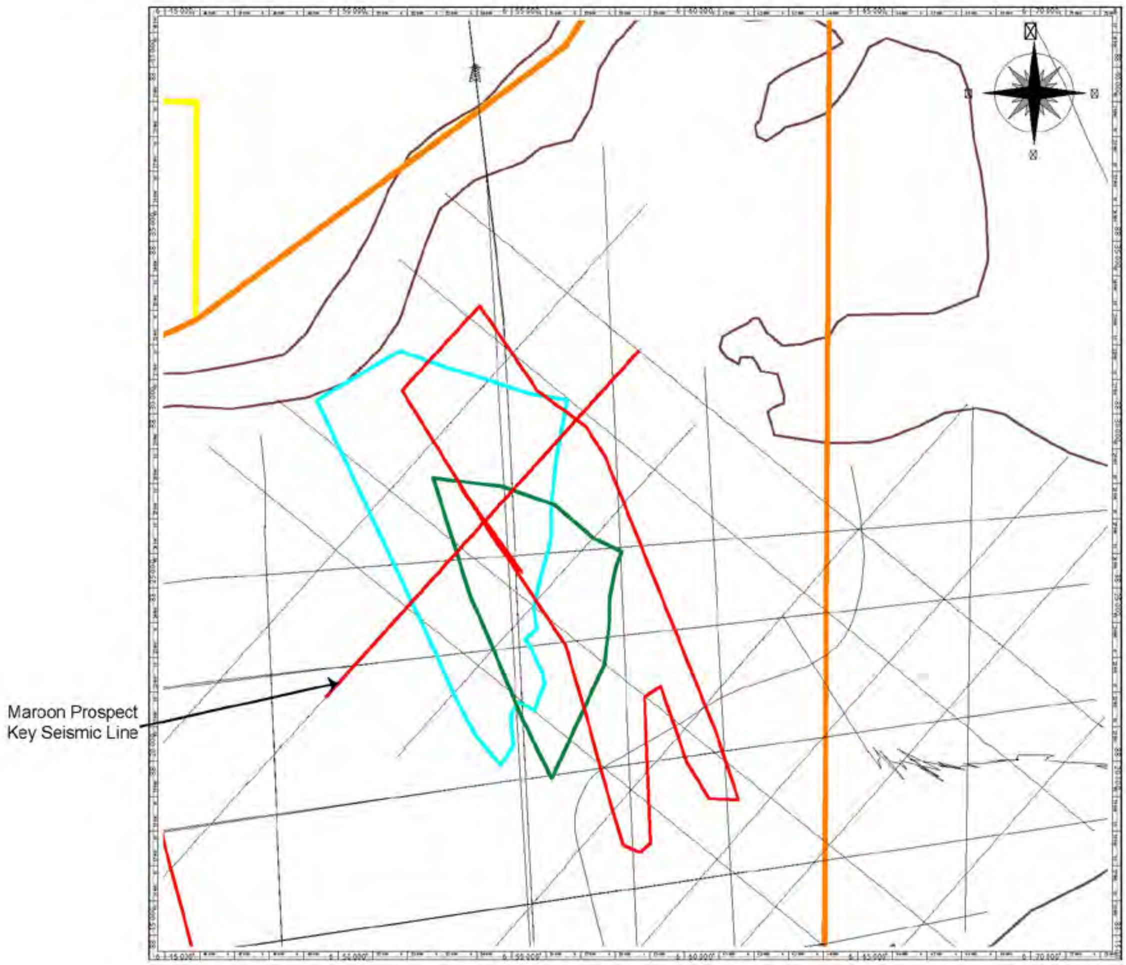

Figure 6-4: Map View of the Maroon Oligocene, Miocene and Eocene Prospects

Note: Oligocene shown in green, Miocene in red and Eocene in light blue. . The red line represents the seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-5: Seismic Line through the Maroon Prospect

6.4 Orange Prospect

The Orange prospect is an onshore prospect with a single formation target of Mio-Oligocene age. The horizon interpretations were made on all of the lines in the vicinity and a polygon was drawn in map view to delineate the extent of the sand body observed on the seismic AVO displays. For this prospect a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closure. A final polygon was drawn in map view to include both the outline of the structural closure and the extent of the interpreted sand.

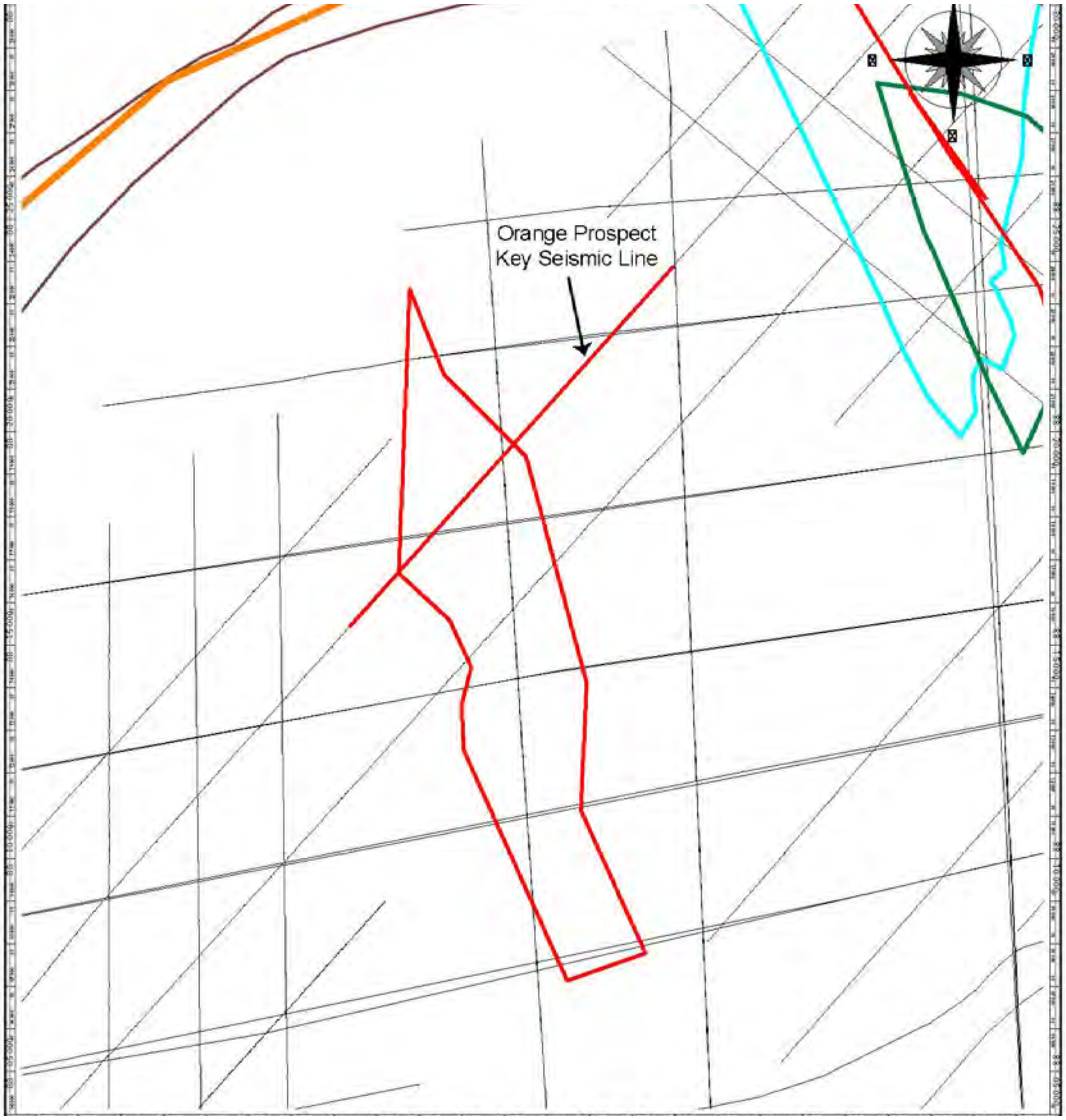

Figure 6-6: Map View of the Orange Prospect

Note: The Miocene prospect outline is in red. The red line represents the seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-7: Seismic Line through the Orange Prospect

6.5 Pink Prospect

The Pink prospect is an onshore prospect with formation targets of Eocene-Paleocene age. The horizon interpretations were made on all of the lines in the vicinity and an isopach of the Eocene to Cretaceous was calculated. For this prospect a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closure. A final polygon was drawn in map view to include the extent of the isopached Eocene-Paleocene package within the structural closure.

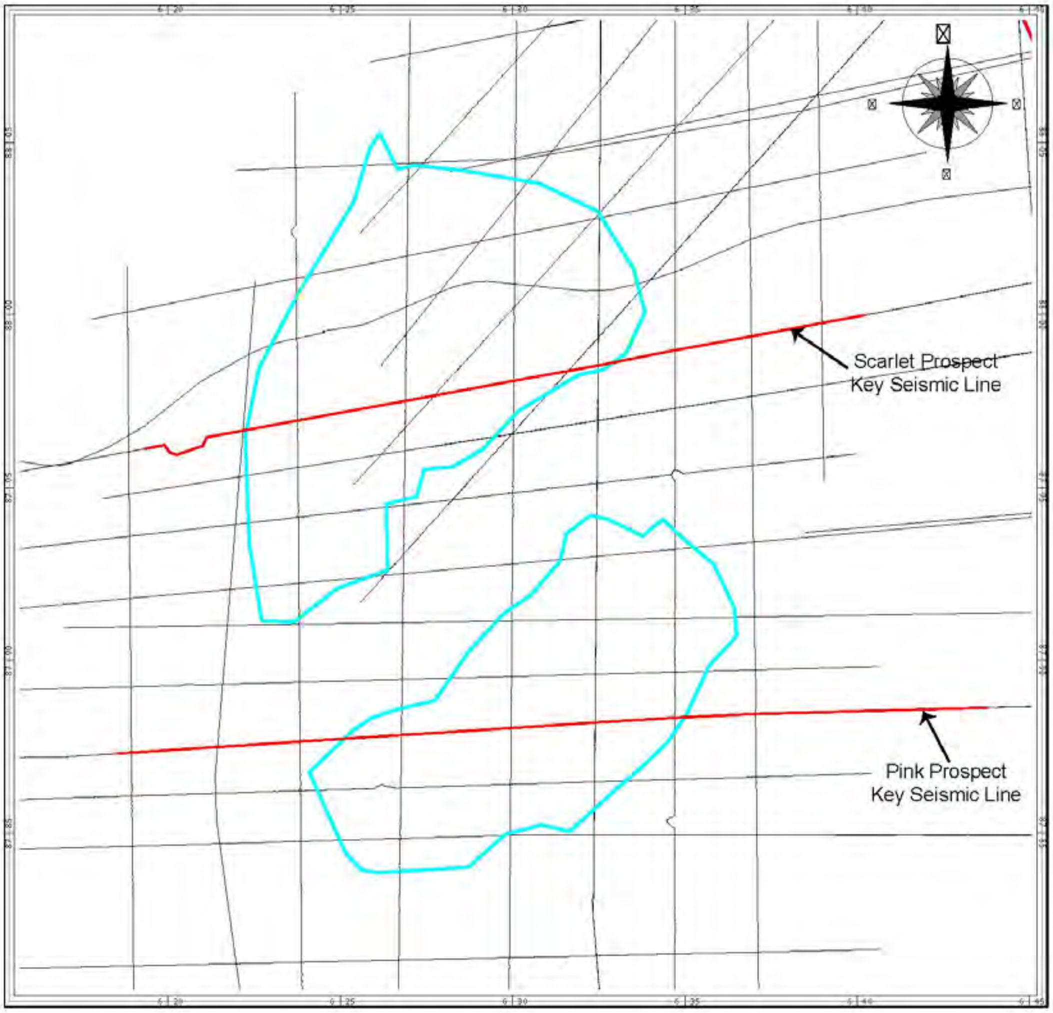

Figure 6-8: Map View of the Pink Prospect

Note: The Eocene/Paleocene prospect outline is in light blue. The red line through the Pink prospect represents the position of seismic line shown below.

This figure has been removed due to confidentiality reasons

Figure 6-9: Seismic Line through the Pink Prospect

6.6 Scarlet Prospect

The Scarlet prospect is an onshore prospect with formation targets of Eocene-Paleocene in age. The horizon interpretations were made on all of the lines in the vicinity and an isopach of the Eocene to Cretaceous was calculated. For this prospect a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the isolated closure. A final polygon was drawn in map view to include the extent of the isopached Eocene-Paleocene package within the structural closure.

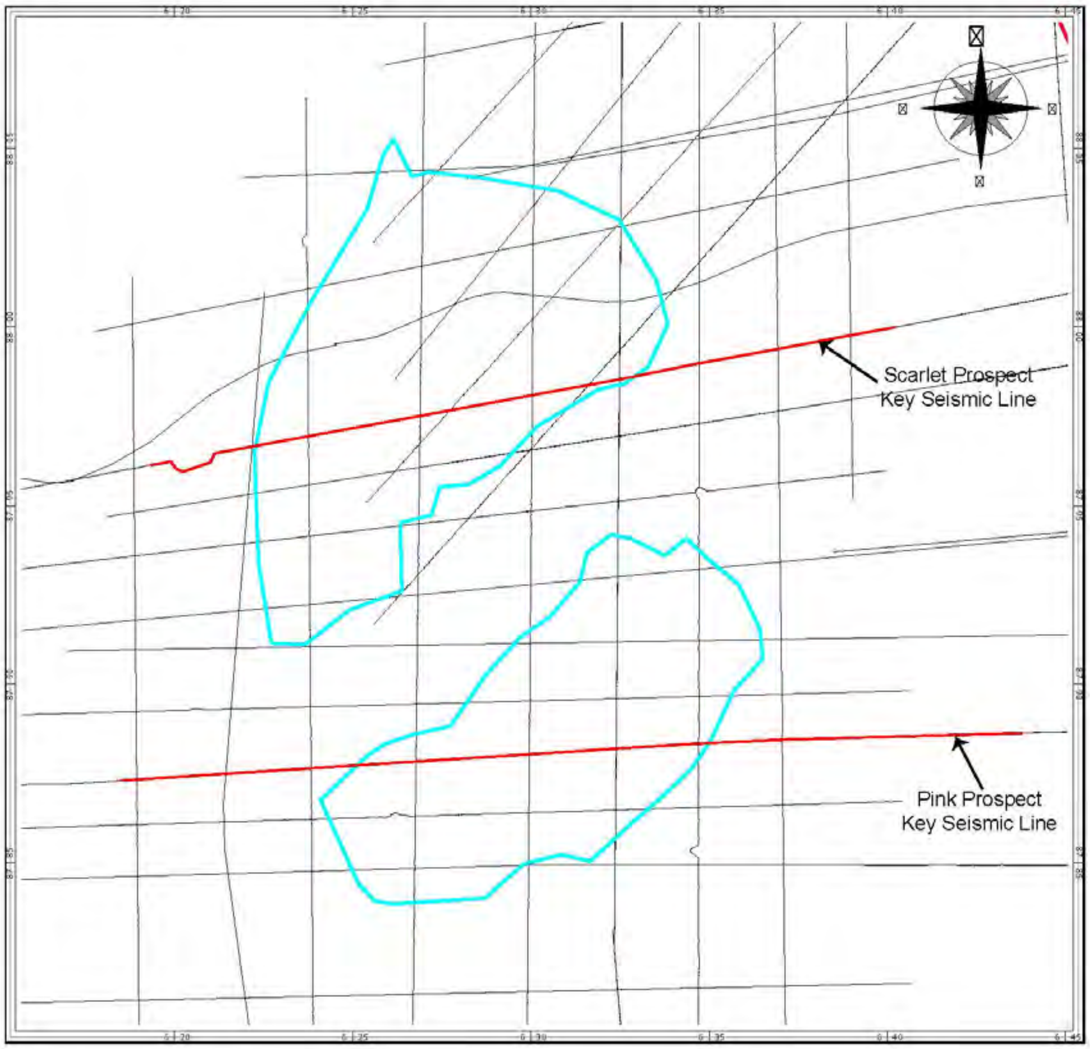

Figure 6-10: Map View of the Scarlet Prospect

Note: The Eocene/Paleocene prospect outline is in light blue. The red line through the Scarlet prospect represents the position of seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-11: Seismic Line through the Scarlet Prospect

6.7 Teal Prospect

Teal is an onshore prospect with two formation targets. The age of these targets are Oligiocene and Eocene. This prospect is formed on the footwall of a thrust fault trending in a northwest-southeast direction. The horizon interpretations were made on all of the available lines in the vicinity but there was limited data to map full closure. For this prospect a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the closures. A polygon was drawn in map view to delineate the extent of the interpreted closures for each prospective formation.

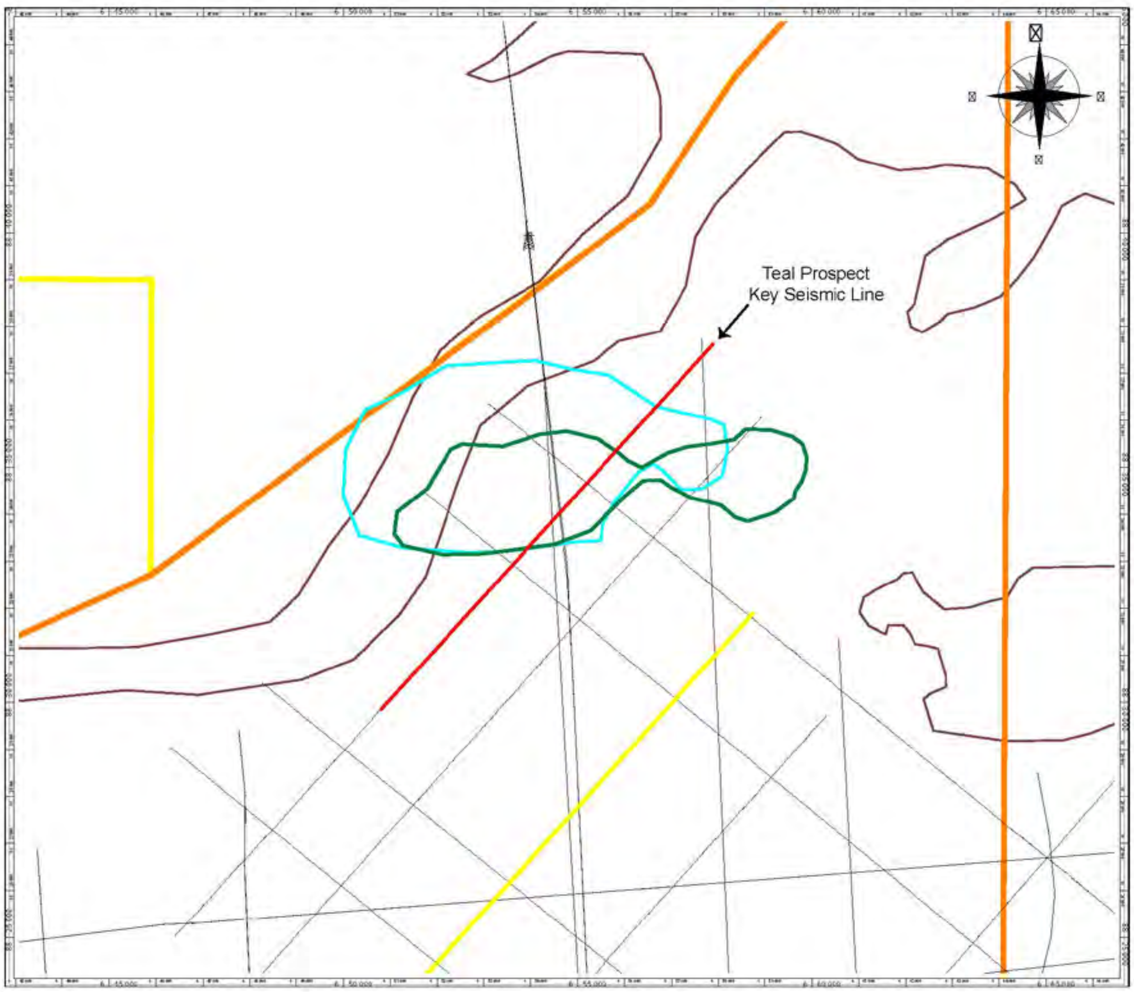

Figure 6-12: Map View of the Teal Prospect

Note: The Eocene prospect outline is in light blue, the Oligocene outline is in green.. The red line through the Teal prospect represents the position of seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-13: Seismic Line through the Teal Prospect

6.8 Yellow Prospect

Yellow is an onshore prospect with two formation targets. The age of these targets are Oligiocene and Eocene. This prospect is formed on the hanging wall of the Teal prospect. The horizon interpretations were made on all of the available lines in the vicinity. For this prospect a number of fault systems were interpreted and the horizons were gridded with the faults to determine the lateral extent of the closures. A polygon was drawn in map view to delineate the extent of the isolated closures for each prospective formation.

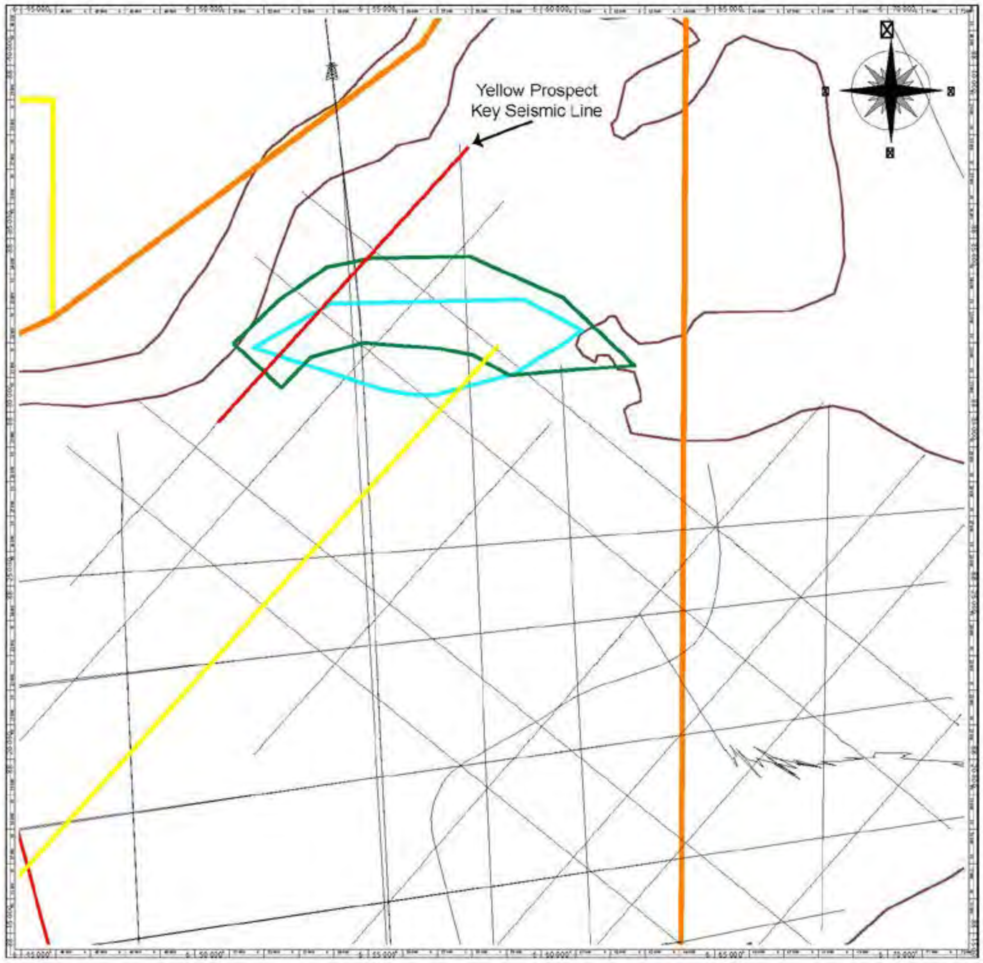

Figure 6-14: Map View of the Yellow Prospect

Note: The Eocene prospect outline is in light blue, the Oligocene outline is in green.. The red line through the Yellow prospect represents the position of seismic line shown below.

This figure has been removed due to confidentiality reasons.

Figure 6-15: Seismic Line through the Yellow Prospect

6.9 Reservoirs

The Tertiary sediments on the Rovuma Onshore Block are fluvial deltaic and marine shelf sands; hydrocarbon is potentially trapped on roll-over structures and/or extensional listric fault structures. Two wells have been drilled on the block Mecupa-1 and Mocimboa-1. Both wells contained reservoir quality sands in the Tertiary.

The Mecupa-1 well contained gas shows but is interpreted to have a poor seal due to late structural movement. The Mocimboa-1 well was drilled for a Cretaceous target; 600 m of reservoir quality Tertiary sands were encountered but not tested (Figure 6-16).

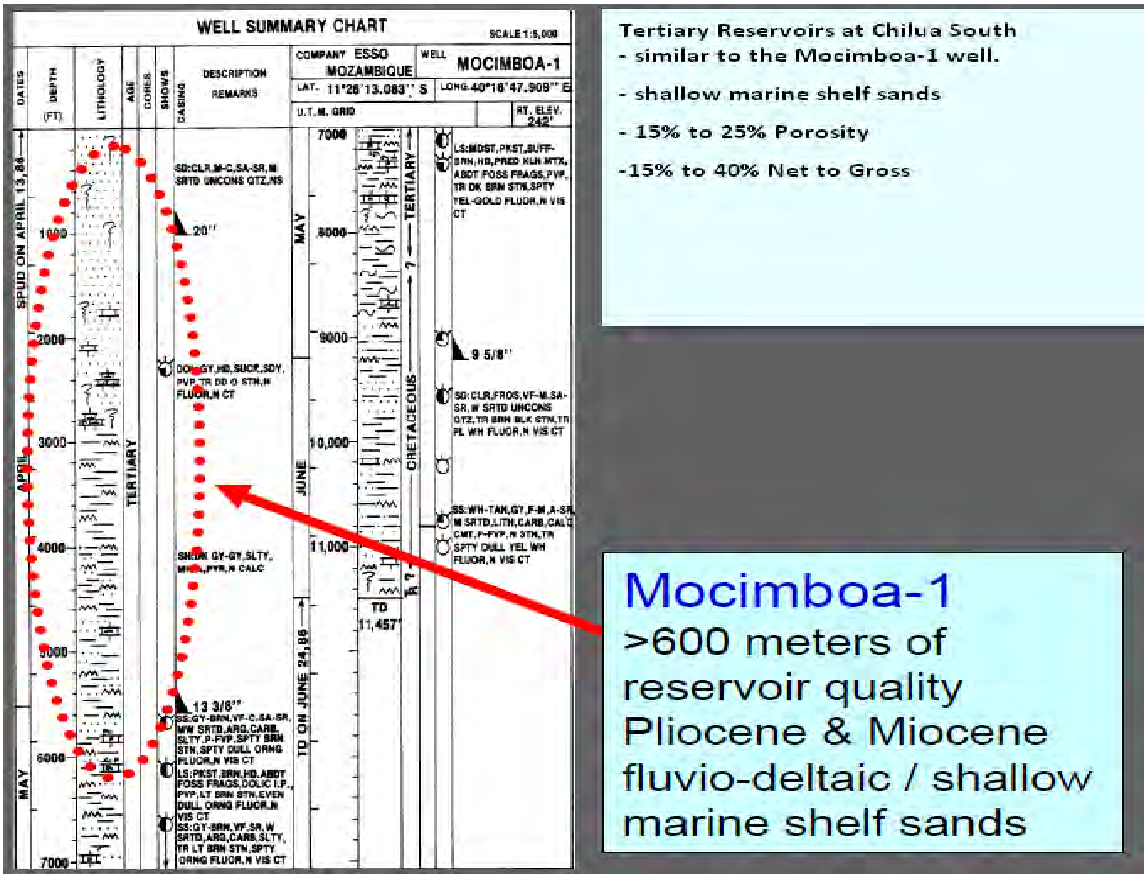

Figure 6-16: Mocimboa-1 Well

(Source: Artumas Internal Presentation)

For all the Rovuma prospects, the depth conversions were calculated with a single velocity from datum to the depth of the specific formation, and then converted to sub-sea values for mapping. The Ziwani-1, MB-1 and Mocimboa-1 wells were used as control points for the velocity calculations and subsequent depth conversion as these wells are the deepest wells with seismic ties in the area.

For the Scarlet and Pink prospects the rock volumes were calculated from an isopach between the top and base to the targeted formation and limited in areal extent by the structural closure of the specific prospect.

For the remaining Rovuma prospects the volumes were calculated by the structural area closures determined from seismic mapping and thicknesses of the respective formations.

6.10 Reservoir Properties – Onshore Mozambique

A volumetric probabilistic methodology has been utilized to determine in-place and recoverable resource volumes. The inputs for the probabilistic analysis are derived by seismic interpretation and analogy:

- Gross Rock Volumes: determined from the seismic interpretations.
- Net/Gross pay ratio: determined by analysis of the Mecupa-1 and Mocimboa-1 wells, Mozambique, Mnazi Bay log evaluations, together with examples from other Tertiary fields within East Africa to determine a wider range of possible distributions.
- Porosity: determined by analysis of the Mecupa, Mocimboa and Mnazi Bay log evaluations, together with examples from other Tertiary fields within East Africa to determine a wider range of possible distributions.
- Water Saturation: determined by analysis of the log evaluations, by layer using the four wells at Mnazi Bay.
- Gas Formation Volume Factor: determined from gas analysis data from the MB-2 well, adjusted for pressure and temperature gradients.
- Recovery Factor: determined using estimates for Mnazi Bay field and also recognizing for a low case that reservoir channel sands in some cases may not be fully connected.

Prospect:	Tembo			
Reservoir:	Cretaceous			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	3.7	67	110
Reservoir Thickness	(m)	25	150	325
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	50
Porosity	(%)	10	15	20
S_w	(%)	40	30	20
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0050	0.0046	0.0043
Recovery Factor	(%)	50	65	80

Table 6-1: Tembo Prospect Properties: Gas Case

Prospect:	Tembo			
Reservoir:	Cretaceous			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	3.7	67	110
Reservoir Thickness	(m)	25	150	325
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	50
Porosity	(%)	10	15	20
S_w	(%)	40	30	20
Fluid		oil	oil	oil
B_o	(Res vol/ Std vol)	1.10	1.40	2.80
Solution GOR	(Scf/stb)	200	600	1200
Recovery Factor	(%)	15	25	40

Table 6-2: Tembo Prospect Properties: Oil Case

Prospect:	Maroon			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	5.8	8.7	22.2
Reservoir Thickness	(m)	80	120	200
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	12	21	30
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0045	0.0043	0.0040
Recovery Factor	(%)	50	65	80

Table 6-3: Maroon Oligocene Prospect Properties

Prospect:	Maroon			
Reservoir:	Eocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	15.1	24.9	37.8
Reservoir Thickness	(m)	80	100	120
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	12	21	28
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0043	0.0038	0.0034
Recovery Factor	(%)	50	65	80

Table 6-4: Maroon Eocene Prospect Properties

Prospect:	Maroon			
Reservoir:	Upper Miocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	33.2	43.2	48.4
Reservoir Thickness	(m)	30	80	150
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	15	23	30
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0120	0.0108	0.0095
Recovery Factor	(%)	50	65	80

Table 6-5: Maroon Upper Miocene Prospect Properties

Prospect:	Orange			
Reservoir:	Mio-Oligocene			
		P_{90}	Mode	P_{10}
Productive Area	(km^2)	16.4	23.1	33.1
Reservoir Thickness	(m)	30	80	150
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	15	23	30
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0069	0.0060	0.0054
Recovery Factor	(%)	50	65	80

Table 6-6: Orange Mio-Oligocene Prospect Properties

Prospect:	Teal			
Reservoir:	Oligocene			
		P_{90}	Mode	P_{10}
Productive Area	(km^2)	2.8	5.0	10.7
Reservoir Thickness	(m)	70	90	120
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	10	16	25
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0045	0.0041	0.0038
Recovery Factor	(%)	0	0	0

Table 6-7: Teal Oligocene Prospect Properties

Prospect: Teal				
Reservoir: Eocene				
		P_{90}	**Mode**	**P_{10}**
Productive	(km^2)	6.3	9.2	16.3
Reservoir T	(m)	80	100	120
Shape Fact	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	10	16	21
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	es vol/ Std vol)	0.0042	0.0038	0.0034
Recovery F	(%)	50	65	80

Table 6-8: Teal Eocene Prospect Properties

Prospect:	Yellow			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	5.1	10.4	20.5
Reservoir Thickness	(m)	70	90	120
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	12	21	28
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0048	0.0044	0.0042
Recovery Factor	(%)	50	65	80

Table 6-9: Yellow Oligocene Prospect Properties

Prospect:	Yellow			
Reservoir:	Oligocene			
		P_{90}	**Mode**	**P_{10}**
Productive Area	(km^2)	5.1	10.4	20.5
Reservoir Thickness	(m)	70	90	120
Shape Factor	(%)	80	80	80
Net/Gross	(%)	15	25	40
Porosity	(%)	12	21	28
S_w	(%)	17	27	40
Fluid		gas	gas	gas
B_g	(Res vol/ Std vol)	0.0048	0.0044	0.0042
Recovery Factor	(%)	50	65	80

Table 6-10: Yellow Eocene Prospect Properties

6.11 Geological Probability of Success

RPS estimate a GPoS (without a commercial cut-off) as the Geological Play Chance multiplied by the Prospect Specific Chance.

The Play Chance, the chance of the play working in the play fairway segment being considered, is estimated using three factors: Source, Reservoir, and Seal. In all cases the assessed chance is the presence and effectiveness of the specified element in the assigned segment of the play fairway. As noted in Section 4 of this report, for the Ruvuma (Rovuma) Basin the source is proven to exist and both the reservoir and seal pairs for Tertiary reservoirs exist. For the focus area considered (North Rovuma Basin – Tertiary Plays), the Play Chance is therefore taken as 100%. For the Cretaceous prospects, the recent Nyorya-1 discovery well west of Mnazi Bay provides evidence of a working petroleum system for gas in the Mid Cretaceous as suspected from the older well Mocimboa-1, which lies to the south and east of the Rovuma prospects.

The overall ‘Geological Probability of Success’ (GPoS) for a lead or prospect is defined as the product of the Play Chance of Success and each of the lead/prospect location specific risks identified above. Thus, the GPoS is always less than the Play Chance of Success.

Risks which are specific to the prospects within the play can be categorised as follows:

Trap & Timing:	chance that a structural / stratigraphic trap exists in a particular location;
Seal:	chance that there is an effective top seal in that location;
Charge:	chance that the trap is in the hydrocarbon migration path;
Reservoir:	chance that reservoir of commercially productive quality exists in the trap.

The prospect-specific chances of success are:

Tembo Prospect

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	56%	P_{10}-P_{90} relies on a combination structural/stratigraphic trap, imaged on 2D seismic data. Only one-way closure is evident.
Seal	64%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	73%	Cretaceous petroleum system is proven by the Ntorya-1 discovery, Mocimboa-1 well (gas and oil shows) and successful gas discoveries off-shore Tanzania. Access to mature source uncertain.
Reservoir	56%	Cretaceous reservoir exists in Mocimboa-1 well, Likonde-1 well and Ntorya-1 discovery
Total	15%	

Maroon Prospect

Prospect Risk Category	Chance of Success			Notes
	Miocene	Oligocene	Eocene	
Trap & Timing	56%	52%	49%	P_{10}-P_{90} relies on stratigraphic and/or structural traps for three prospective formations imaged on 2D seismic data.
Seal	68%	64%	64%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	73%	73%	73%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	56%	56%	56%	Deep-water sands and channel slope deposits – all evident in onshore or near offshore wells
Total	16%	14%	13%	

Orange Prospect

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	56%	P_{10}-P_{90} relies on a stratigraphic trap within a channel slope/deep water sand system, and simple rotated fault structures, imaged on 2D seismic data.
Seal	64%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	73%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	68%	Deep-water sands and channel slope depositsas seen at Mnazi Bay
Total	18%	

Pink Prospect

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	77%	P_{10}-P_{90} relies on a stratigraphic trap within a channel slope/deep water sand system, and simple rotated fault structures, imaged on 2D seismic data.
Seal	81%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	65%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	56%	Deep-water sands and channel slope deposits as seen in offshore Chewa area
Total	22%	

Scarlet Prospect

Prospect Risk Category	Chance of Success	Notes
Trap & Timing	77%	P_{10}-P_{90} relies on a stratigraphic trap within a channel slope/deep water sand system, and simple rotated fault structures, imaged on 2D seismic data.
Seal	81%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	65%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	56%	Deep-water sands and channel slope deposits as seen in offshore Chewa area
Total	22%	

Teal Prospect

Prospect Risk Category	Chance of Success		Notes
	Oligocene	Eocene	
Trap & Timing	72%	56%	P_{10}-P_{90} relies on a structural trap within a channel slope/deep water sand system, and simple roll-over structures, imaged on limited 2D seismic data.
Seal	64%	64%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	73%	65%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	64%	52%	Deep-water sands and channel slope deposits as seen in Mnazi Bay (Oligocene target) and offshore Chewa area (Eocene reservoir)
Total	21%	12%	

Yellow Prospect

Prospect Risk Category	Chance of Success		Notes
	Oligocene	Eocene	
Trap & Timing	68%	64%	P_{10}-P_{90} relies on a stratigraphic trap within a channel slope/deep water sand system, and simple roll-over structures, imaged on 2D seismic data.
Seal	64%	68%	Overlying shales and reservoir-seal pairs provide adequate top and lateral seal.
Charge	65%	73%	Successful gas discoveries off-shore Mozambique and at Mnazi Bay.
Reservoir	68%	64%	Deep-water sands and channel slope deposits as seen in Mnazi Bay (Oligocene target) and offshore Chewa area (Eocene reservoir)
Total	19%	20%	

6.12 Prospective Resources – Results Summary

The resources for the prospects onshore Rovuma have been estimated using a probabilistic volumetric methodology. As these resources are undiscovered, they have been classified as Prospective Resources. The geologic chance of success used in the stochastic consolidations are as estimated by RPS in section 6-11.

The results of the probabilistic assessment are shown below for the whole prospects (100% WI). These are presented in both the unrisked total volumes as well as the consolidated risked volumes in the following tables. Note that the distributions have been derived using probabilistic evaluation, and will not sum arithmetically, except at the mean values.

Tembo Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Cretaceous	243	1,643	5,610	2,441	143	974	3,419	1,482
Tembo - Stochastic Total Risked	**36**	**246**	**842**	**366**	**21**	**146**	**513**	**222**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Table 6-11: Rovuma Licence Tembo Prospect

For the case where the Tembo Prospect is oil charged, the in place and prospective resources volumes are as follows:

Tembo Prospect - Oil Case	100% Full Field Oil Initially In Place				100% Full Field Prospective Oil Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	MMstb	MMstb	MMstb	MMstb	MMstb	MMstb	MMstb	MMstb
Cretaceous	107	756	2,808	1,205	25	192	780	277
Tembo Prospect - Stochastic Total Risked	**16**	**113**	**421**	**181**	**3.8**	**29**	**117**	**42**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Table 6-12: Rovuma Licence Tembo Prospect – Oil Case

Maroon Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Oligocene	117	385	1,024	498	69	229	620	302
Upper Miocene	108	360	851	432	63	217	522	263
Eocene	258	654	1,395	759	149	391	865	461
Maroon Prospect - Stoch. Total(1)	882	1,571	2,627	1,679	524	940	1,613	1,018
Maroon Prospect - Stoch. Total(2)	149	499	1,286	**631**	86	298	789	**382**
Maroon Prospect - Stoch. Total Risked(3)				**227**				**138**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-13: Rovuma Licence Maroon Prospect

Orange Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Mio-Oligocene	105	366	904	453	62	219	559	275
Orange Prospect - Stoch. Total Risked	**19**	**66**	**163**	**82**	**11**	**39**	**101**	**50**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-14: Rovuma Licence Orange Prospect

Pink Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Eocene	376	846	1,816	1,001	216	506	1,120	607
Pink Prospect - Stoch. Total Risked	**83**	**186**	**400**	**220**	**48**	**111**	**246**	**134**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-15: Rovuma Licence Pink Prospect

Scarlett Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Eocene	353	992	2,471	1,253	205	591	1,515	760
Scarlett Prospect - Stoch. Total Risked	**78**	**218**	**544**	**276**	**45**	**130**	**333**	**167**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-16: Rovuma Licence Scarlett Prospect

Teal Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Oligocene	37	115	282	142	22	68	173	86
Eocene	89	216	457	251	51	129	283	152
Teal Prospect - Stoch. Total(1)	183	356	649	392	108	214	397	238
Teal Prospect - Stoch. Total(2)	48	156	395	**195**	28	93	241	**118**
Teal Prospect - Stoch. Total Risked(3)				**60**				**37**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-17: Rovuma Licence Teal Prospect

Yellow Prospect	100% Full Field Gas Initially In Place				100% Full Field Prospective Gas Resources			
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf
Oligocene	74	241	580	294	44	144	355	178
Eocene	63.1	211.0	527.0	262.0	37	126	322	159
Yellow Prospect - Stoch. Total(1)	234	497	942	551	138	301	586	337
Yellow Prospect - Stoch. Total(2)	72	250	648	**315**	42	148	396	**191**
Yellow Prospect - Stoch. Total Risked(3)				**113**				**69**

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a license level.

Table 6-18: Rovuma Licence Yellow Prospect

Wentworth owns an 11.59% working interest in the Mozambique Onshore licence area. The following table shows the consolidated prospect volumes owned by Wentworth according to its working interest.

Rovuma Onshore Block	100% Full Field Prospective Gas Resources				Wentworth 11.59% WI Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf	Bscf		
Tembo	143	974	3,419	1,482	17	113	396	172	15%	Anadarko
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,849**	**4,347**	**7,121**	**4,745**	**330**	**504**	**825**	**550**	<<1%	
Rovuma Onshore Block - Stoch. Total(2)	**119**	**620**	**2,017**	**919**	**14**	**72**	**234**	**107**	**88%**	
Rovuima Onshore Block - Stoch. Total Risked(3)				**809**				**94**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Table 6-19: Rovuma Licence Prospective Resources: Full Field and Wentworth Working Interest Consolidated Volumes

For the case where the Balck Prospect is Oil filled (RPS attributes a P50 probability of 40% of this occurring if the prospect is hydrocarbon bearing the Rovuma prospects' summary is as follows:

Rovuma Onshore Block - Oil Case	100% Full Field Prospective Gas Resources				Wentworth 11.59% WI Prospective Gas Resources				GPoS	Operator
	P_{90}	P_{50}	P_{10}	Mean	P_{90}	P_{50}	P_{10}	Mean	(%)	
OIL	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**	**MMstb**		
Tembo (Unrisked)	25	192	780	277	3	22	90	32	15%	Anadarko
GAS	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**	**Bscf**		
Maroon	524	940	1,613	1,018	60.7	109	187	118	14%	Anadarko
Orange	62	219	559	275	7	25	65	32	18%	Anadarko
Pink	216	506	1,120	607	25	59	130	70	22%	Anadarko
Scarlett	205	591	1,515	760	24	68	176	88	22%	Anadarko
Teal	108	214	397	238	12.5	25	46	28	15%	Anadarko
Yellow	138	301	586	337	16.0	35	68	39	19%	Anadarko
Rovuma Onshore Block - Stochastic Total (Unrisked)(1)(2)	**2,194**	**3,100**	**4,428**	**3,234**	**254**	**359**	**513**	**375**	<<1%	
Rovuma Onshore Block - Stoch. Total(2)	**104**	**521**	**1,500**	**694**	**12**	**60**	**174**	**80**	**86%**	
Rovuima Onshore Block - Stoch. Total Risked(3)				**597**				**69**		

Notes:
(1) Statistical aggregation assuming that all intervals in all prospects are successful. The probability of this occurring is the product of all risks and is extremely small.
(2) Statistical aggregation assuming at least 1 prospect is successful.
This total take takes into account all possible successful outcomes and the mean value of this distribution represents the true expectation of success.
(3) Statistical aggregation of all prospects taking into account success or failure in each prospect on a licence level.

Table 6-20: Rovuma Licence Prospective Resources: Full Field and Wentworth Working Interest Consolidated Volumes - Oil Case

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APPENDIX 1

Glossary of Technical Terms

APPENDIX 1: GLOSSARY OF TECHNICAL TERMS

AOF	Absolute Open Flow
API	American Petroleum Institute
B	Billion
Bbls	Barrels
BOE	Barrels of oil equivalent
Bopd	barrels of oil per day
Bscf	billion standard cubic feet
E_{gi}	Gas Expansion Factor
Ft	feet
FWL	Formation Water Level
GAP	Multiphase network optimisation software
GIIP	Gas Initially In Place
GOC	gas-oil contact
GRV	Gross Rock Volume
GWC	Gas-water-contact
IPR	Inflow performance relationship
k_h	Horizontal permeability
m	metre
M	thousand
MBAL	Material balance software
MD	measured depth
mD	permeability in millidarcies
MDT	Modular formation dynamics tester tool
MM	million
MMscf/d	Million standard cubic feet per day
M£	thousand UK pounds
MM£	million UK pounds
Mbbls	thousand barrels
MMbbls	million barrels
N:G	net to gross ratio
NMR	Nuclear magnetic resonance
OWC	oil-water contact
psi	pounds per square inch
RF	Recovery Factor
RFT	Repeat Formation Testing
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
S_w	Water saturation
TVDSS	true vertical depth (sub-sea)
TWT	Two-way-time
Z	a measure of the “non-idealness” of gas

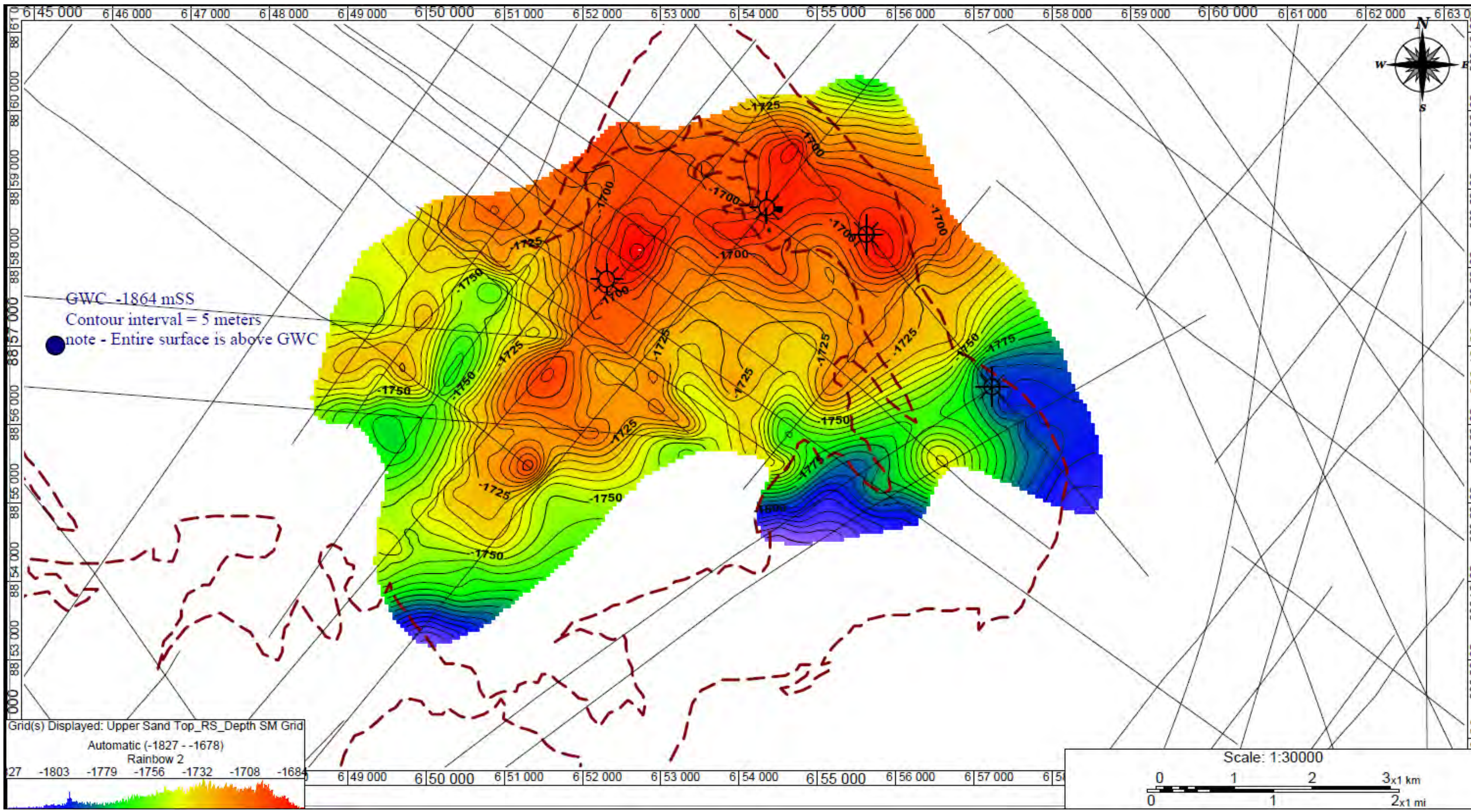
APPENDIX 2

Mnazi Bay/Msimbati Contingent Resource Structure and Isopach Maps

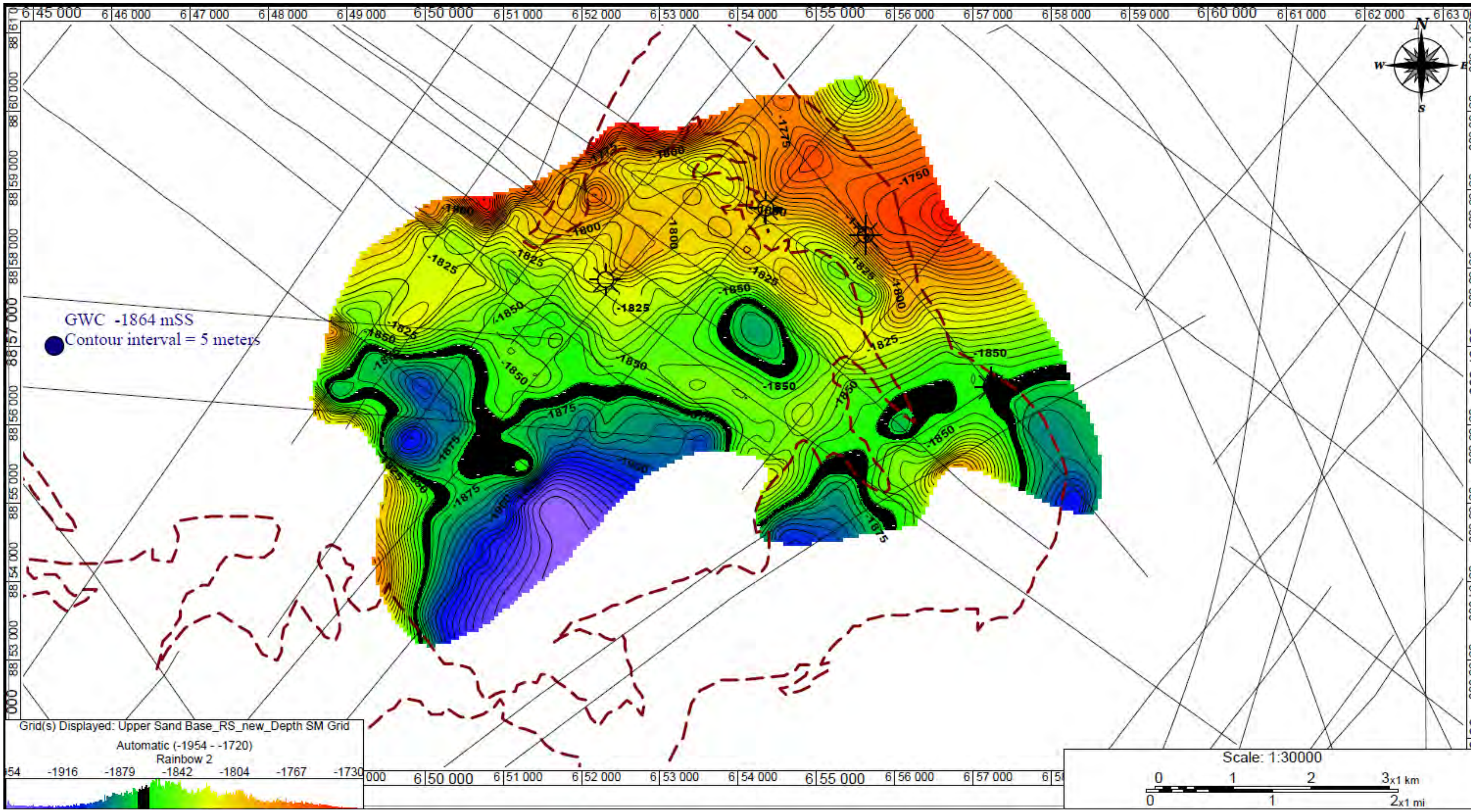
Mnazi/Msimbati 2013 Resource Assessment

Structure and Isopach Maps

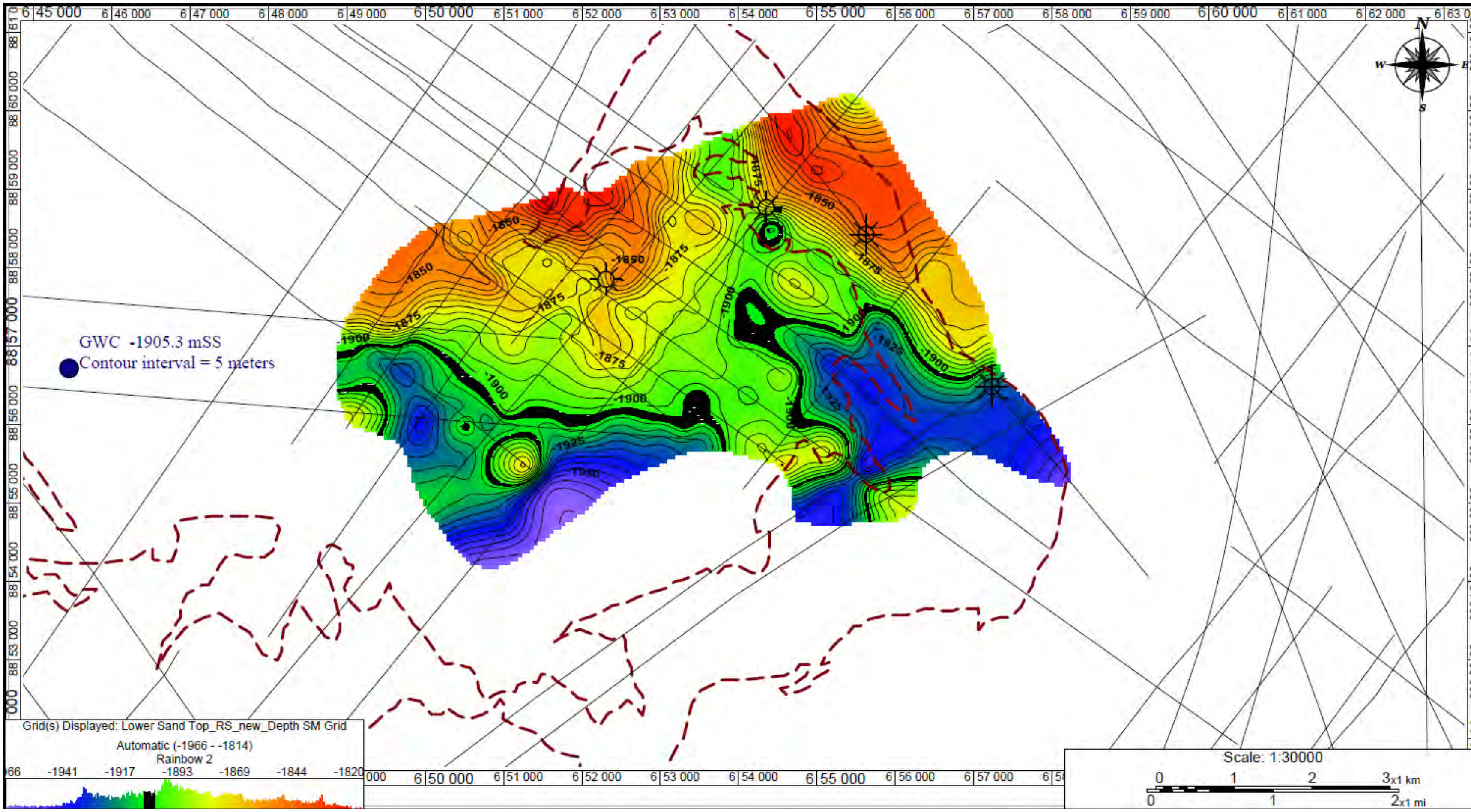
Mnazi Bay: Upper Sand Top



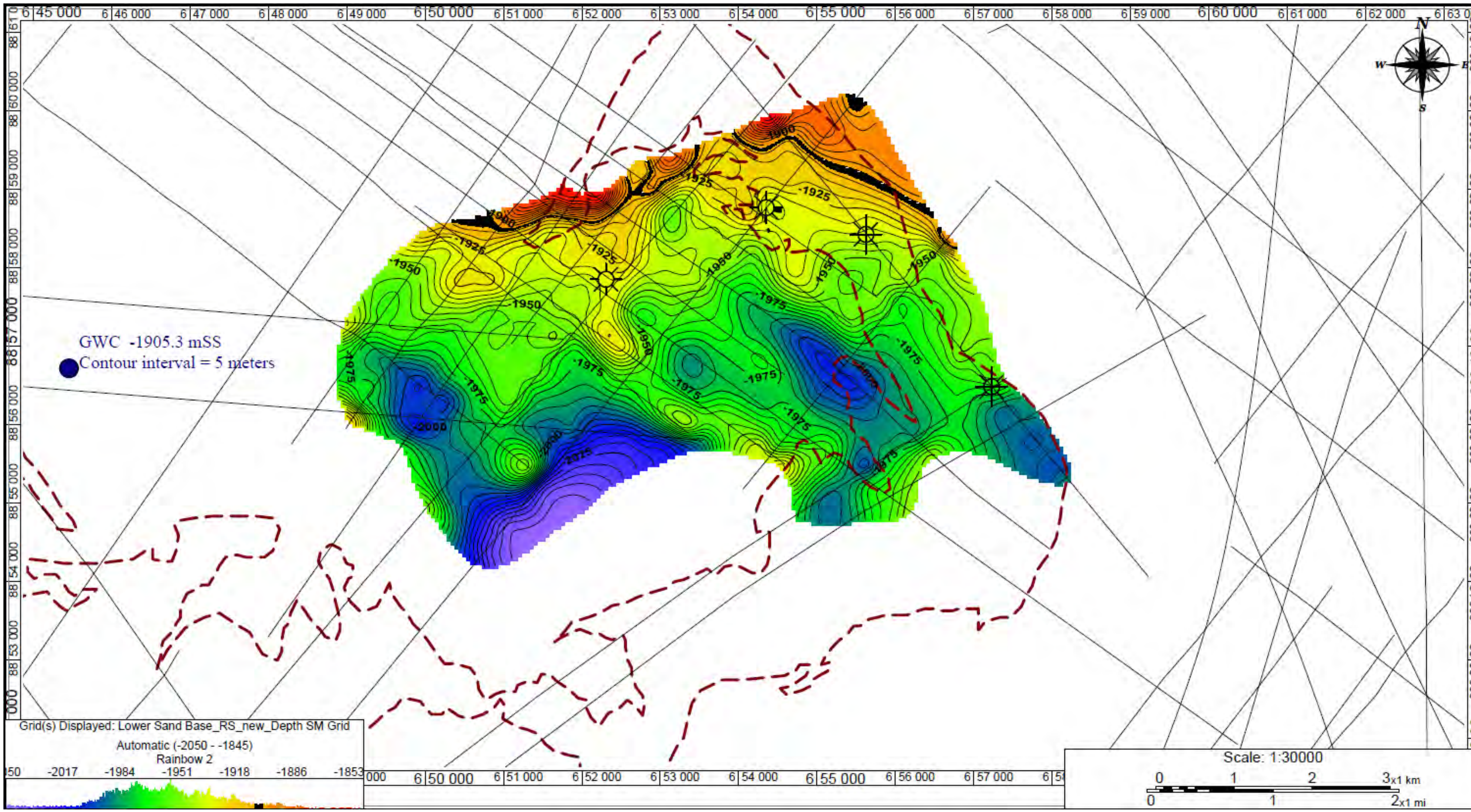
Mnazi Bay: Upper Sand Base



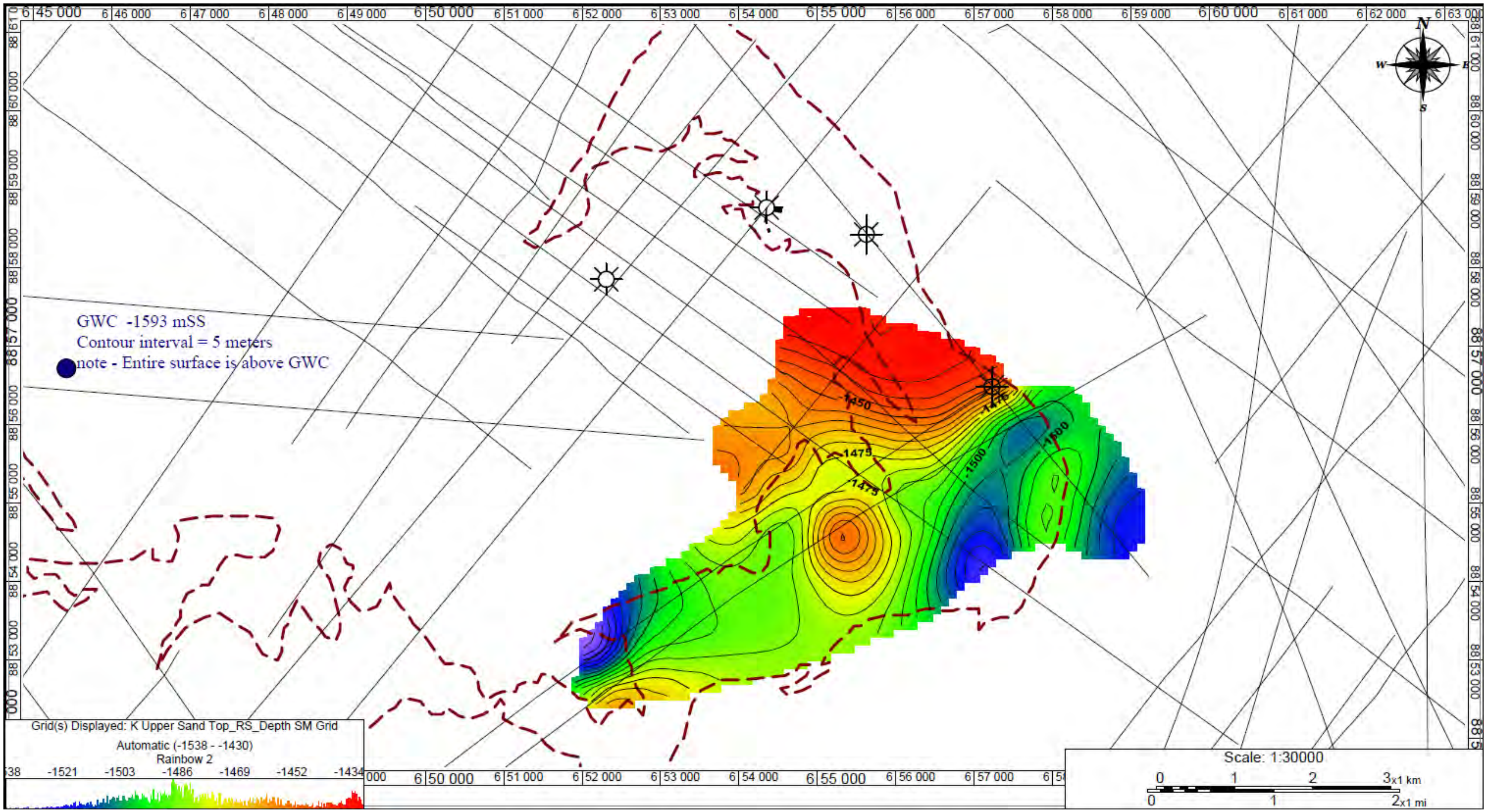
Mnazi Bay: Lower Sand Top



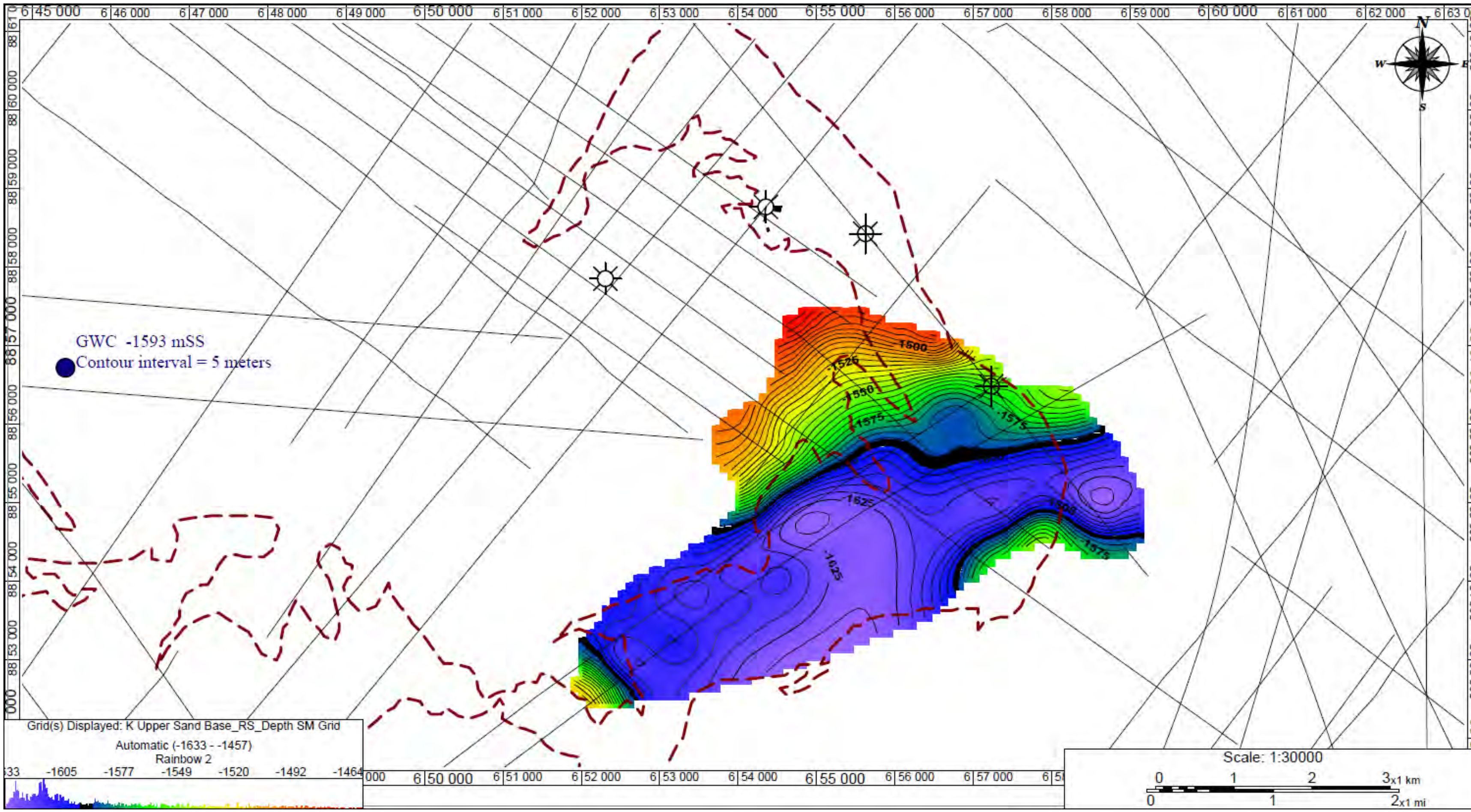
Mnazi Bay: Lower Sand Base



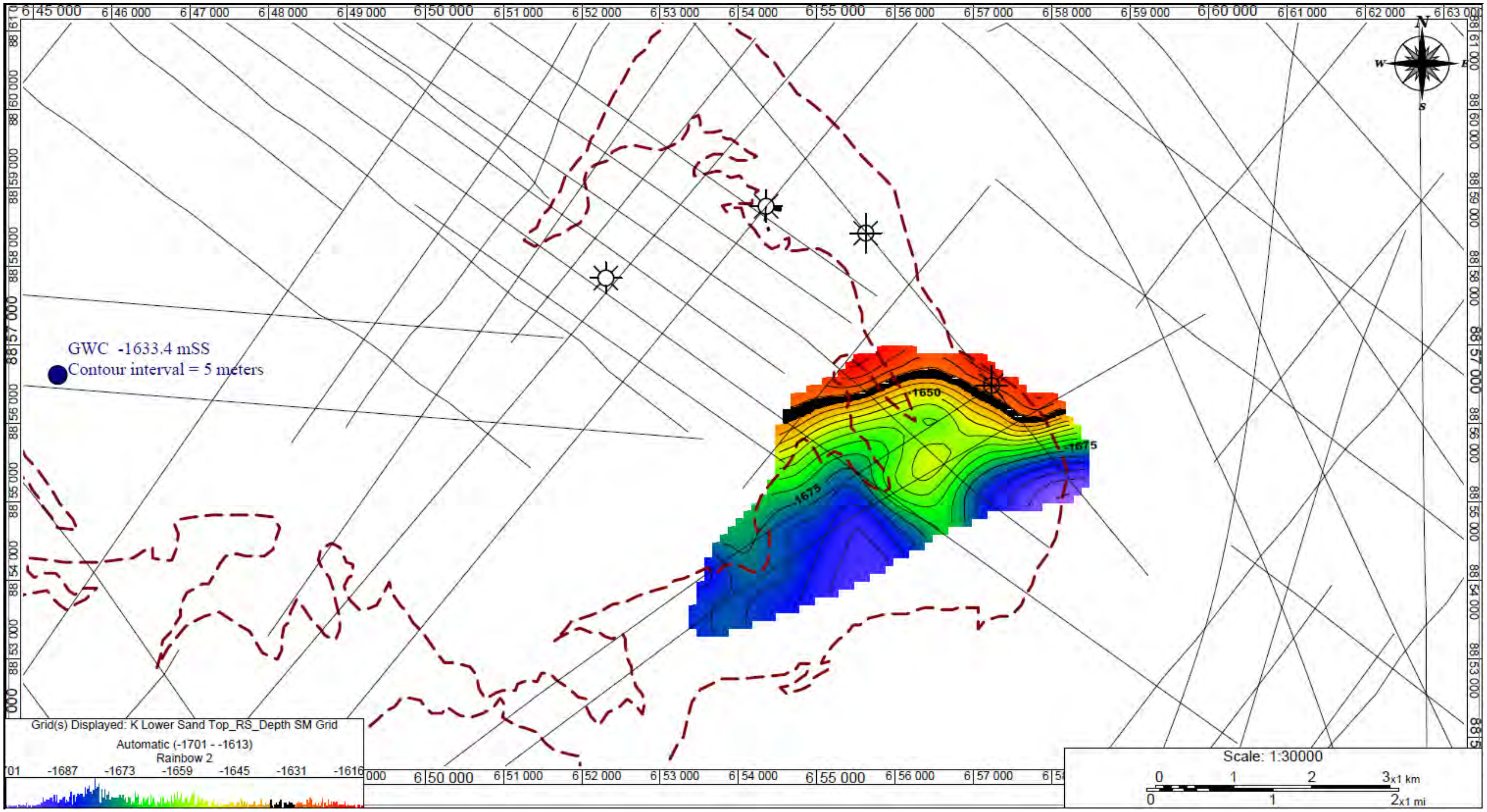
Msimbati: Upper K Sand Top



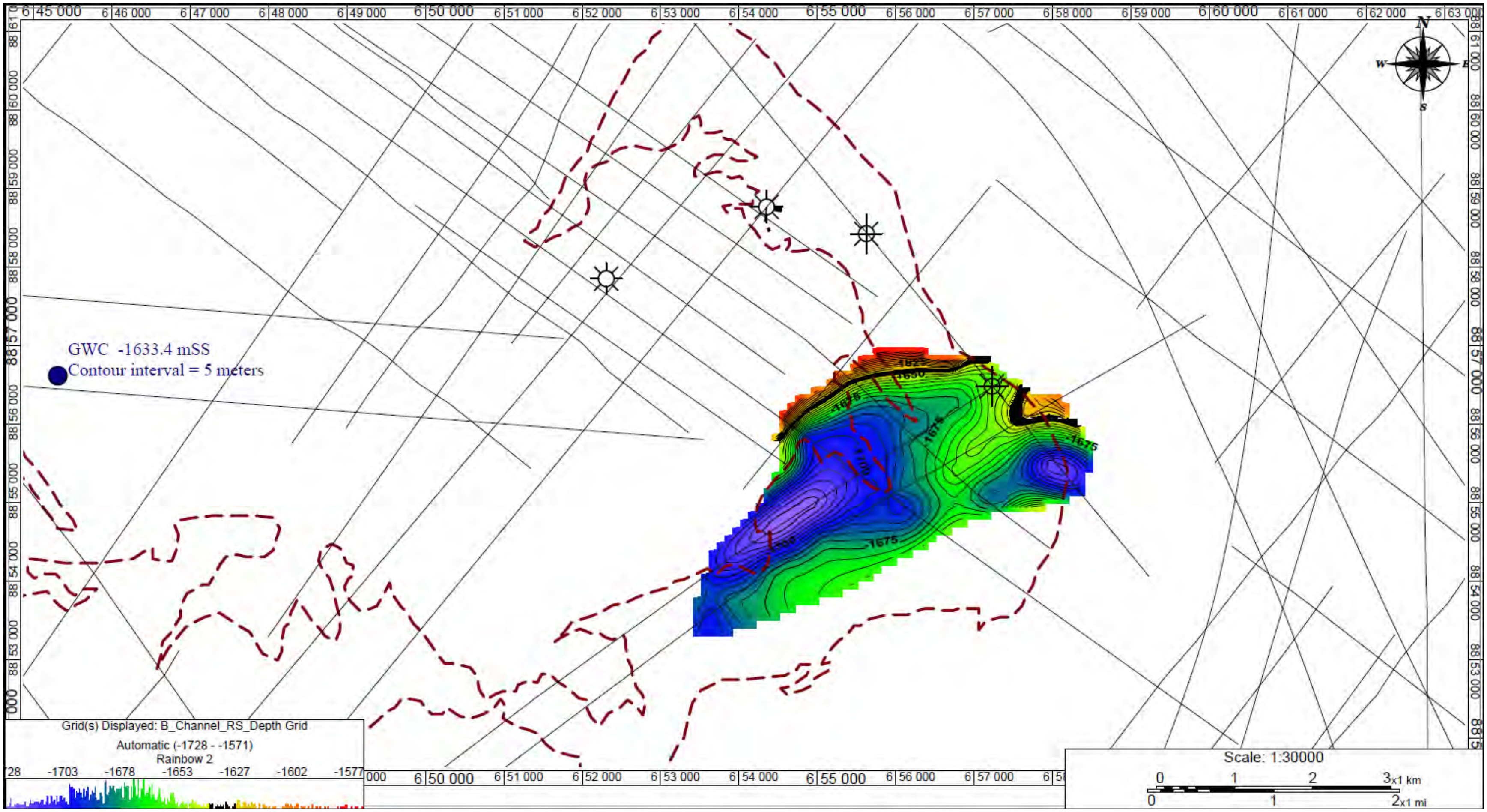
Msimbati: Upper K Sand Base



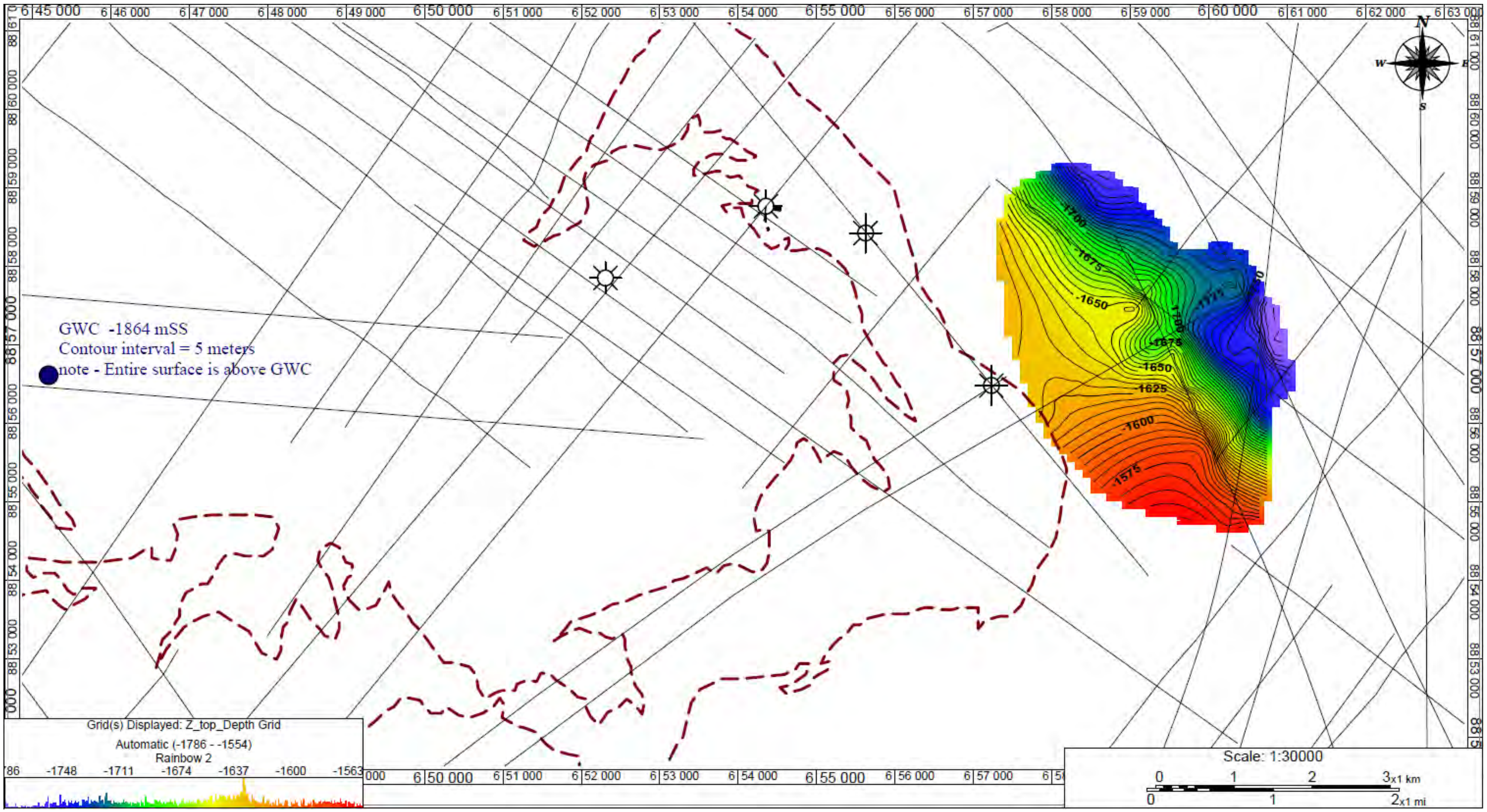
Msimbati: Lower K Sand Top



Msimbati: Lower K Sand Base



Msimbati NE: Sand Top



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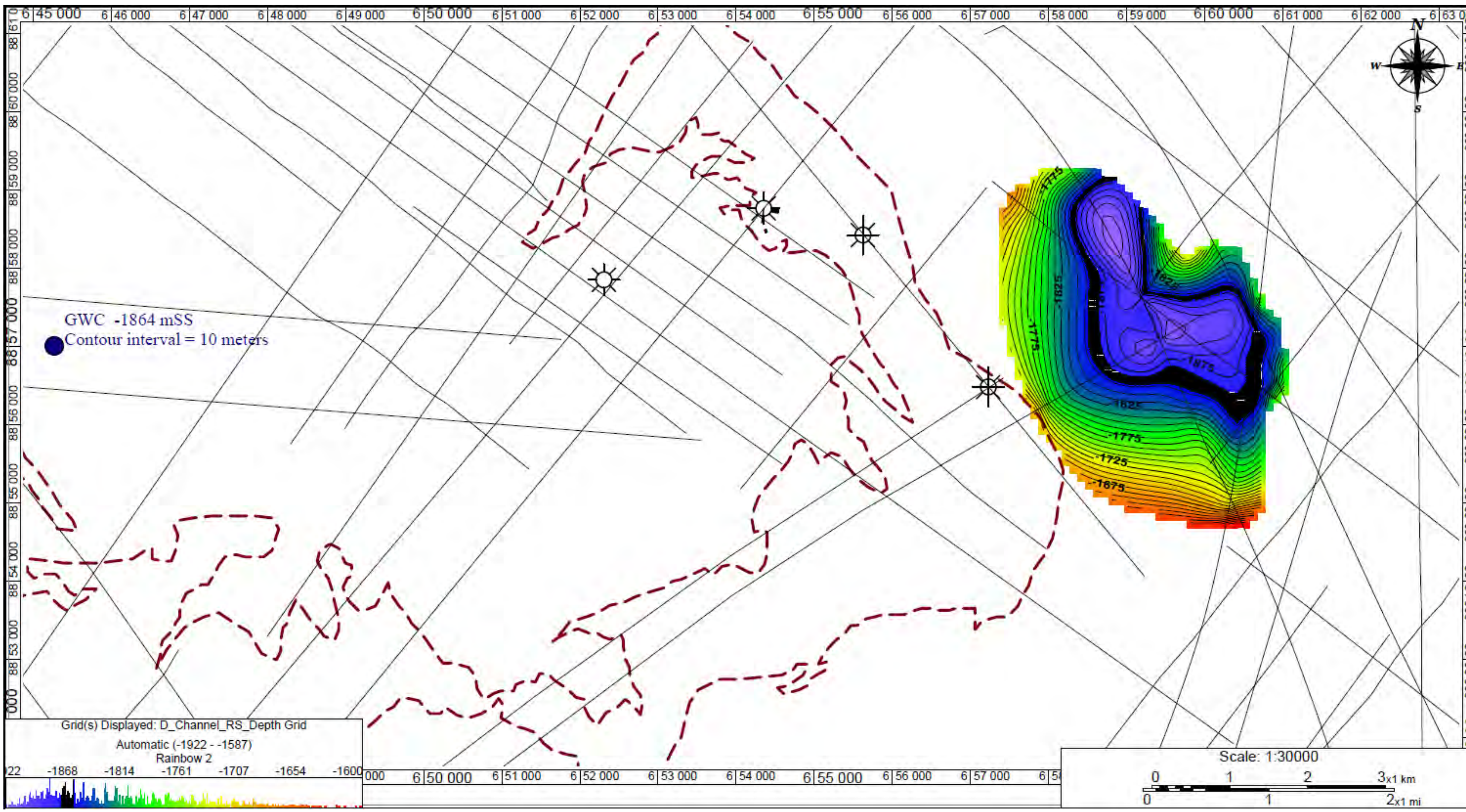

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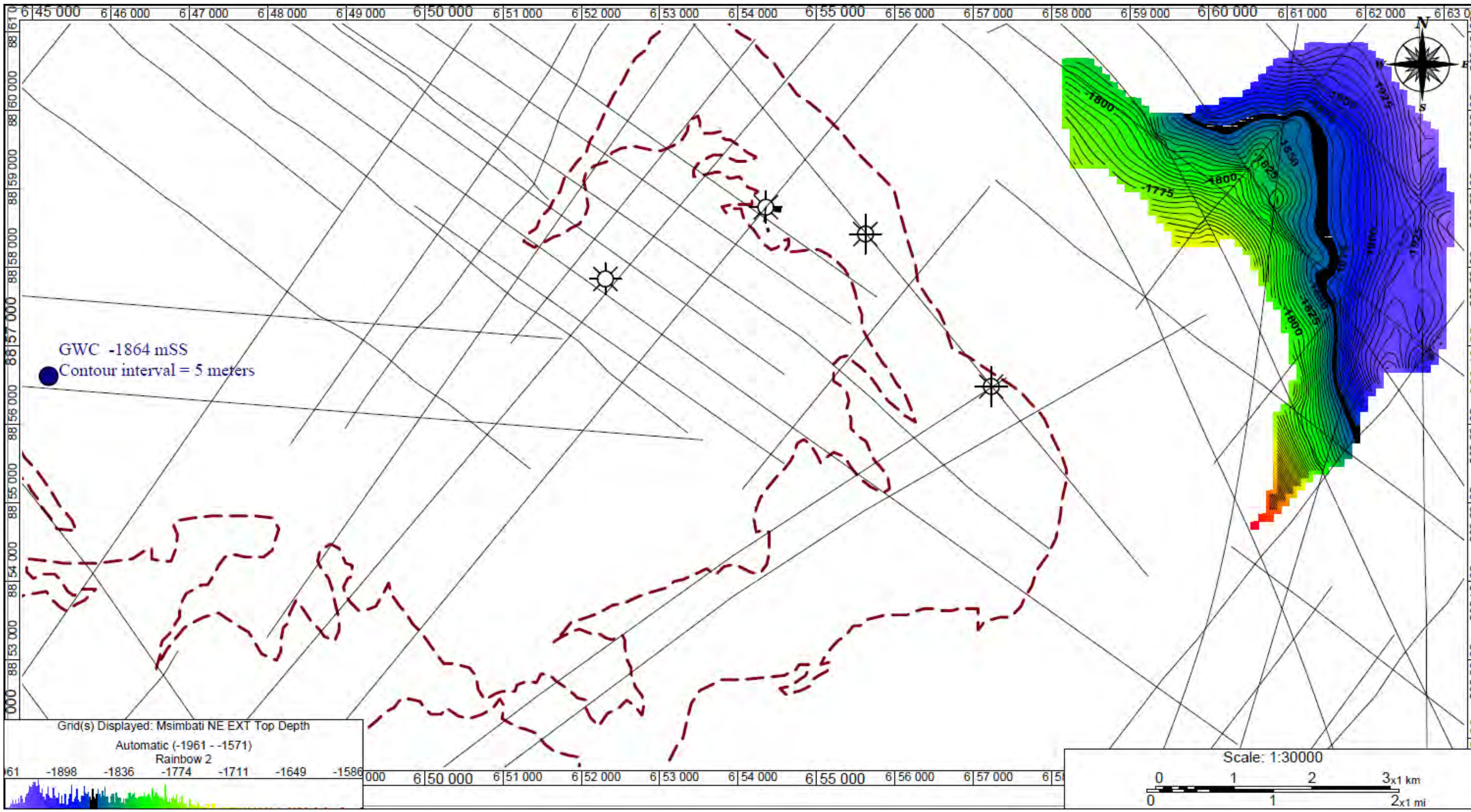

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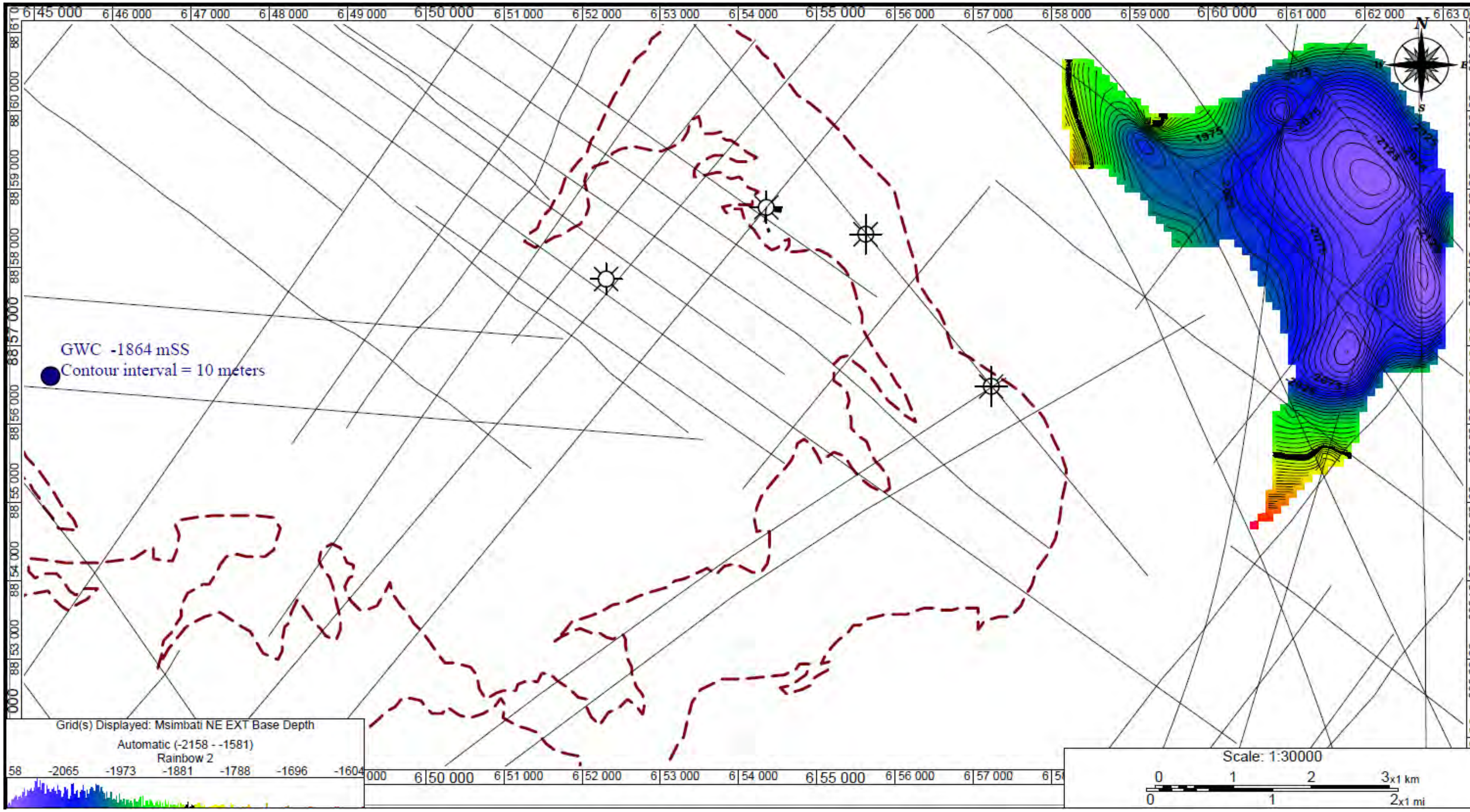
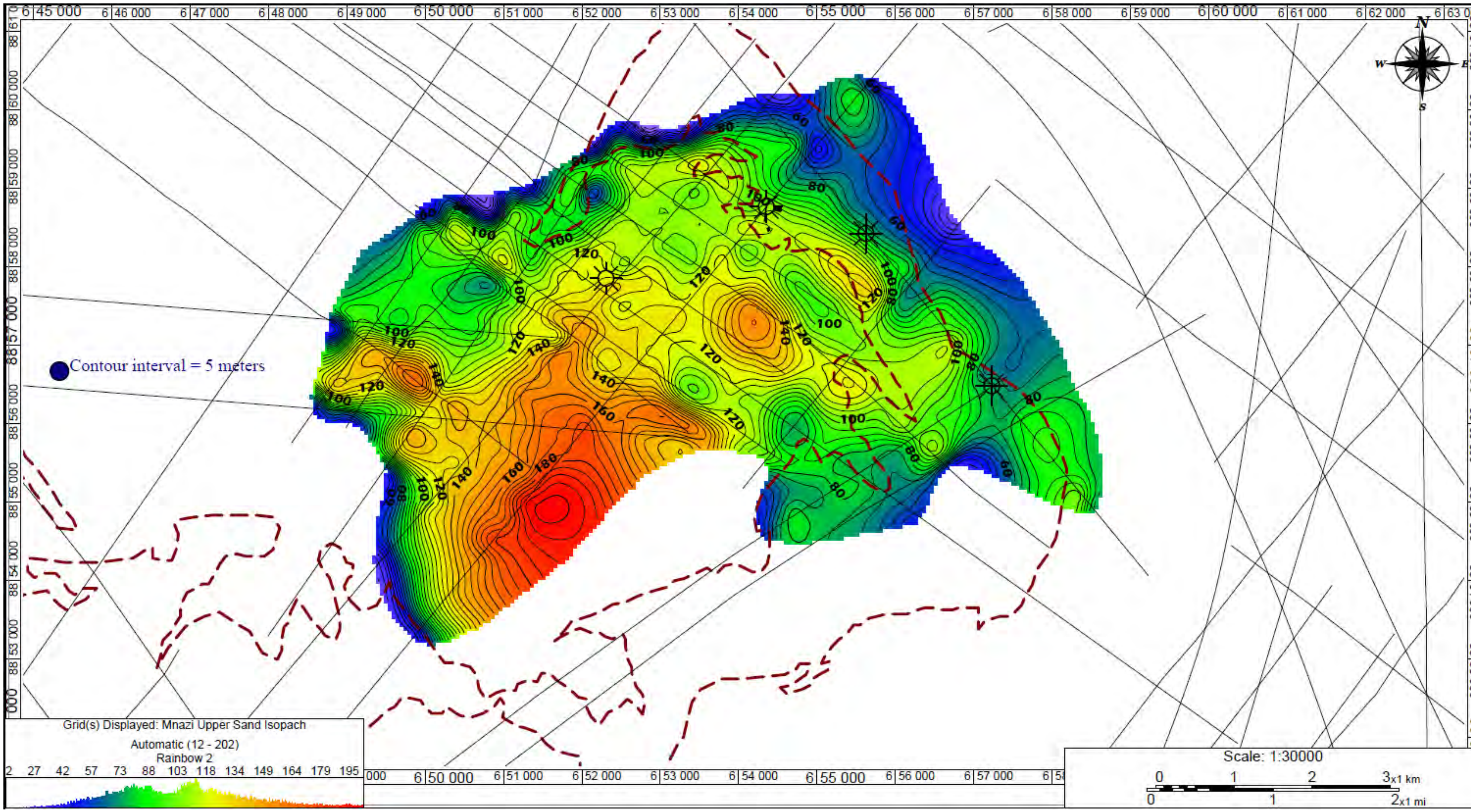
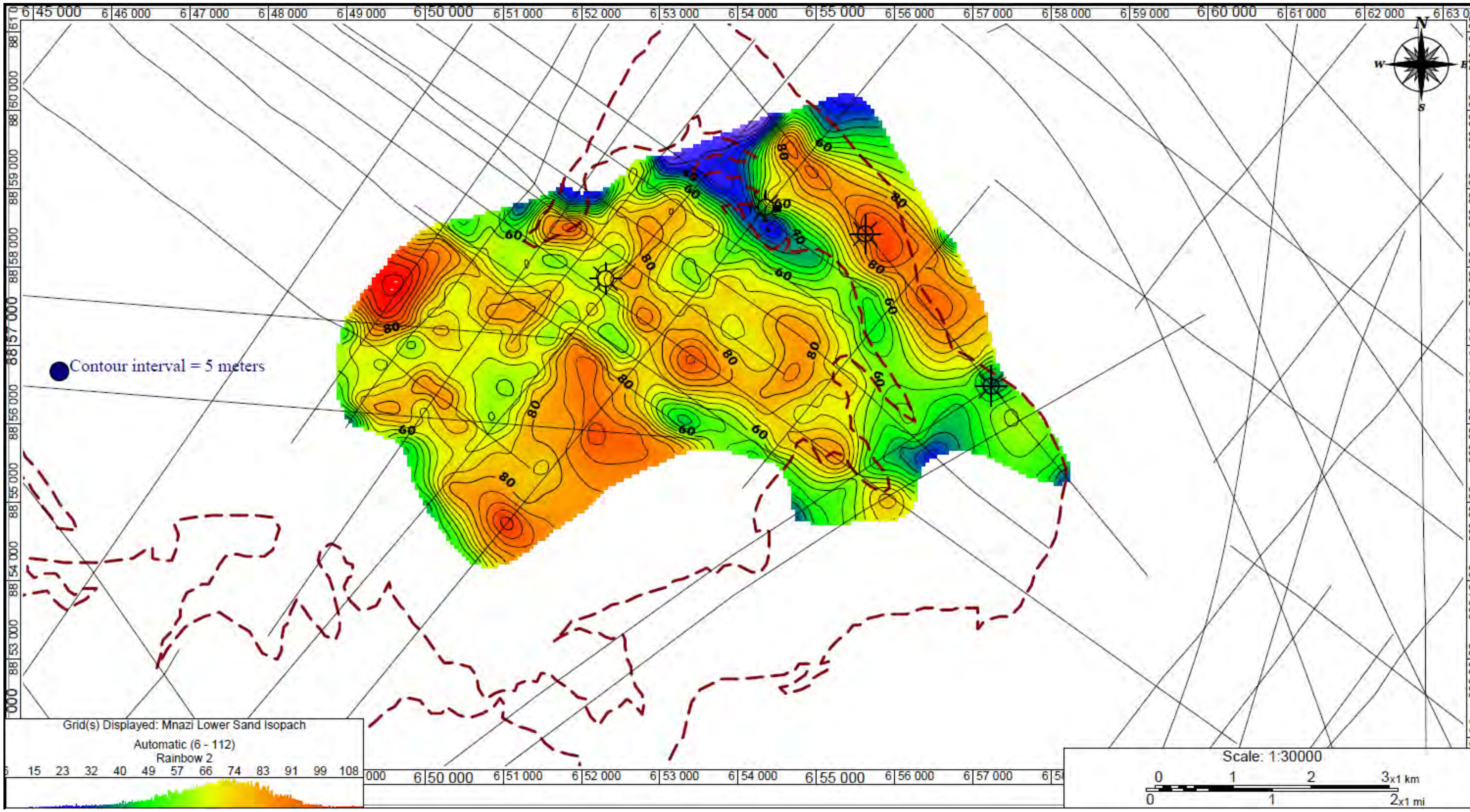


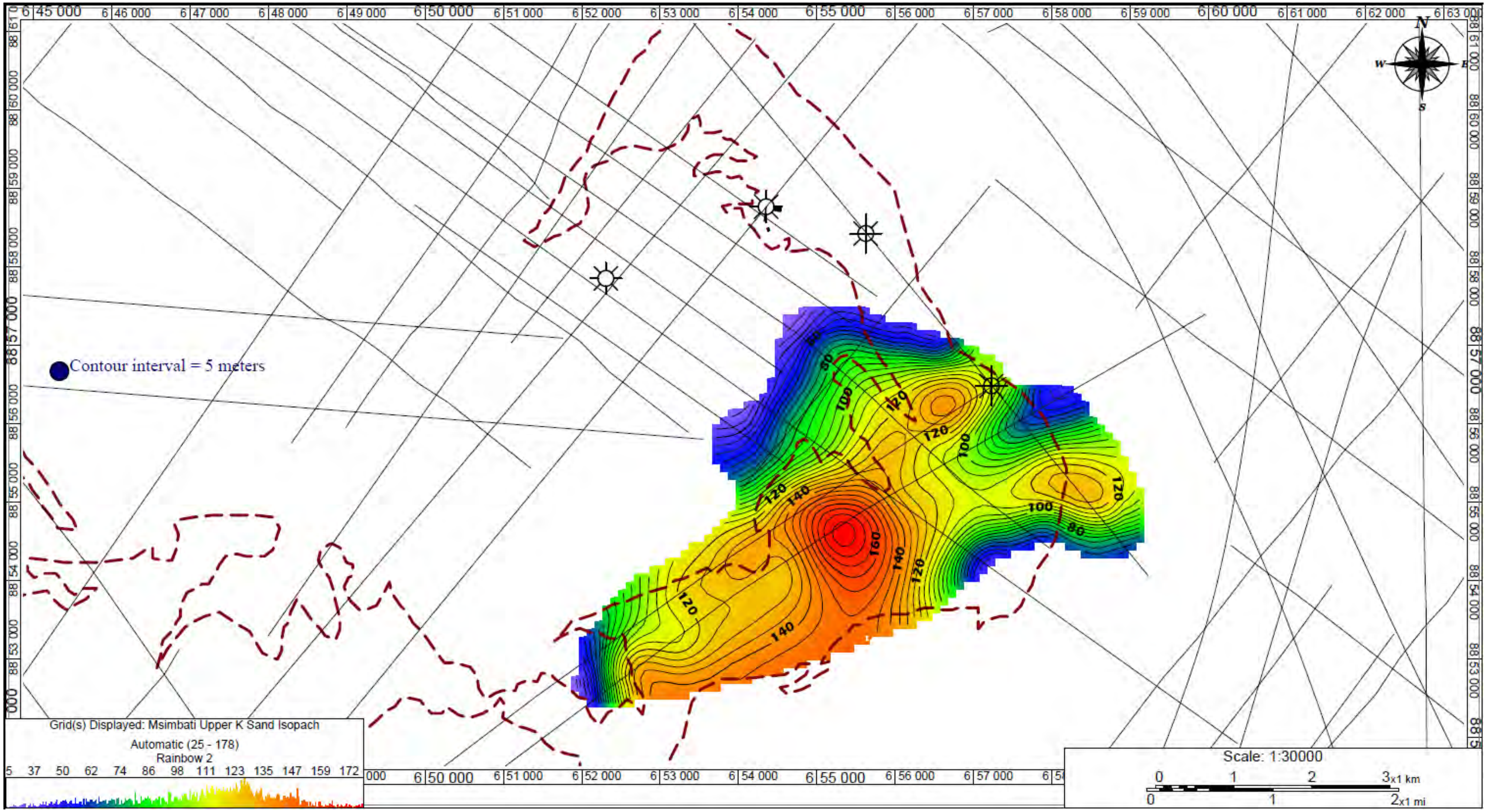
Mnazi Bay: Upper Sand Isopach



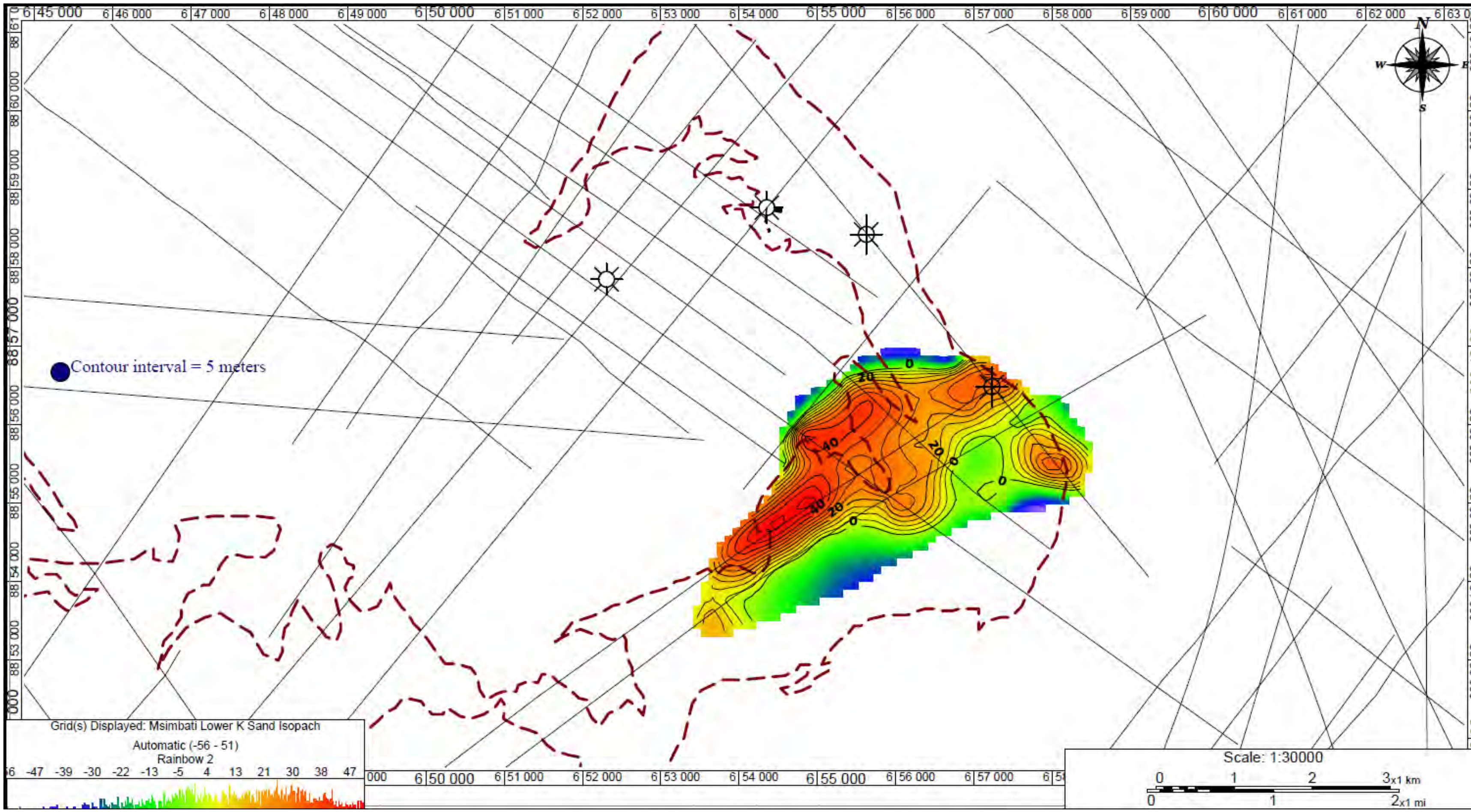
Mnazi Bay: Lower Sand Isopach



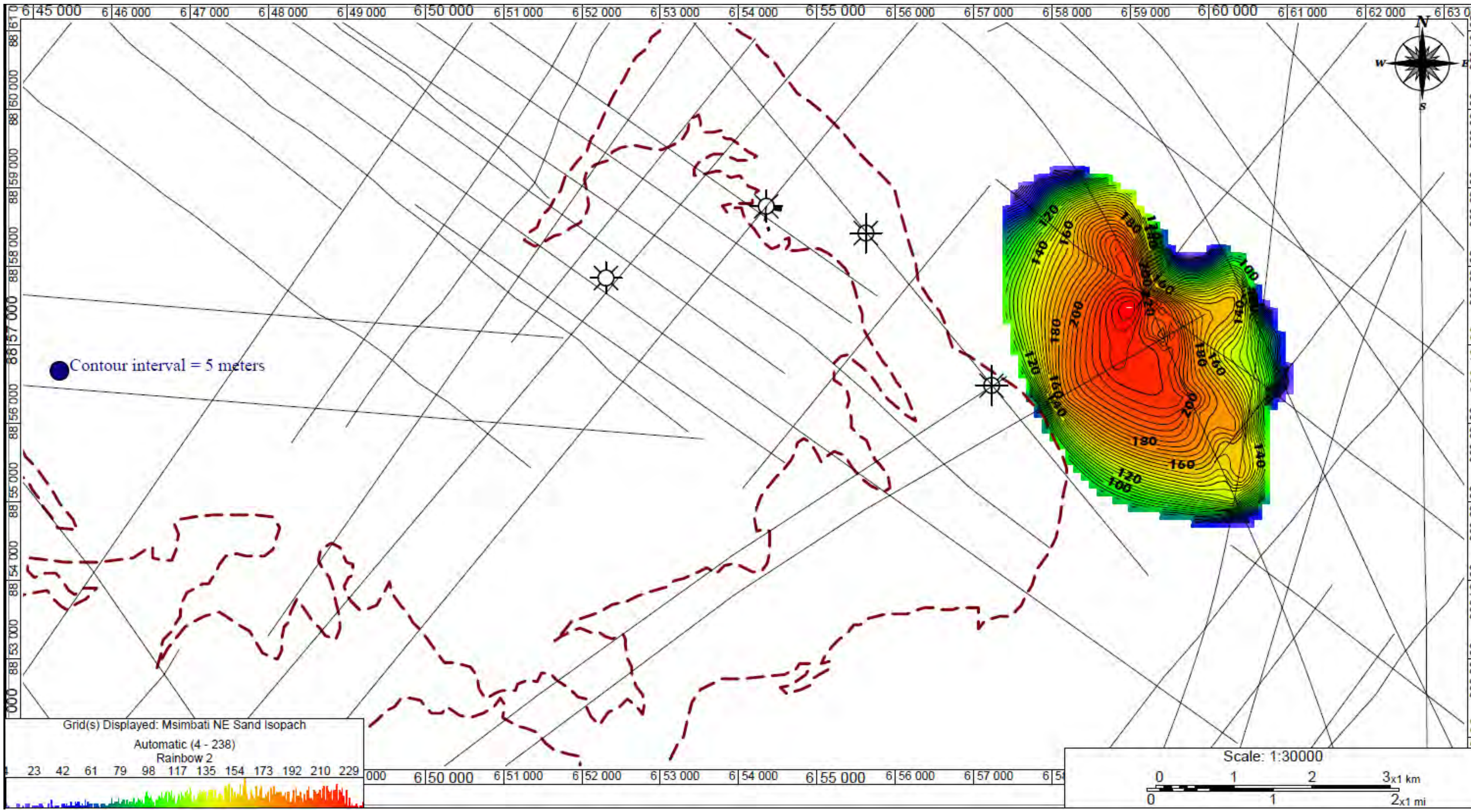
Msimbati: Upper K Sand Isopach



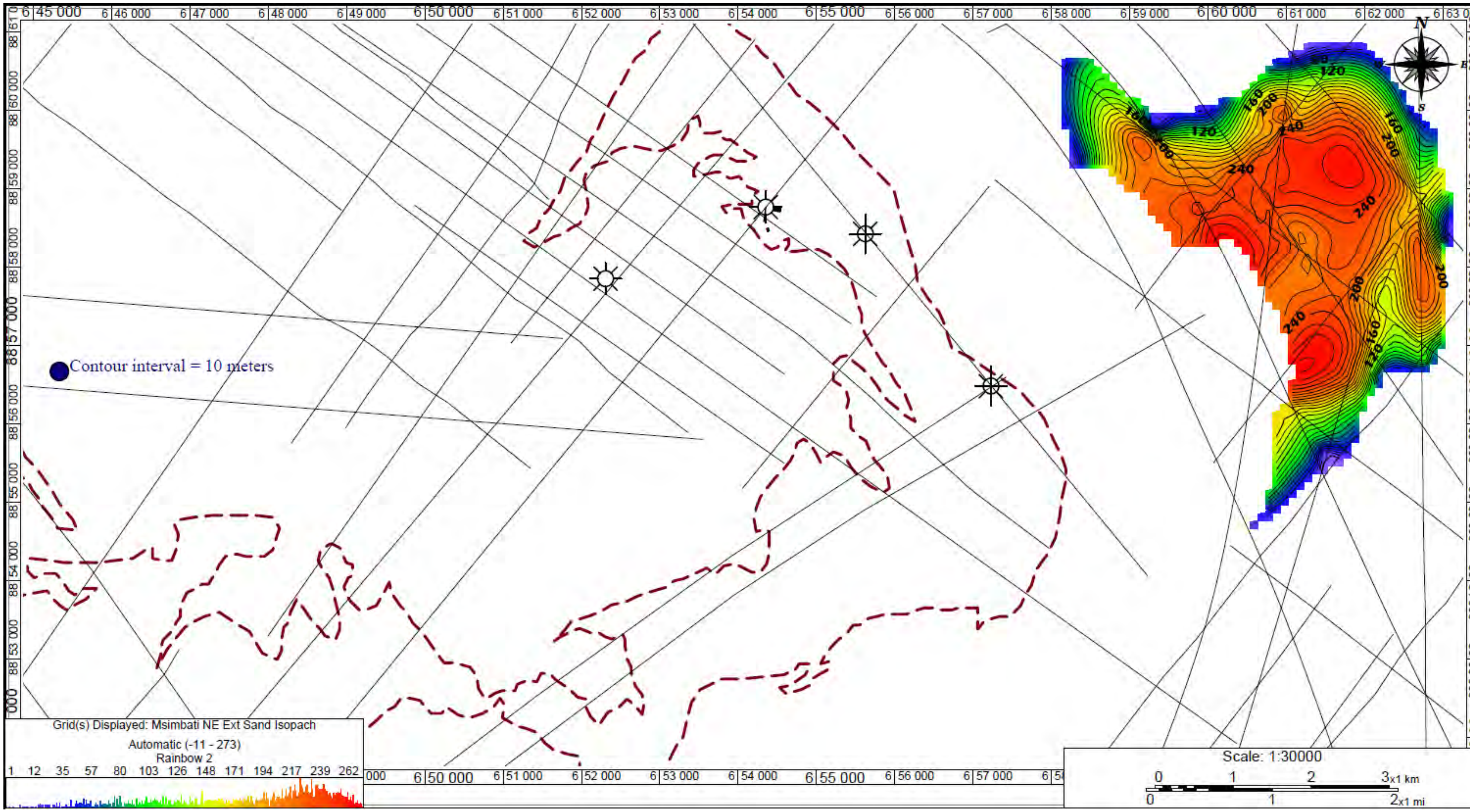
Msimbati: Lower K Sand Isopach



Msimbati NE: Sand Isopach



Msimbati NE Ext: Sand Isopach



APPENDIX 3

Mnazi Bay Licence Prospective Resources Structure and Isopach Maps

APPENDIX 3

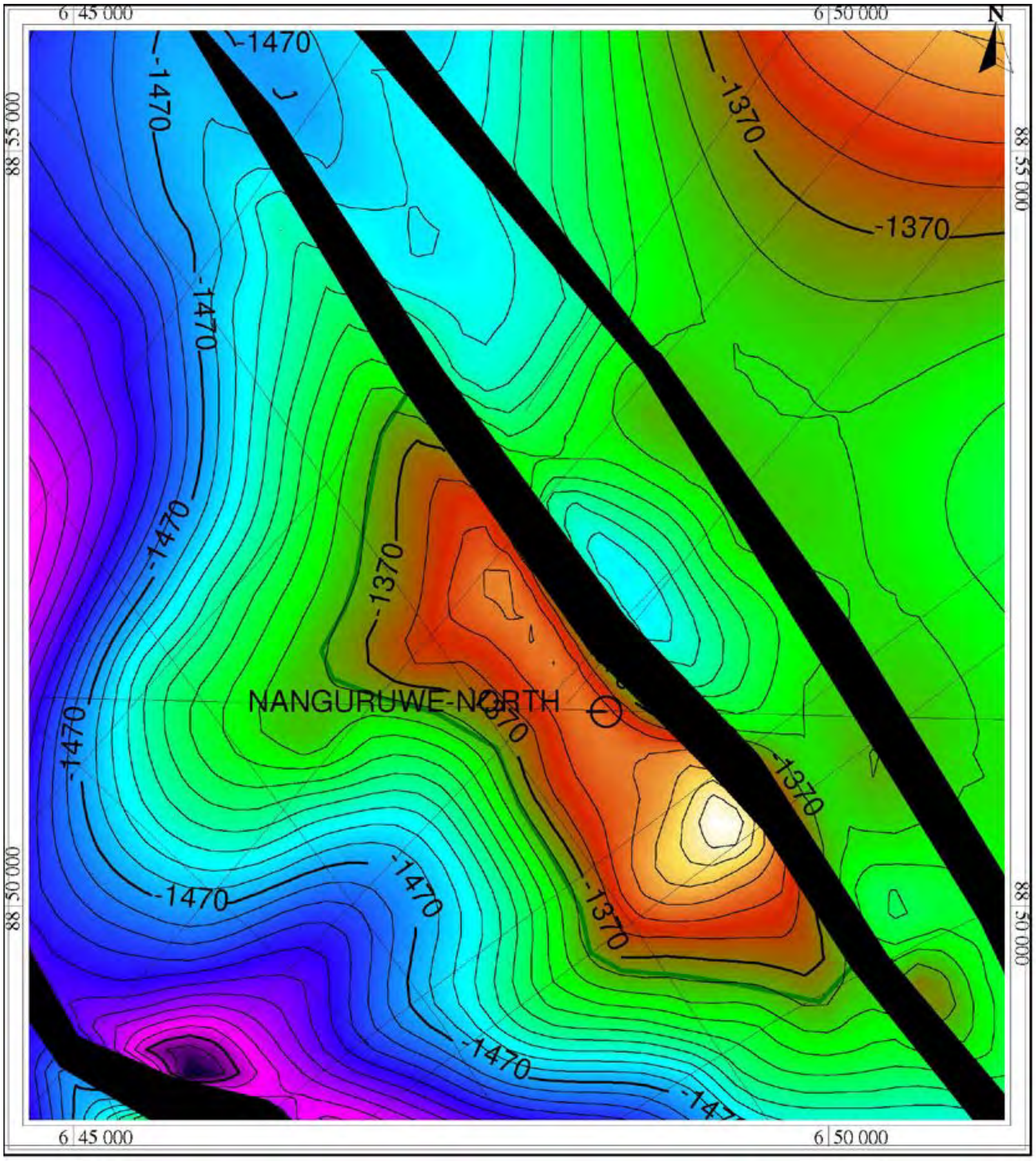


Figure App 3- 1: Nanguruwe North Oligocene Depth Structure Map

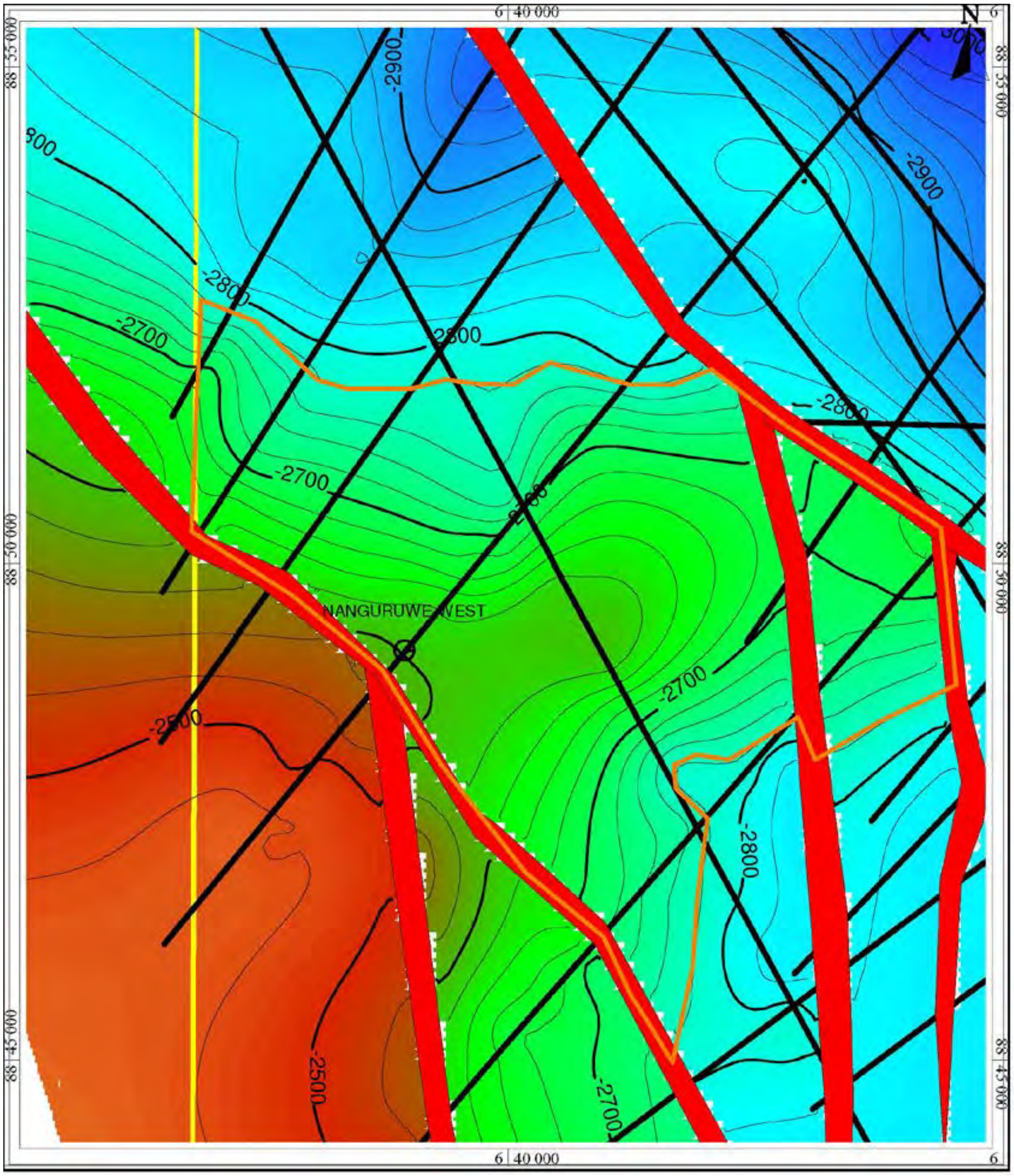


Figure App 3- 2: Nanguruwe West Cretaceous Depth Structure Map

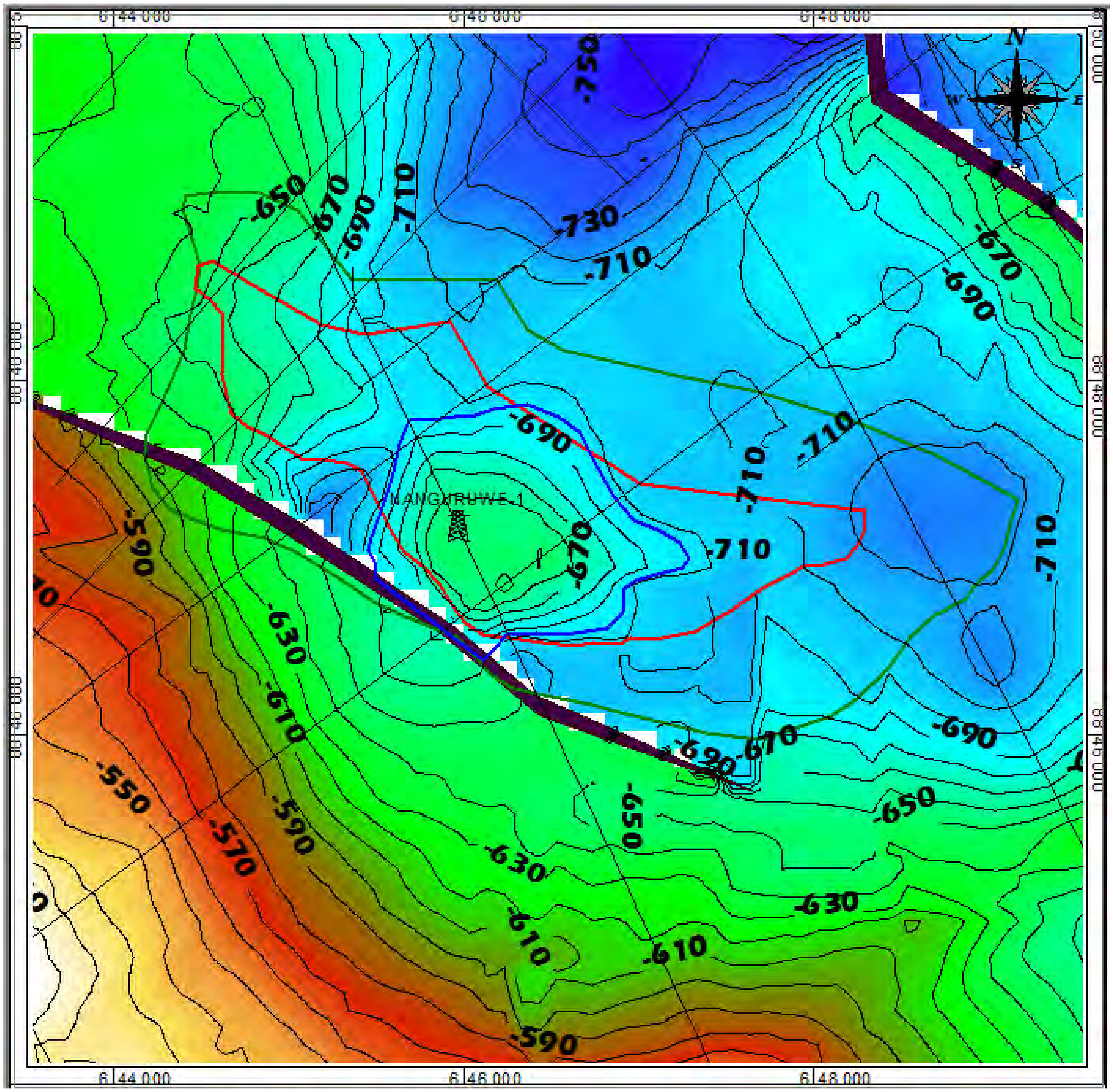


Figure App 3- 3: Top depth structure for the Nanguruwe Pliocene prospect. Contour interval is 10 meters.

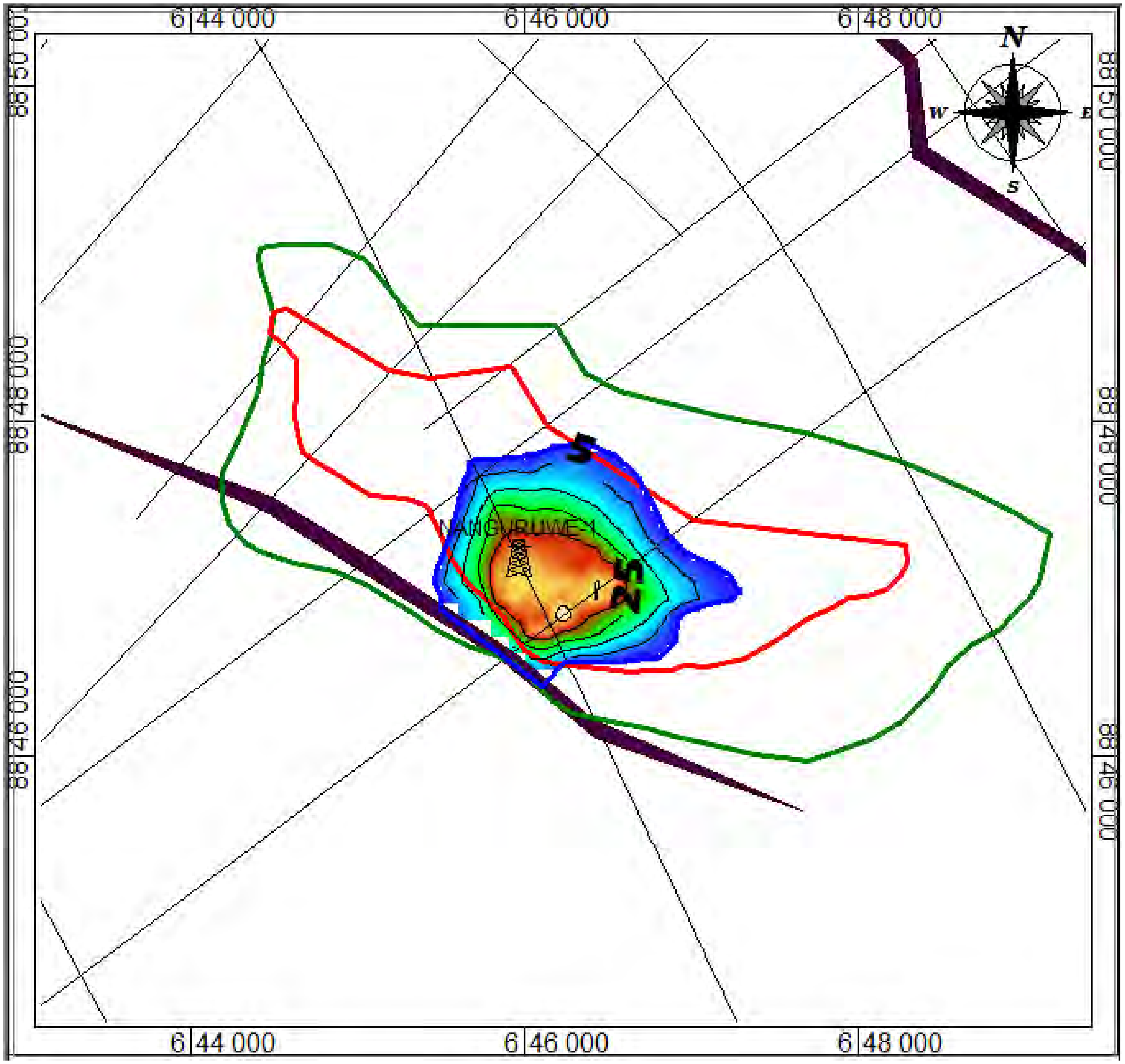


Figure App 3- 4: Isopach for the Nanguruwe Pliocene prospect. Contour interval is 10 meters.

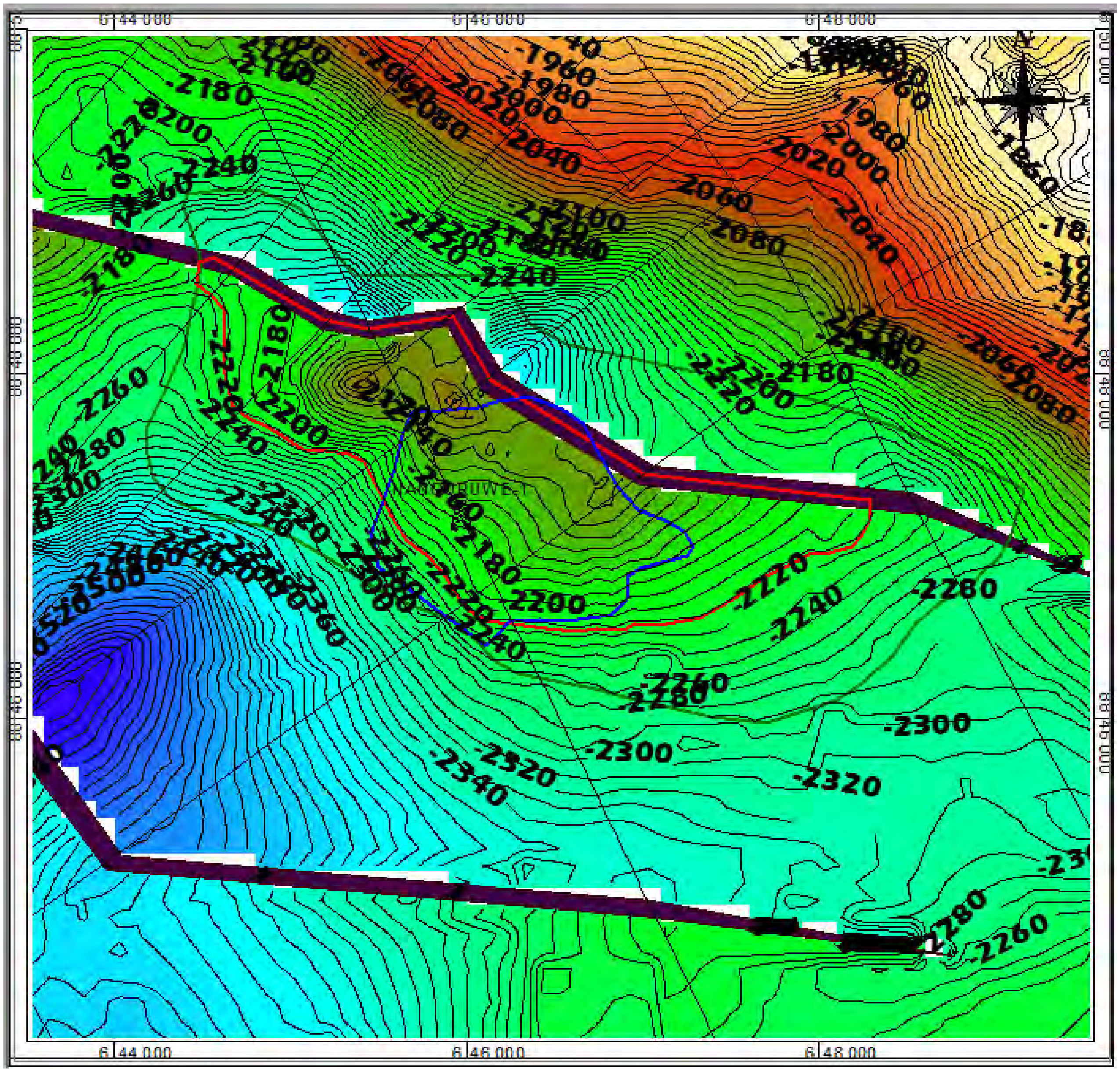


Figure App 3- 5: Top depth structure for the Nanguruwe Miocene prospect. Contour interval is 10 meters.

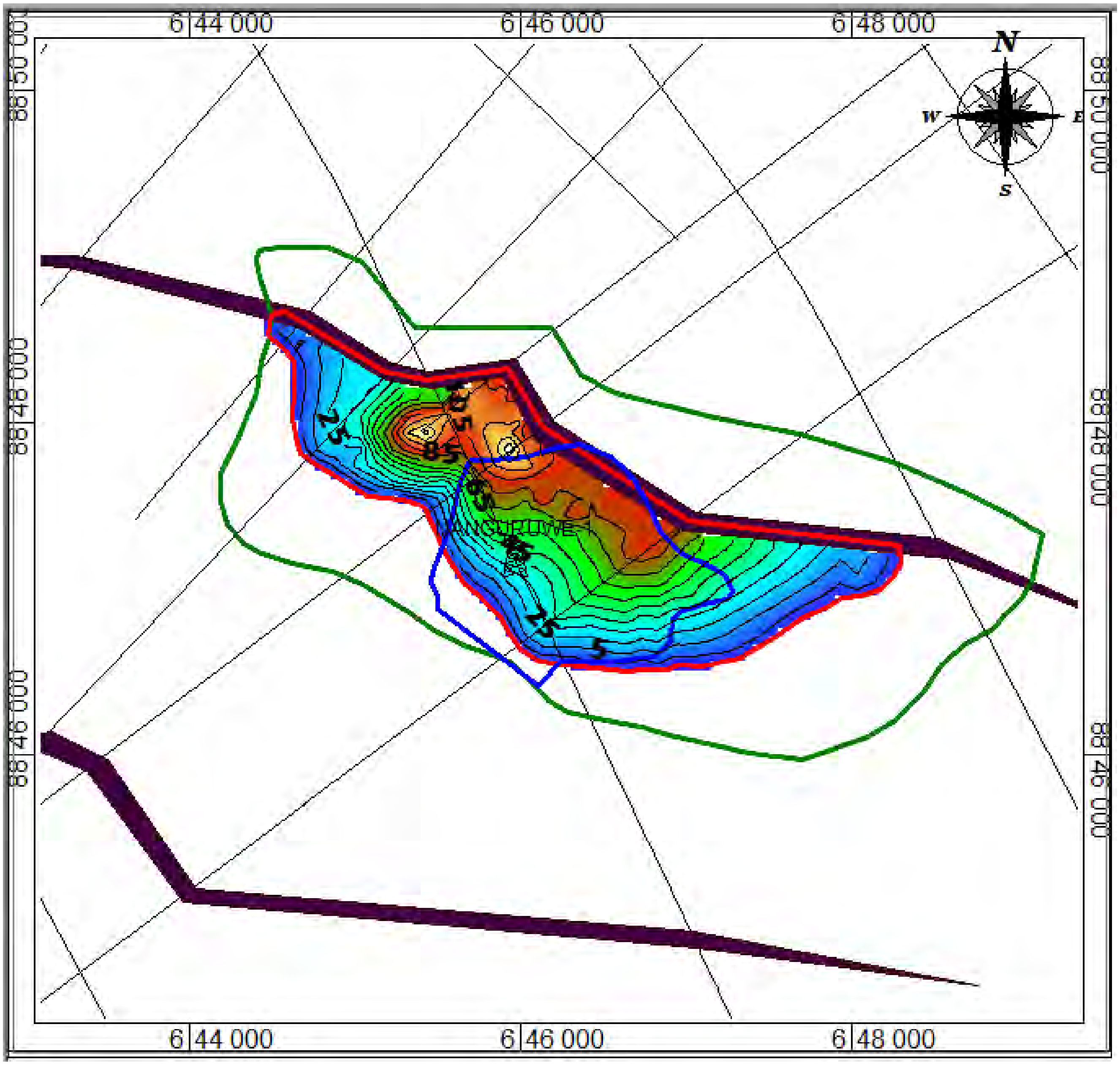


Figure App 3- 6: Isopach for the Nanguruwe Miocene prospect. Contour interval is 10 meters.

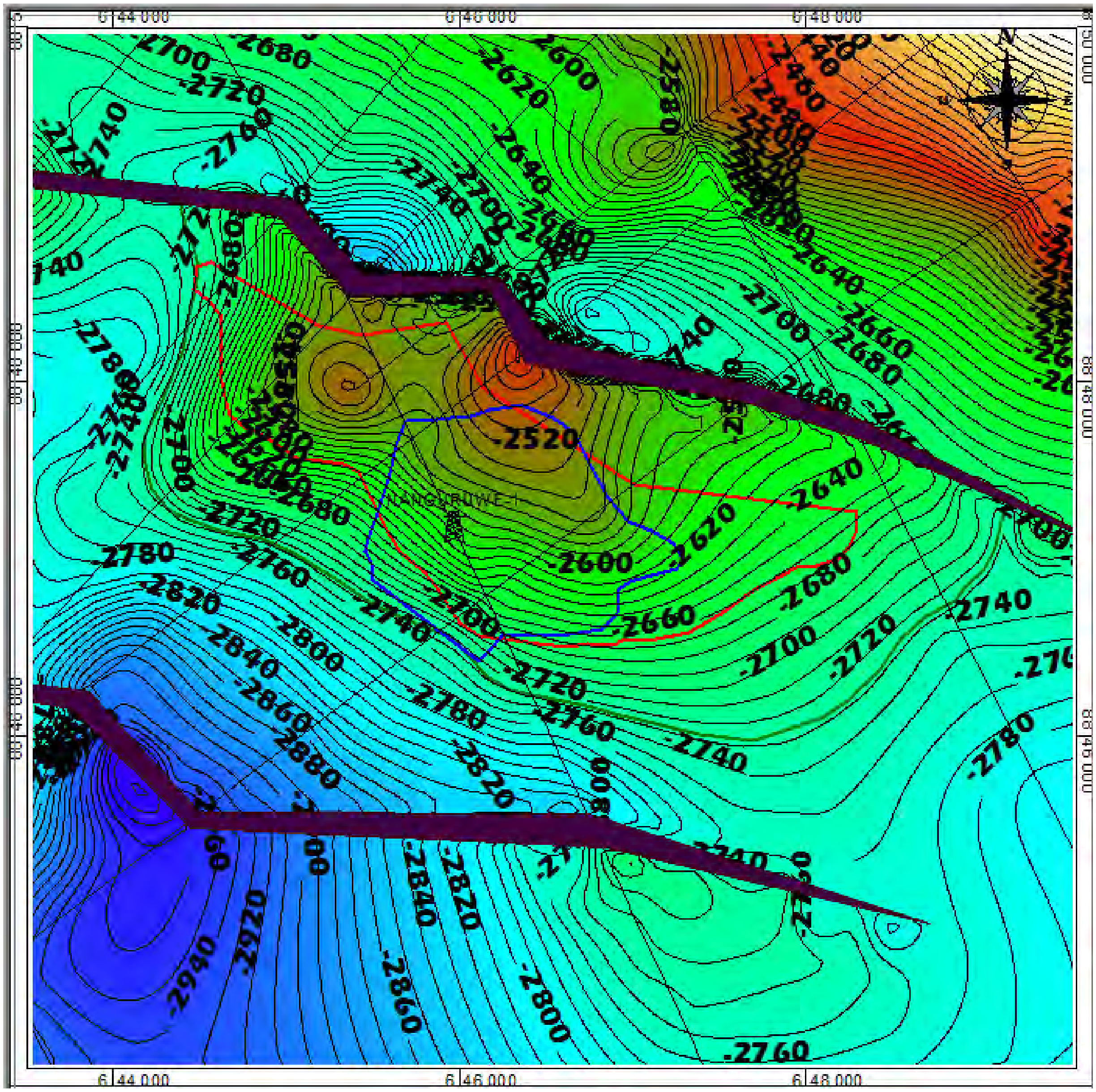


Figure App 3- 7: Top depth structure for the Nanguruwe Oligocene prospect. Contour interval is 10 meters.

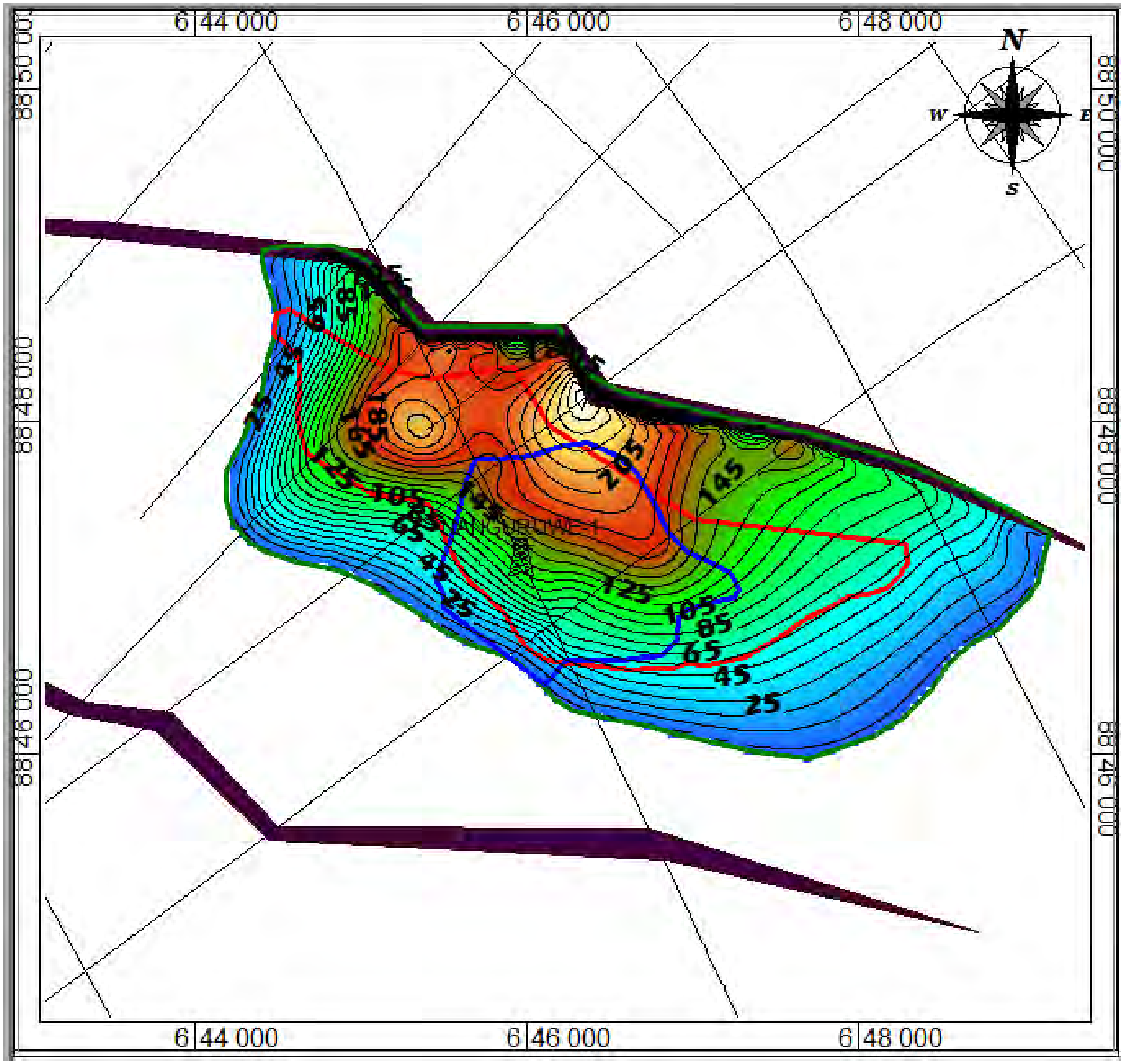


Figure App 3- 8: Isopach for the Nanguruwe Oligocene prospect. Contour interval is 10 meters.

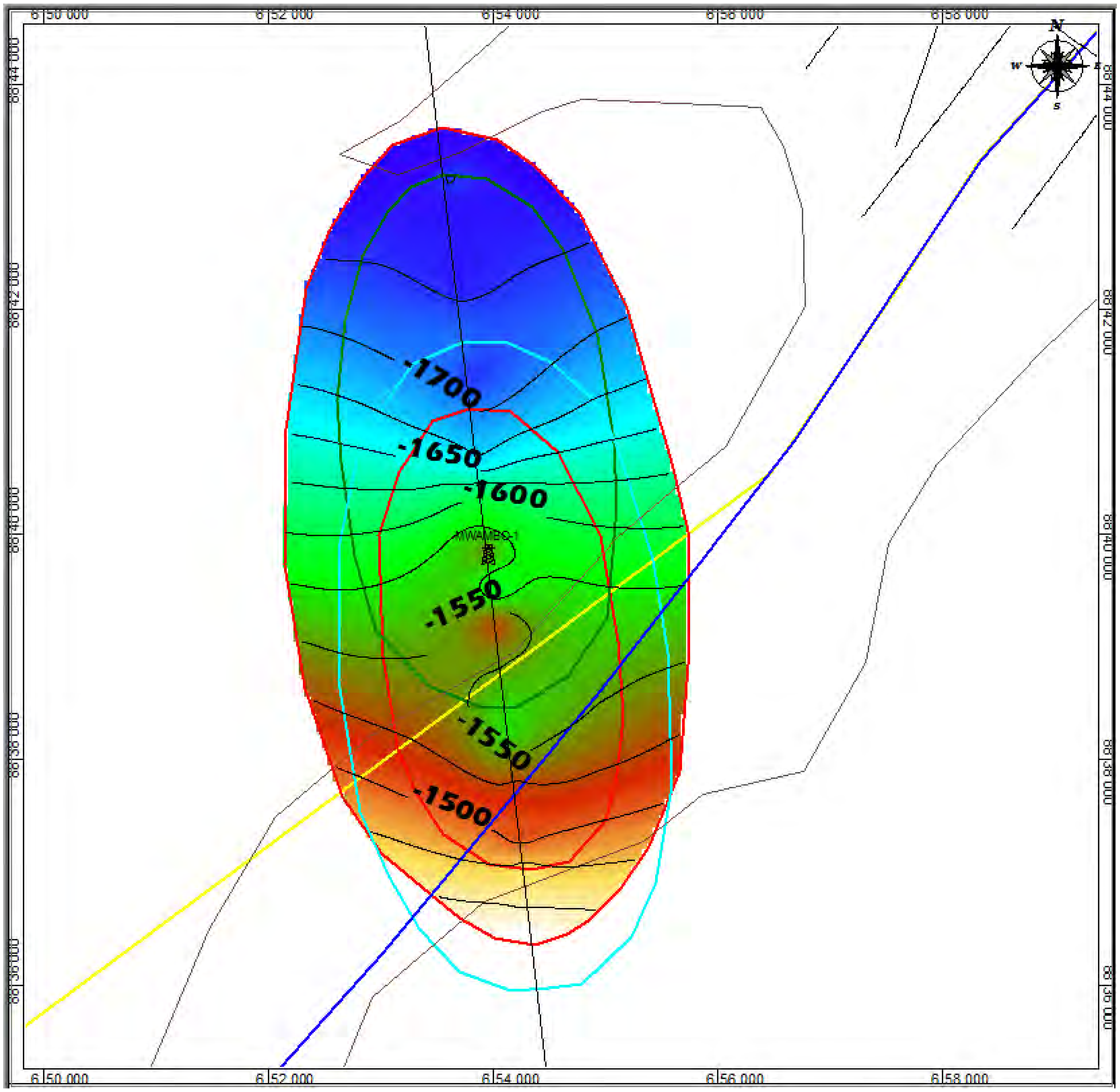


Figure App 3- 9: Top depth structure for the Mwambo Miocene prospect. Contour interval is 25 meters.

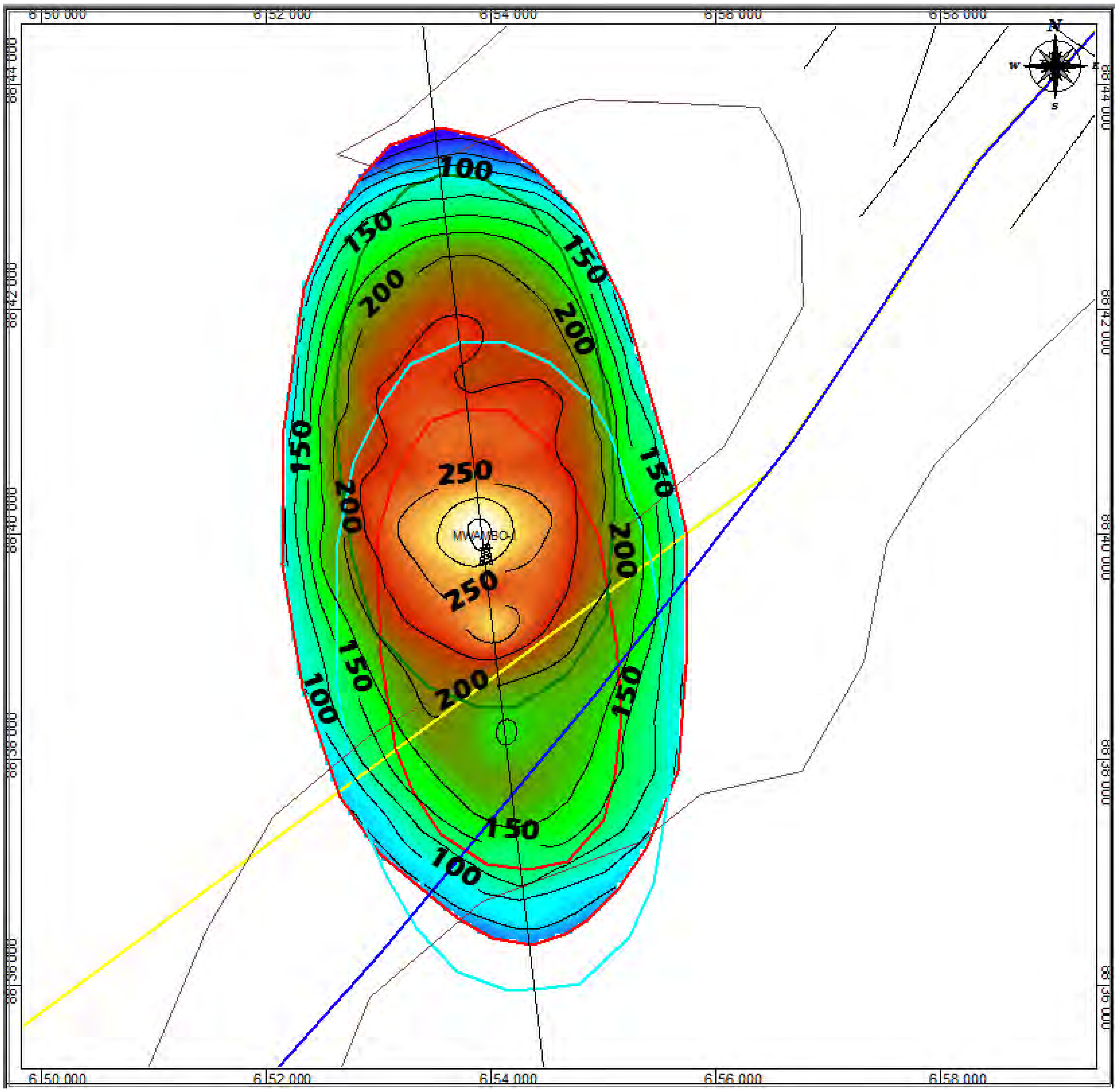


Figure App 3- 10: Isopach for the Mwambo Miocene prospect. Contour interval is 25 meters.

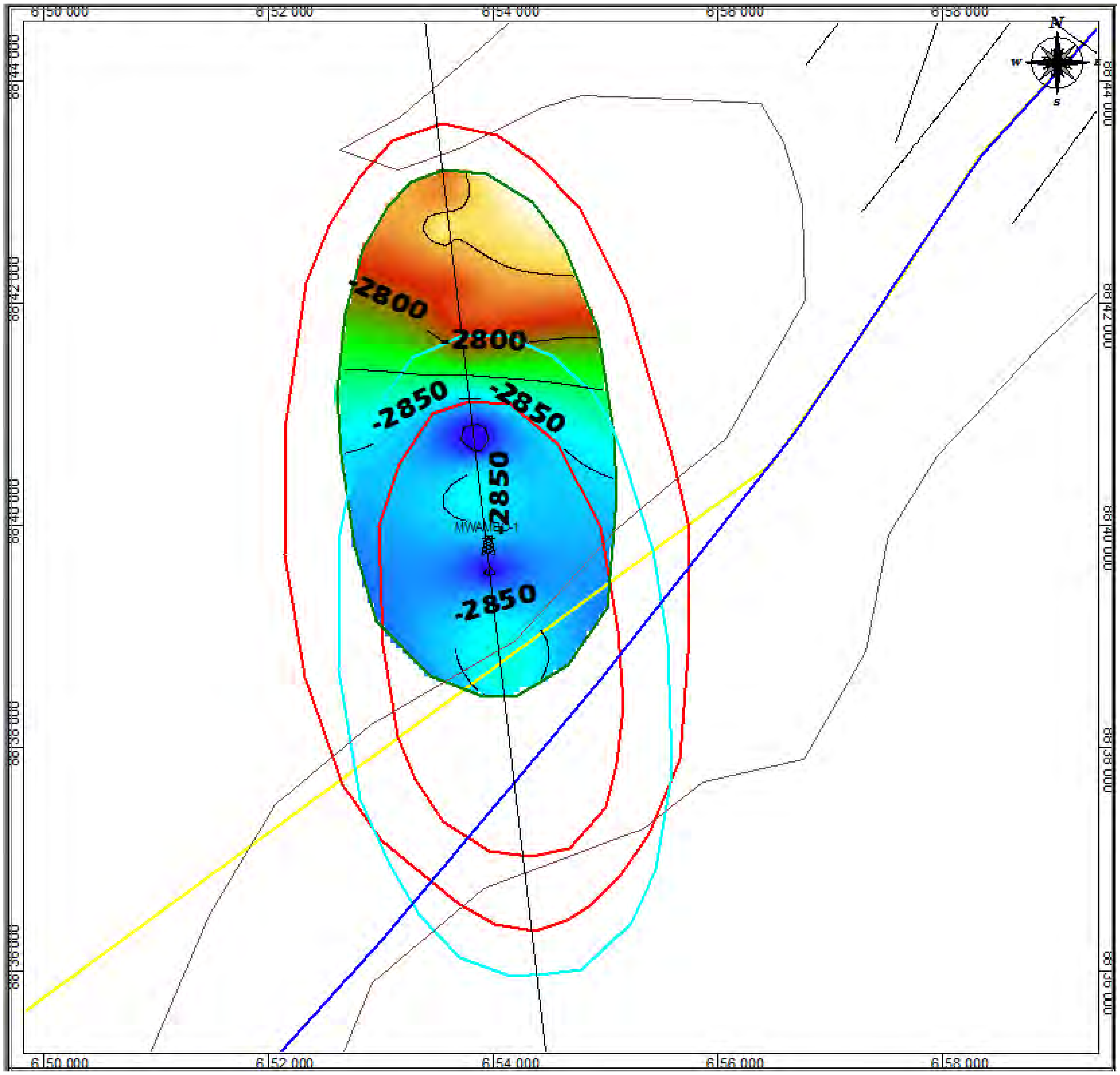


Figure App 3- 11: Top depth structure for the Mwambo Oligocene prospect. Contour interval is 25 meters.

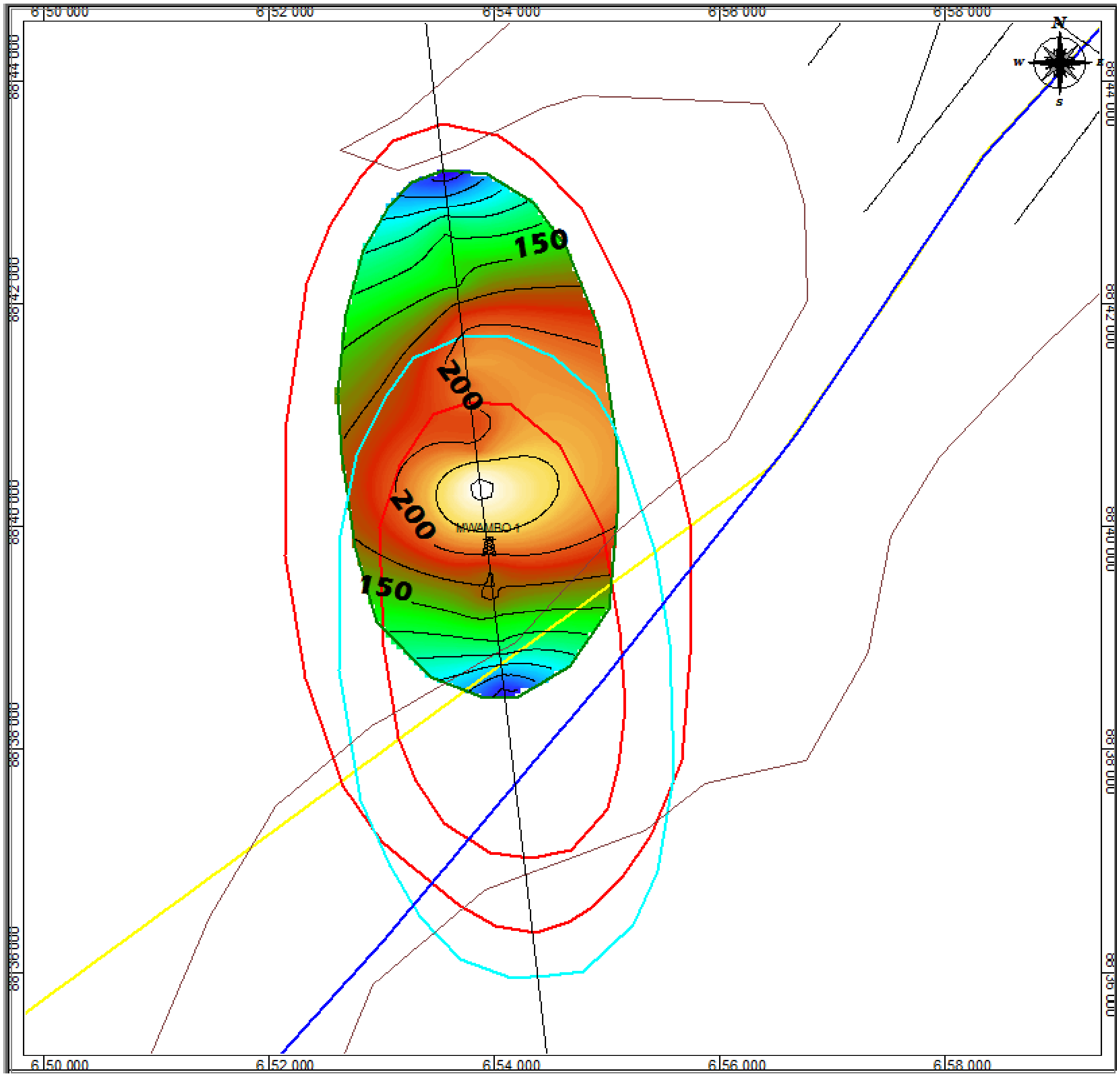


Figure App 3- 12: **Isopach for the Mwambo Oligocene prospect. Contour interval is 25 meters.**

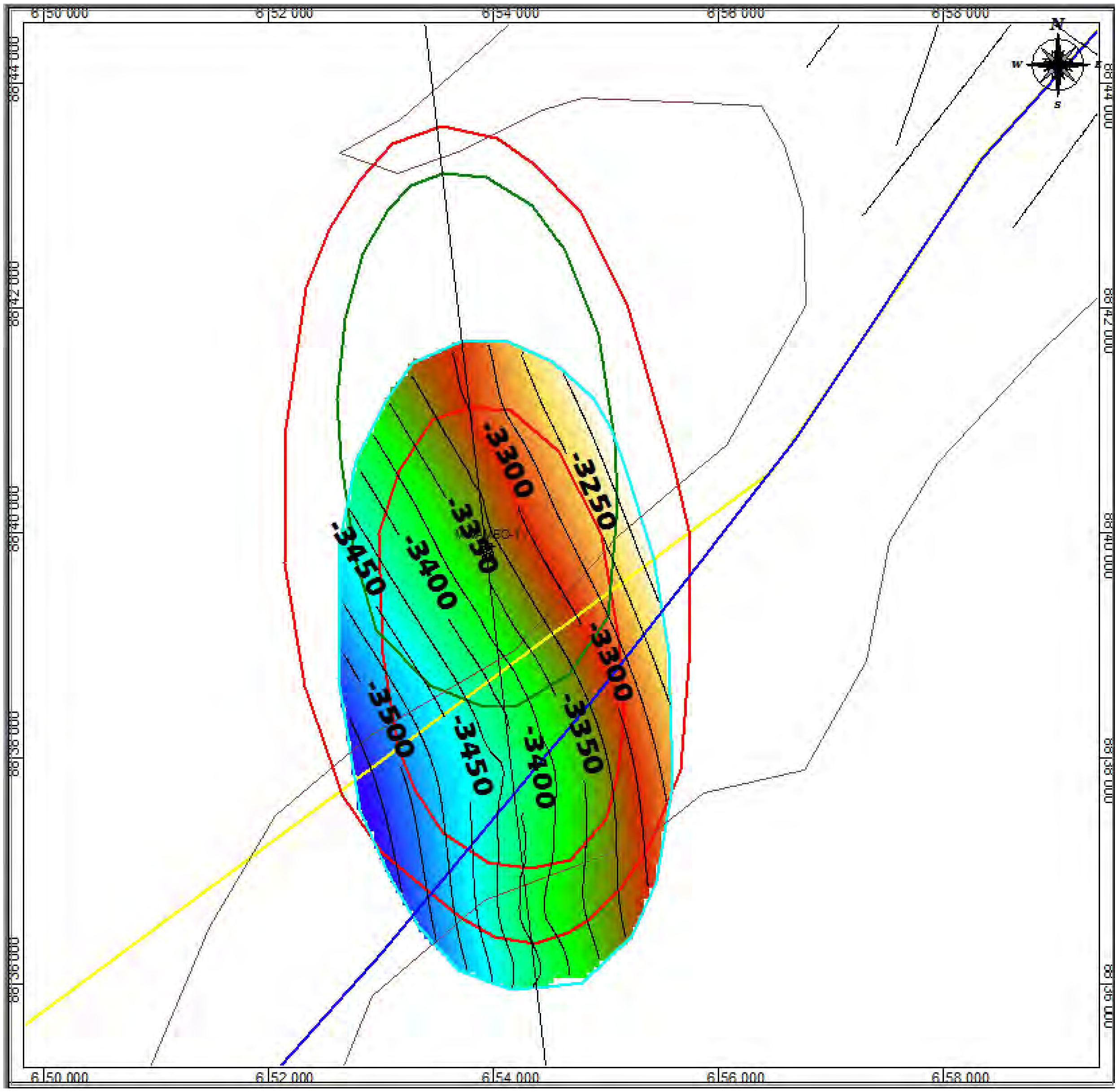


Figure App 3- 13: Top depth structure for the Mwambo Eocene prospect. Contour interval is 25 meters.

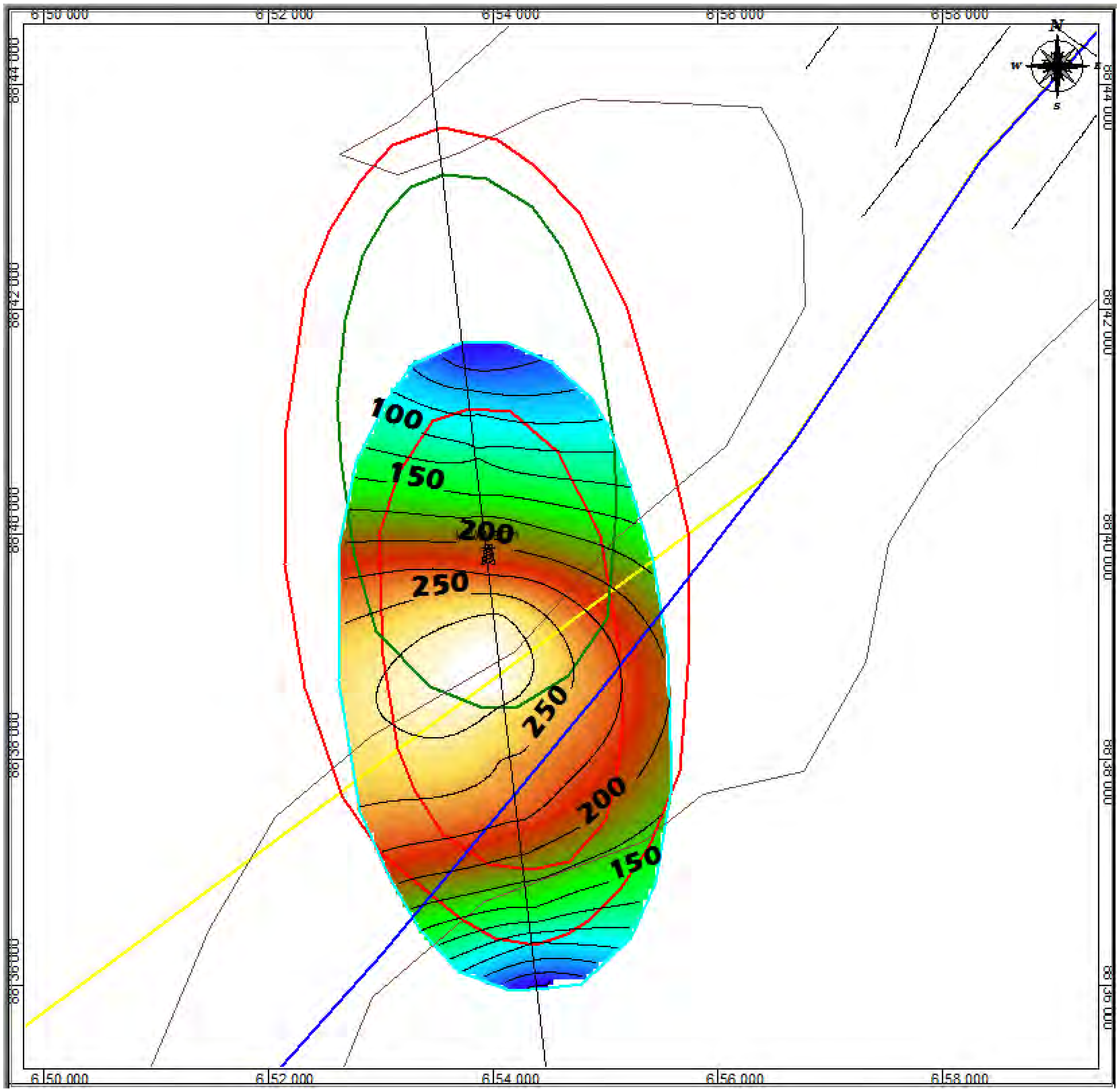


Figure App 3- 14: **Isopach for the Mwambo Eocene prospect. Contour interval is 25 meters.**

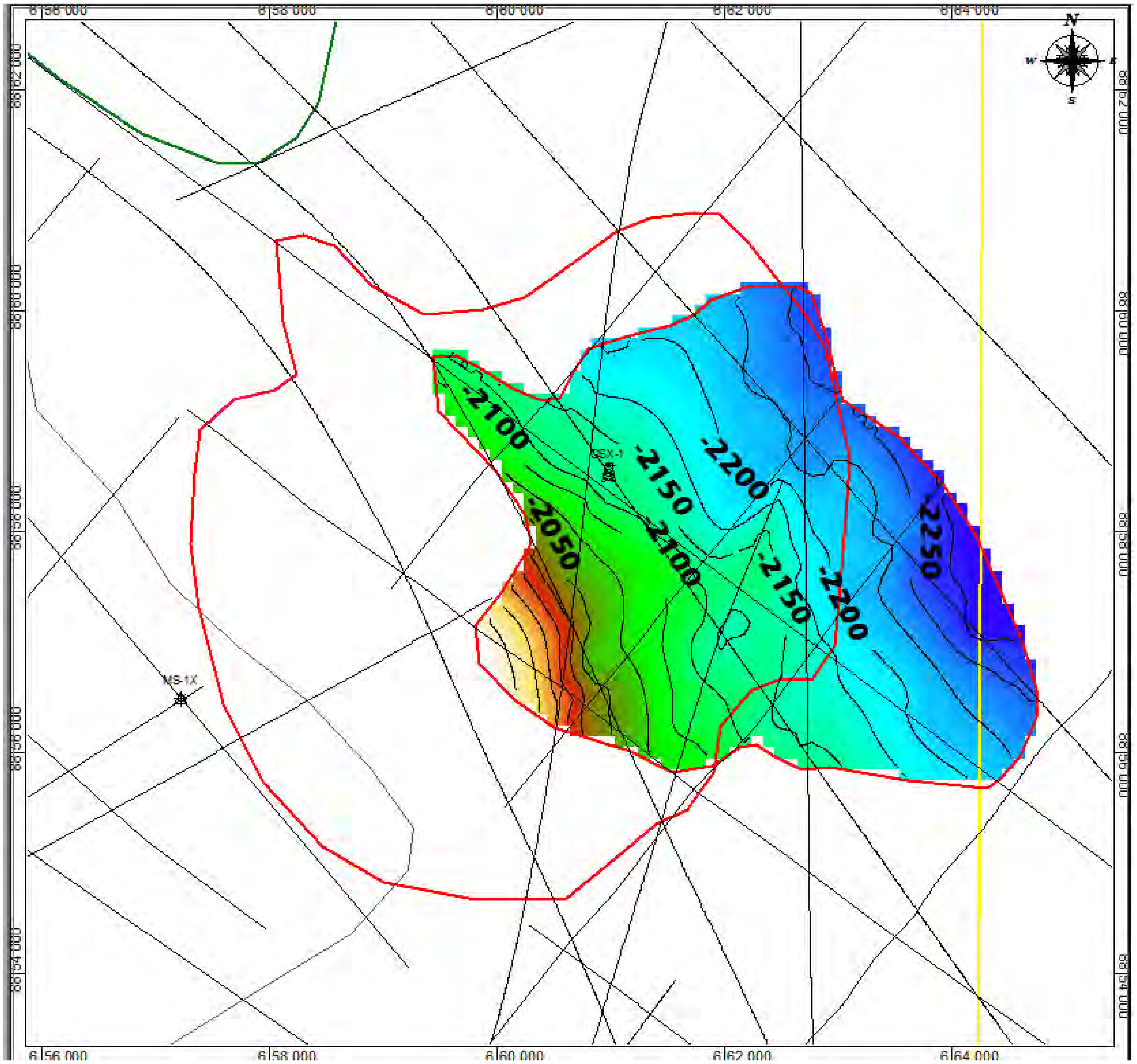


Figure App 3- 15: Top depth structure for the OSX-1 Miocene 1 prospect. Contour interval is 25 meters.

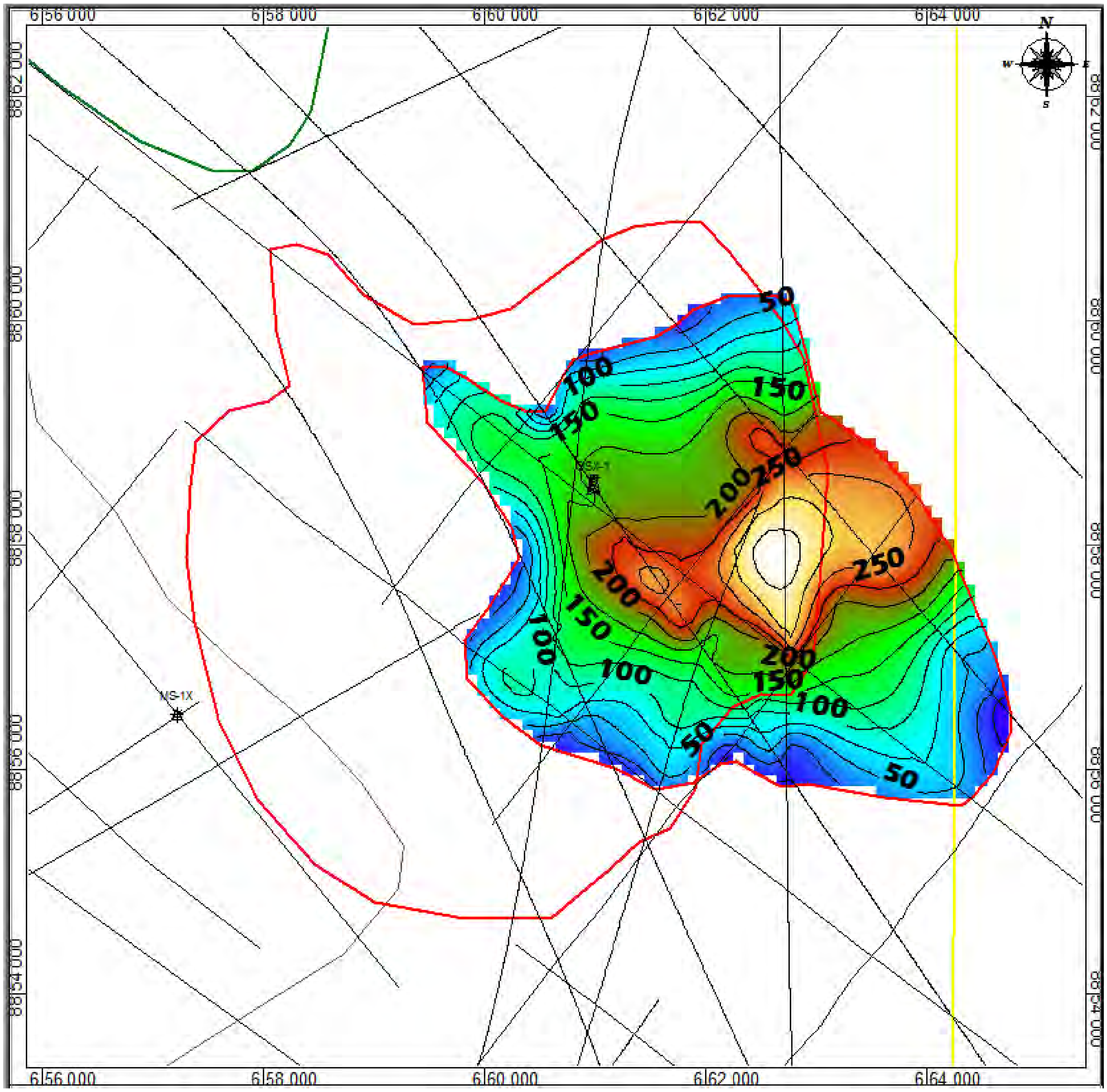


Figure App 3- 16: **Isopach for the OSX-1 Miocene 1 prospect. Contour interval is 25 meters.**

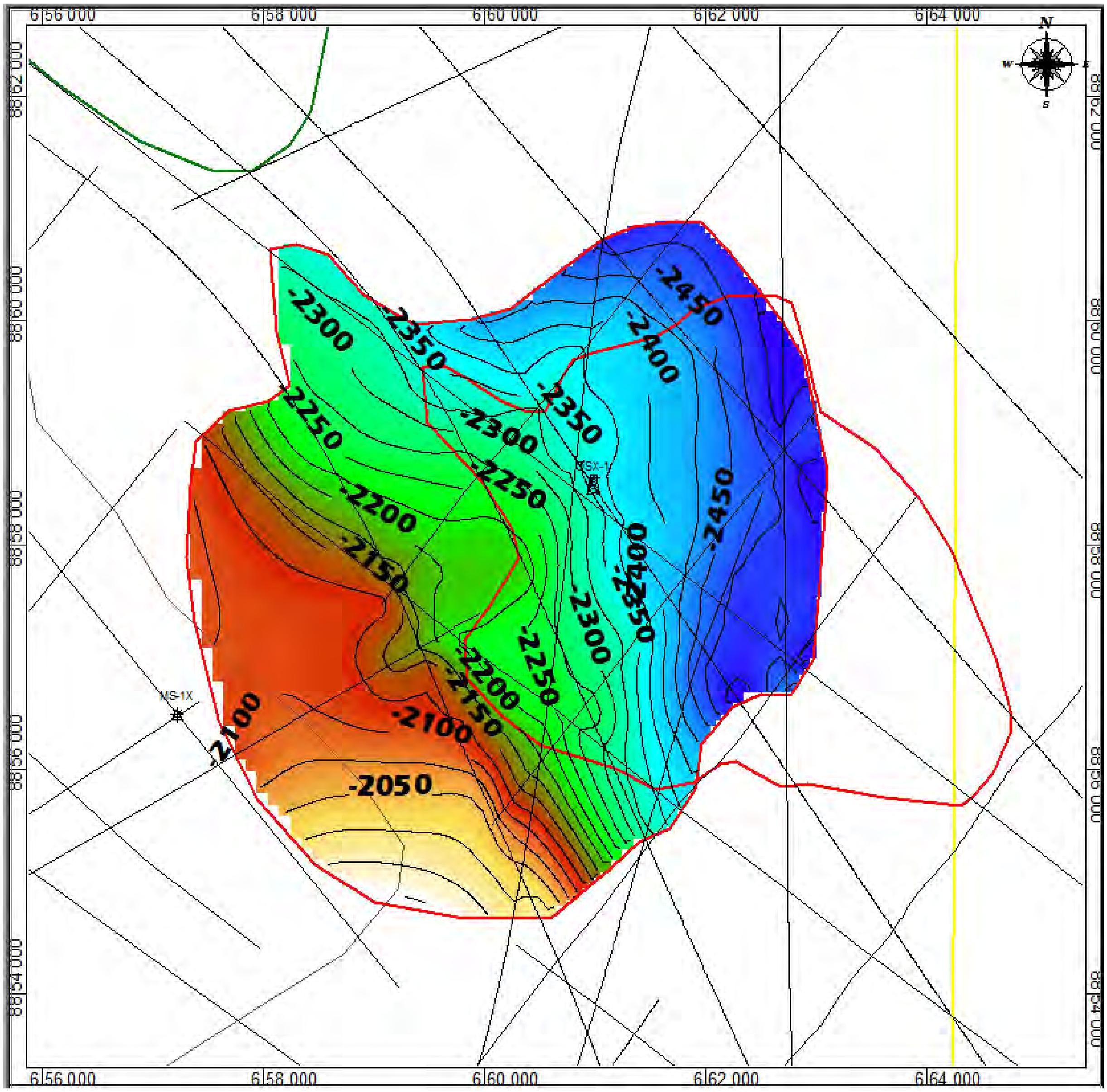


Figure App 3- 17: **Top depth structure for the OSX-1 Miocene 2 prospect. Contour interval is 25 meters.**

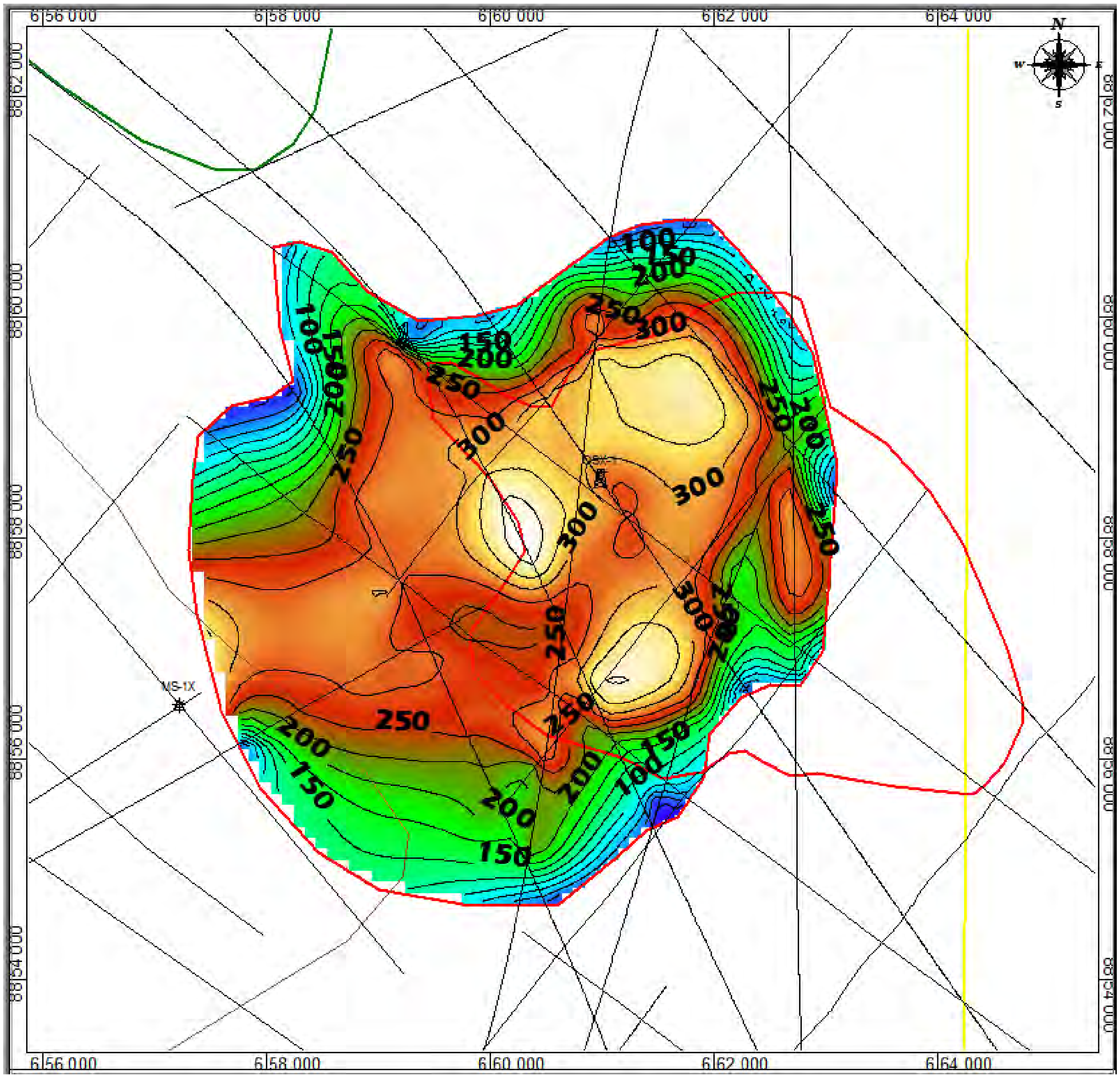


Figure App 3- 18: **Isopach for the OSX-1 Miocene 2 prospect. Contour interval is 25 meters.**

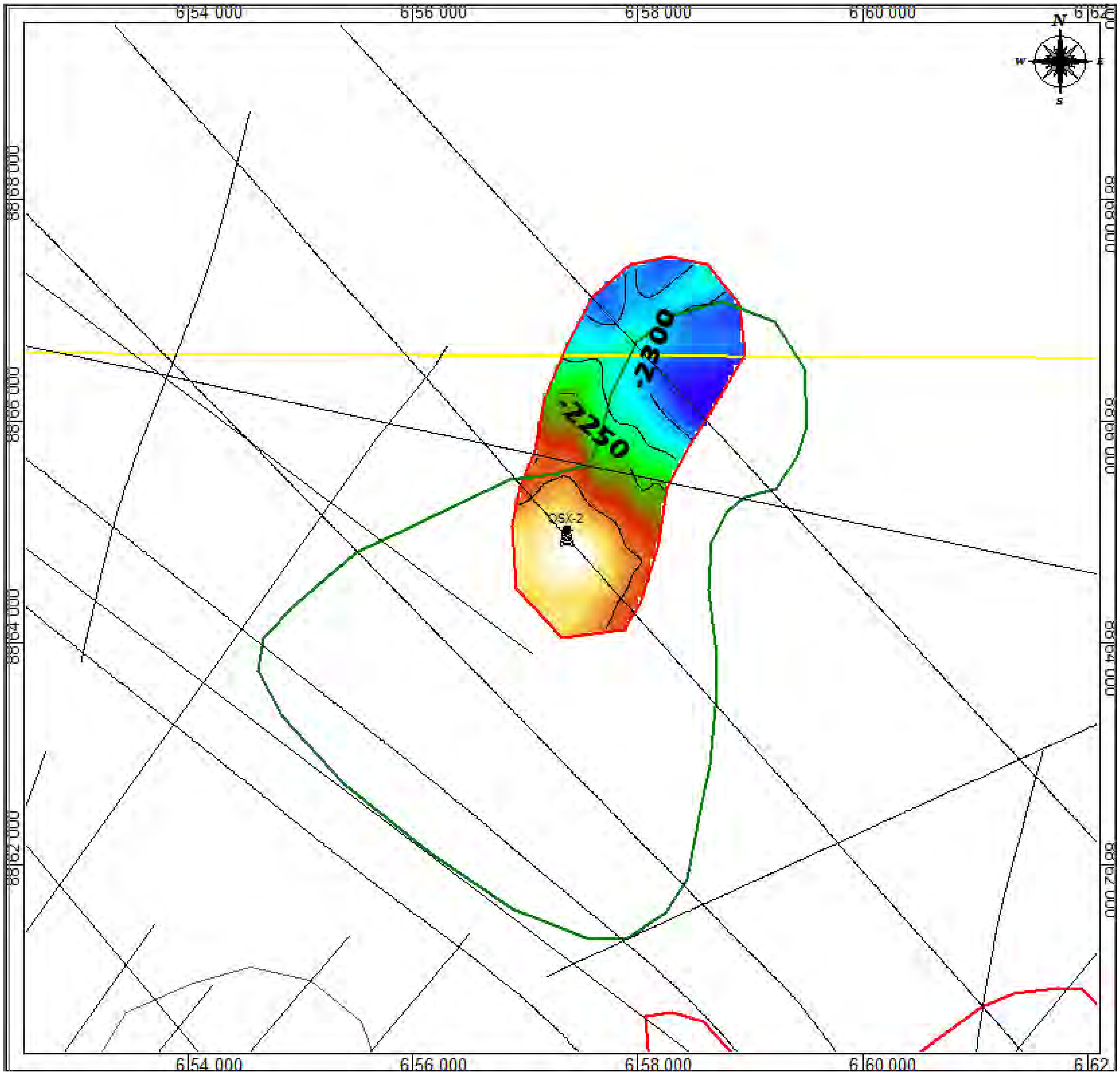


Figure App 3- 19: **Top depth structure for the OSX-2 Miocene prospect. Contour interval is 25 meters.**

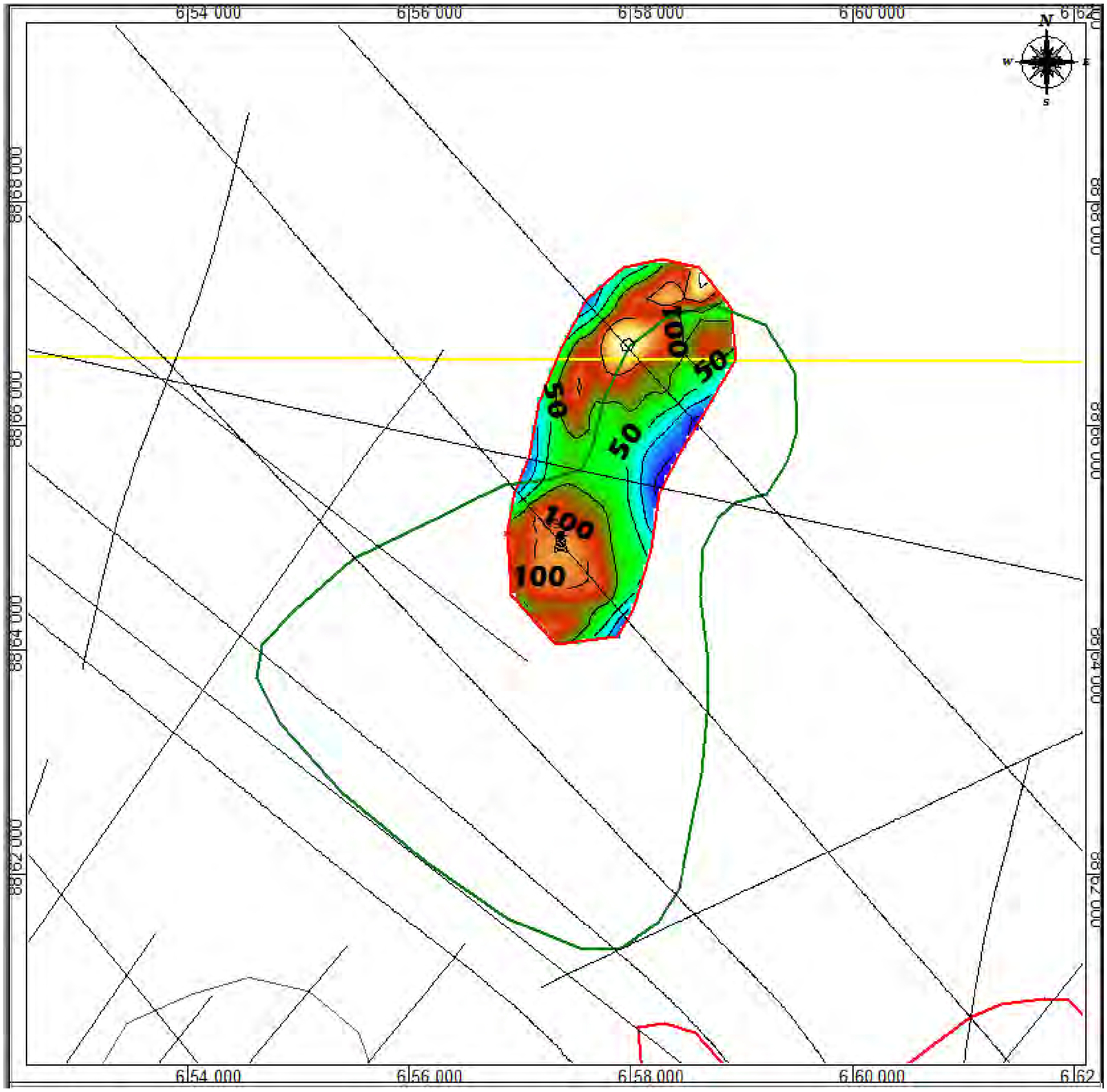


Figure App 3- 20: **Isopach for the OSX-2 Miocene prospect. Contour interval is 25 meters.**

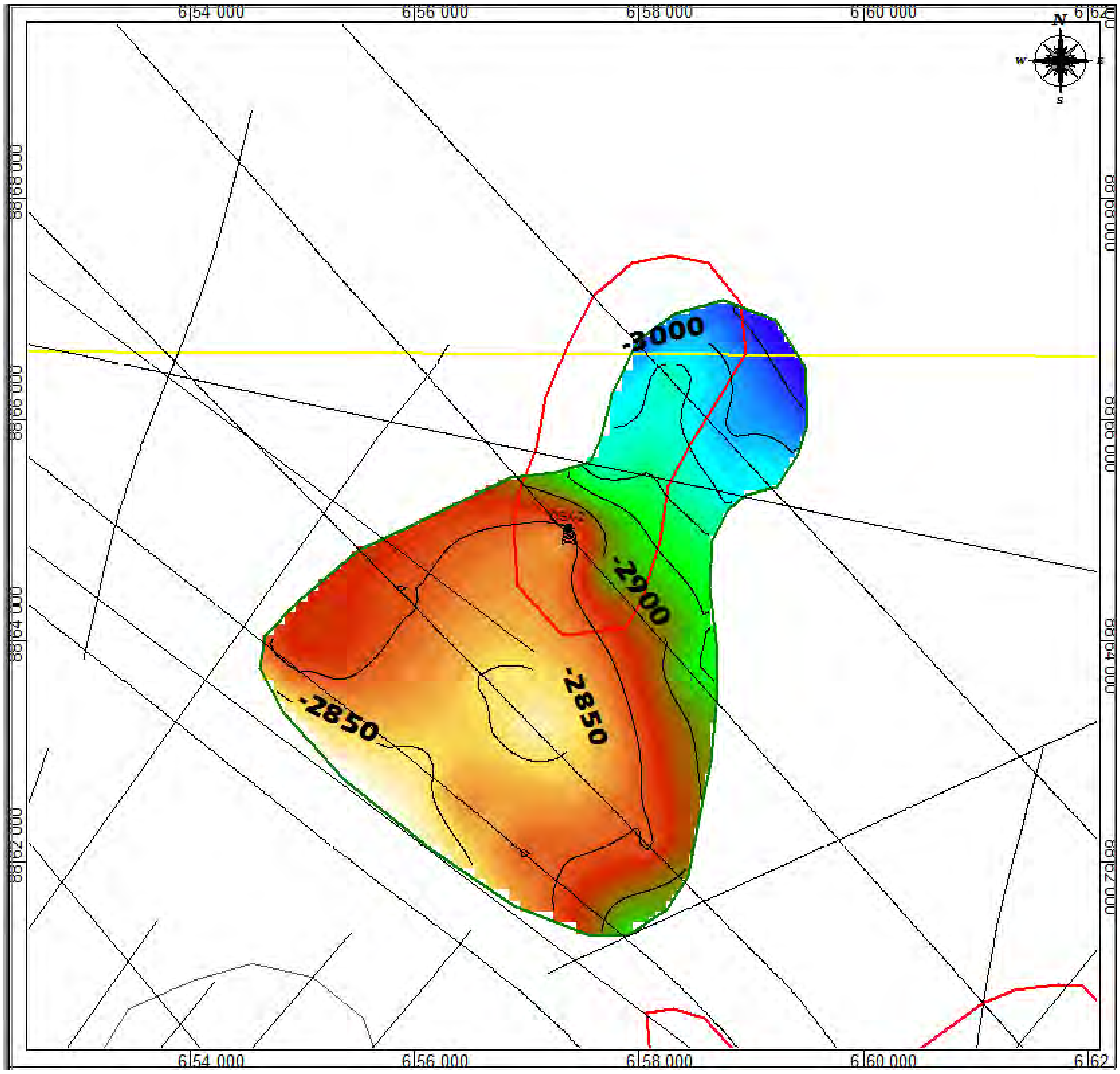


Figure App 3- 21: **Top depth structure for the OSX-2 Oligocene prospect. Contour interval is 25 meters.**

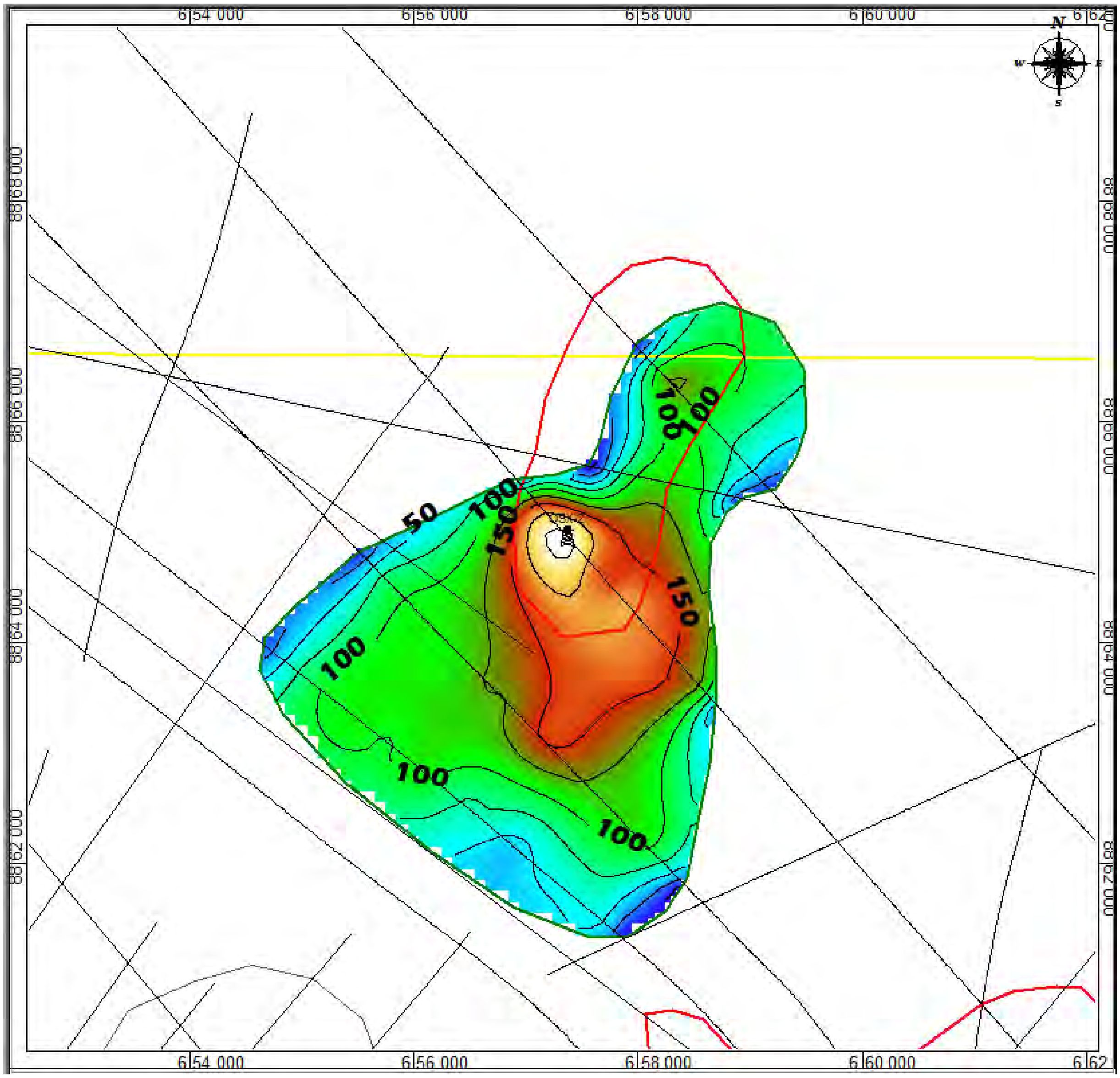


Figure App 3- 22: **Isopach for the OSX-2 Oligocene prospect. Contour interval is 25 meters.**

APPENDIX 4

Rovuma Onshore Block Prospective Resources Structure and Isopach Maps

APPENDIX 4

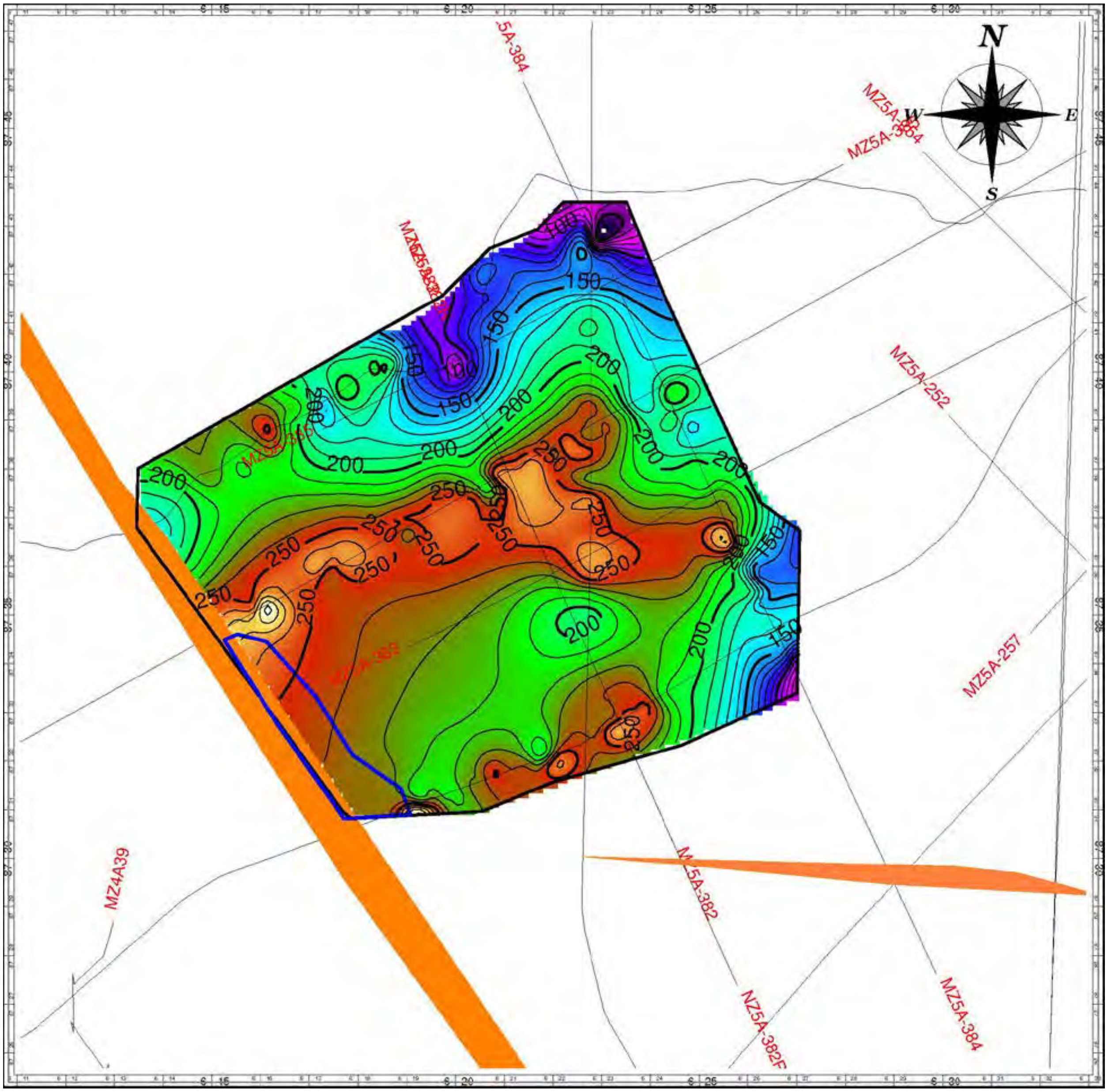


Figure App 4-1: Tempo Prospect Mid Creaceous Isopach Map

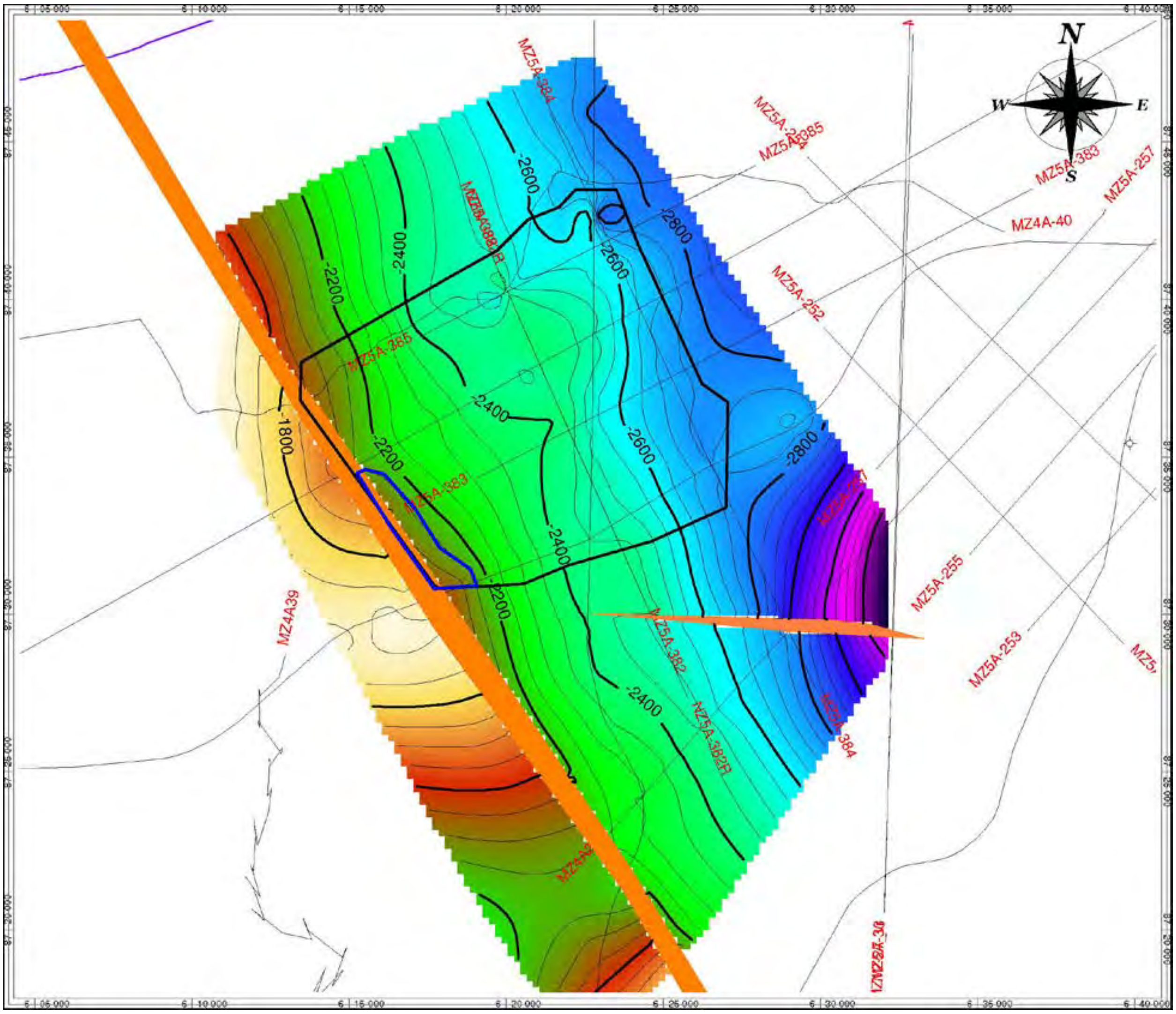


Figure App 4-2: Tembo Prospect Mid-Cretaceous Structure Map

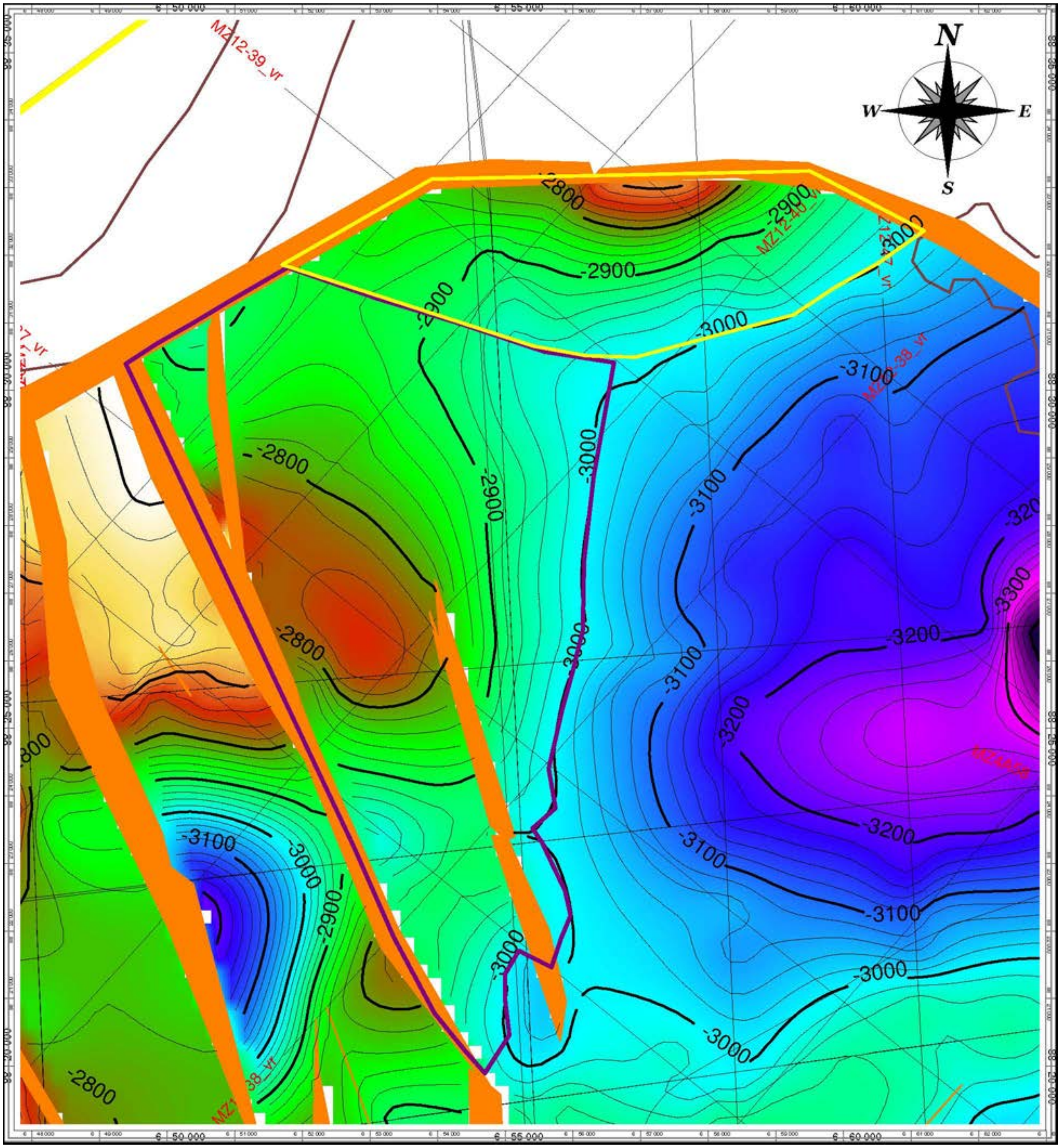


Figure App 4-3: Maroon and Yellow Prospects Eocene Structure Map

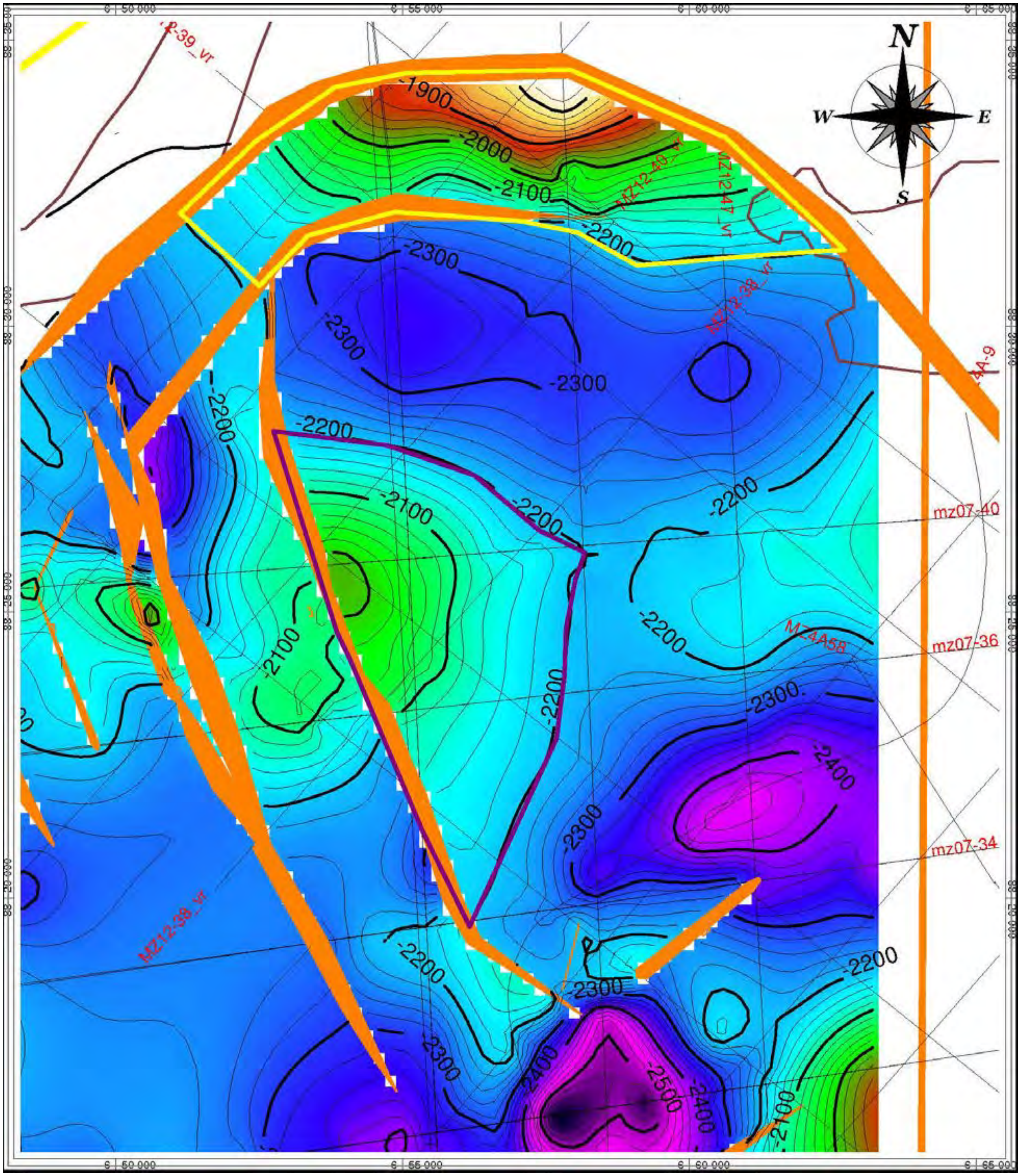


Figure App 4-4: Maroon and Yellow Prospects Oligocene Structure Map

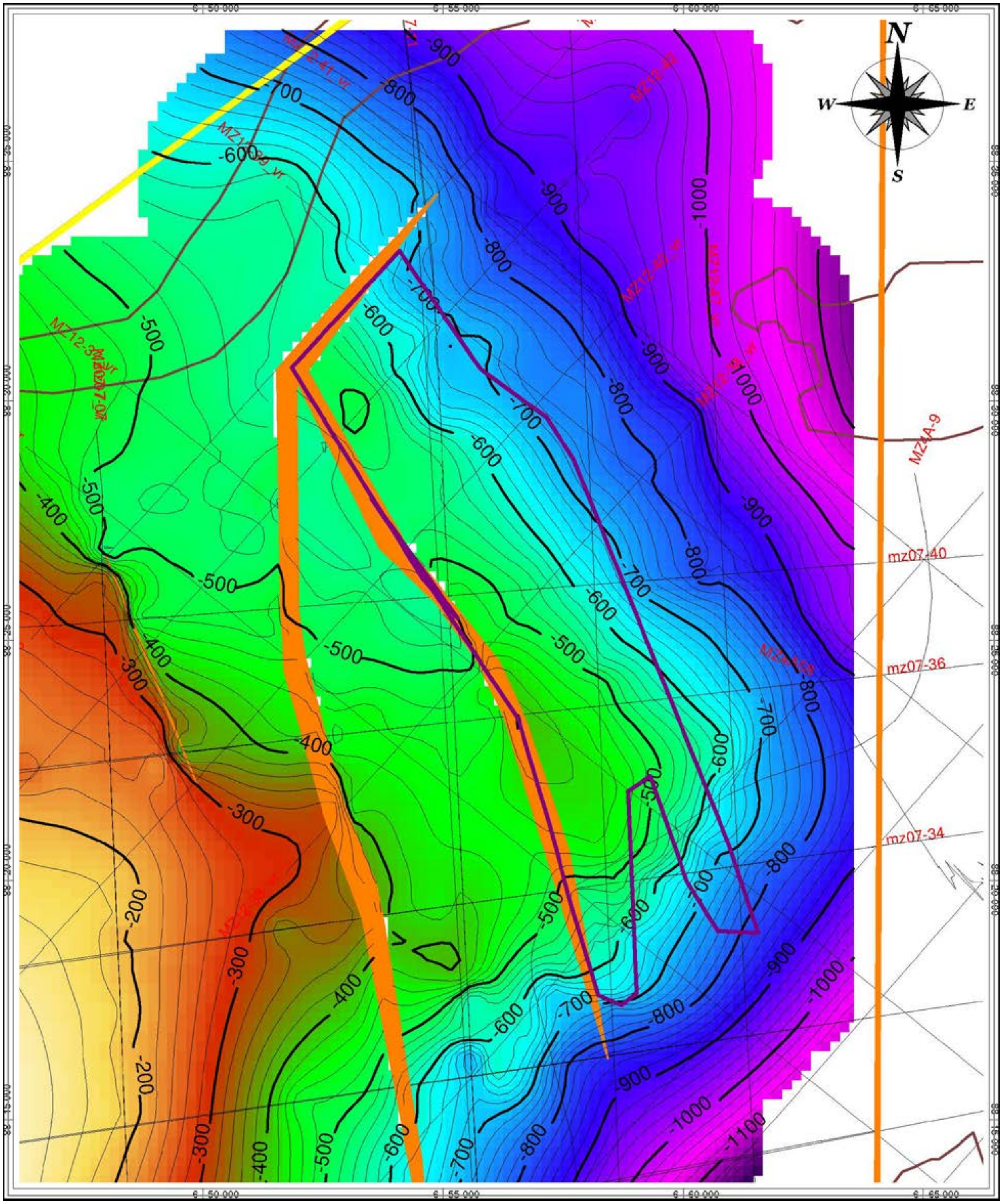


Figure App 4-5: Maroon Prospect Upper Miocene Structure Map

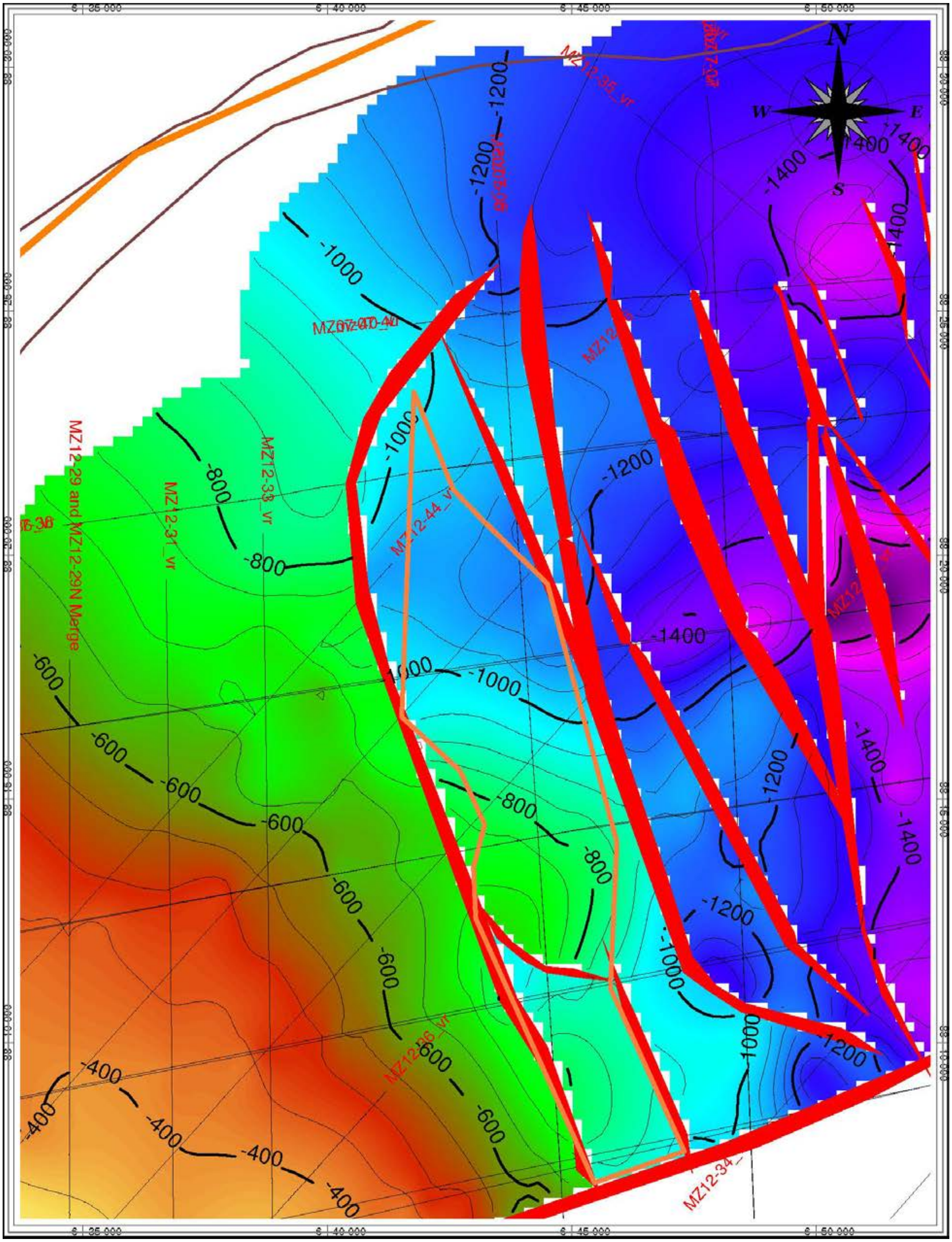


Figure App 4-6: Orange Prospect Mio Oligocene Structure Map

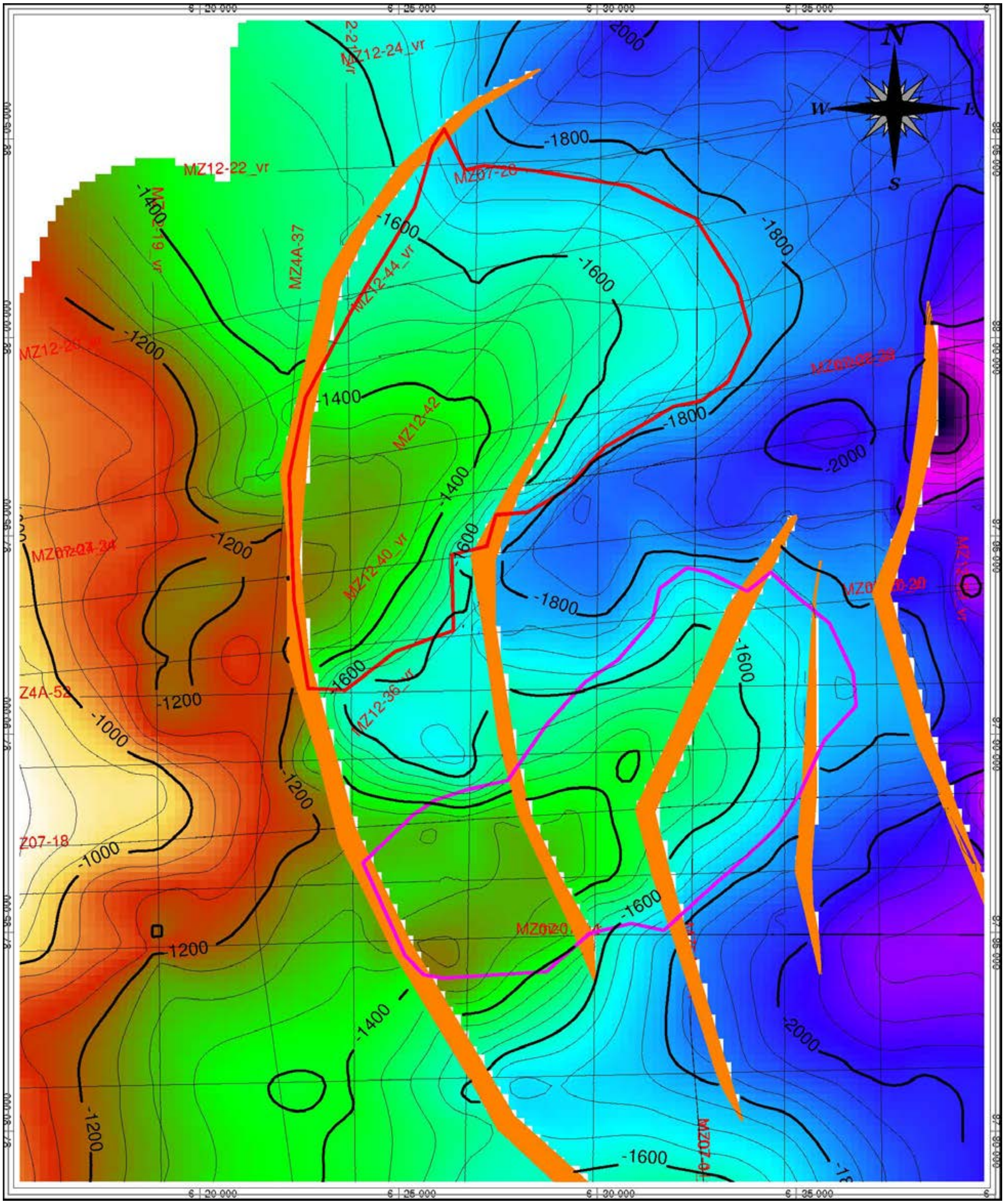


Figure App 4-7: Scarlet and Pink Prospects Eocene Structure Map

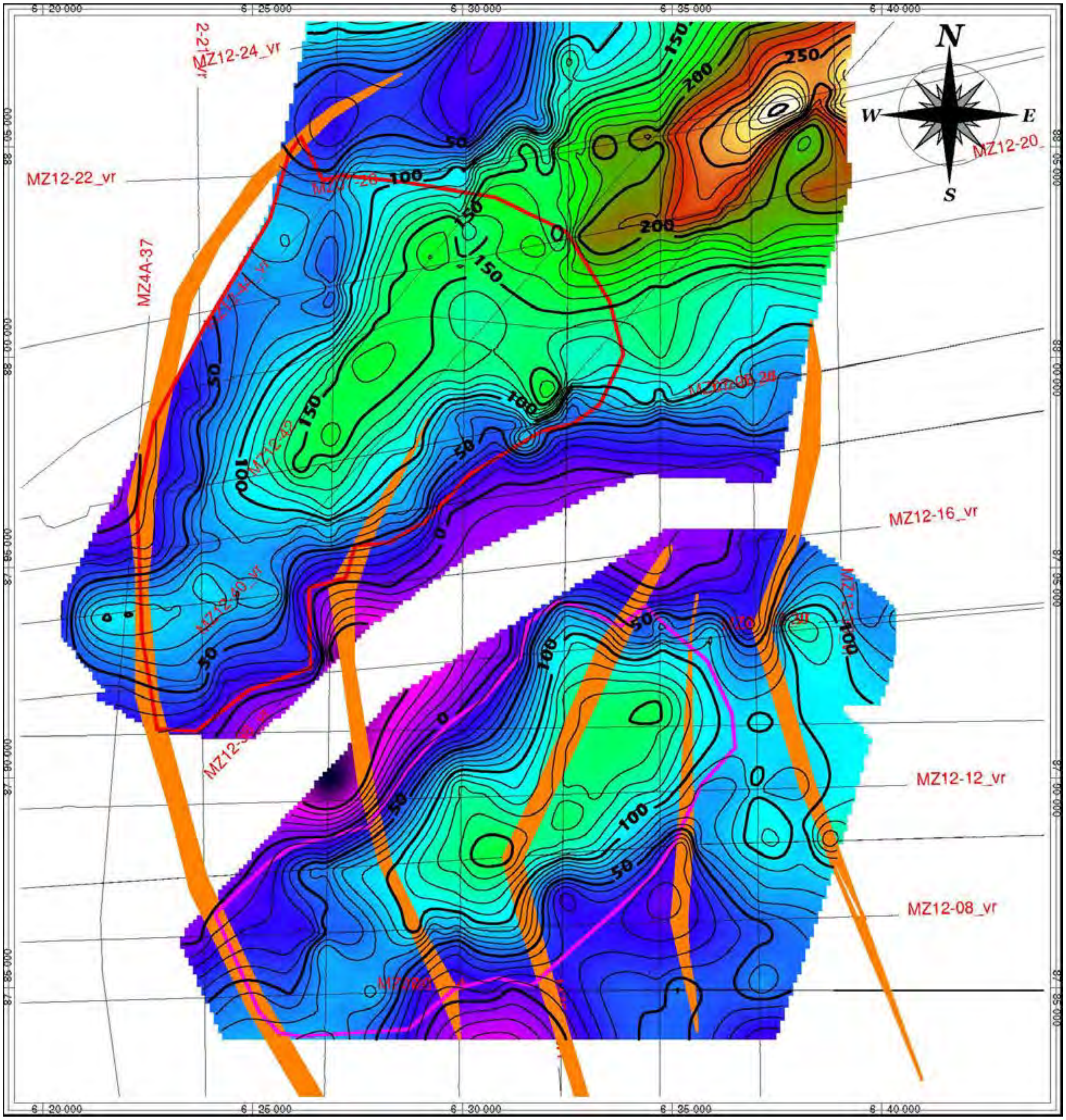


Figure App 4-8: Scarlet and Pink Prospects Isopach Map

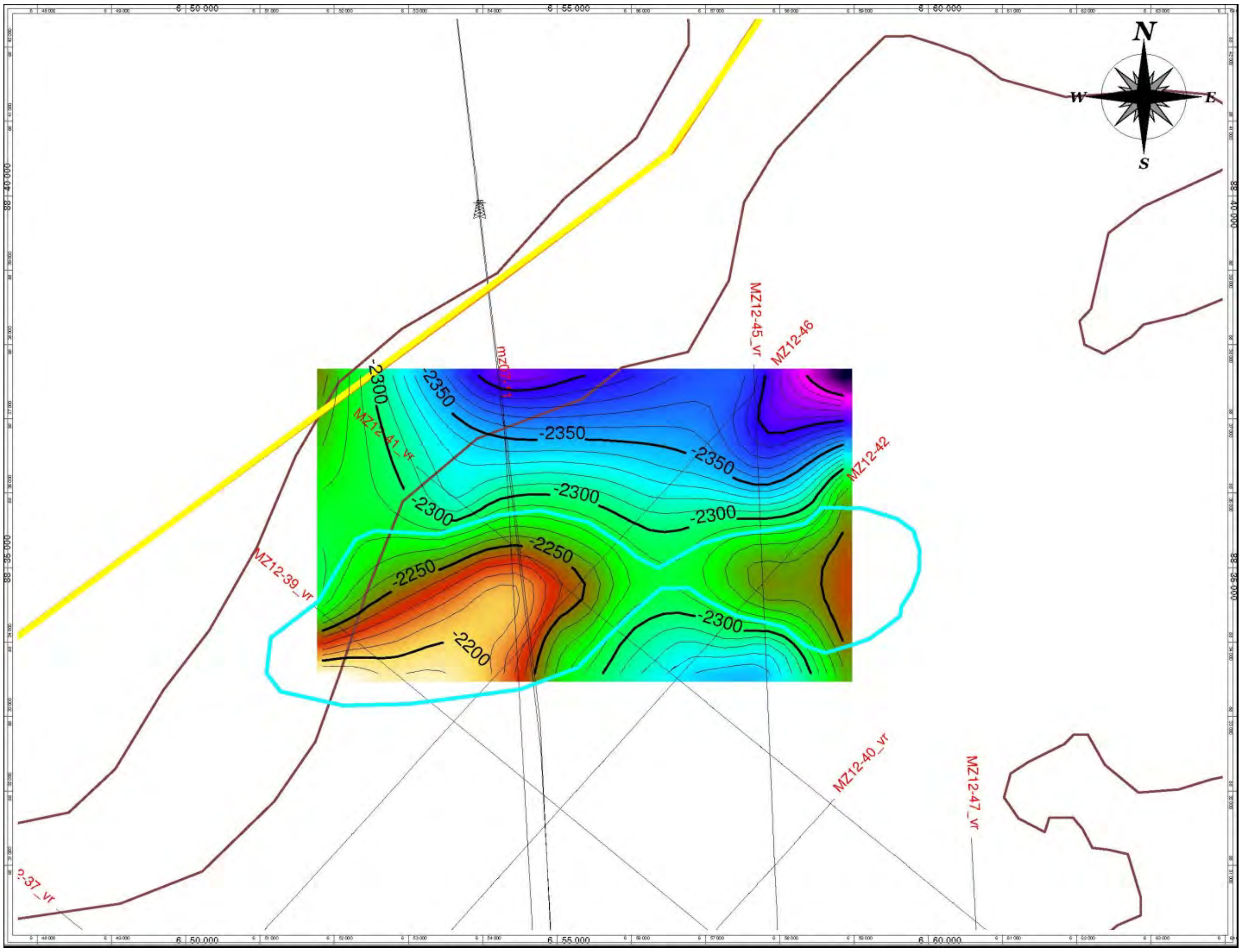


Figure App 4-9: Teal Prospect Eocene Structure Map

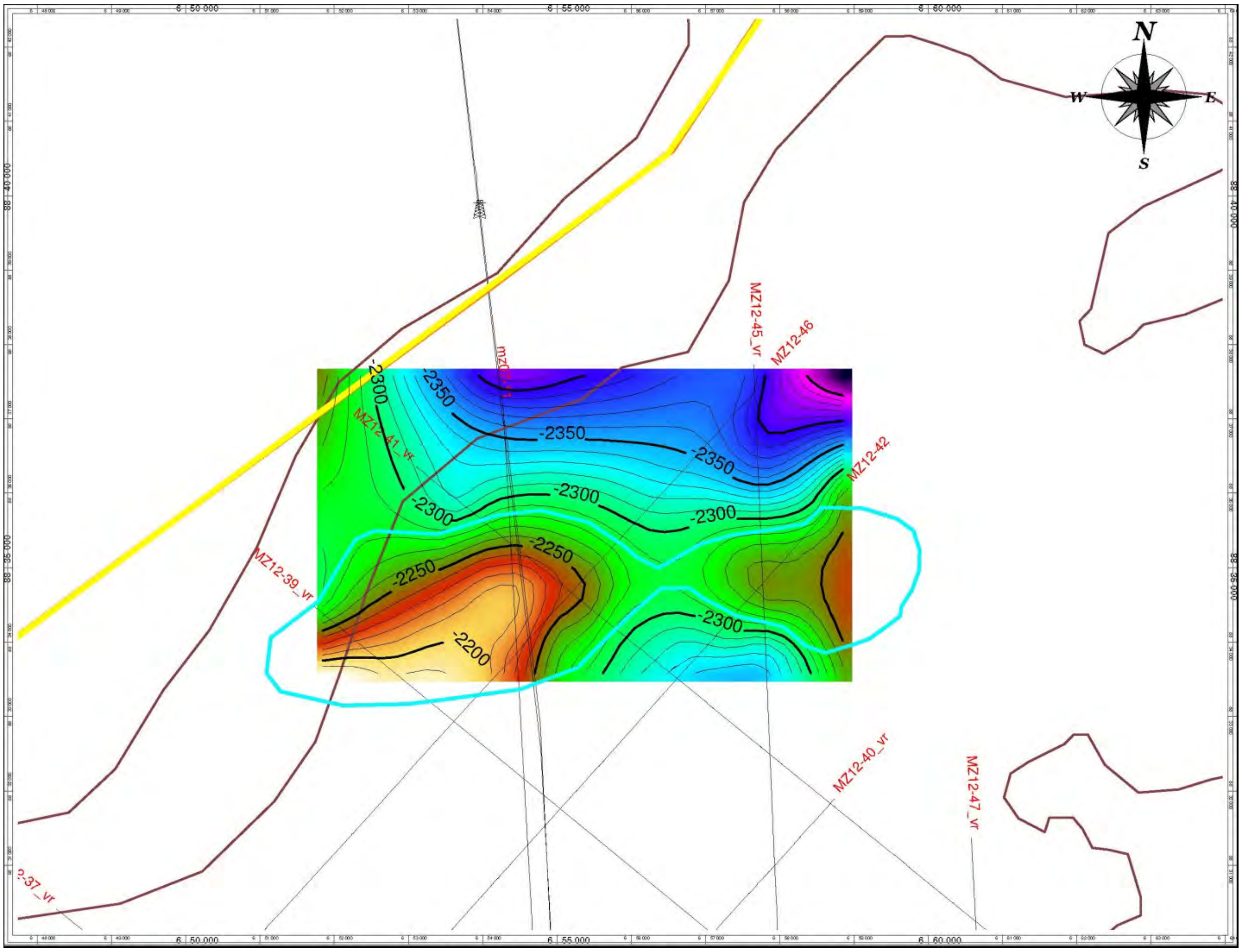


Figure App 4-10: Teal Prospect Oligocene Structure Map