MNAZI BAY FIELD

Reserves Assessment as at December 31, 2019

204989
Version
January 28, 2020

rpsgroup.com

MNAZI BAY FIELD

Reserves Assessment as at December 31, 2019

Prepared by:

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January 28, 2020

Wentworth Resources plc
Thames Tower, 2nd Floor,
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Reading RG1 1LX
United Kingdom

Attention: Ms. Katherine Roe, Chief Executive Officer

Dear Ms. Roe

Re: MNAZI BAY FIELD - Reserves Assessment as at December 31, 2019

As requested by Wentworth Resources plc ("Wentworth") in the Letter of Engagement dated October 29, 2019 (the "Agreement"), RPS Energy Consultants Ltd. ("RPS") has completed an independent reserves assessment of Wentworth's interest in the Mnazi Bay Licence in Tanzania.

Reserves volumes for the Mnazi Bay Licence were based on an IPM model set up based upon Petrel™ geological model volumetrics then adjusted to reflect material balance history matching of pressure depletion in some sands. The volumetrics were derived from a 3D geological static model which was constructed utilizing the Maurel et Prom 2014 seismic interpretation, calibrated to the horizon tops as identified in the five wells drilled on the licence. The volumes derived from the Petrel model were combined with petrophysical evaluations and well test data from the five 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 and material balance modeling. The material balance modeling has been updated using a Petex™ IPM model incorporating production and pressure data up to Q3 2019.

Wentworth owns a 31.94% non operating working interest in the production operations and 39.925% working interest in exploration operations in the Mnazi Bay licence block.

Changes in reserves volumes since the year end 2018 report are due to the gas volumes produced during 2019, and adjustments to the RPS forecast of ultimate recovery based on production and pressure performance data measured during 2019. The reserves volumes are summarized in the following table:

Reserves Summary for Mnazi Bay as at December 31, 2019						
	Field		Wentworth 31.94% WI			
Reserves Category	Gross[1] Reserves Sales Gas (Bscf)	BOE (MMbbl)	Gross[1] Reserves Sales Gas (Bscf)	BOE (MMbbl)	Net[2] Reserves Sales Gas (Bscf)	BOE (MMbbl)
Proved Developed Producing (PDP)	57.9	9.6	18.5	3.1	15.1	2.5
Proved Developed Non-Producing (PDNP)	69.9	11.6	22.3	3.7	18.0	3.0
Total Proved Developed (PD)	**127.7**	**21.3**	**40.8**	**6.8**	**33.2**	**5.5**
Proved Undeveloped	160.6	26.8	51.3	8.5	29.8	5.0
Total Proved (1P)	**288.3**	**48.1**	**92.1**	**15.3**	**63.0**	**10.5**
Proved + Probable (2P)	**468.9**	**78.1**	**149.8**	**25.0**	**95.1**	**15.8**
Proved + Probable + Possible (3P)	**725.7**	**120.9**	**231.8**	**38.6**	**138.7**	**23.1**

(1) Gross Reserves are Company Working Interest Share of Total Field Reserves
(2) Net Reserves are calculated as the product of Company Gross Reserves and the ratio of Company net revenue to Company WI share of field gross revenue

The Mnazi Bay Licence also contains additional hydrocarbon potential in a number of undrilled locations; however, evaluation of these prospects is outside of the scope of this engagement.

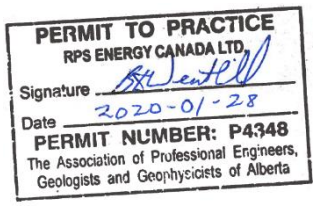
This report is issued by RPS under the appointment by Wentworth and is produced as part of the engagement detailed therein and subject to the terms and conditions of the Agreement. Those terms and conditions contain inter alia restrictions on the use and distribution of information and materials contained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

This report is addressed to Wentworth and 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 (none of whom were named in the Agreement) and any amendments thereto.

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 that may be added to the agreement by amendment) 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,
for RPS Energy Canada Ltd



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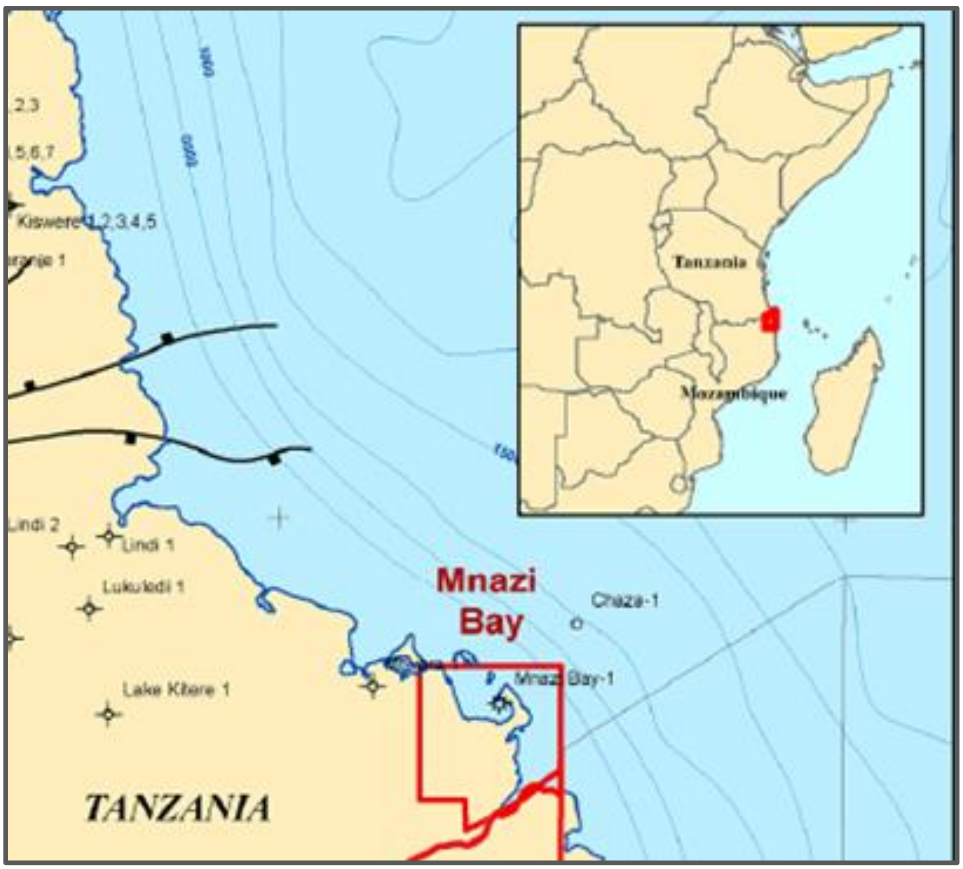
EXECUTIVE SUMMARY

RPS has reviewed the available data for the Mnazi Bay concession area in South-East Tanzania and has evaluated Wentworth 31.94% (production operations) working interest in the reserve volumes of the 756 km2 area. The effective date of this report is December 31, 2019.

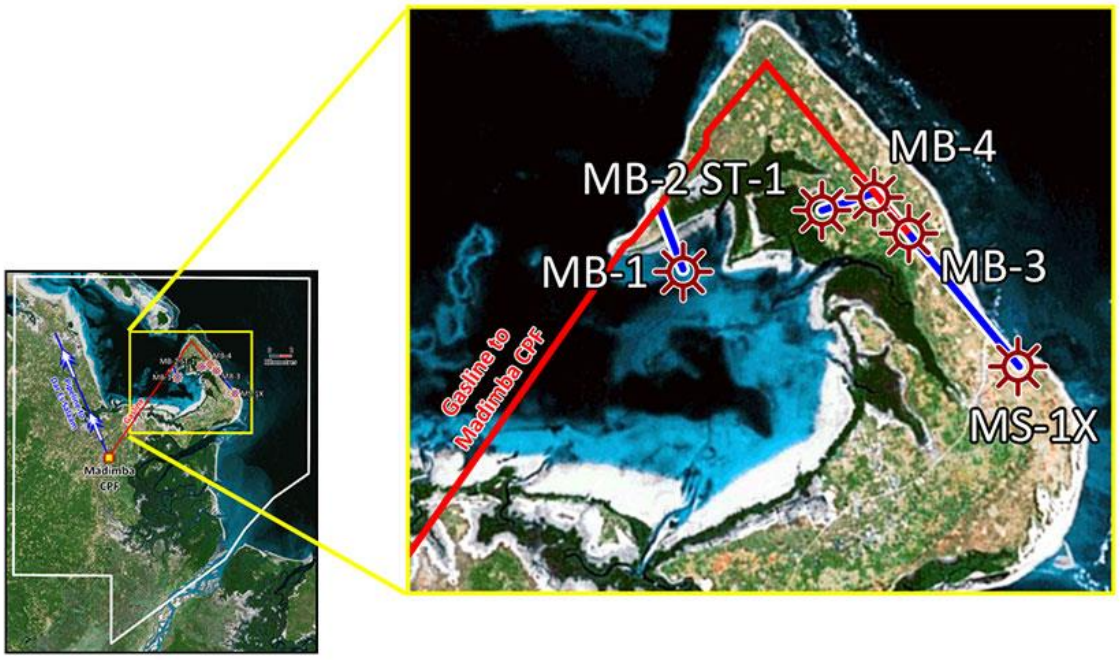


Source: Wentworth

In total, there are five gas wells drilled on the licence, all of which are capable of production. These wells define the Mnazi Bay and Msimbati gas fields.

A Gas Sales Agreement ("GSA") was signed between the partners (M&P, Wentworth Gas Limited, Cyprus Mnazi Bay Limited and Tanzania Petroleum Development Corporation) and the buyer, Tanzania Petroleum Development Corporation ("TPDC") on September 12, 2014 for delivery of raw gas at the outlet of the Mnazi Bay gas processing facilities. Facilities associated with export to the processing plant at Madimba (trans-national pipeline to Dar Es Salaam) were completed in 2016 enabling increased offtake above the previous sole sales outlet, fuel for local electric power generation at Mtwara.

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 five wells denoted with red symbols. 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

As part of an independent resources assessment of this licence for Wentworth Resources in 2013 and a reserve evaluation conducted for year-end 2014, RPS reviewed 1,658 km of 2-D seismic data (103 lines) on the Mnazi Bay Licence, with the interpretation focus on drill-ready prospects. Additional data reviewed included offsetting well logs and field production histories, details of new competitor discoveries in Tanzania and geological and reservoir information from publicly-available sources. In 2019, the seismic derived geological mapped volumes were adjusted in some producing sands, to reflect material balance history matching of the reservoir pressure performance during production depletion of those sands.

RPS estimates of reserves volumes for the Mnazi Bay Licence, as of December 31, 2019 are summarized for the Wentworth interest in the Table below.

Wentworth Resources Working Interest Reserves for Mnazi Bay as at December 31, 2019
RPS Forecast 2020-01-01

Reserve Category	Gross Reserves Oil (MMstb)	Gross Reserves Sales Gas (Bscf)	Gross Reserves NGL& C5+ (MMbbl)	Gross Reserves BOE (MMbbl)	Net Reserves Oil (MMstb)	Net Reserves Sales Gas (Bscf)	Net Reserves NGL& C5+ (MMbbl)	Net Reserves BOE (MMbbl)
PROVED								
Producing	-	*18.5*	-	*3.1*	-	*15.1*	-	*2.5*
Non Producing	-	*22.3*	-	*3.7*	-	*18.0*	-	*3.0*
Undeveloped	-	*51.3*	-	*8.5*	-	*29.8*	-	*5.0*
Total Proved	**-**	**92.1**	**-**	**15.3**	**-**	**63.0**	**-**	**10.5**
Probable	-	*57.7*	-	*9.6*	-	*32.1*	-	*5.3*
PROVED + PROBABLE	**-**	**149.8**	**-**	**25.0**	**-**	**95.1**	**-**	**15.8**
Possible	-	*82.0*	-	*13.7*	-	*43.7*	-	*7.3*
PROVED + PROBABLE + POSSIBLE	**-**	**231.8**	**-**	**38.6**	**-**	**138.7**	**-**	**23.1**

Cash flow forecasts for the field have been generated using production forecasts generated by RPS incorporating development plans and future production commercial constraints supplied by M&P, and financial data up until year-end 2019 supplied by Wentworth. The NPV estimates associated with these reserve volumes, for Wentworth, are:

Wentworth Resources Working Interest Reserves for Mnazi Bay
as at December 31, 2019
RPS Forecast 2020-01-01

Reserve Category	NPV Before Tax Million US$					NPV After Tax Million US$				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
PROVED										
Producing	*10.1*	*10.8*	*10.8*	*10.5*	*10.1*	*8.9*	*9.8*	*10.0*	*9.7*	*9.4*
Non Producing	*61.0*	*53.7*	*47.9*	*43.2*	*39.4*	*56.0*	*49.4*	*44.1*	*39.8*	*36.3*
Undeveloped	*71.7*	*51.4*	*37.8*	*28.4*	*21.8*	*66.5*	*47.5*	*34.8*	*26.1*	*19.9*
Total Proved	**142.8**	**115.9**	**96.5**	**82.2**	**71.2**	**131.4**	**106.7**	**88.9**	**75.7**	**65.6**
Probable	*71.4*	*46.2*	*32.3*	*24.4*	*19.8*	*64.9*	*42.3*	*29.7*	*22.5*	*18.3*
PROVED + PROBABLE	**214.2**	**162.2**	**128.9**	**106.6**	**91.0**	**196.3**	**149.0**	**118.6**	**98.2**	**83.9**
Possible	*106.4*	*68.1*	*48.0*	*36.9*	*30.2*	*97.3*	*62.6*	*44.2*	*34.0*	*27.8*
PROVED + PROBABLE + POSSIBLE	**320.6**	**230.2**	**176.9**	**143.5**	**121.3**	**293.6**	**211.6**	**162.8**	**132.2**	**111.8**

The following table provides a reconciliation of the Wentworth gross reserves to those from year end 2018:

Reserves Reconciliation Year End 2019
Wentworth Resources Ltd - 31.94% WI
Gross Reserves - Gas - Company WI

Tunisia	Proved Developed Producing (Bscf)	Proved Non-Developed Producing (Bscf)	Proved Undeveloped (Bscf)	**Proved (Bscf)**	Probable (Bscf)	**Proved+Prob (Bscf)**	Possible (Bscf)	**Proved+Prob+Poss (Bscf)**
Opening Balance (Dec. 31, 2018)	27.4	13.9	51.3	92.6	61.3	153.9	89.2	243.1
Extension & Improved Recovery								
Technical Revisions	**- 1.8**	**9.5**	**- 0.0**	**7.7**	**3.2**	**10.9**	**- 15.8**	**- 4.9**
Reclassifications								
Discoveries								
Acquisitions								
Dispositions								
Economic Factors	**1.0**	**- 1.0**			**- 6.8**	**- 6.8**	**8.5**	**1.7**
Production	**- 8.2**			**- 8.2**		**- 8.2**		**- 8.2**
Closing Balance (Dec. 31, 2019)	18.5	22.3	51.3	92.1	57.7	149.8	82.0	231.8

These assessments are made in accordance with the standards defined in the Petroleum Resources Management System (Revised 2018) sponsored by SPE, WPC, AAPG, SPEE, SEG, SPWLA, and EAGE.

RESERVE DEFINITIONS

The following definitions have been used by RPS Energy Canada Ltd. (RPS) in evaluating reserves. These definitions are based on the Petroleum Resources Management System, published in 2007, and revised in June 2018, and sponsored by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Association of Geoscientists & Engineers (EAGE).

Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are classified according to a range of uncertainty according to the following categories:

Proved Reserves (P1)

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that

the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves (P2)

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves (P3)

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

Reserves in each of the above three categories are subdivided according to their development and producing status according to the following:

Developed Reserves

Developed Reserves are reserves that are expected to be recovered from existing wells and facilities.

Developed Reserves may be further sub-classified as Producing or Non-Producing.

> **Developed Producing Reserves** are Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
>
> **Developed Non-Producing Reserves** are Developed Reserves that are either shut-in or behind-pipe.

Undeveloped Reserves are those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

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Appendices

Appendix A Glossary of Technical Terms

Appendix B Mnazi Bay/Msimbati Structure and Isopach Maps

LEGAL NOTICE

This report is issued by RPS under the appointment by Wentworth Resources plc ("Wentworth") in the engagement letter dated October 29, 2019 (the "Agreement") and is produced as part of the engagement detailed therein and subject to the terms and conditions of the Agreement.

This report is addressed to Wentworth 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.

This document was prepared by RPS Energy Canada Ltd. (operating as RPS) solely for the benefit of Wentworth and the Third Parties named in the Agreement.

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Project Title	**Mnazi Bay Field Reserves Assessment as at December 31, 2019**		
Project Number	Project Number	204989	
	AUTHORS:	**Project Manager**	**Date of Issue**
	Brian D. Weatherill	Brian D. Weatherill	2020-01-28
	Sam Nassar		
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CERTIFICATE OF QUALIFICATION

B.D. Weatherill

I, Brian D. Weatherill, a Professional Engineer at RPS Energy Canada Ltd., and co-author of a property evaluation (the "Evaluation") dated January 28, 2020 prepared for Maurel et Prom and Wentworth Resources plc (“Wentworth”), 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 Maurel et Prom and Wentworth, as of December 31, 2019.
- 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 (APEGA); and that I have in excess of 45 years’ experience in Petroleum Engineering relating to Canadian and international oil and gas properties.
- I and my employer are independent of Wentworth and Maurel et Prom and our remuneration is not related in any way to Maurel et Prom, nor Wentworth’s value or any Maurel et Prom or 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 Maurel et Prom or Wentworth or any associate or affiliate of those companies.
- The evaluation was prepared based upon information supplied by Maurel et Prom and Wentworth as well as other public data sources.
- 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.

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 reserves of the Tanzanian property owned by Maurel et Prom and Wentworth Resources plc and it hereby gives consent to the use of its name and to the said report. The effective date of the report is December 31, 2019.

In the course of the assessment, Maurel et Prom and Wentworth Resources plc provided RPS Energy personnel with 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 Maurel et Prom and Wentworth Resources plc. 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 INTRODUCTION

1.1 Background and Historical Description

Maurel et Prom ("M&P") and Wentworth Resources plc ("Wentworth") own working interests in the Mnazi Bay Development Licence in Tanzania (Figure 1-1). M&P, the operator of the concession, owns its interests through its local subsidiary, M&P Exploration and Production Tanzania Ltd and a share of Cyprus Mnazi Bay Limited ("CMBL"). Similarly, Wentworth owns a non-operating working interest in the Tanzanian legal entity Wentworth Gas Limited and a share of CMBL. The other working interest owner in the Licence is the national oil company, the Tanzania Petroleum Development Corporation ("TPDC").

Figure 1-1: Location Map of Mnazi Bay Licence

Source: Wentworth

Asset	Working Interest	Status	Licence Expiry Date	Licence Area	Comments
Mnazi Bay PSA and Development Licence, Tanzania	**Maurel et Prom** 48.060% production 60.075% exploration **Wentworth Resources plc** 31.940% production 39.925% exploration	Production, Development and Exploration	October 26, 2031	756 km^2	Field development currently on production. Additional exploration and development potential

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 seismically-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 age zones; the "D" zone producing 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) 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 conceptual GTP project had several components; development of the gas reservoir, by drilling and tie-in of sufficient production wells, a gas pipeline, a gas-fired electric power plant and an upgraded power transmission system for local power distribution.

In August 2003 an Agreement Of Intent ("AOI") 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 concession 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 was comprised of a 756.8 km2 (75,680 hectare) exploration area, both onshore and offshore (Figure 1-2). The concession PSA is also supported by the AOI and several other related agreements with the Government of Tanzania to implement the other aspects of the GTP 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 covering the same area as the original PSA exploration licence. The development licence has an initial twenty-five-year term to October 26, 2031, with provisions to be extended under certain conditions.

Figure 1-2: Mnazi Bay Licence Area

In 2005 Artumas initiated a program 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;

In 2007 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 led 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, northwest, to Mtwara. The production facilities and pipeline were 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 the Mnazi Bay field. Commissioning of the Mnazi Bay gas processing facility and tie-in connection to the Mtwara area power generating facility was completed on March 5, 2007. Production increased, from approximately 0.5 MMscf/d initially, to over 2 MMscf/d in 2015. In August 2015 with the development of an export route to Madimba, gas deliveries to the Tanzanian transnational pipeline commenced, delivering gas to alternative users including the Kinyerezi power plant at Dar Es Salaam, Mnazi Bay field production rates subsequently ramped up, achieving a peak production rate of just over 100 MMscf/d in 2018.

In November 2009, Artumas completed a sale of a portion of its interest in the Mnazi Bay Licence to Maurel et Prom S.A. and Cove Energy Tanzania Mnazi Bay Ltd., and on December 1, 2009, Maurel et Prom assumed operatorship. In September 2010 Artumas completed the process of changing its name to Wentworth Resources Limited, and then in July 2012, the Cove Energy interest in the licence were purchased by Maurel et Prom and Wentworth, resulting in the share ownerships in place at the effective date of this report.

1.2 Scope

This evaluation covers the gas reserves within the Tertiary formations within the Mnazi Bay licence, Tanzania.

1.3 Data Sources

RPS has based this reserves assessment on publicly-available basin data, data supplied by both Maurel & Prom and Wentworth and work previously carried out by RPS and one of its predecessor companies, APA Petroleum Engineering Inc.

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

- Maurel et Prom proprietary 2D & 3D seismic data
- Mnazi Bay and Msimbati field - well and production data (five wells).
- Previous RPS and APA studies and resource reports

In addition, RPS has relied upon, and accepted without independent verification, land and concession term data and financial information supplied by Maurel et Prom and Wentworth.

No site visit was conducted as a part of this evaluation; however, RPS has previously conducted site visits to the Mnazi Bay property during 2007 and 2008.

1.4 Prior Assessments

RPS and its predecessor company APA Petroleum Engineering Inc. have prepared various previous resource assessments on the Mnazi Bay Licence for Wentworth and its predecessor company Artumas. Some basic data from these prior assessments, and where applicable, some analyses have been utilized and incorporated into this evaluation. The prior works are listed in the list of References to this document.

1.5 Reserve Definitions

Reserves detailed in this report have been assessed using the definitions of the Petroleum Resources Management System, published in 2007, and revised in June 2018, and sponsored by the Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geologists ("AAPG"), Society of Petroleum Evaluation Engineers ("SPEE"), Society of Exploration Geophysicists ("SEG"), Society of Petrophysicists and Well Log Analysts ("SPWLA"), and the European Association of Geoscientists & Engineers ("EAGE") [1].

2 CONCESSION AREAS

2.1 Mnazi Bay Licence, Tanzania

The Mnazi Bay concession area is located in south-eastern Tanzania in the Ruvuma (alternately-spelled 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 age Mnazi Bay and Msimbati fields and extensions are defined by relatively sparse and variable quality 2D seismic data and by good quality 3D data over the offshore portion of the licence. Six wells have been drilled on the concession to date; five in the Mnazi Bay field (MB-1, MB-2, MB-3, MB-4 and MS-1X) and one exploration well, Ziwani-1, which was non commercial. Additionally, several exploration prospects have been identified on the licence; however, these prospects are outside of the scope of this reserve evaluation.

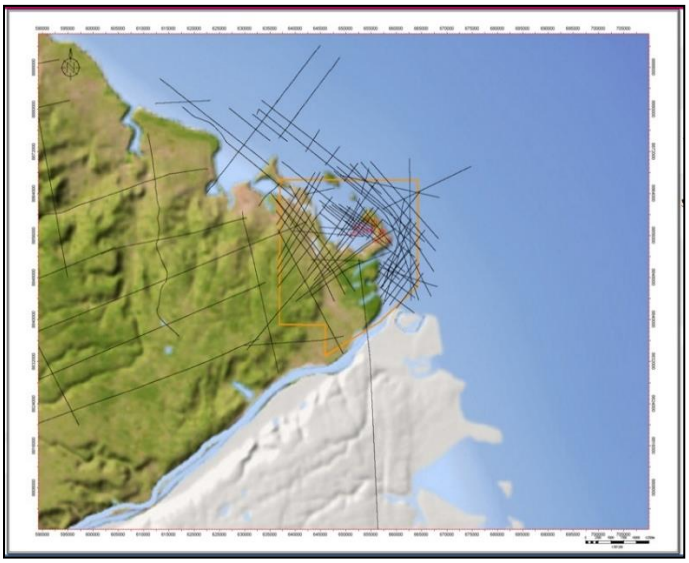


Figure 2-1: Mnazi Bay Concession, Tanzania

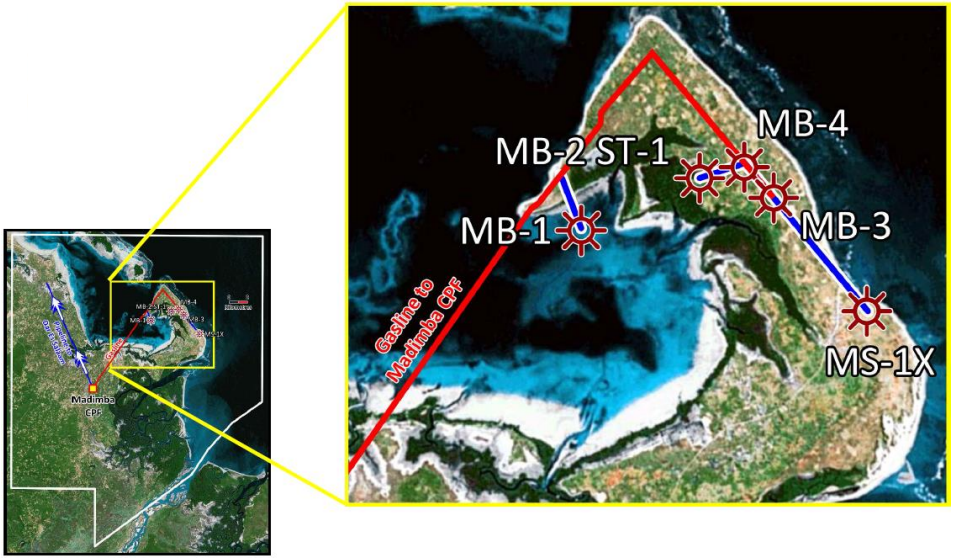


Figure 2-2: Mnazi Bay showing Mnazi Bay/Msimbati Field

2.1.1 Interests and Burdens

2.1.1.1 Maurel et Prom

Maurel et Prom owns a 48.06% operating working interest in petroleum operations other than exploration on the Mnazi Bay Licence block together with partners Wentworth Resources plc 31.94%, and TPDC 20.00%.

Maurel et Prom also owns a 60.075% working interest in exploration operations on the block, together with Wentworth's 39.925% working interest. The exploration 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 up to 20% interest. If TPDC should exercise this right, M&P and Wentworth's interest in the discovery would decrease proportionally to the development licence values above. The company working interests represent the interest in field gross recoverable volumes (and cost commitments), not net entitlements after application of royalty or equivalent deductions.

Previous receivables owing to Maurel et Prom by TPDC, resulting from TPDC's 2006 election to participate in the Mnazi Bay and Msimbati gas field discoveries, and representing TPDC share of past costs plus accumulated interest have all been retired as at the effective date of this evaluation.

Production operations on the development licence area are governed by the PSA 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.

2.1.1.2 Wentworth

Wentworth owns a 31.94% working interest in petroleum operations other than exploration on the Mnazi Bay Licence block together with operator Maurel et 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. The exploration 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, M&P and Wentworth's interest in the discovery would decrease to the development licence values above. The company working interests represent the interest in field gross recoverable volumes (and cost commitments), not net entitlements after application of royalty or equivalent deductions.

Previous receivables owing to Wentworth from TPDC, resulting from TPDC's 2006 election to participate in the Mnazi Bay and Msimbati gas field discoveries, and representing TPDC share of past costs plus accumulated interest have all been retired as at the effective date of this report. Wentworth also retains an option to transfer a further 5% working interest per well in exchange for other parties' 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.

2.1.2 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 two appraisal wells (MB-2, MB-3) and one

exploration-discovery well (MS-1X) were drilled and completed as gas producers. Two additional seismic programs were shot in 2007 and 2008 by Artumas (now Wentworth).

Maurel et Prom assumed operatorship of the Mnazi Bay PSA during 2009. A 3D seismic data survey covering the offshore portion of the block was recorded and processed during 2012 / 2013. In 2013 a 328 km2 3D offshore seismic survey was conducted, and in 2014 an additional 315 km of 2D onshore seismic and 58 km of high resolution onshore seismic data was collected. The MB-4 well was drilled and completed as a gas producer in June 2015.

3 REGIONAL GEOLOGY AND PETROLEUM SYSTEM

3.1 Regional Geological Setting

The Mnazi Bay Licence area in Tanzania is 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. Regionally, 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.

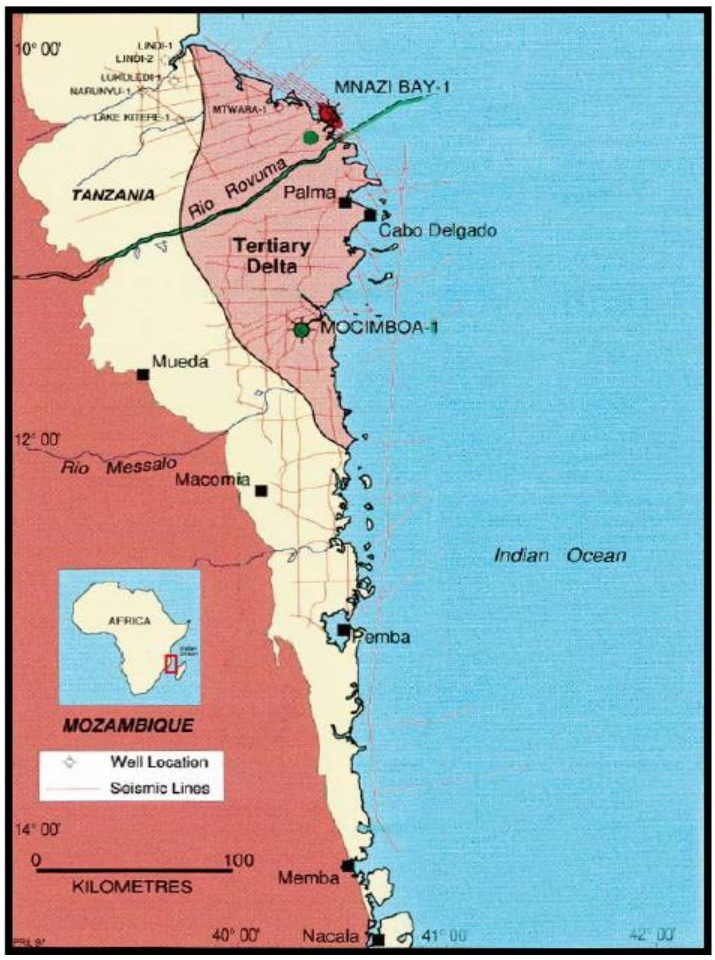


Figure 3-1: Location Map Ruvuma Basin

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 depo-centre was constrained by fault block rotation and basin subsidence during the Tertiary, with the early centre located towards the northern part of the Ruvuma Basin. These sediments have been subjected to intensive gravity-driven deformation, shale diapirism 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:

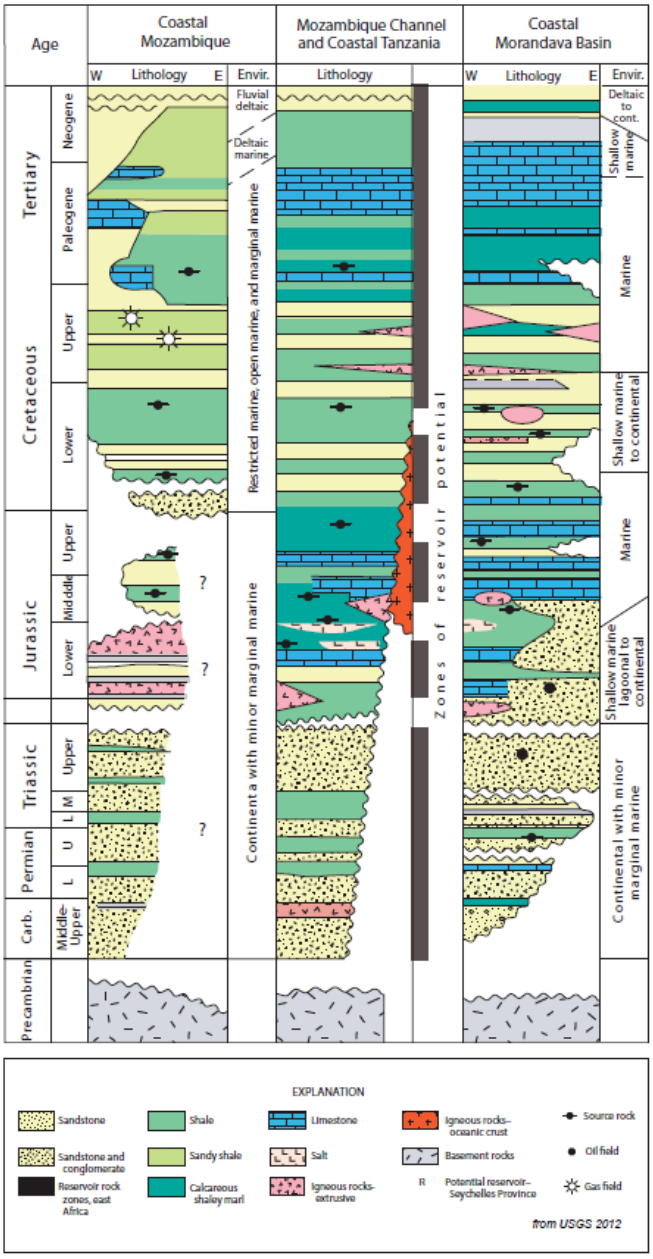


Figure 3-2: Stratigraphic Chart [2]

3.2 Tertiary Depositional Environments

The Tertiary sequence in the Mnazi Bay area is situated within the canyon slope setting (Figure 3 3); these marine canyon-fill gravity deposits contain sandstones, which provide good reservoirs, and shales, which enable 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 deep-water fan deposits, which contain excellent quality reservoir sands; hydrocarbons are trapped on toe thrust structures. (Figure 3 3 and Figure 3 4).

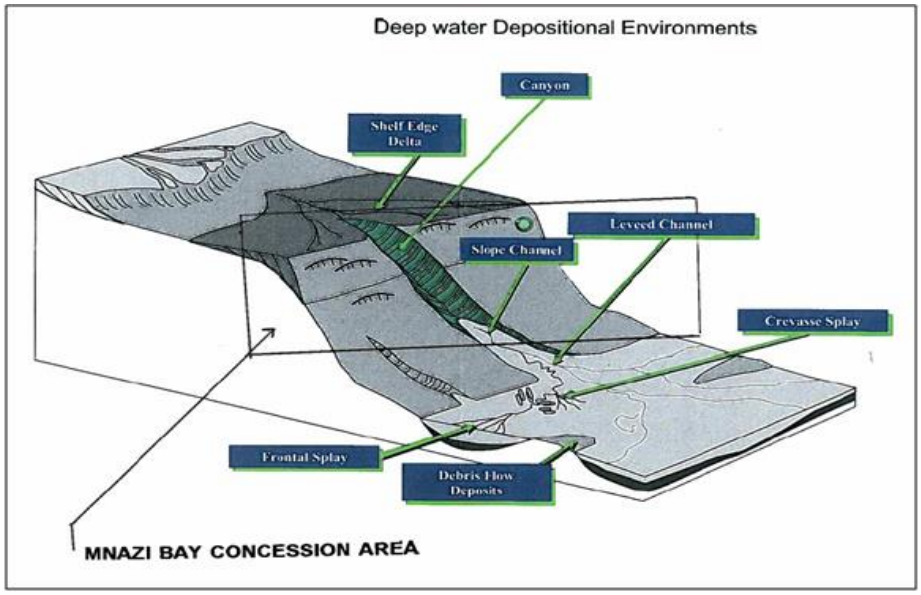


Figure 3-3: Tanzania Tertiary Deposition - Canyon Slope Setting

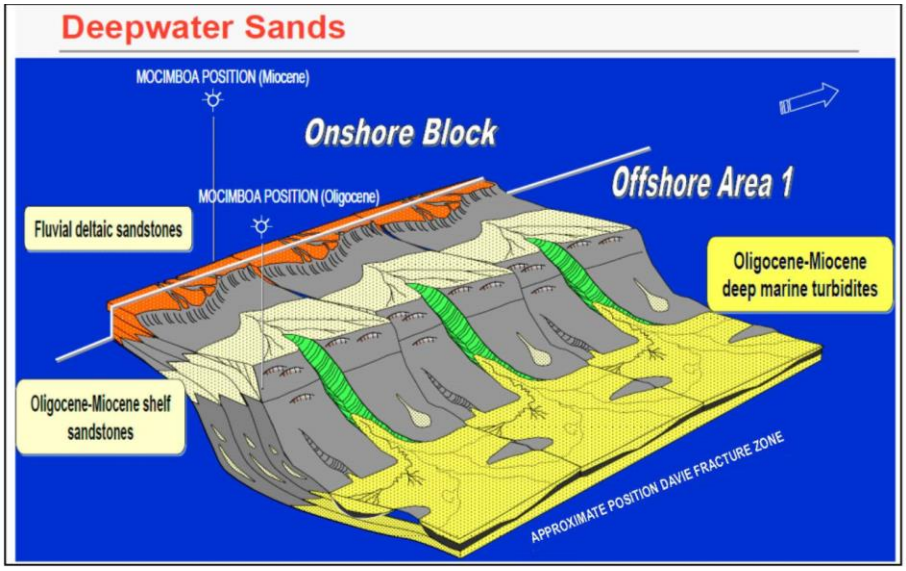


Figure 3-4: Mozambique Tertiary Deposition. Onshore Block: Fluvial-Deltaic and Marine Shelf Sandstone. Offshore Area 1: Deep Marine Turbidites and Fans

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.

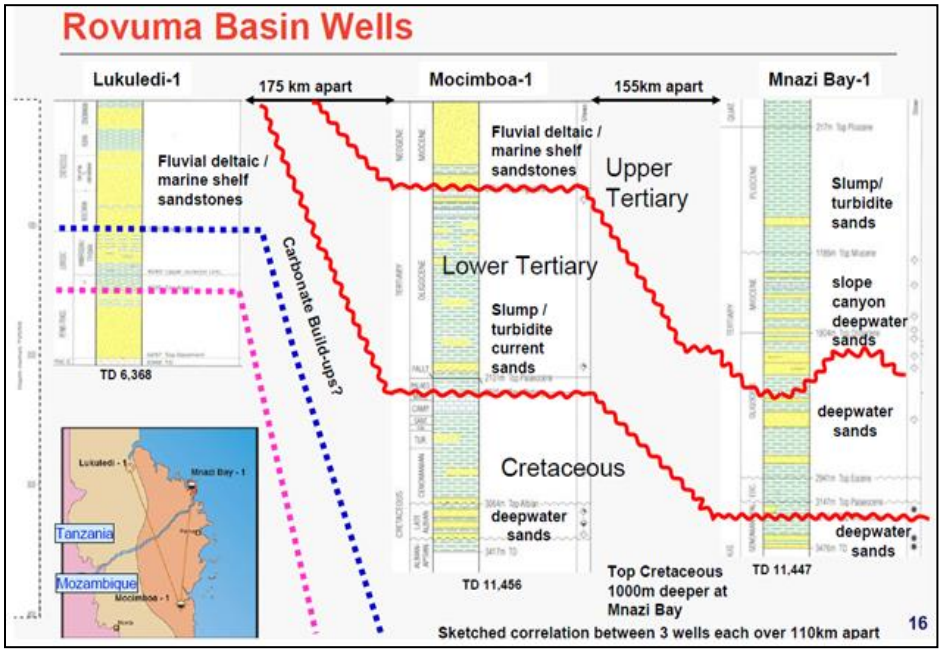


Figure 3-5: Cross Section across On-Shore Tanzania and Mozambique Showing Upper and Lower Tertiary Environments and Reservoir/Seal Pairs

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).

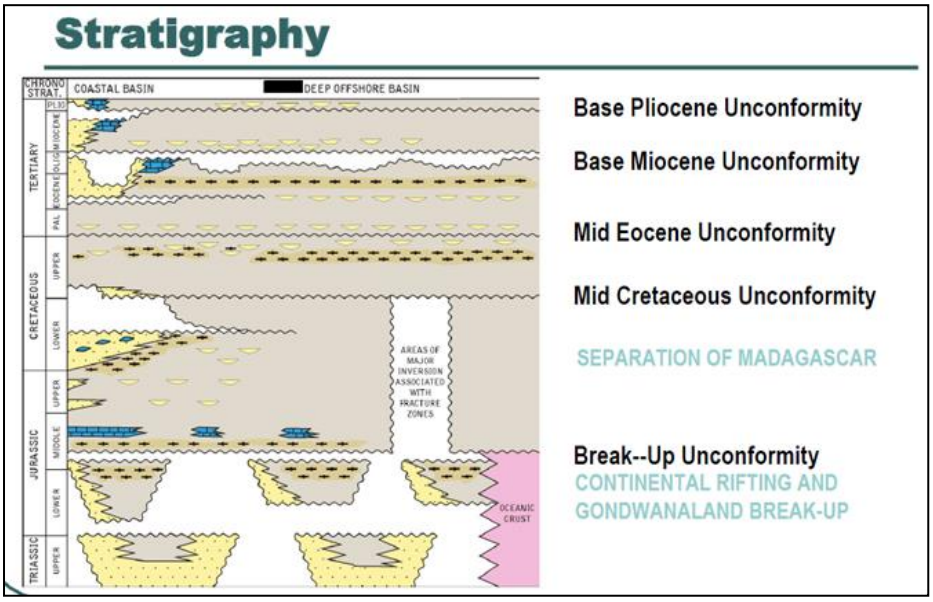


Figure 3-6: Evolution of the Ruvuma Basin with Stratigraphic Units

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, intra-slope 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 offshore 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 Tertiary plays in offshore Mozambique.

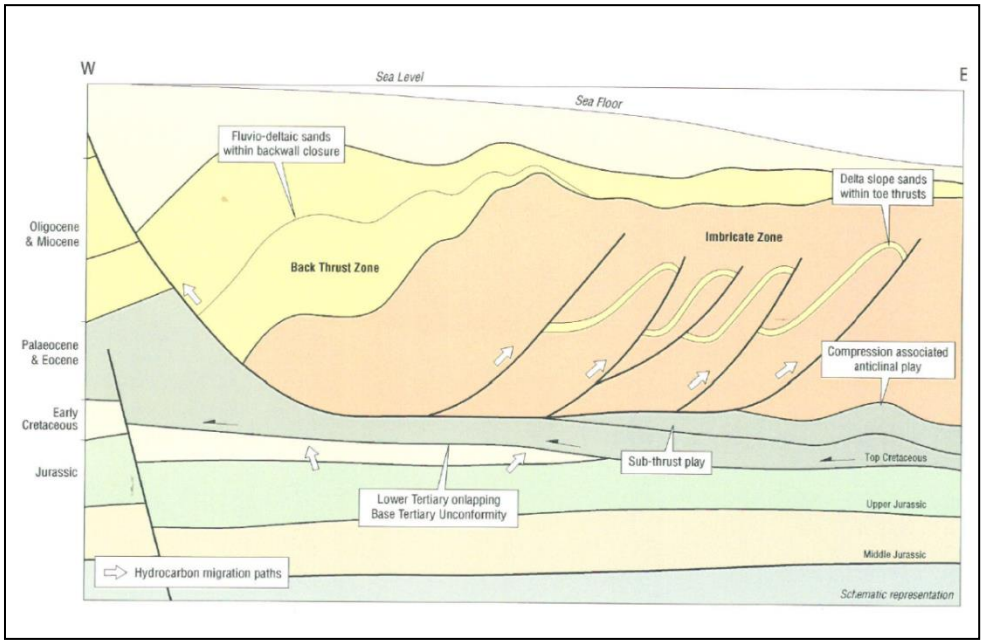


Figure 3-7: Cross Section Showing the Linked Extensional and Basinward Toe Thrust System

Source: Artumas Internal Presentation

4 MNAZI BAY FIELD – RESERVES

The Mnazi Bay and Msimbati discoveries together comprise the Mnazi Bay Field and the reservoirs are collectively referred to as comprising the Mnazi Bay Licence. RPS has previously derived volumetric assessments of the in-place volumes based on geological mapping of the sands, and then used those volumes as the initial basis for developing an integrated production model ("IPM") for production forecasting. Since then, the field has been on production for several years, and pressure depletion data available on some of the production zones exhibiting depletion trends. Therefore it is now appropriate to modify the interpreted in-place volumes based on material balance analysis of those sands.

Accordingly, for this year-end 2019 evaluation, RPS has adopted a hybrid analysis approach, whereby the in-place volumes for those reservoir sands with production depletion have been adjusted to reflect the material balance matches of pressure for the sands.

In this section of the report, we review the geological modeling basis for initial volumetric assessment, and then the adjustments based on material balance made to the IPM model for production forecasting purposes.

4.1 Reservoir Geology

The depositional model for the reservoirs is based on a stratigraphically complex series of stacked channels deposited in a deep-water canyon/slope setting.

4.1.1 Stratigraphy

Mnazi Bay and Msimbati reservoirs lie at the northern end of the Ruvuma Basin. The Ruvuma Basin contains a succession from shallow deltaic through deep slope. 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, MB-4 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 deep-water 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.

Five wells at Mnazi Bay, MB-1, MB-2, MB-3, MB-4 and MS-1X contain gas in the Miocene.

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

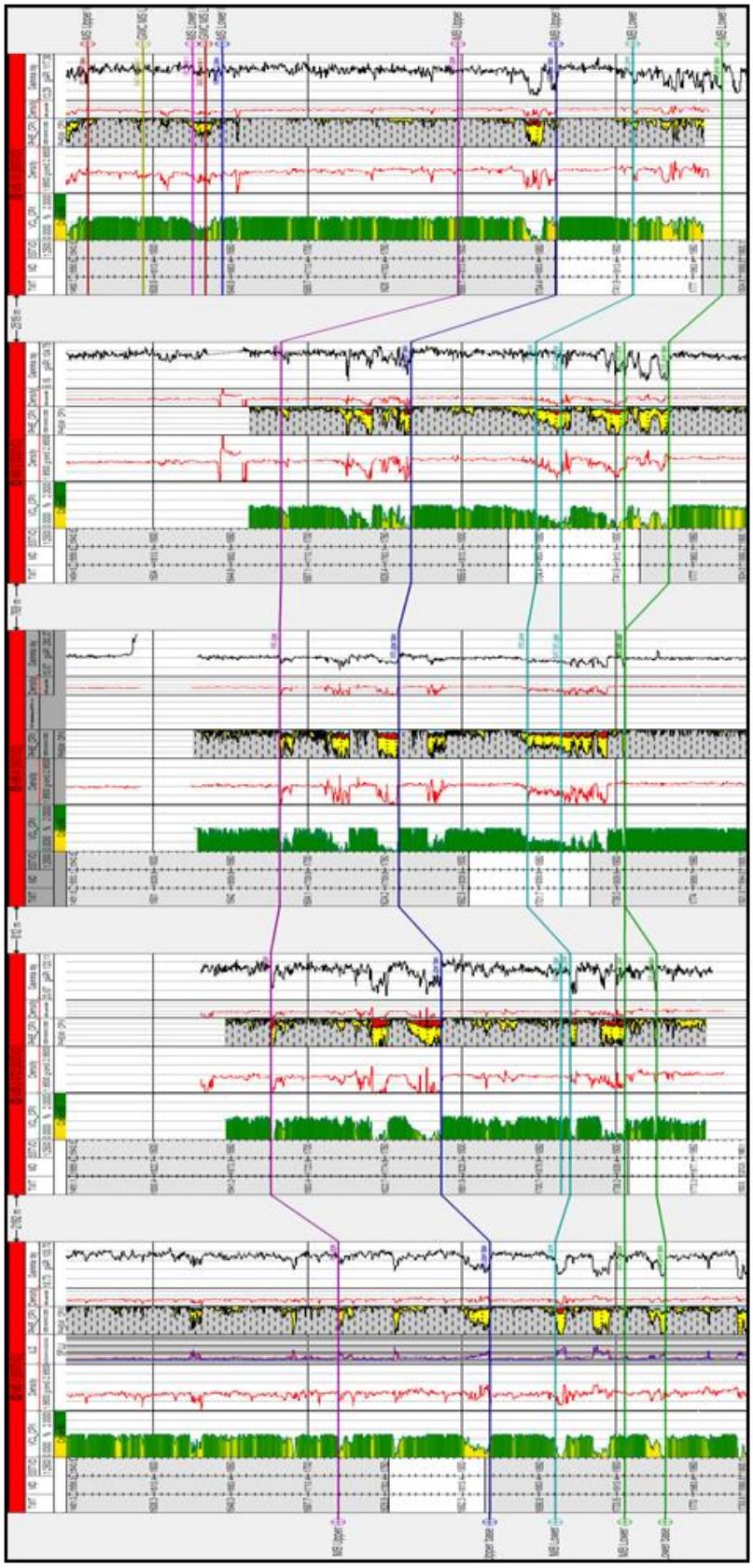


Figure 4-1: Mnazi Bay Stratigraphic Section

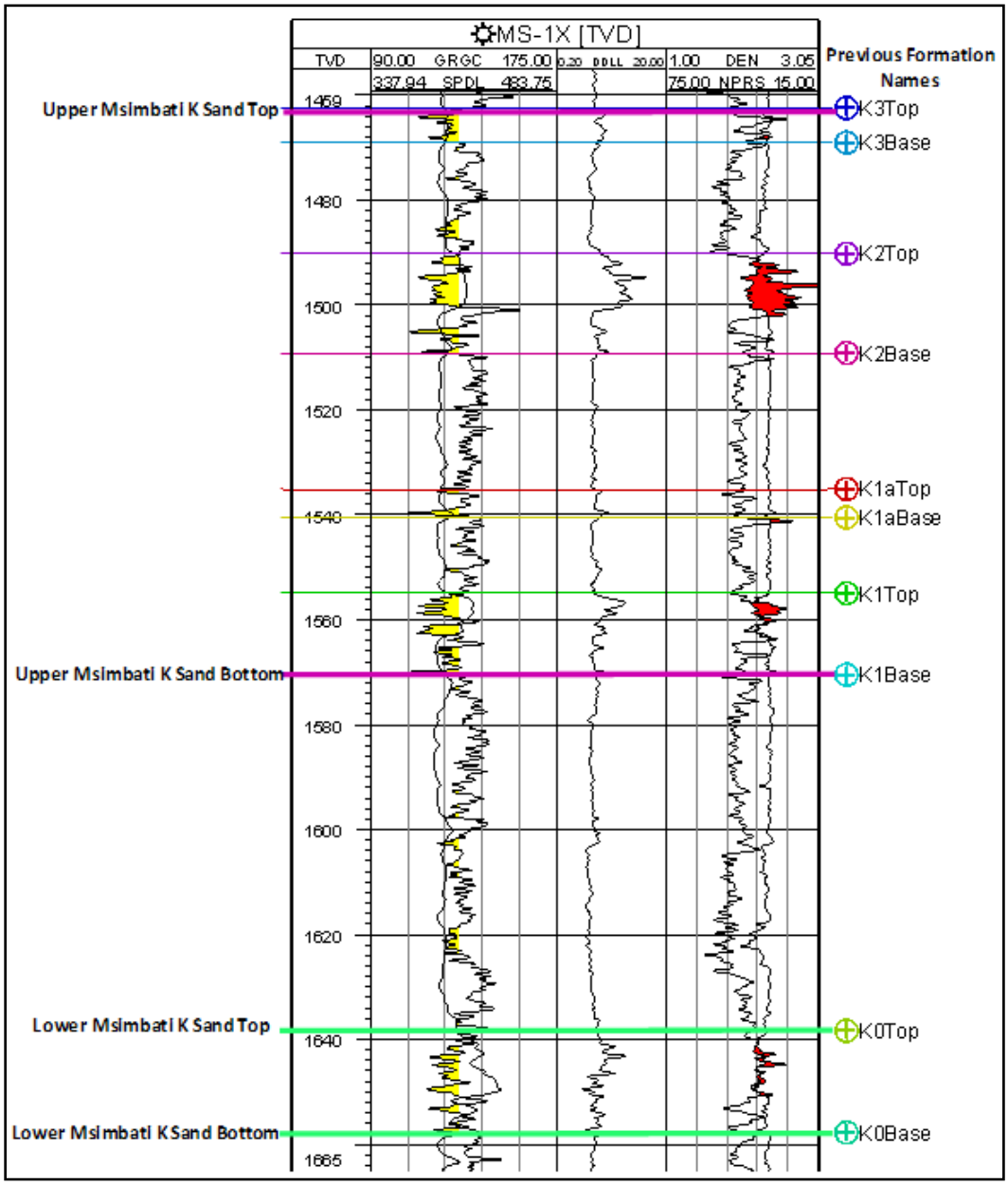


Figure 4-2: Msimbati Field MS-1X K Sands – Stratigraphic Section

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.

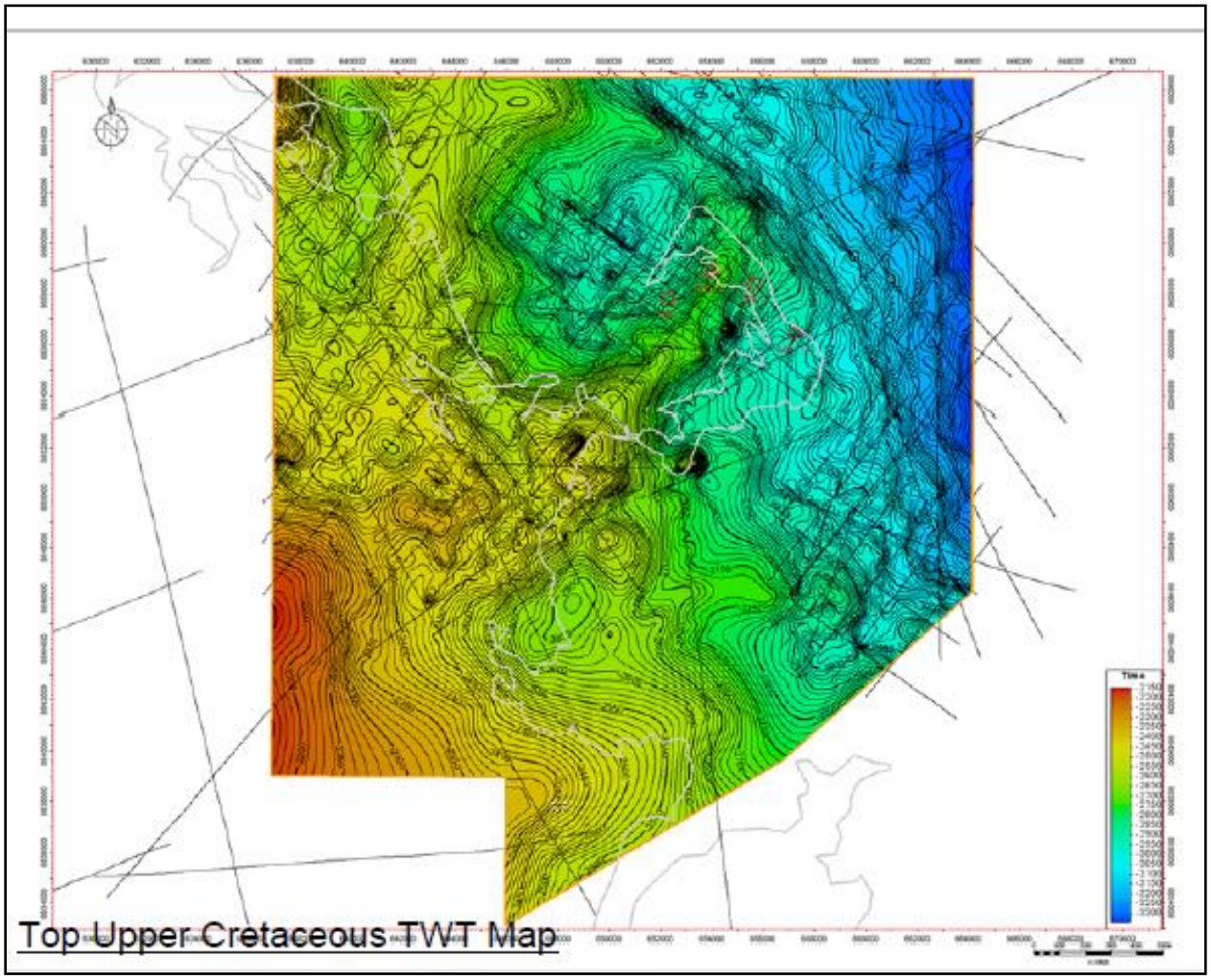


Figure 4-3: Pre-Tertiary Unconformity Surface (Top Upper Cretaceous)

4.1.3 Seismic Interpretation

4.1.3.1 Mnazi Bay Field

Four horizons have been picked within the Mnazi Bay channel structure; the Upper K and Lower K sands and the MB Upper and MB Lower Sands. The MB Lower Sand package contain sands which have previously been described as the C, D and E sands, while the MB 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 shows the Mnazi Bay channel feature with the upper sand package tops identified in yellow, the bases in red.

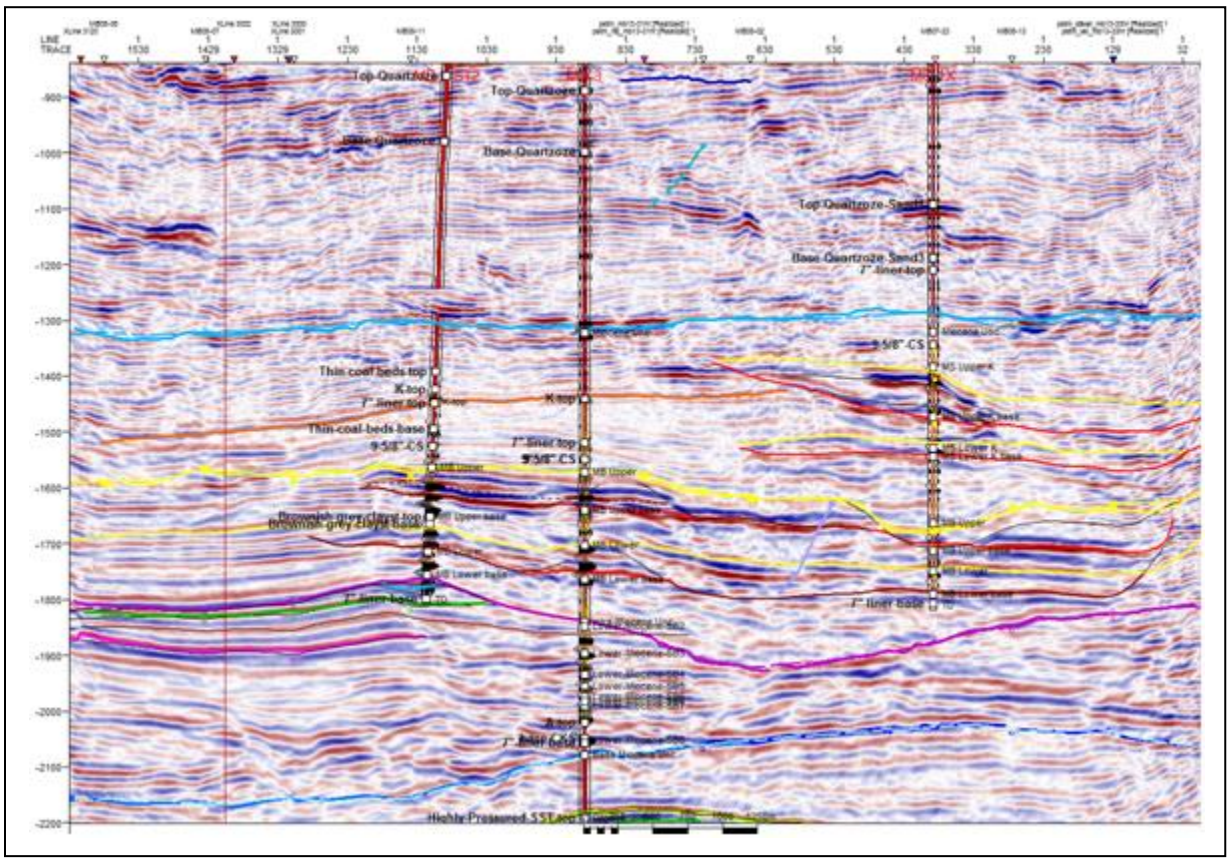


Figure 4-4: Line MB13-29 Showing the Mnazi Bay Channel

4.1.4 Geological Model – Gross Rock Volume

4.1.4.1 Mnazi Bay

A simple geological/geophysical structural model was constructed using depth grids created by seismic mapping and log data from the five wells; MB-1, MB-2, MB-3, MB-4 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 above gas-water contacts. 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:

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

- MB Upper Sand Isopach
- MB Lower Sand Isopach
- Gross Thickness above gas-water contact (“GWC”)
- Upper K Sand Isopach
- Lower K Sand Isopach

Figure 4 5 and Figure 4 6 are examples of these maps. All the maps are included in Appendix 2.

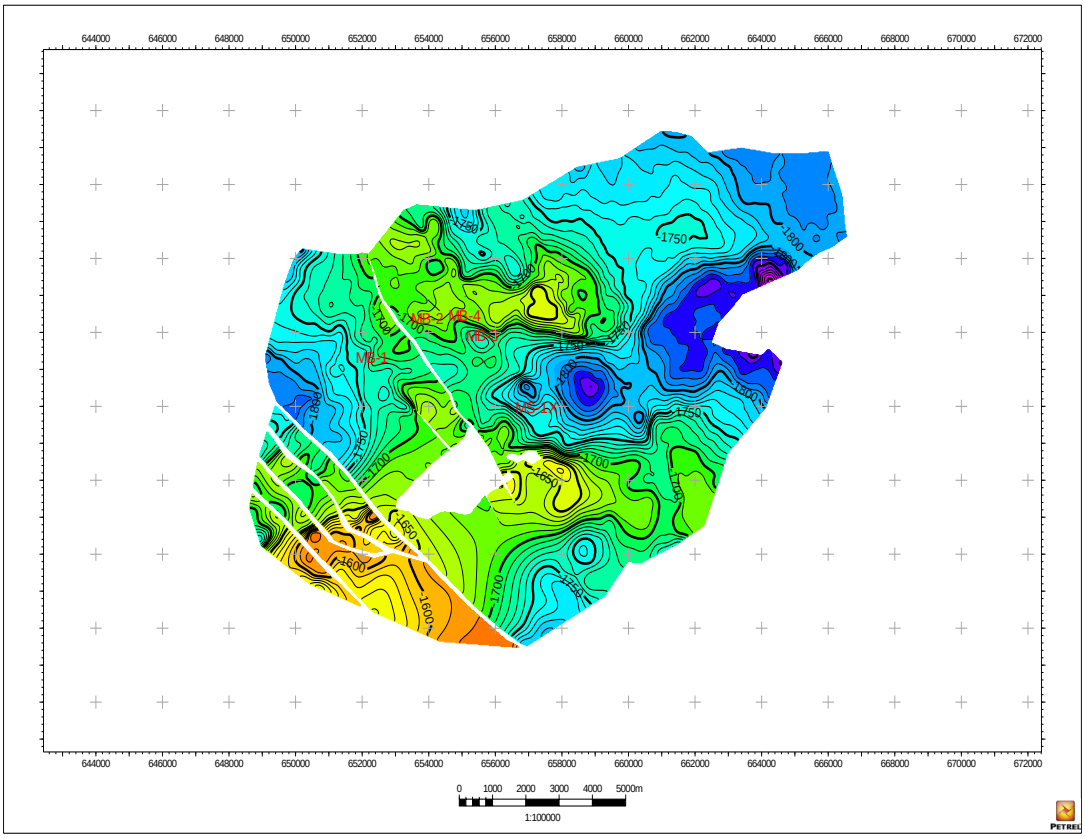


Figure 4-5: Mnazi Bay - Upper Sand Top Structure Map

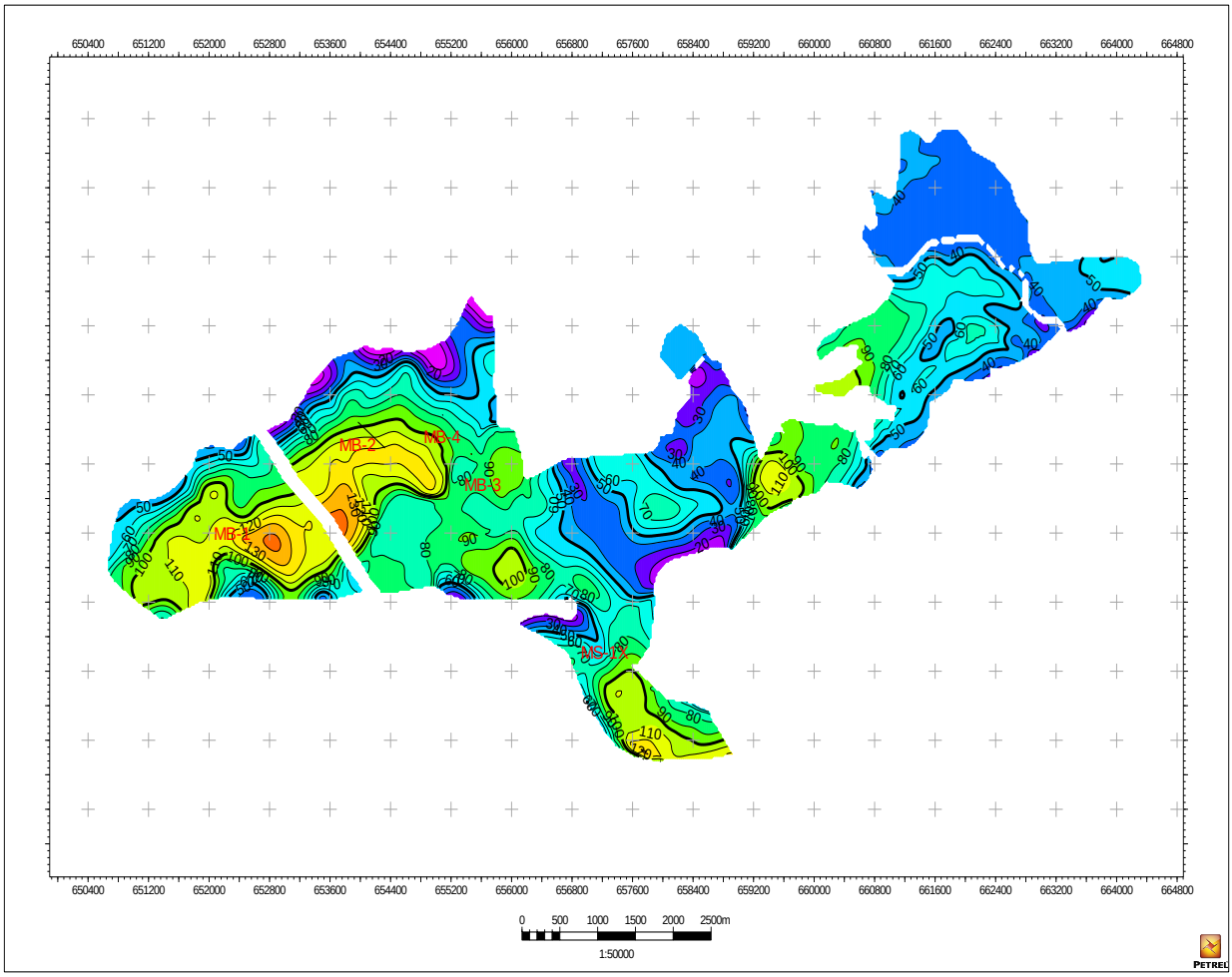


Figure 4-6: Mnazi Bay - Upper Sand Isopach above GWC

4.1.5 Petrophysical Analysis

The Mnazi Bay reservoirs have been penetrated by five 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
- Mnazi Bay #4 (“MB-4”); drilled by Maurel et Prom in 2015

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; side-wall core samples were obtained from the latest well, MB-4, but not used in the analysis.

Logs from MB-1, MB-2, MB-3 and MS-1X have been previously evaluated to identify potentially productive intervals and establish reservoir parameters[3, 4, 5, 6]. The CPIs and values from these wells, provided by Maurel et Prom for the 2014 reserves analysis, remain valid and show close

agreement with the values established previously. To derive net reservoir thicknesses and petrophysical parameters for the MS Upper Sand, MS Lower Sand, MB Upper Sand and MB Lower Sand gas-prone intervals the following cut-offs were used:

- Vsh < 0.50,
- Φe > 0.08, and
- Sw < 0.60

RPS was provided with the raw log and interpreted data for the most recent well, MB-4, and conducted a quick-look analysis which confirmed the evaluation conducted by Maurel et Prom.

On this basis, RPS considers the formation tops, logs, CPIs and petrophysical parameter values provided by Maurel et Prom to be reliable.

A composite of the logs from the four wells is shown in Figure 4 1 and Figure 4 2 of Section 4.1. The input values used to define the distributions for the probabilistic volumetric assessment are summarized in Table 4-1.

MS UPPER	P90	P50	P10	Mean	Distrib.	MS LOWER	P90	P50	P10	Mean	Distrib.
N/G	0.06	0.13	0.20	0.13	Normal	N/G	0.20	0.35	0.50	0.35	Normal
Porosity	0.20	0.25	0.30	0.25	Normal	Porosity	0.15	0.185	0.22	0.185	Normal
Sw	0.35	0.45	0.55	0.45	Normal	Sw	0.41	0.51	0.61	0.51	Normal
MB UPPER	**P90**	**P50**	**P10**	**Mean**	**Distrib.**	**MB LOWER**	**P90**	**P50**	**P10**	**Mean**	**Distrib.**
N/G	0.20	0.27	0.34	0.27	Normal	N/G	0.35	0.49	0.63	0.49	Normal
Porosity	0.16	0.23	0.30	0.23	Normal	Porosity	0.18	0.21	0.24	0.21	Normal
Sw	0.30	0.39	0.48	0.39	Normal	Sw	0.28	0.37	0.46	0.37	Normal

Table 4-1: Petrophysical Input Ranges to Volumetric Calculations

4.2 Reservoir Fluids

4.2.1 Pressure vs. Depth Relationships

In all five 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 in the Mnazi Bay sands and 2500 to 2580 psia in the Msimbati sands. Pressure data from the MB-4 well, drilled in 2015, after eight years of field production, showed depletion (see Figure 4 11). The pressure in the intermediate sands in MB-4 was broadly aligned with the Lower Mnazi Bay reservoir, indicating communication with these sands (though it is not inconceivable that these sands are not connected and representative of a separate, slightly shallower, GWC). Depletion in the Lower Mnazi Bay varied between 15 and 23 psi. Depletion at the top of the Upper Mnazi Bay amounted to 8 to 9 psia and in the main part of the Upper Mnazi 25 to 32 psi.

The initial pressure data set is comprised of Repeat Formation Test (“RFT”), Modular Formation Dynamics Tester (“MDT”) and Drill Stem Test (“DST”) 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 are shown in Figure 4 7 to Figure 4 10. A composite pressure vs. depth plot for the initial four wells drilled (prior to depletion) is shown in Figure 4 12. On each plot the range of pressure gradient derived gas-water contact (“GWC”) depths is shown.

The composite DST, MDT, RFT pressure data suggest that multiple GWC depths are likely prevalent throughout the fields and are probably both structurally and stratigraphically-controlled.

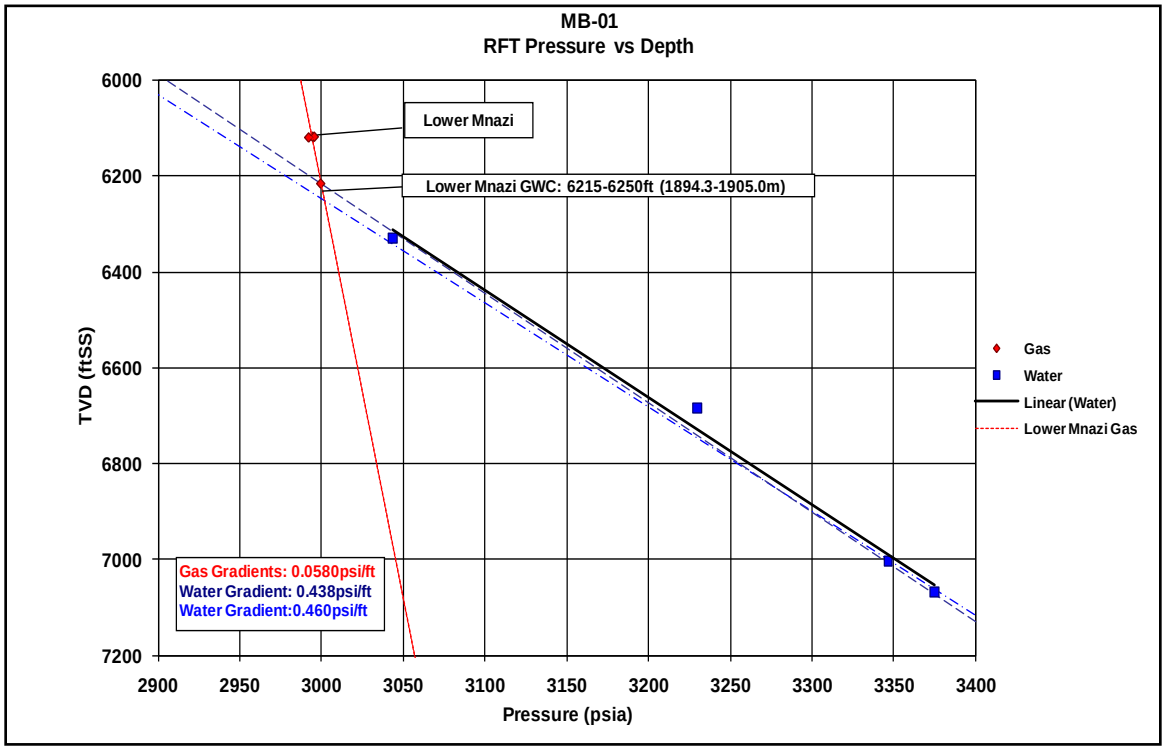


Figure 4-7: MB-01 RFT Pressure vs. Depth

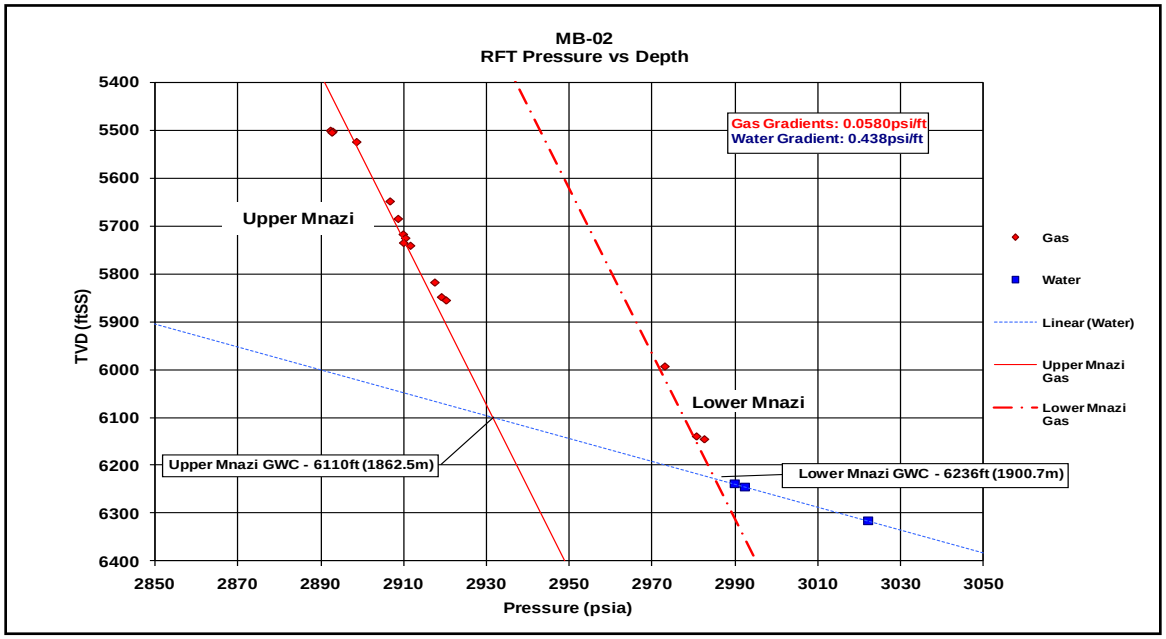


Figure 4-8: MB-02 Pressure vs. Depth

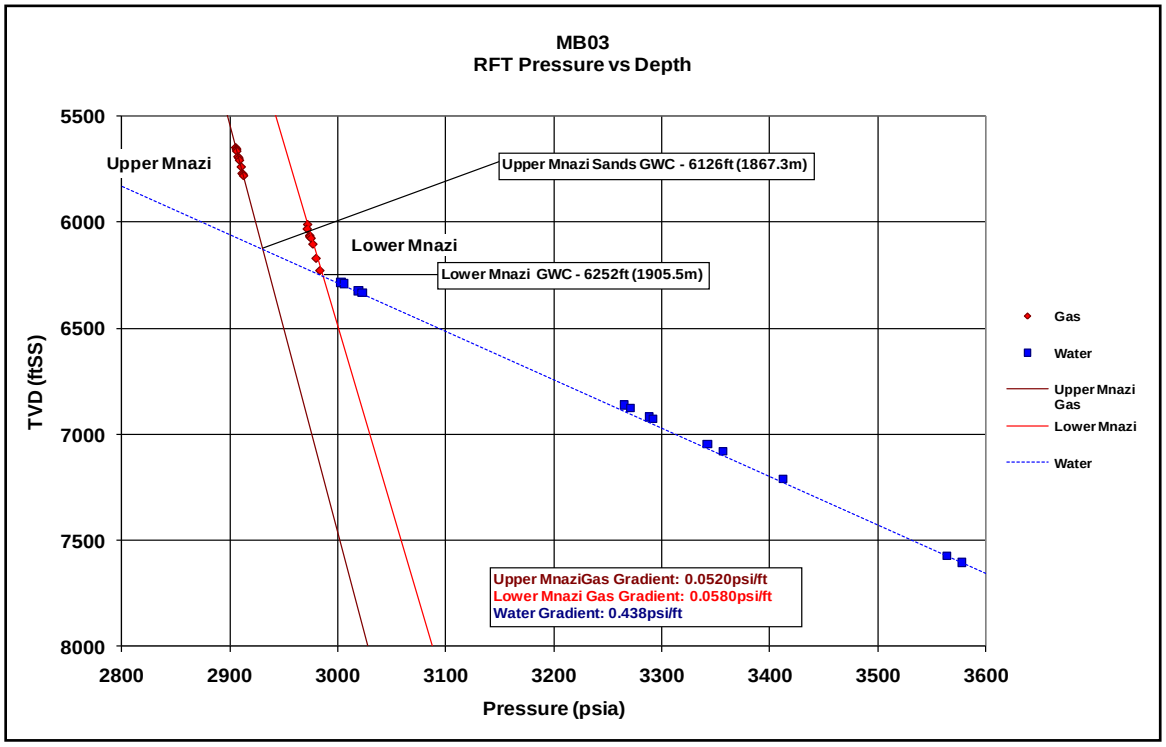


Figure 4-9: MB-03 RFT Pressure vs Depth

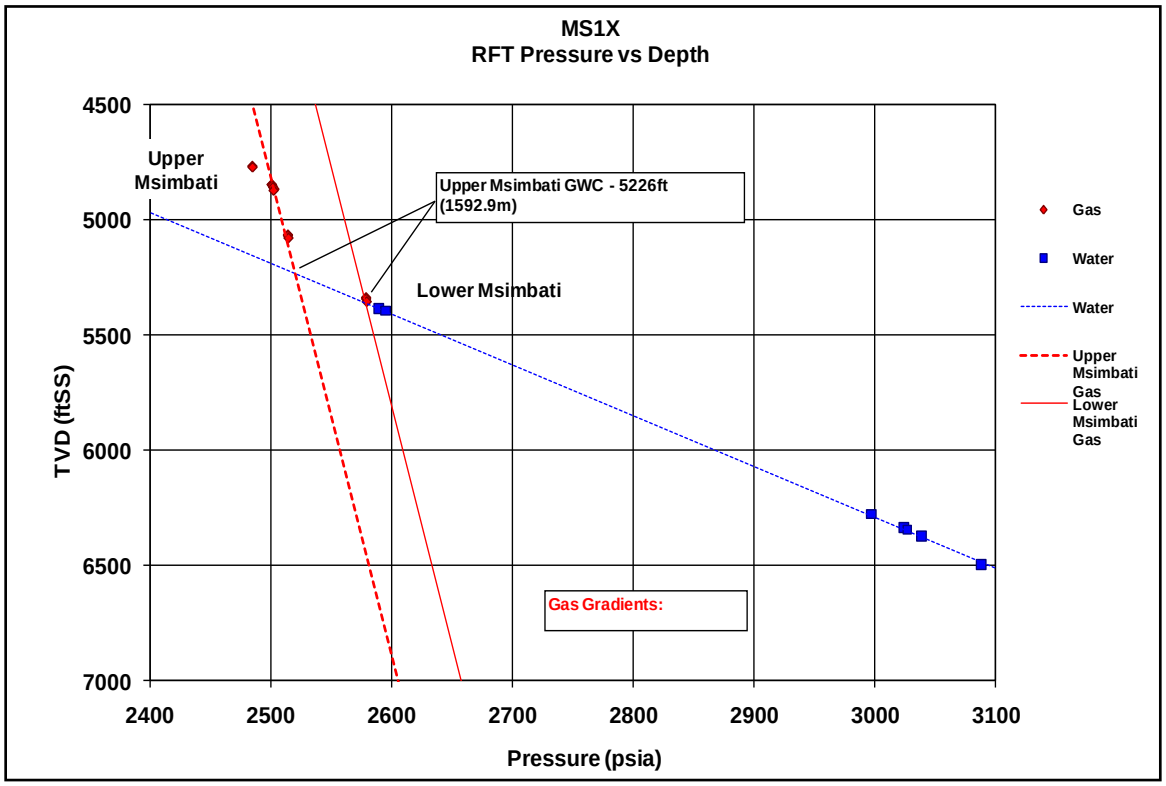


Figure 4 10: MX-1 RFT Pressure vs. Depth

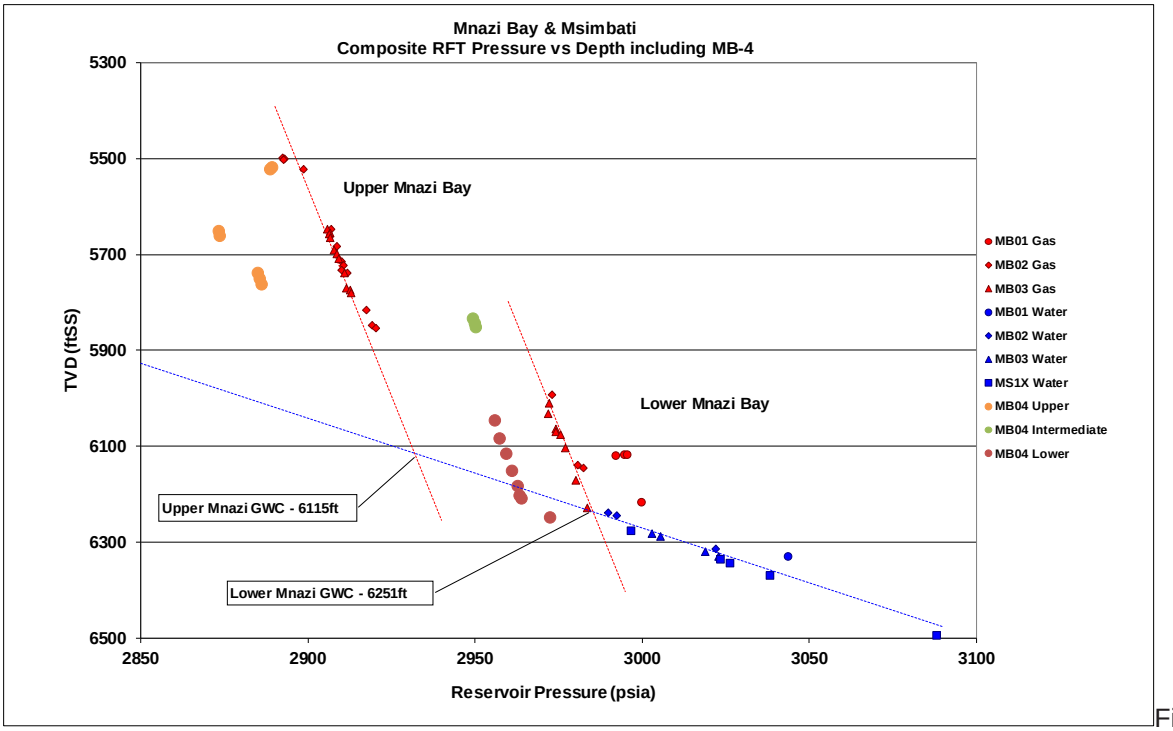


Figure 4 11: MB-4 MDT Pressures vs Depth (with original pressure gradients)

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 the repeat formation tester (RFT or MDT) 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 Mnazi Bay Sands, and two GWC levels in the Msimbati K sands. These sets of GWC levels can be seen on the composite RFT plot shown below:

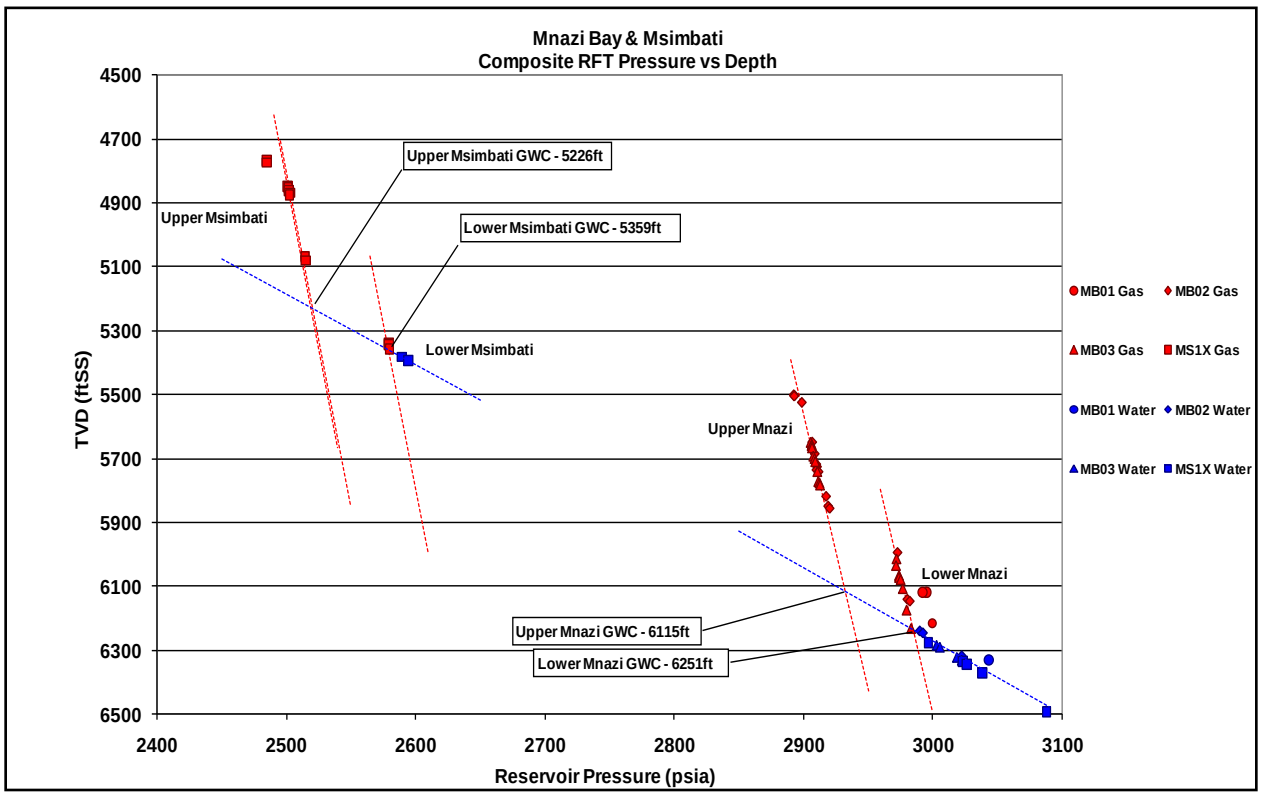


Figure 4 12: Composite RFT Pressure vs. Depth

The data used in determination of GWC depths for the field are summarized in Table 4 2:

Mnazi Bay and Msimbati Gas Fields Gas Water Contact Depths - all depths listed as subsea depth				
	MB#1	**MB#2-ST2**	**MB#3**	**MS-1X**
KB Elevation (ft above msl)	44	43	44	44
GWC Evidence				
Well Logs	No GWC on logs	C: GWC @ 6249 ftSS (1904.7 mSS)	C: GWC @ 6252 ftSS (1905.6 mSS)	K0: GWC @ 5358 ftSS (1633.1 mSS) F: GWC >6074 ftSS (1851.4 mSS) and < -6082 ftSS (-1853.8 mSS)
Test Data	D: tested clean gas to 6218 ftSS (1895.2 mSS)	C: Water and gas produced interval 6214 ftSS to 6253 ftSS (1894 to 1906 mSS)	C: tested clean gas to 6251 ftSS (1905.3 mSS)	K: tested clean gas to mid point of K1 sands @ 5085 ftSS (1549.9 mSS) F&G: produced clean gas to 6066 ftSS (1848.9 mSS)
GDT	D: 6218 ftSS (1895.2 mSS)	C: 6249 ftSS (1904.7 mSS)	C: 6251 ftSS (1905.3 mSS)	K1,2,3: 5082 ftSS (1549.0 mSS) K0: 5355 ftSS (1632.2 mSS)
RFT/MDT Data GWC	D,E: 6215 to 6250 ftSS (1894.3 to 1905.0 mSS)	H& I: 6106 ftSS (1861.1 mSS) G: 6110 ftSS (1862.5 mSS) F: 6119 ftSS (1865.0 mSS) C,D: 6236 ftSS (1900.7 mSS)	F,G: 6126 ftSS (1867.3 mSS) C,D,E: 6252 ftSS (1905.5 mSS)	K3: 5193 ftSS (1583.0 mSS) K2: 5226 ftSS (1592.9 mSS) K1: 5229 ftSS (1593.9 mSS) K0: 5357 ftSS (1632.7 mSS) F&G: n/a
Regional Water Gradient	Measured below 6330 ftSS P (psia) = (TVDSS (ft) + 623)/2.284	Measured below 6239 ftSS P (psia) = (TVDSS (ft) + 584)/2.284	Measured below 6288 ftSS P (psia) = (TVDSS (ft) + 568)/2.284	P (psia) = (TVDSS (ft) + 333)/2.207

Table 4 2: 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 4-12.

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 3. 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.

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 3: 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 initial four wells, separator gas samples were analyzed on-site using gas chromatographic analysis. These analyses were limited to hydrocarbon components up to nC5. Further, separator gas and liquid samples were collected during extended well tests, and subject to full compositional lab analyses[7], [8], [9] . 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 H2S has been measured in any of the samples. Most gas samples showed a specific gravity of about S.G. = 0.57 and Molecular Weight of 160 g/gmol. 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. Samples analysed from MB-4 production during initial production in 2015, show compositional analysis to be in line with the original wells.

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 C37+ 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 4.

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 4: 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 5. In this table, the non-hydrocarbon components have been added, and the measured hydrocarbon components normalized, using the non-hydrocarbon analysis 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 5: 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 ("OGR") 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 6:

	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 (ºAPI)	24	25	25	27

Table 4 6: Extended Well Testing Fluid Production Summary

The volume of the liquid hydrocarbons produced is relatively small, however limited quantities (<1 bbl/MMscf) of 23˚ to 31˚ API oil have been produced and identified. Currently, field liquid production is relatively stable, and an OGR value of 0.15 bbl/MMscf is reported from mid-2016 to date.

Since the volumes are small, the analysis of the provenance of the liquid is not possible, and there is no plan of development to market any such volumes, for the purposes of this reserves evaluation the reservoir fluids are assumed to be gas only, and no reserves volumes have been attributed to any 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 composition from the MB-2-ST2 analyses, and an average reservoir temperature of 93°C. The resulting gas viscosity and formation volume factor is shown in Figure 4 13.

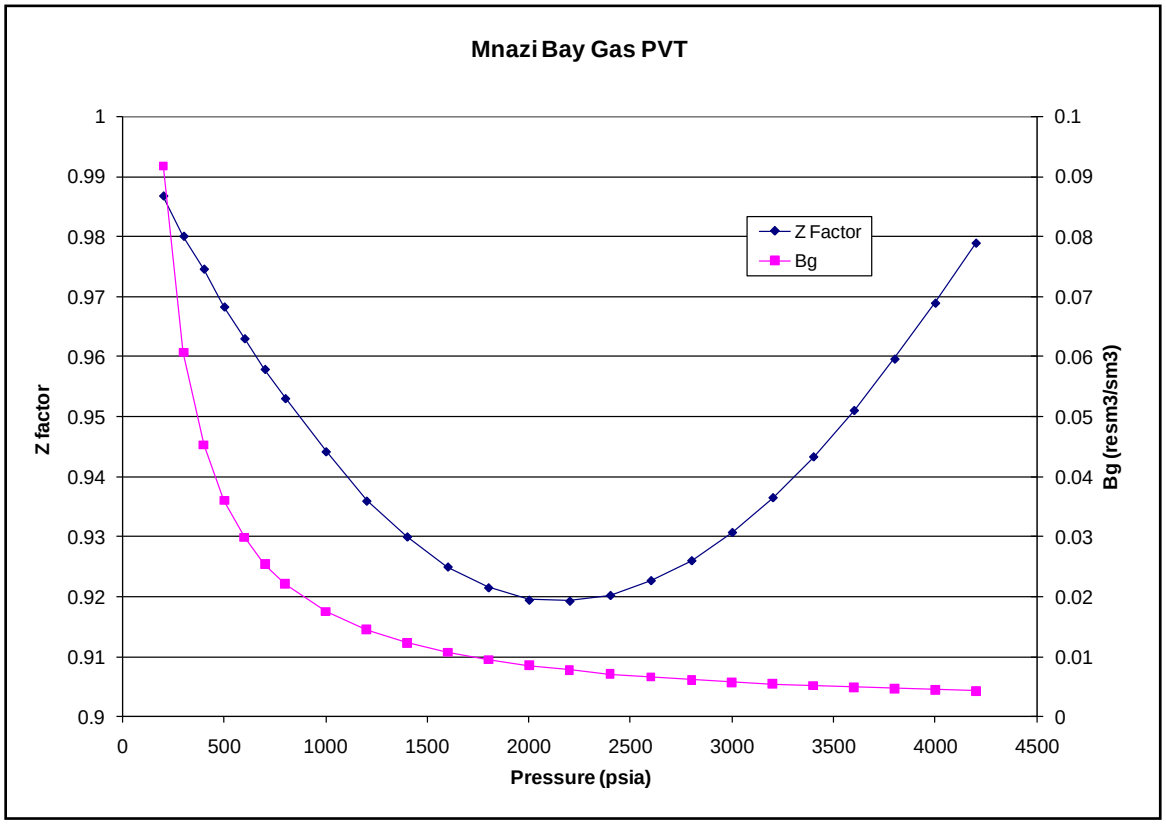


Figure 4 13: Mnazi Bay (MB-02-ST2) Gas PVT

4.3 Well Deliverability Testing

The four initial Mnazi Bay wells were 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. Bottomhole pressures, flowing tubing head pressures, separator pressures and gas flow rates were recorded during each of the tests. The flowing and pressure data were analyzed for each test to determine average reservoir pressure, reservoir flow properties and reservoir flow barriers [10],[11], [12] .

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), Zone D
  - 6150 – 6170 ftKB (6106 – 6126 ftSS), Zone E
- Upper Mnazi Bay:
  - 5962 – 5992 ftKB (5918 – 5948 ftSS), Zone F
  - 5803 – 5813 ftKB (5759 – 5769 ftSS), Zone G

A dual packer with dual string (2 3/8”) tubing with sliding sleeves was installed. This allows commingled production from the perforations in the Lower Mnazi Bay (D & E) through the long string and production

from either of the Upper Mnazi Bay intervals through the short string, installed with a sliding side door. Since the F Zone produced water during production testing, the Upper Mnazi Bay production is limited to the Zone G perforations.

A summary of the above test interpretations is shown in Table 4 7. 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.

Mnazi Bay & Msimbati Drill Stem Test Summary Table

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

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

MB-4

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
1	Upper Mnazi	5,629 5,724	5,663 5,767	34.5 43.5	80	106	13	0.29	2877	20000	92
2	Lower Mnazi	5,832 6,044 6145.2	5,861 6,135 6183.8	28.7 91.8 38.5	139	220	21	0	2936	5630	92

Table 4 7: Mnazi Bay and Msimbati DST Summary

In addition to the DSTs, the following table summarizes the results of Extended Well Tests ("EWT"s) carried out during 2007 in wells MB-02, MB-3 and MS-1X wells[13],[14],[15] .

Mnazi Bay & Msimbati EWT Summary Table

Well	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
MB-02	F	5,843	5,863	20	18	103	11.0	0.25	2,911	2,198	204
MB-03	G	5,648	5,714	66	32	87	11.1	0.26	2,903	7,618	233
MS-1X	K-2	4,846	4,866	20	31	80	9.4	0.19	2,502	16,470	211

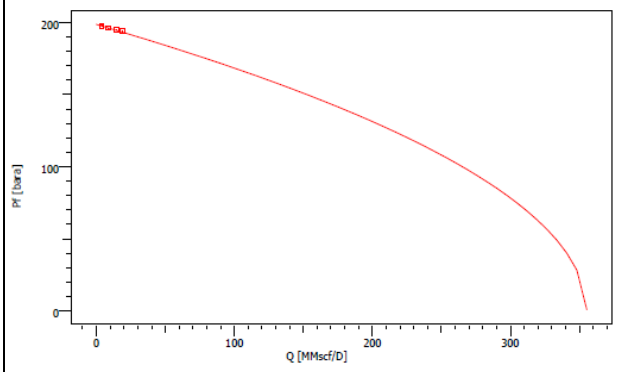
Table 4 8: Mnazi Bay & Msimbati Fields EWT Summary

Following drilling and completion of MB-4 in mid-2015, the well was production tested separately over the Upper and Lower Mnazi Bay intervals. The well is completed with a packer installed between the two intervals, allowing access to the lower interval via the tailpipe, and through a sliding side door to the straddled Upper Mnazi Bay, from which interval the well is presently producing.

Multi-rate tests were conducted, and back-pressure (C,n) analyses were conducted. The rates and results are shown in the table below. It can be seen that the deliverability of both zones is potentially high, if the back-pressure can be lowered sufficiently (compression), and the rates are in line with other wells completed on the Upper and Lower Mnazi Bay reservoirs.

Upper Mnazi Bay (T1)

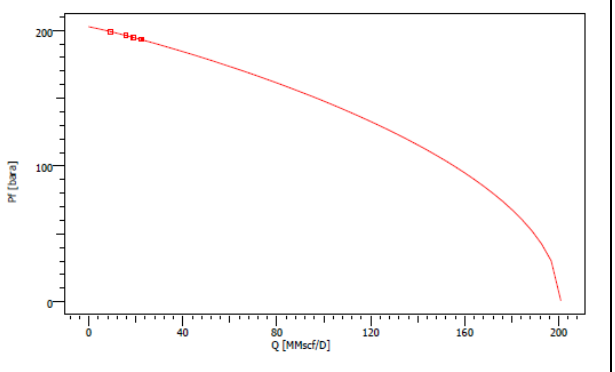
Flow Period	Choke size (1/64 in)	Gas rate (MMscf/d)	WHP (bara)	BHP (bara)
1	16	3.9	174.3	197
2	24	8.7	173	196
3	32	14.7	169	195
4	36	18.9	166	194
Final BU	0	0	177	198.5



BHP vs. Flowrate

Lower Mnazi Bay (T2)

Flow Period	Choke size (1/64 in)	Gas rate (MMscf/d)	WHP (bara)	BHP (bara)
1	24	9.2	176.1	199.1
2	32	15.8	171.3	196.2
3	36	19.1	166.6	194.5
4	40	22.2	163	193.3
Final BU	0	0	181.5	202.5



BHP vs. Flowrate

Table 4 9: MB-4 Production Test Rates and Back-Pressure Analysis

Well test interpretations were conducted to determine reservoir parameters, assuming a number of different reservoir models. The best model matches (based on boundaries) are shaded in grey in the table below, and these are the parameters that RPS has used in the assumptions for forecasting.

Reservoir	Intervals (mMD)		Date	Period	Pi (bara)	Porosity (%)	kh (mD.ft)	h (ft)	k (mD)	S (-)	Model
	Top	Base									
Upper MB (T2)	1725.5 1754.5	1736 1767.75	14-15 Jun 2015	Initial BU	202.5	28.6	21600	80	270	15.1	Infinite-acting
				Final BU	198.1	28.6	23200	80	290	22	Infinite-acting
				All	198.1	28.6	23200	80	290	22	Single Fault, L = 65.1 m
				All	198.1	28.6	8010	80	100	2.7	Two Layers
				All	198.4	28.6	20000	80	250	14.4	Parallel Faults
Lower MB (T1)	1787.5 1852 1883	1796.25 1880 1894.75	13-14 Jun 2015	Initial BU	202.6	23.4	5620	139	40	11.4	Infinite-acting
				All	202.1	23.4	2900	139	21	-0.27	2-Porosity Slab
				All	202.5	23.4	2700	139	19	-0.37	Two Layers
				All	202.5	23.4	5630	139	40	4	Single Fault, L = 15 m

Table 4 10: MB-4 Production Test Interpretation Results

4.4 Production History

The Mnazi Bay field was first put on stream in January 2007 and production has been more or less continuous ever since. Erratic and low gas nominations in 2016 and 2017 resulted in numerous shut in periods for all wells except MB-1, which supplied direct to Mtwara power generation plant at the time. Gas delivery rates were adjusted based on sales nominations.

Production has occurred from both the lower and upper zones (D/E and G sands) in MB-01, the F Zone in MB-03 from mid-2012, the F Zone in MB-2 from late 2015, the F and G zones commingled in MB-4 from early 2016, and MB-2 and starting in 2019, and the K2 zone in MS-1X from late 2015. Produced gas was originally processed and sent via pipeline to the town of Mtwara where it is used as the fuel gas in an 18 MW natural-gas-fired power generation facility, with production rates being limited by the requirements of the Mtwara facility to about 2 MMscf/d.

To supplement sales to the Mtwara power plant, in August 2015, a tie-in to the Tanzanian transnational gas pipeline was completed and first gas deliveries to this pipeline commenced, followed by commissioning of gas production facilities at Madimba and a newly built Kinyerezi power plant gas receiving facility, near Dar Es Salaam. Gas production rates have increased as the Kinyerezi power plant generation capacities ramped up. In 2019 Mnazi Bay field production rates reached a maximum of 96 MMscf/d, with 2019 total year-to-date production to end of October 2019 achieving 21.4 Bscf (raw gas). Field total cumulative production as at October 31, 2019 was 96.2 Bscf (raw gas) and is forecast by RPS to be 100 Bcf at year end 2019.

The entire field production history, by well, is shown in Figure 4 14 and the production from 2015 through mid-November 2019 is presented in more detail in Figure 4 15.

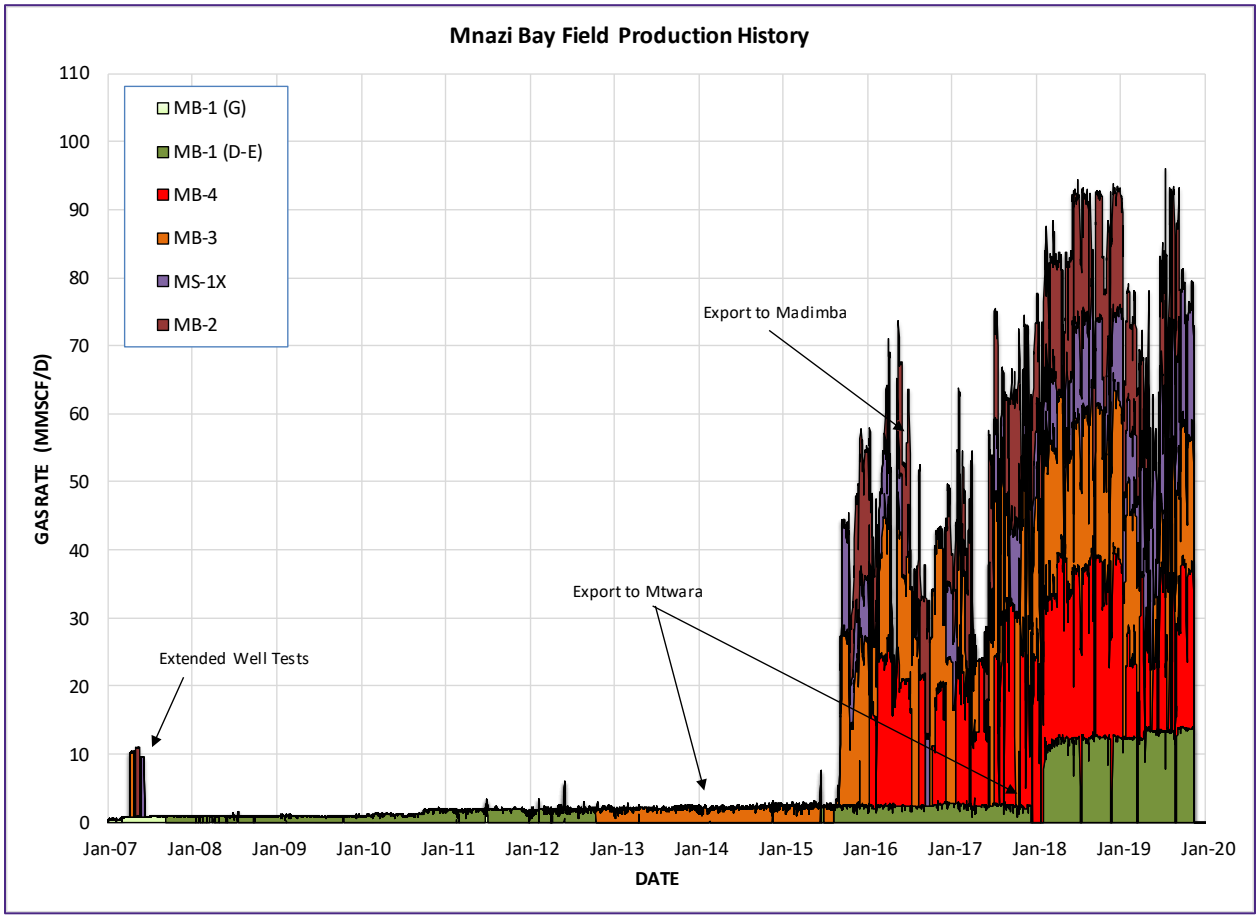


Figure 4 14: Production History Mnazi Bay Gas Field, from 2007 to 2019

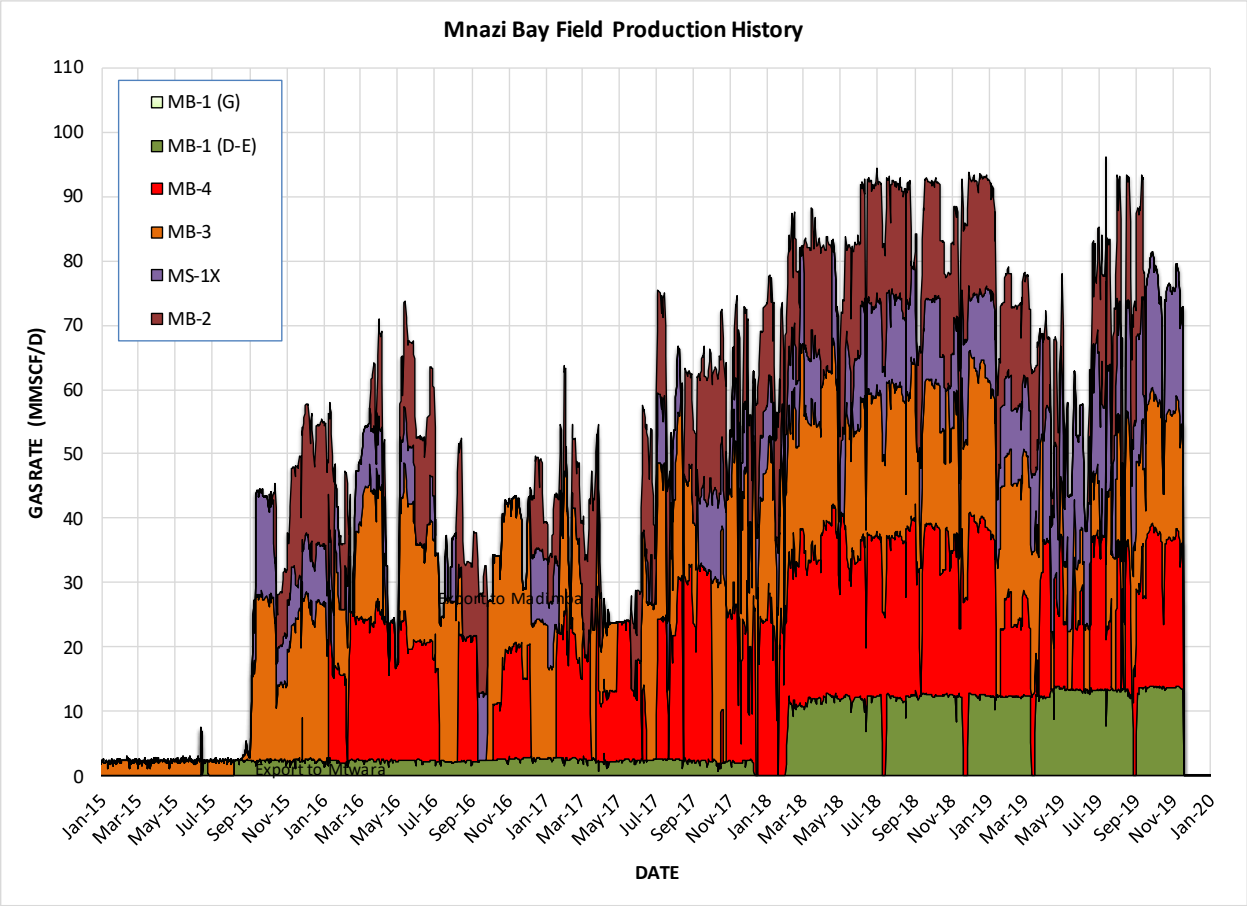


Figure 4 15: Production History Mnazi Bay Gas Field 2015-2019

Production history for each of the producing wells is shown below in Figure 4-10 to Figure 4-20.

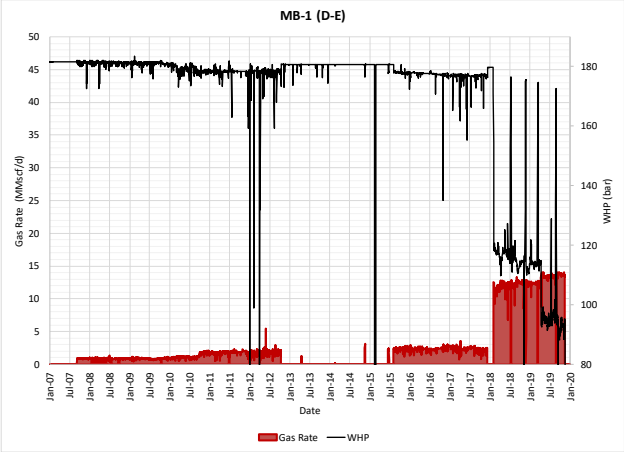


Figure 4-10: MB-1 Lower MB (Zone D/E) Production History

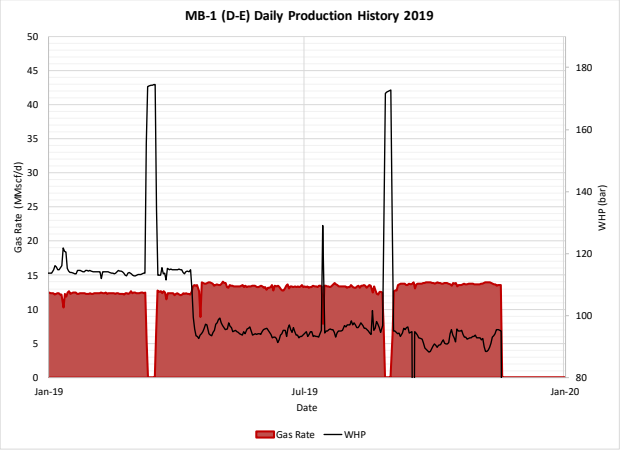


Figure 4-11: MB-1 Lower MB (Zone D/E) Production History 2019

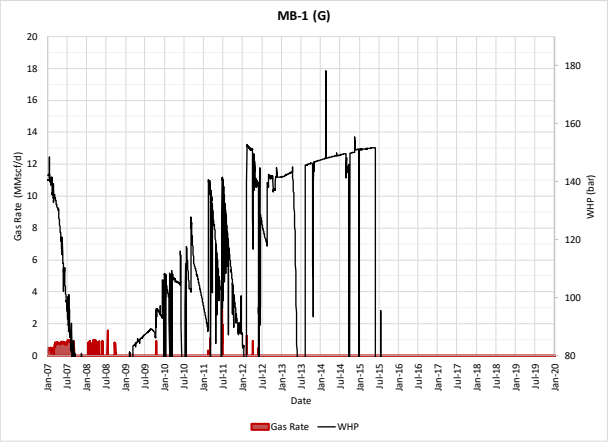


Figure 4-12: MB-1 Zone G Production History

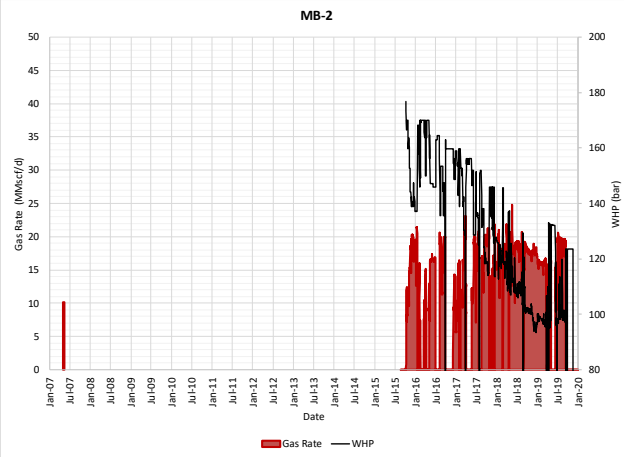


Figure 4-13: MB-2 Upper MB (Zone F) Production History

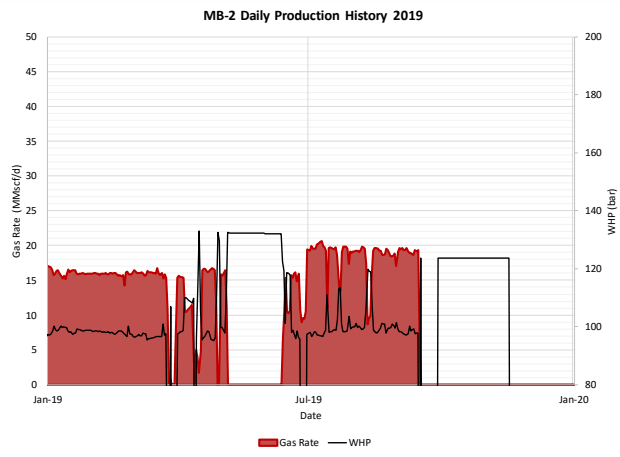


Figure 4-14: MB-2 Upper MB (Zone F) Production History 2019

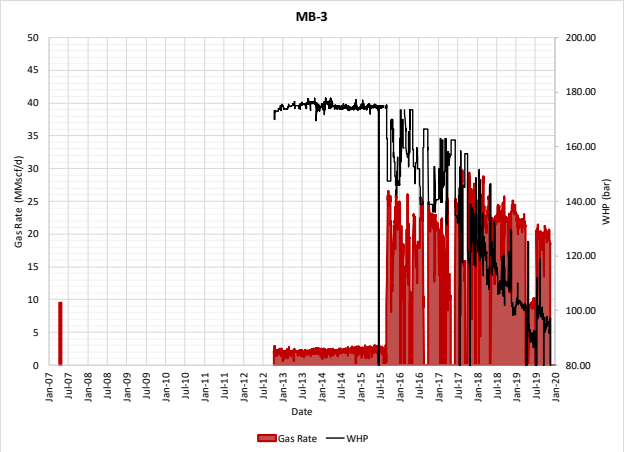


Figure 4-15: MB-3 Upper MB (Zone F) Production History

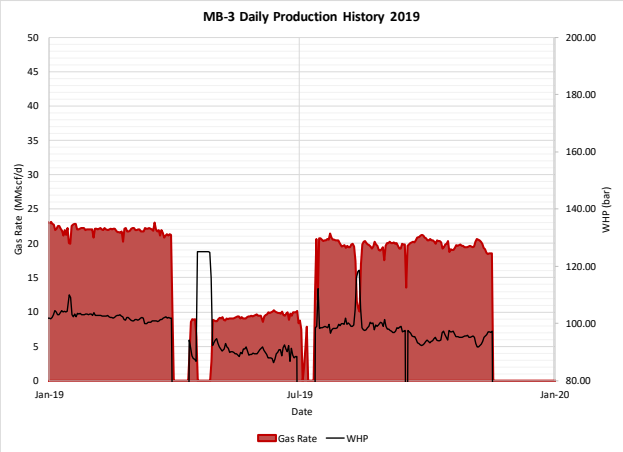


Figure 4-16: MB-3 Upper MB (Zone F) Production History 2019

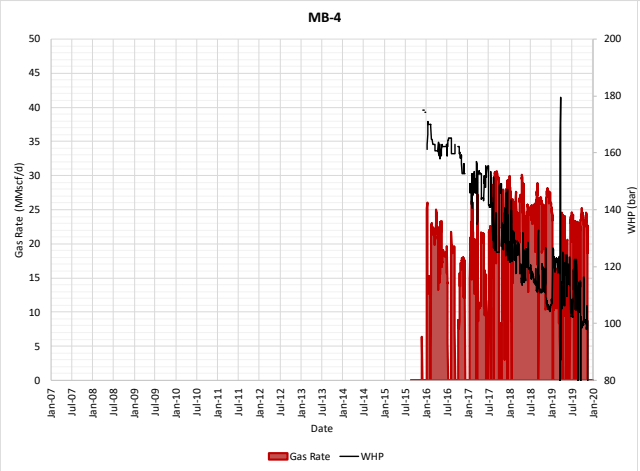


Figure 4-17: MB-4 Upper MB (Zone F & G) Production History

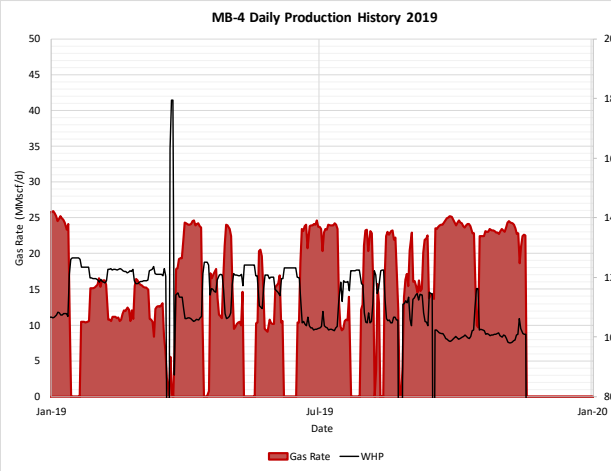


Figure 4-18: MB-4 Upper MB (Zone F & G) Production History 2019

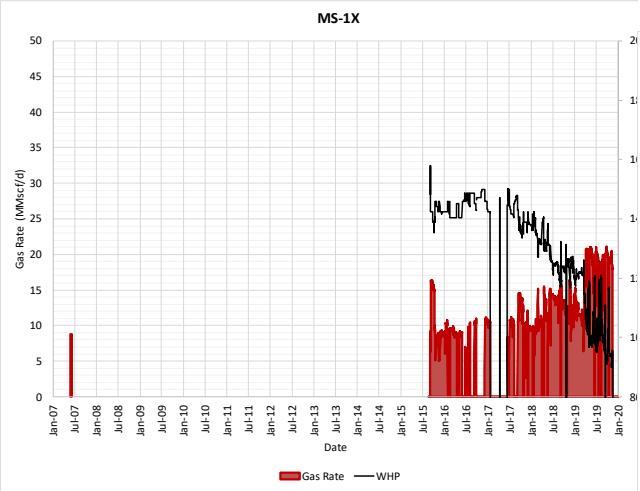


Figure 4-19: MS-1X Upper MS (Zone K2) Production History

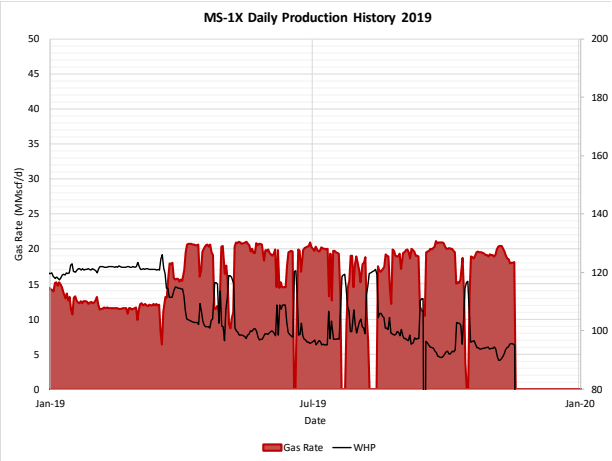


Figure 4-20: MS-1X Upper MS (Zone K2) Production History 2019

4.5 Mnazi Bay Volumes and Reserves

In carrying out this review, RPS has utilized information and data from Maurel et Prom 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, MB-4, and MS 1X
- DST and production testing reports, and production data from MB-1, MB-2-ST2, MB-3, MB-4, and MS-1X
- IPM model of the field, utilizing PETEX™ software, incorporating historical production and pressure data

RPS has reviewed the aforementioned information, interpretations and data and is of the opinion 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 Reserves Determination Methodology

RPS has utilized a combination of volumetric and material balance methodologies to determine in-place and recoverable volumes. Volumetric analysis based on geologic mapping and initial petrophysical parameters has been used to define the initial estimates of reservoir in place volumes, then for several of the sands where sufficient pressure depletion data has become available since the onset of field production, those estimates have been adjusted to the history matched material balance volumes.

The initial volumetric analysis utilizes a probabilistic methodology utilizing, and recognizing the uncertainties in:

- Gross Rock Volumes: determined from the geo-statistical 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 pressure, temperature and gas analysis data from each of the four wells.

Recovery factor has been determined through production forecasting with an integrated production model which utilizes material balance, well models, and surface gathering system, accounting for well deliverability and surface network constraints.

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 the Mnazi Bay field. The P90 case is mainly restricted, in terms of surface topography, to onshore and lagoonal areas in the vicinity of wells showing gas bearing sands. The mid-case includes areas extending into the offshore, comprising those areas exhibiting strong or moderate seismic amplitudes. The MB Upper is an exception as the north-east segment is separate to the main reservoir area (see Appendix B). The P10, upside case also includes areas interpreted to be crevasse splays from amplitude maps. Based on this methodology, the small, MS Lower K reservoir has the same polygon area for all cases, so to introduce uncertainty a ±15% variation from the P50 case was used for the upper and lower cases.

A summary of the derived gross rock volumes for each layer is shown in Table 4 11.

Volume above GWC (Km^3)			
	P90	**P50**	**P10**
MS Upper K	0.567	0.891	1.587
MS Lower K	0.032	0.037	0.043
MB Upper	0.980	1.634	1.999
MB Lower	0.498	0.878	1.124

Table 4 11: Hydrocarbon-bearing Gross Rock Volumes

4.5.3 Gas Initially in Place ("GIIP")

The volumetric based GIIP for the Mnazi Bay field was derived probabilistically using Logicom's REP™ software and the following variables:

- Gross rock volume ("GRV"): GRVs for each sand package were calculated by the creation of polygons limited by the interpreted channel belt facies, the GWCs and the extent of the seismic amplitude anomalies as discussed above. A beta distribution was utilized for the GRV for each layer.
- Net to Gross ratio ("N/G"): A normal distribution for each of the sand packages was utilized, with the P90 and P50 input values constrained by results derived from the petrophysical analyses for each layer at each well.
- Water Saturation ("Sw"): Normal distributions defined by P90 and P50 input values constrained by results derived from the petrophysical analyses for each layer at each well.
- Gas Formation Volume Factor (1/Bg): A normal distribution was used, with the P50 input value for each formation based on a dry gas molecular weight of 16, plus pressure and temperature data derived during the well tests. Values for 1/Bg (equivalent to Eg) vary between 154 in the MS Upper and 171 in the MB Upper horizons.

A summary of the input ranges and distributions used for the probabilistic analysis is shown in Table 4-12.

MS UPPER	P90	P50	P10	Mean	Distrib.	MS LOWER	P90	P50	P10	Mean	Distrib.
GRV	567	891	1587	1049	Beta	GRV	31	37	43	37	Beta
N/G	0.06	0.13	0.20	0.13	Normal	N/G	0.20	0.35	0.50	0.35	Normal
Porosity	0.20	0.25	0.30	0.25	Normal	Porosity	0.15	0.185	0.22	0.185	Normal
Sw	0.35	0.45	0.55	0.45	Normal	Sw	0.41	0.51	0.61	0.51	Normal
Eg	145	154	163	154	Normal	Eg	145	155	165	155	Normal
MB UPPER	**P90**	**P50**	**P10**	**Mean**	**Distrib.**	**MB LOWER**	**P90**	**P50**	**P10**	**Mean**	**Distrib.**
GRV	980	1634	1999	1511	Beta	GRV	498	878	1124	821	Beta
N/G	0.20	0.27	0.34	0.27	Normal	N/G	0.35	0.49	0.63	0.49	Normal
Porosity	0.16	0.23	0.30	0.23	Normal	Porosity	0.18	0.21	0.24	0.21	Normal
Sw	0.30	0.39	0.48	0.39	Normal	Sw	0.28	0.37	0.46	0.37	Normal
Eg	162	171	180	171	Normal	Eg	160	170	180	170	Normal

Table 4 12: Input Parameters and Distributions

It is apparent that the principal uncertainties relate to the distribution of reservoir quality sands (GRV and N/G).

The GIIP estimates, derived from this probabilistic analysis, are shown for the formations and the total of all of the formations in Table 4 13. The summed totals were derived by statistical consolidation within the REPTM software program. A partial dependency (50%) was applied to the GRV values during the consolidation process, as the areal limits of the sand bodies are largely defined by seismic attributes and hence based on the same assumptions.

Mnazi Bay & Msimbati Gas Initially In Place				
Field	P90	P50	P10	Mean
	Bscf	Bscf	Bscf	Bscf
MS Upper	35	90	187	103
MS Lower	3.2	6.1	10	6.4
MB Upper	170	325	544	343
MB Lower	162	304	491	317
Total *	502	754	1069	773
* Totals determined probabilistically and do not sum arithmetically except at the mean values				

Table 4 13: Mnazi Bay GIIP Volumes (Bscf)

During 2019 the field operator, Maurel et Prom, refined its IPM model to achieve a history match of reservoir pressures in the zones on production. RPS utilised the M&P IPM model to further fine tune the history match on the Mnazi Bay Upper "F" sand. The final history matched IPM model results in GIIP distribution amongst the sands as shown in the P50 column of the table below. In this model, RPS has utilized the history matched MBAL volumes for the MS Upper and MS Lower sands, the MB Upper G and F sands, and the MB Lower C, D, E and E' sands. For the MB Upper I and H sands, where there is scant production testing to date for material balance analysis, RPS has retained the volumetric based GIIP values. For the P90 and P10 cases RPS has used the P90/P50 and P10/P50 ratios for each sand grouping from the probabilistic volumetric analysis and applied those ratios to the P50 sand volumes of the MBAL matched P50 model. The resulting GIIP volumes utilized in the IPM model are summarized in the table below:

		Gas Initially in Place (Bscf)											
		P90 GIIP (Bscf)				P50 GIIP (Bscf)				P10 GIIP (Bscf)			
Unit	Sand	West	Central	East	Total	West	Central	East	Total	West	Central	East	Total
MS Upper	K2	35			42	69			83	120			144
	K1	7				14				24			
MS Lower	K0	5			5	7			7	10			10
MB Upper	I	16	14		215	23	20		315	32	28		440
	H	20	0			29	0			40	0		
	G	20	22			30	32			42	45		
	F		123				181				253		
MB Lower	E'												
	D-E	124	104		228	178	150		328	240	202		442
	C												
MB Upper and Lower Total		180	263			260	383			354	527		
		All Units Total			489	All Units Total			733	All Units Total			1,036

4.5.4 Material Balance

Material balance plots (P/Z vs. Gp) for the producing sands have been updated with new static pressure data acquired in 2019 for each of the reservoirs. These material balance plots give an indication of the GIIP in the connected sands contributing to flow at the production wells, and generally corroborate the GIIP estimates from the IPM model material balance and the volumetric analyses.

For the Lower Mnazi Bay (C, D, and E) sands, pressure build up measurements were obtained in MB-1 and MB-4 during 2019, adding to the database from previous years. Overall, the analysis remains unchanged, and confirms that MB-1 production is steady and does not indicate excessive depletion. Shown below are the data plotted on a coarse scale and a finer scale.

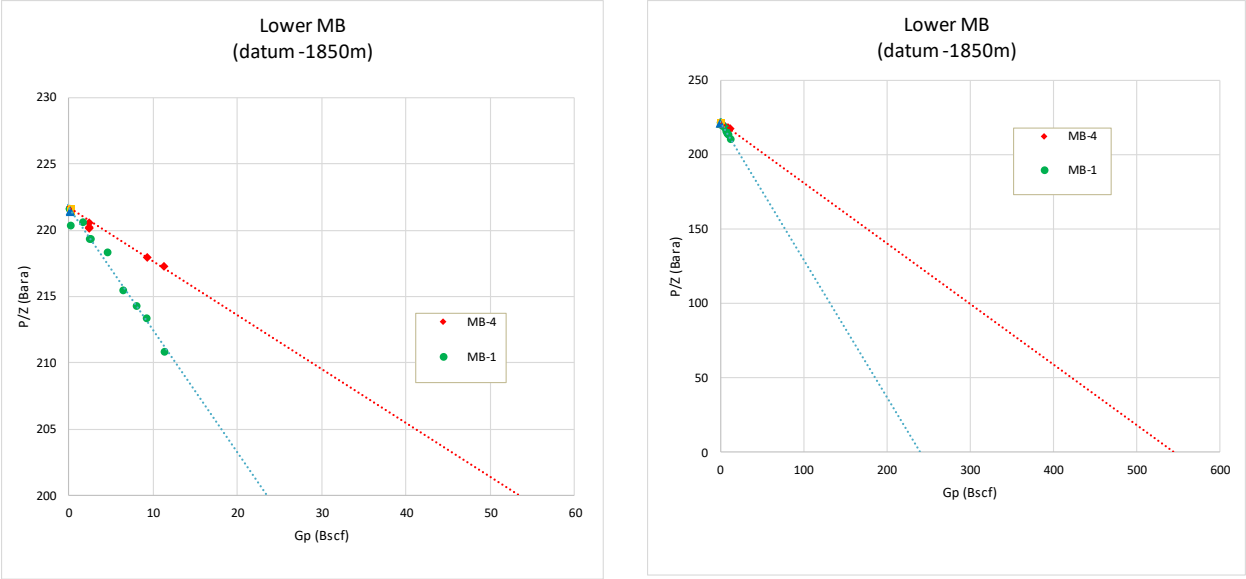


Figure 4 27: Lower Mnazi Bay (D,E Sands) Material Balance (p/Z vs. Gp)

The above P/Z vs. Gp estimate remains uncertain given the relatively limited offtake and the potential inaccuracy of extrapolating pressures from surface. Nevertheless, a GIIP value of approximately 350 Bcf for the Lower Mnazi Bay is indicated, which is bracketed by the 2P (328 Bcf) and 3P (442 Bcf) estimates derived by the history matched MBAL models.

For the Upper Mnazi Bay F and G sands, the additional 2019 static pressure data also allows a better understanding of the pressure depletion . The material balance plot, assuming all wells communicate, is shown in Figure 4 28. The in-place volume is indicated to be between approximately 190 and 240 Bscf.

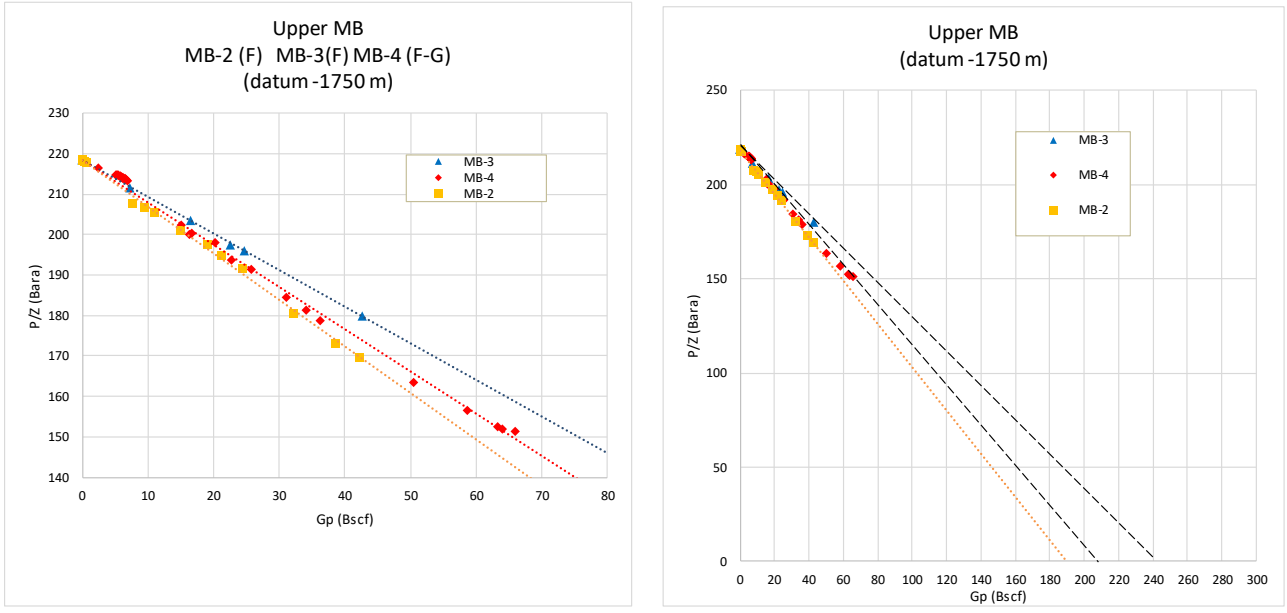


Figure 4 28: Upper Mnazi Bay Sands Material Balance (P/Z vs. Gp)

For the Msimbati reservoir, currently only being produced from MS-1X, the material balance analysis is on trend with the evaluation of last year, and indicates a GIIP value of about 73 Bscf, as shown in the material balance plots below shown in Figure 4 29.

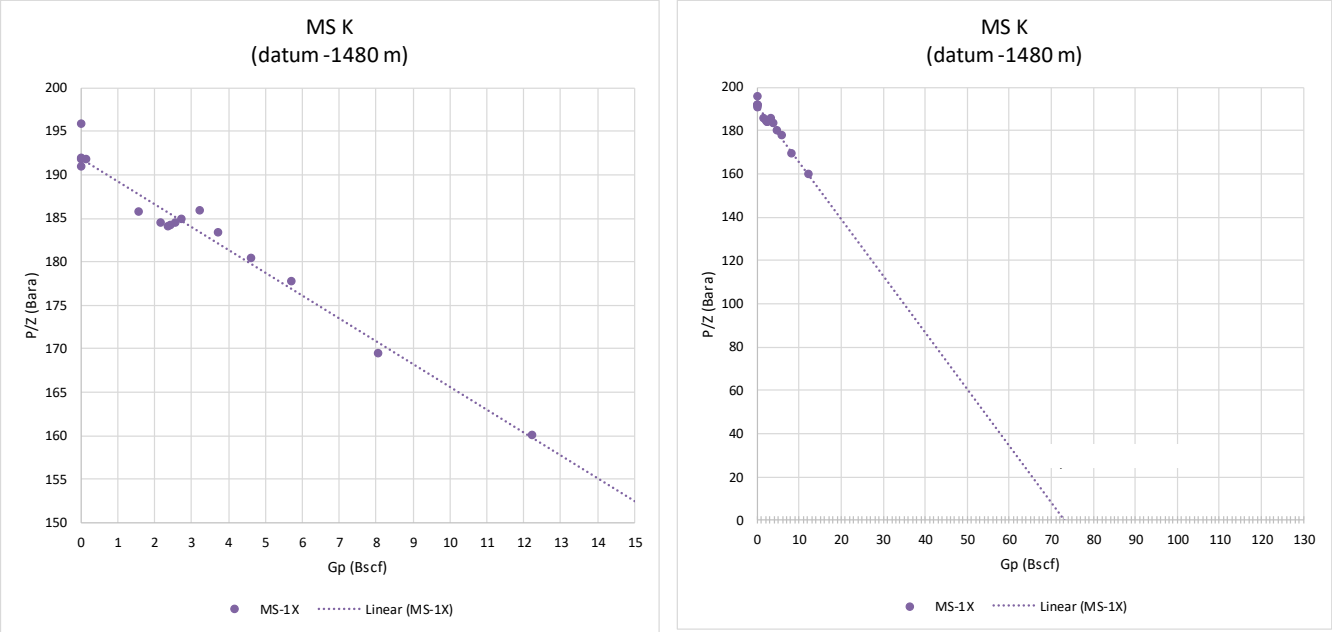


Figure 4 29: Msimbati Sands Material Balance (P/Z vs. Gp)

4.5.5 Technically Recoverable Volumes

The volume of raw gas ultimately recoverable (Estimated Ultimate Recovery, or "EUR") is a function of both technical factors governing gas deliverability from the gas reservoir sands and economic factors governing the commerciality of potential gas recovery schemes. This section describes the methodology to determine the technical recovery factors for the reservoirs. Note that these volumes are higher than reserves volumes, as when economic limits and surface shrinkage (residue to raw ratio) are later applied, the volumes are reduced from the technical recoverable volumes presented here.

The ultimate technical gas recovery for the Mnazi Bay Field has been estimated using material balance calculation of reservoir pressure depletion, based on Petroleum Experts (PETEX) MBAL™ reservoir models and PROSPER™ well models linked together with a GAP™ surface facilities networking model and using system constraints provided by Maurel et Prom. Forecasts were generated using the range of in-place volumes derived in Section 4.5.3.

The resulting estimated ultimate recovery, as predicted by the IPM models forecasting to January 1, 2054, are summarized by sands in the following table.

		EUR to 2054-01-01														
		P90 EUR (Bscf)			Total	RF (%)	P50 EUR (Bscf)			Total	RF (%)	P10 EUR (Bscf)			Total	RF (%)
Unit	Sand	West	Central	East			West	Central	East			West	Central	East		
MS Upper	K2	31			35	84%	60			70	84%	98			119	82%
	K1	4					10					21				
MS Lower	K0	4			4	88%	6			6	85%	8			8	86%
MB Upper	I	0	25		182	85%	5	24		241	77%	-5	55		368	84%
	H	17	0				4	0				31	0			
	G	17	19				26	39				35	65			
	F		105					143					186			
MB Lower	E'															
	D-E	54	139		193	85%	74	203		278	85%	102	247		349	79%
	C															
MB Upper and Lower Total		87	288				109	409				164	554			
		All Units Total			414	85%	All Units Total			595	81%	All Units Total			845	82%

4.5.6 Production Forecasting

The field production system includes:

- Five production wells (MB-1, -2, -3, -4 and MS-1X)
- Infield pipelines and pigging equipment, with manifolding
- Separation facilities at Mnazi Bay to allow export
  - from MB-1 via pipeline, after separation and dehydration, to the Mtwara power generation facility (to the northwest), and
  - from the remaining wells via a 16” pipeline to a TPDC-operated central processing facility (“CPF”) constructed at Madimba (“NNGIDP”) to the southwest, including pig-launching facilities and metering.
- Individual well monitoring (pressure/flowrate and well testing) equipment
- Liquid/Gas separation
- Tie-in of MB-1 for gas delivery to Madimba

The facilities allow separate treatment of gas exported to Mtwara and to Madimba. From Madimba, the gas is exported to Dar Es Salaam via 36” pipeline. The future gas production constraint schedule, as supplied by M&P is shown in Figure 4 30. The gas sales agreement allows for production rates ranging from 80 to 130 MMscf/d. RPS has assumed the continuing application of these constraints in forecast scenarios and has characterised the plateau rates as 1P (82.5 MMscf/d), 2P (92.5 MMscf/d) and 3P (130 MMscf/d). Compression is planned, in the best estimate case, to start up mid 2024.

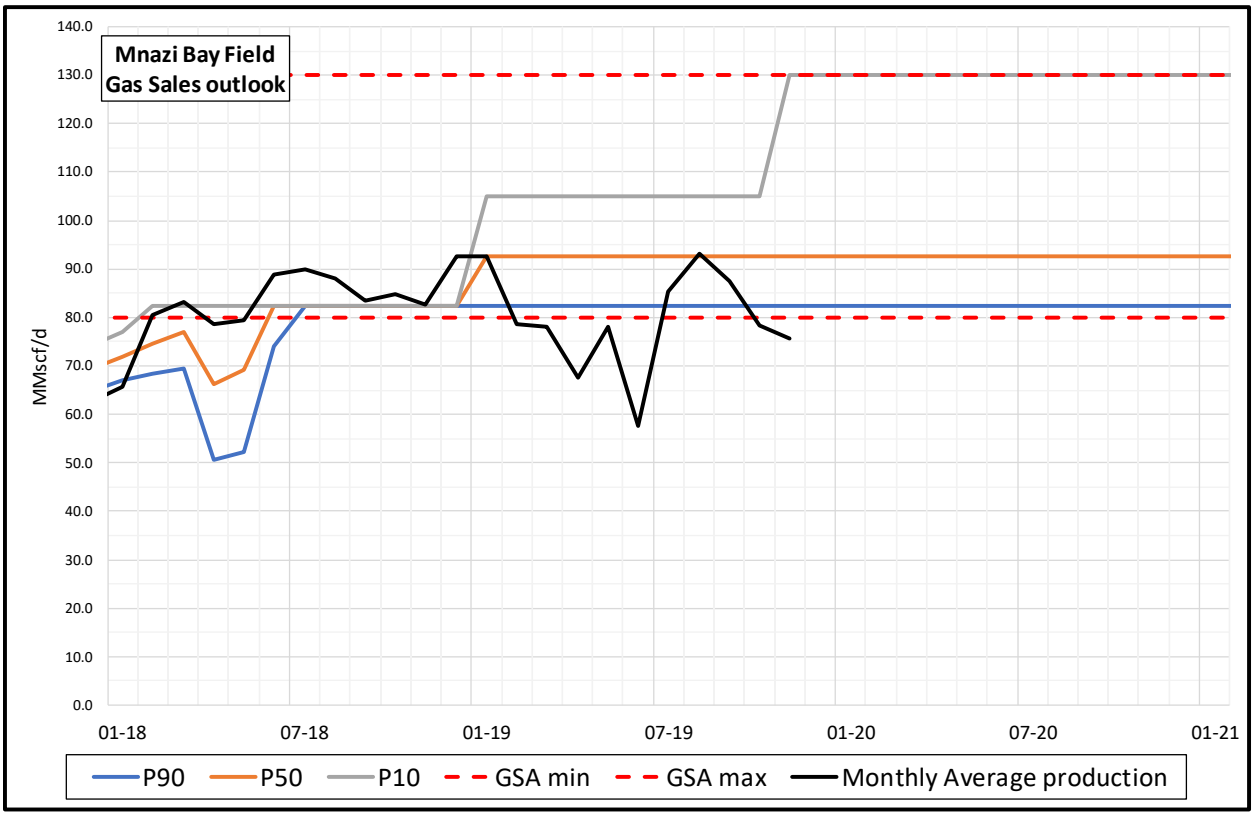


Figure 4 30: Mnazi Bay Field Gas Sales Outlook

Dependent on reservoir performance, additional potential projects in the area may be implemented and supplied by the Mnazi Bay gas, such as the petrochemical facility identified in Figure 4 31.

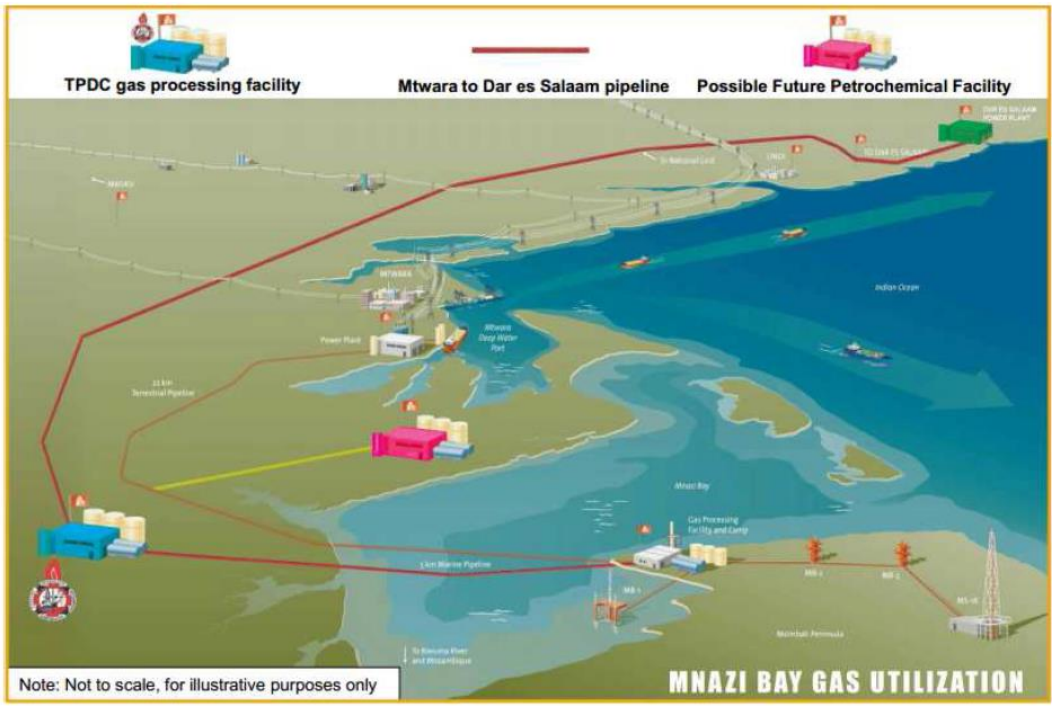


Figure 4 31: Mnazi Bay Gas Export Schematic

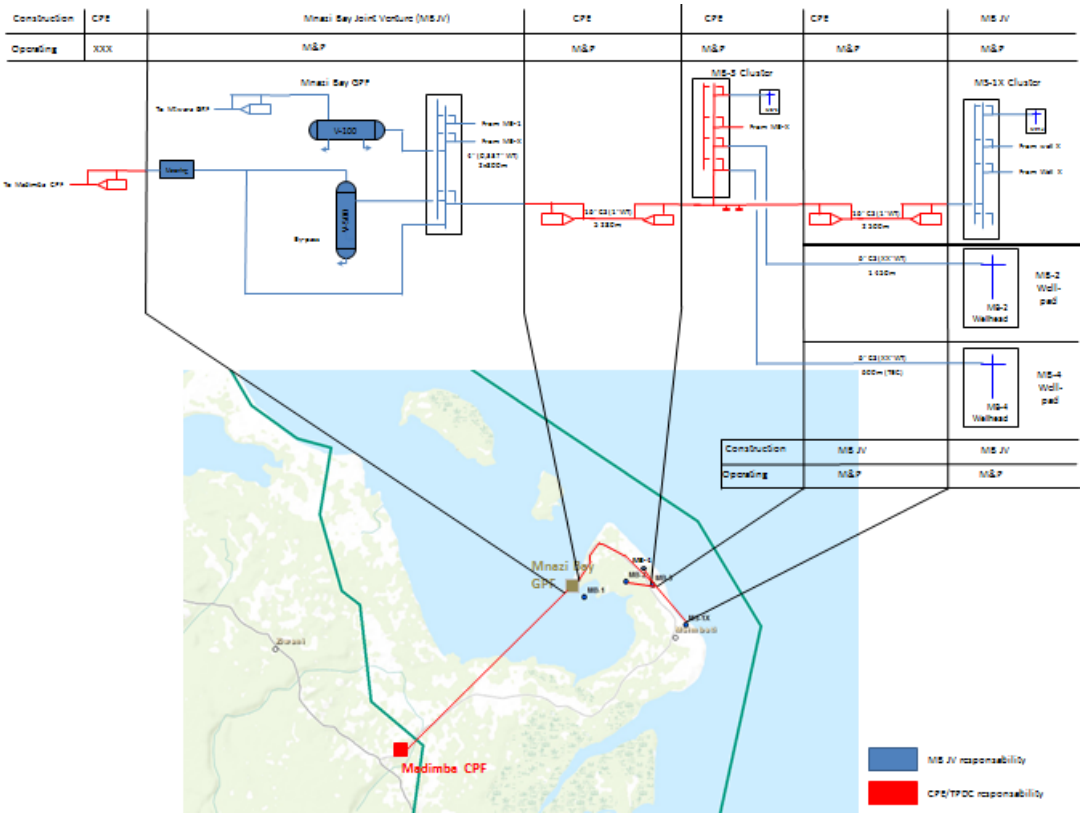


Figure 4 32: Mnazi Bay Process Schematic including export to Madimba

The inlet pressure to the CPF at Madimba is approximately 84 barg (1,218 psig). For forecasting, RPS has assumed that the delivery pressure at the Mnazi Bay facilities will be 85 barg (1,233 psig). Following compression, RPS assumes that the pressure through the facilities will be dropped to 30 barg (435 psig).

GAP™ models provided by M&P were reviewed, adjusted, and tuned to the most recent production data sets, then used to simulate production for deterministic PDP, PD, 1P, 2P and 3P cases, based on the combination material balance and volumetric based GIIP ranges as mentioned in section 4.5.3. An example of the GAP™ model set-up is shown in Figure 4 33.

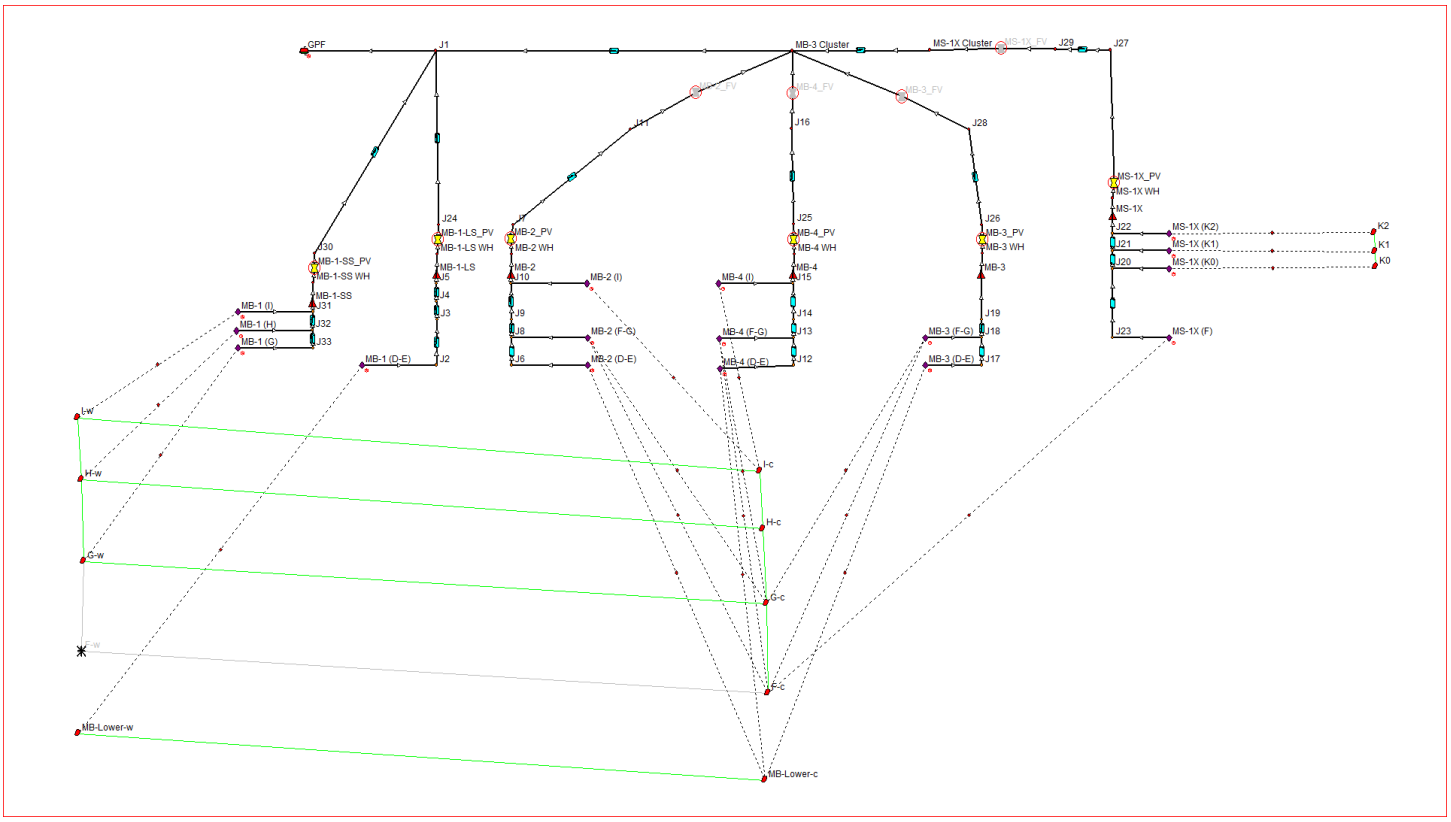


Figure 4 33: Mnazi Bay GAP model example (with 5 wells)

MBAL™ tank models were provided by M&P for each of the different reservoir zones as indicated in Figure 4 33 and Figure 4 34 rather than for each reservoir (i.e. MB Upper and Lower and MS Upper and Lower). This approach was taken as a result of the well deliverability having been calibrated on a zonal level from the DST, EWT and production data. As discussed in Section 4.5.3 and 4.5.4, in the 2019 model, RPS has tuned and utilized the history matched MBAL™ volumes for the MS Upper and MS Lower sands, the MB Upper G and F sands, and the MB Lower C, D, E and E' sands. For the MB Upper I and H sands, where there is insufficient production to date to provide meaningful material balance analysis, therefore RPS has retained the volumetric based GIIP values.

Geologically, the zones represent stacked, non-correlatable, interconnecting channels. This is supported by the Lower Mnazi Bay (D-E) material balance performance and, with some pressure-baffling observed, the Upper Mnazi Bay MB-4 pressures (which were depleted by MB-1 production). Therefore, transmissibility connections were introduced, across the different areas of the reservoirs and vertically between different zones in each reservoir.

For the 2016, 2017, and 2018 year-end evaluations, the models assumed connectivity within each of the reservoirs, implemented by including transmissibility factors both areally and vertically between the different layers. This year, in the 2019 model, the transmissibility factors have been adjusted to align with performance of the redefined material balance based tank models, provided by M&P, which have been tuned by history-matching using additional pressure data acquired in 2019. A simpler approach to the tank models has been adopted for 2019, limiting transmissibility connections to only between two tanks, not multiple tanks as in previous years. This approach has been adopted due to the increased pressure and production information acquired and the ability to calculate an improved history match in the material balance based tank model showing the limited impact of including extra transmissibility connections.

This calibration results in the following transmissibility values used between the tanks within each reservoir.

Transmissibility (rd/d/psi)	Proved (PDP,1P)	Probable (2P)	Possible(3P)
K0 - K1	0	0	0
K1 - K2	0.1	0.1	0.1
MB-Lower-w - MB-Lower-c	1.51	1.1	0.43
F-w - F-c	0	0	0
G-w - G-c	0	0	0
H-w - H-c	1	1	1
I-w - I-c	1	1	1
F-c - G-c	0	150	150

Allocation of production by well and zones, for each of the reserve cases is shown for all reserve cases in Figure 4 34 below and specifically for the Proved Reserves cases in Figure 4 35 below:

Development Plans Breakdown								
			West	Central				East
Case	Layer		MB-1	MB-2	MB-3	MB-4	MB-5	MSX-1
PDP	MS Upper	K3						
		K2						
		K1						
	MS Lower	K0						
	MB UPPER	I						
		H						
		G						
		F						
	MB LOWER	D-E						
		C						
PD	MS Upper	K3						
		K2						
		K1						
	MS Lower	K0						
	MB UPPER	I						
		H						
		G						
		F						
	MB LOWER	D-E						
		C						
1P	MS Upper	K3						
		K2						
		K1						
	MS Lower	K0						
	MB UPPER	I						
		H						
		G						
		F						
	MB LOWER	D-E						
		C						
2P	MS Upper	K3						
		K2						
		K1						
	MS Lower	K0						
	MB UPPER	I						
		H						
		G						
		F						
	MB LOWER	D-E						
		C						
3P	MS Upper	K3						
		K2						
		K1						
	MS Lower	K0						
	MB UPPER	I						
		H						
		G						
		F						
	MB LOWER	D-E						
		C						

Figure 4 34: Development Plan Zonal Modelling Schematic for Reserves Cases

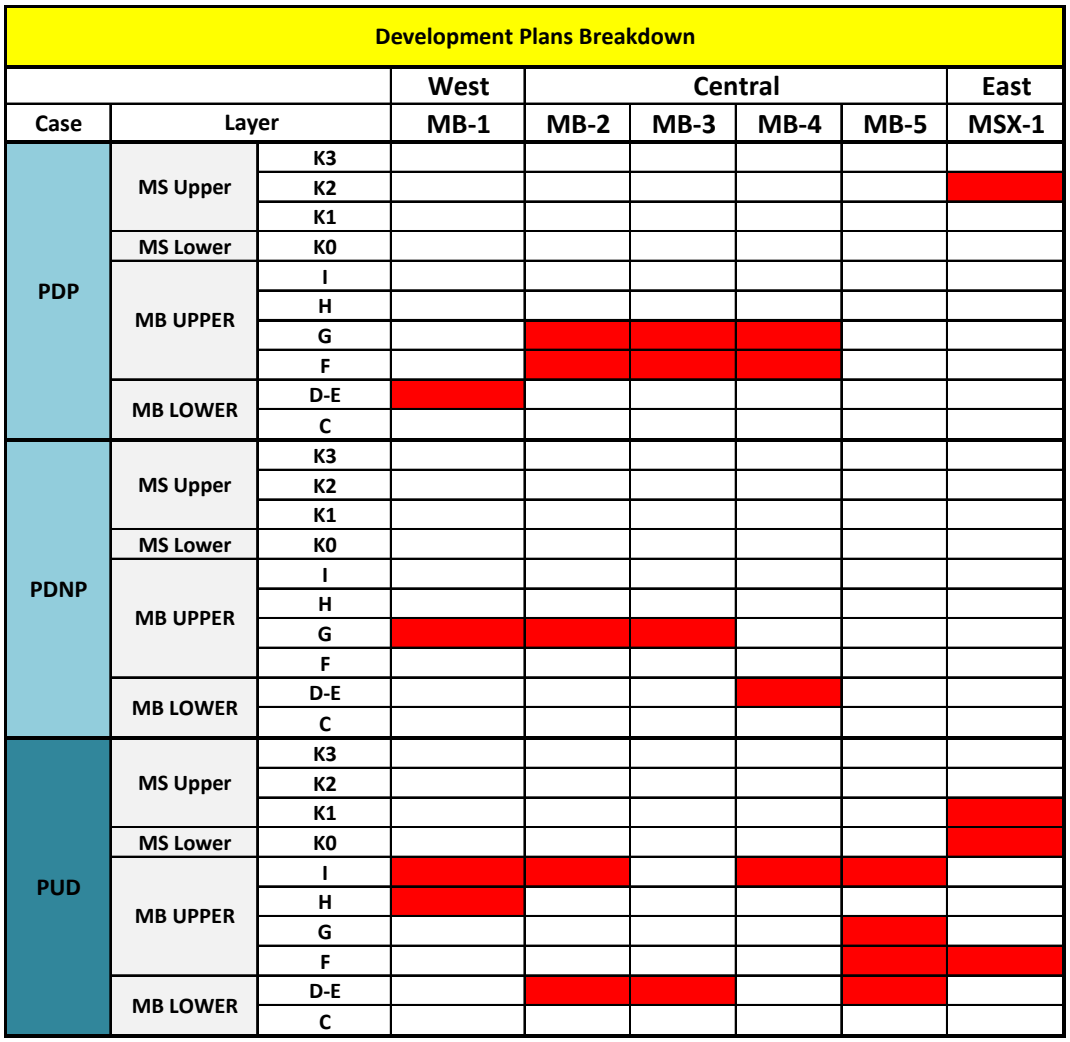


Figure 4 35: Development Plan Zonal Modelling Schematic for Reserves Cases

From a well-access perspective, the PDP case assumes access only to intervals currently or recently producing. This does not include those intervals connected through the completions which require access by slickline operation of sliding-sleeve side doors or removal of wireline plugs, which are now categorised as PDNP (Proved Developed Non-Producing. The other (undeveloped) cases assume workovers and additional perforations (with associated Capex) for zones that have been shown to be gas-bearing and productive.

Well deliverability was based on well test data where available (most zones in the existing wells). For the new intervals (new wells), reservoir properties were based on averages of existing wells.

Tubing lift was included in the models using PROSPER™ and the Petroleum Experts 3 correlation.

Production rates in 2019 showed a modest decrease in the average daily rate (~71 MMscf/d in 2019 compared to ~83MMscf/d in 2018) with daily rates ranging from approximately 33 to 96 MMscf/d, with a maximum weekly nomination of 93 MMscf/d.

The production forecasts were constrained by the gas sales outlook provided by M&P shown previously in Figure 4 30. The 1P case is capped at 82.5 MMscf/d starting 2020-01-01, the 2P case at 92.5 MMscf/d, and the 3P at 130 MMscf/d. Workovers, perforations, and new wells were then scheduled to maintain a

production plateau as long as possible, with planned compression starting when required to maintain production in each case. The resulting production rate and cumulative production profiles are shown in the following two figures:

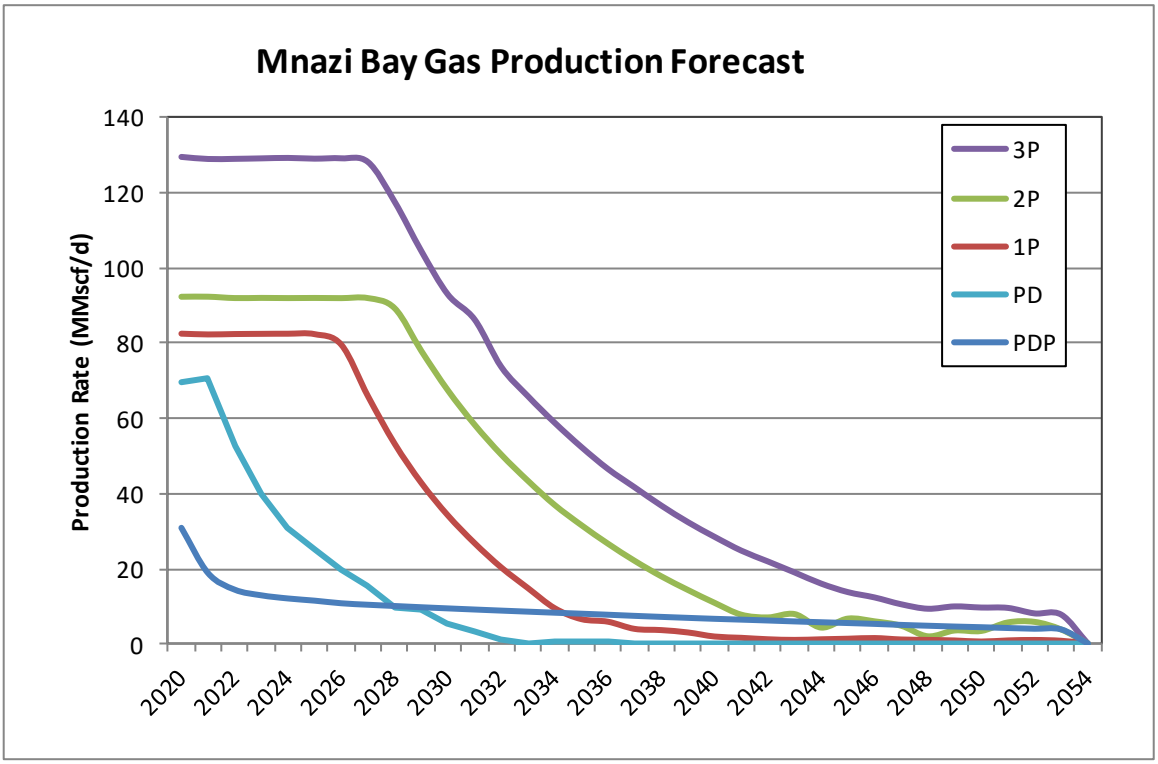


Figure 4 36: Mnazi Bay Field Gas Production Forecast

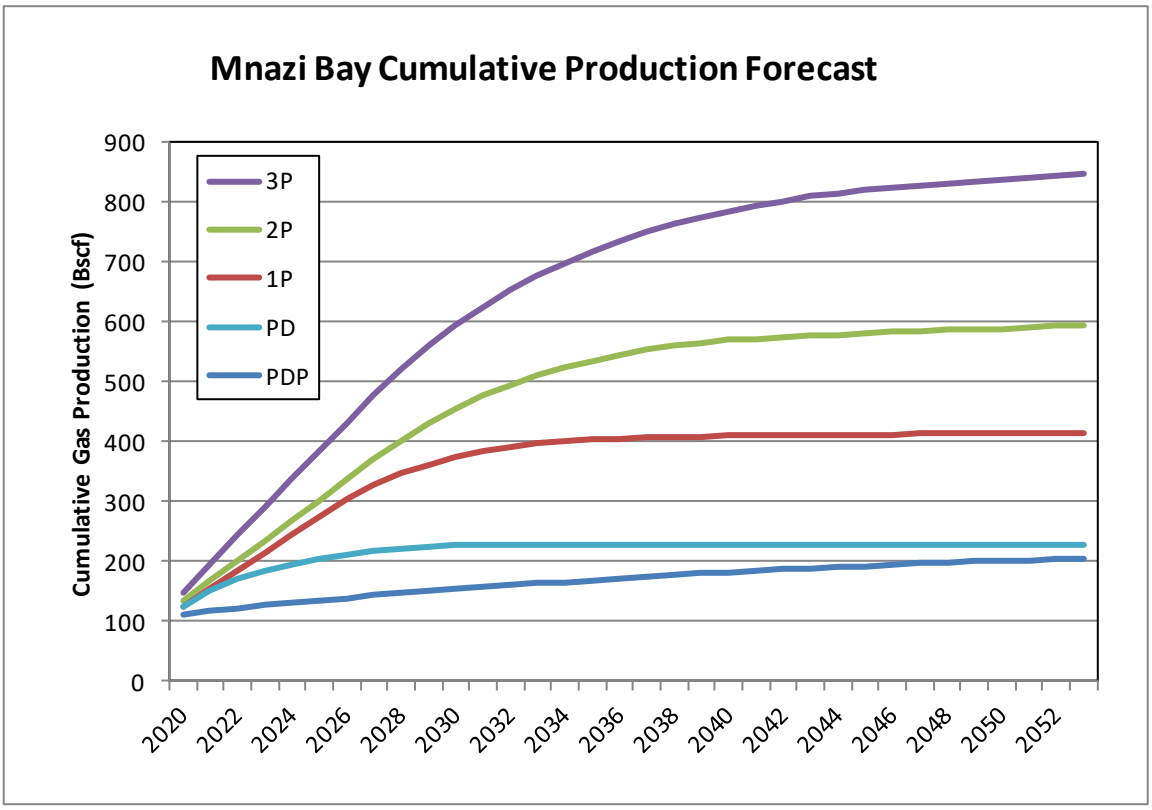


Figure 4 37: Mnazi Bay Field Cumulative Gas Production Forecast

The above forecasts yield the following technical recoveries and recovery factors.

Case	GIIP (Bscf)	EUR (Bscf)	Rec. Factor (%)
PDP	489	205.6	42%
PD	489	229.2	47%
1P	489	414.9	85%
2P	733	594.7	81%
3P	1036	848.8	82%

Table 4 15: Technical EUR and Recovery Factor Summary

5 ECONOMICS AND RESERVES

An economic evaluation has been carried out based on the forecast volumes in Section 4 and their associated development plans, with the objective of determining the net-entitlement, reserves and NPV for each working interest owner company. The 2004 PSA, and the 2014 Gas Sales Agreement were used to provide the fiscal constraints to the evaluation. The economic spreadsheet model used for the December 31, 2019 reserves evaluation was updated as required for the current evaluation.

From the output of the model, the net cash flow was used to derive NPV values at various discount rates for the different reserves categories. Working interest entitlement reserves were calculated based on SPE reserve definitions and guidance as follows:

- Gross Reserves were calculated as the product of total sales production volumes and the company working interest.
- Net Reserves were calculated as the product of the field gross sales volumes and the ratio of the company's summation of net Cost and Profit Petroleum revenue to the field total gross sales revenue.

The following table shows the Technical and economic volumes/reserves for the total field.

Summary of Technical Gas Reserves - Total Field Sales Gas

	Estimated[1] Ultimate Technical Recovery	Cumulative Production (2019-12-31) [3]	Remaining[1] Technical Recovery	Remaining[2] Economic Recovery
	(Bscf)	(Bscf)	(Bscf)	(Bscf)
Oil Reserves (Total field)				
Proved Developed Producing (PDP)	**205.6**	**100.4**	**105.2**	**57.9**
Proved Developed Non Producing (PDNP)	25.0	0.0	25.0	69.9
Proved Undeveloped (PUD)	187.9	0.0	187.9	160.6
Total Proved	**418.4**	**100.4**	**318.0**	**288.3**
Probable Additional (PROB)	172.6	0.0	172.6	180.6
Total Proved + Probable (P+PROB)	**591.1**	**100.4**	**490.7**	**468.9**
Possible (POSS)	251.2	0.0	251.2	256.8
Total Proved + Probable + Possible (P+PROB+POSS)	**842.2**	**100.4**	**741.8**	**725.7**

1. Assuming shrinkage of 1% when compression installed
2. Economic recovery based on economic limit. Economic limit for proved cases is the earlier of calculated economic limit or the license expiry in 2031. For 2P and 3P , it is based on the calculated economic limit
3. Estimated end-year cumulative production based on extrapolation of historical data to mid of November 2019

Table 5 1: Total field technical and economic recoveries

5.1 PSA and Development Licence

The Development Licence, issued in October 2006, provides the right for the concession holders to develop the Mnazi Bay Field according to the 2004 PSA and within the same exploration licence boundary. The PSA stipulates the sharing of the gross revenue from petroleum sales amongst the Company (M&P and Wentworth), TPDC (as participating partner) and the Government of Tanzania ("GOT") based on calculation of Cost and Profit Petroleum.

The term of the development licence is 25 years (to 2031); however, there are provisions to extend the licence beyond this time and it is likely that this will be enacted. PD and 1P category reserves forecasts extend to 2033 and 2035 respectively, just beyond the licence expiry date, however these additional years have not been included in the economic and reserves calculation for these Proved reserves cases. For the 2P and 3P reserve cases, the production to economic limit beyond the current licence expiry date has been included in reserves.

Royalty is payable at 12.5% of the gross revenue; however, the liability is discharged through TPDC's share of Profit Petroleum and so does not affect the Company's net entitlement.

The maximum allowance for Cost Petroleum amounts to 60% of the gross production revenue and the entitlement is the lesser of this maximum allowance and the total contract expenses in any given year. This includes operating expenses ("opex"), exploration capital and development capital ("capex") and includes head office and local office G&A. Unrecovered costs are accumulated and carried forward to the following year. At year end 2015 there remains a large pool of unrecovered costs, including previous exploration costs, to be recovered through Cost Petroleum. The cost oil is apportioned according to the historical amount owed to each individual company or else by working interest.

The balance of the petroleum produced in a year is shared between the parties as Profit Petroleum. For liquid hydrocarbons (crude oil), the share is TPDC 70% and the Company 30%. For gas production, the share is calculated on a sliding scale, dependent on the total production.

Increments of Daily Natural Gas Production (MMscf/d)	TPDC Share	Company Share
0-2.5	50% less Adjustment Factor	50% plus Adjustment Factor
2.5-5.0	60% less Adjustment Factor	40% plus Adjustment Factor
5.0-10.0	65% less Adjustment Factor	35% plus Adjustment Factor
Above 10.0	70% less Adjustment Factor	30% plus Adjustment Factor

The "Adjustment Factor" is an amount of Profit Petroleum, the value of which is equal to the amount necessary to fully pay and discharge all liability of the Company for Tanzanian taxes. The Company assigns to the Government an amount of its share of Profit Petroleum equal to the Adjustment Factor as security to the Government for the payment of the Company's liability for Tanzanian taxes.

Hence, the net tax effect from an NPV perspective on the Company is zero and the tax is effectively paid from the TPDC share of Profit Petroleum. From a reserves perspective, however, since the income tax is paid as a share of Profit Petroleum, the Adjustment Factor is included as net reserves entitlement.

5.2 Company Ownership and Working Interest

Both Maurel et Prom and Wentworth Resources hold their respective interests through a combination of Tanzanian legal entities and Cyprus Mnazi Bay Limited (in their respective shares).

TPDC owns a 20% interest in the development licence but does not participate in exploration.

The interests are shown in the tables below:

Maurel et Prom	Wentworth Resources Limited		TPDC
48.06%	31.94%		20%
M&P Exploration and Production Tanzania Ltd	Cyprus Mnazi Bay Limited		Wentworth Gas Limited
38.22%	9.84%	6.54%	25.4%
Mnazi Bay Development License			

Table 5 2: Mnazi Bay Development Licence - Company Interests

Maurel et Prom	Wentworth Resources Limited	
60.075%	39.925%	
M&P Exploration and Production Tanzania Ltd	Cyprus Mnazi Bay Limited	Wentworth Gas Limited
47.775%	12.30%	8.175%	31.75%
Mnazi Bay Exploration License		

Table 5 3: Mnazi Bay Exploration Licence Company Interests

5.3 Product Price

Two different sales prices are applicable to gas produced from Mnazi Bay. Firstly, gas is sold to TPDC via Madimba, under a September 12, 2014 gas sales agreement between TPDC and the Mnazi Bay working interest owners (also including TPDC). Secondly, the owners sell (approximately 2 MMscf/d) gas to Tanzania Electric Supply Company Limited ("TANESCO"), as fuel for the local Mtwara power facility based on the existing gas price.

The GSA for supply to power plants at Dar Es Salaam, and other end-users, via the CPF at Madimba specifies raw gas volumes to the delivery point at the downstream flange of the 16" pipeline at the Mnazi Bay Facilities.

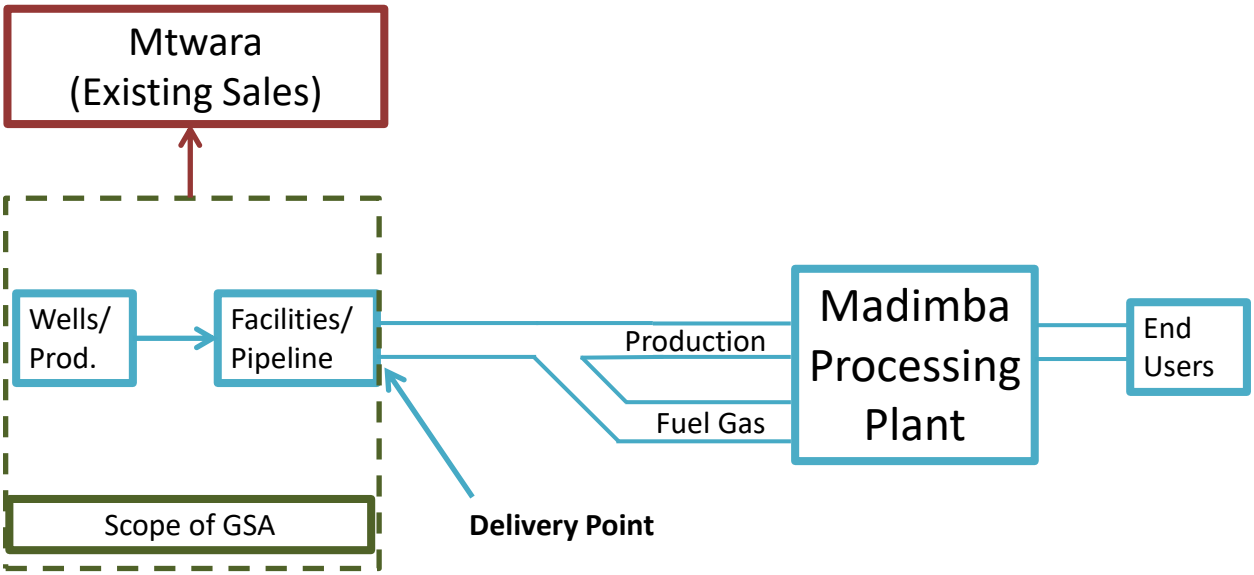


Figure 5 1: Gas Sales Agreement Delivery Point Schematic

Commercial operation of the Madimba Plant commenced in 2015 and gas is made available for nomination, with a maximum daily rate of approximately 96 MMscf/d achieved in 2019, and weekly nominations during the past year of between 40 and 92 MMscf/d. There is no fixed term for the GSA and it is linked to the expiry of the PSA (in year 2031).

Given the continuing uncertainty in volumes, and longer-term deliverability of well(s) at this early stage of the development, the contract provides for flexibility in the nominated contract quantities for delivery and outlines the procedures for the nominations. The sellers are required to make available up to 80 MMscf/d, with the potential for this to be increased to 130 MMscf/d, for the buyer to nominate. There is a take-or-pay minimum delivery based on 85% of the nominated annual contract quantity.

The total gas price is based on three elements:

A. Gas Charge

B. Regulatory Charge

C. Other Charges

Total Gas Price = A + B + C US$/MMBtu

The Gas Charge (A) was initially (January 1, 2016) set at US$3.00 / MMBtu and inflated at US CPI and indexed annually. Using this formula, the gas price for 2019 is US$3.11/ MMBtu. RPS has estimated the future US CPI escalation at 1.61% per annum based on a continuation of the historical 2019 data.

The Regulatory Charge means any tariff, duty, levy or tax charged by any regulatory authority and incurred by the sellers.

"Other Charges" means:

a) any taxes (except for the sellers' taxes) that are payable in connection with the sale and delivery of gas under the agreement, including all taxes of an excise duty nature that arise in relation to sale of the gas under the agreement; and/or

b) any new taxes, from the date of the agreement, that become due and payable or collectable by the sellers; provided always that the following shall be excluded:

   i. all royalties and licence fees arising under the PSA (which the sellers shall pay pursuant to the terms of the PSA); and

   ii. Taxes arising in respect of the sellers' income, profits and capital gains; and any local municipal levies.

The intention of the pricing structure is that the seller will be credited with the gas charge (A) though direct invoicing whereas the regulatory commitments and local taxes will be calculated and recorded on the invoices but passed downstream to TPDC or beyond to TANESCO for payment to the relevant authorities. For this reason, the second two elements in the gas price equation above are not included in the calculation of NPV and reserves entitlement.

TPDC has requested a quantity of gas specifically assigned for fuel at the Madimba GPF. RPS has assumed that this gas stream will be sold at the same price (Gas Charge, A) as all the gas exported from Mnazi Bay. For the economic evaluation it is assumed that 2 MMscf/d of the gas will be sold to TANESCO at the historical Mtwara power facility gas sales price.

Figure 5 2 shows the forecast prices for Madimba (Gas Charge) and Mtwara gas with the calculated blended price for the 2P case (varies by production forecast).

Gas has been sold to the local Mtwara power generation facility since 2007 at rates of up to 2 MMscf/d and at a price of $5.36 / MMBtu. It is expected that this will continue in parallel to the Madimba export since power generation will be required for the local population at Mtwara.

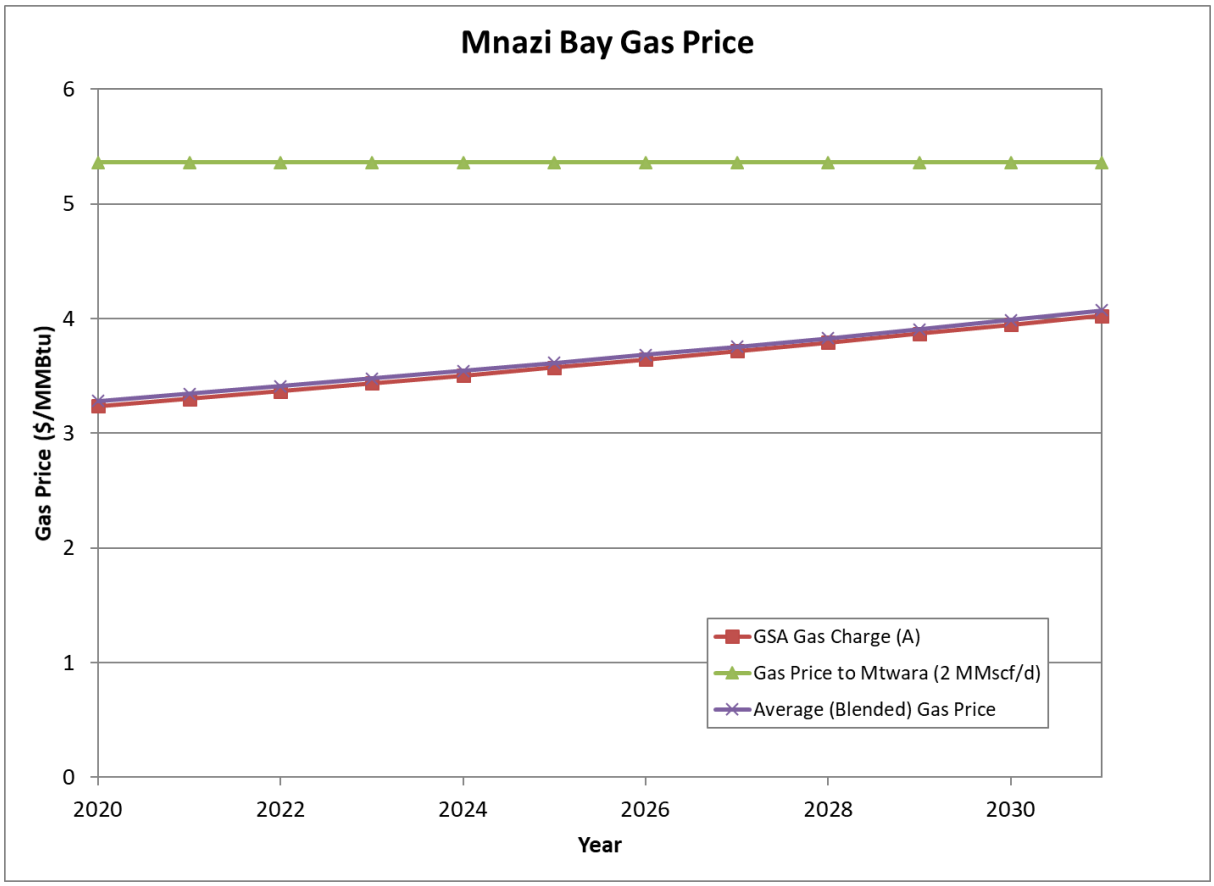


Figure 5 2: Mnazi Bay Gas Price with 2P Blended Price

The price forecast assumptions are also tabulated in Table 5-7.

5.4 Capital Costs

RPS utilized capital cost expenditure ("capex") budget numbers supplied by the Operator, including the capex phasing estimate for compression. Historical workover and perforation costs were also available in the material supplied by the Operator.

The capex estimates were reviewed and accepted as reasonable. All costs have been escalated based on US CPI values to 2019 and escalated to provide nominal values at 2% inflation thereafter.

In the 3P case, an additional production well is required to access the eastern area of the field. It is considered that this well will either have to be drilled from a MODU or drilled as a long reach, deviated well from onshore and will be more costly than the land wells (e.g. MB-4) previously costed by the operator. The offshore well cost is estimated to be US$31.8 million (2019 dollars).

The capex costs are shown in the cost summary tables for each reserves case in Tables 5.8 to 5.12.

5.5 Operating Costs

With the start up of facilities enabling gas export to Madimba and the associated higher offtake levels, valid historical data exists to enable forward prediction of operating cost expenditures ("opex") on a fixed and variable basis. The Operator`s 2019 estimated budget values are used in this analysis.

The 2016 through 2019 (extrapolated to year-end) data, and the Operator`s 2020 budget values have been used to fit a relationship between total opex and gas production rate, as shown in Figure 5 3 and Figure 5 4. Data prior to 2016 pre-date the current facilities and operating mode and are, hence, not included in this analysis.

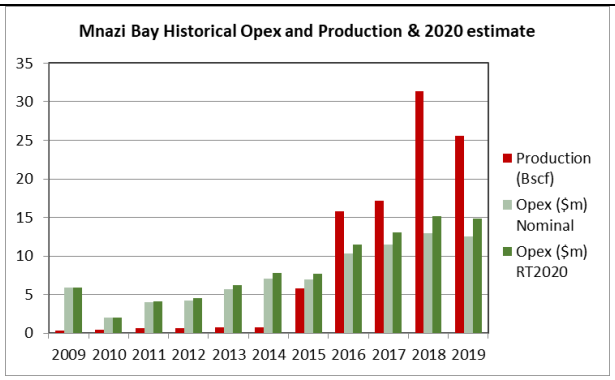


Figure 5-1: Historical and Budget 2019 Opex and Production

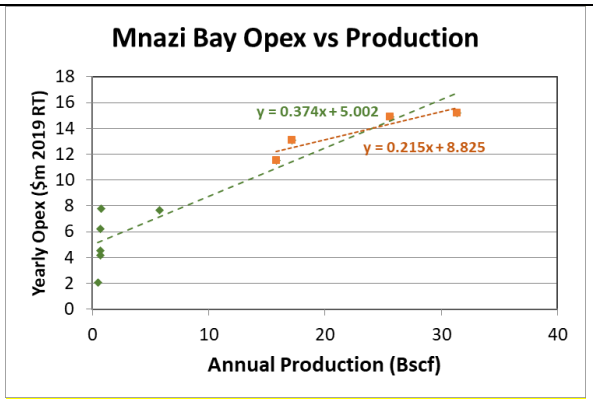


Figure 5-2: Opex vs Production

Additional opex will be incurred following the installation of compression. In previous years` evaluations, it was assumed that an additional $1.6 million per annum would be incurred, relating to the increased maintenance costs. An increment, similar in magnitude, has been included this year, but now on the basis of fixed (2% of compression capex), and variable ($/Mscf). The values for opex used in the evaluation are tabulated in Table 5 4.

	Base Operation	Compression increment
Fixed ($m RT 2020)	8.83	0.80
Variable ($m RT 2020/Mscf))	0.21	0.05

Table 5 4: Fixed and Variable Opex Values

Note that operating costs remain uncertain, pending further calibration of the expanded development. The total opex estimate is shown in Figure 5 5 and tabulated in Tables 5.8 to 5.17.

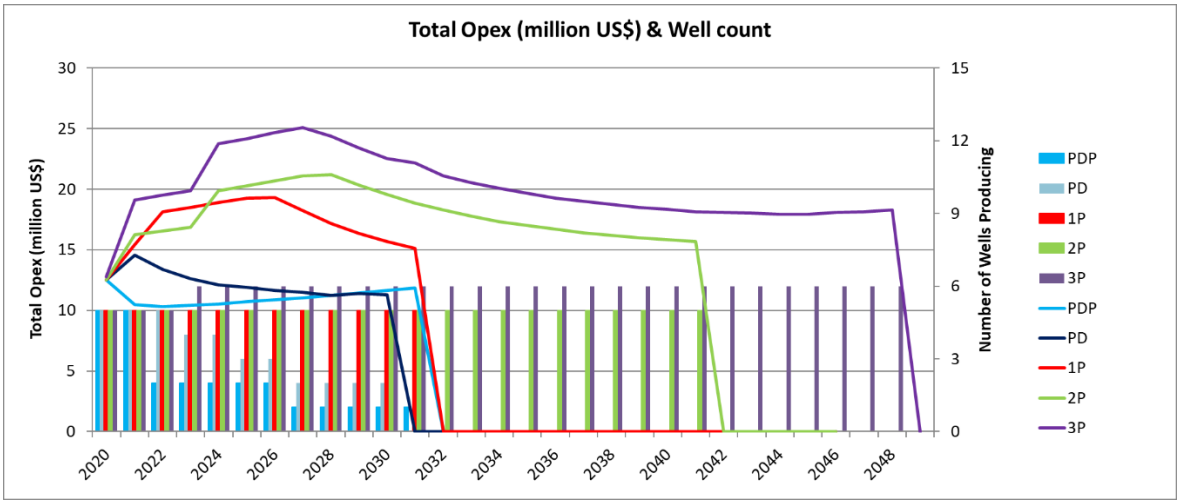


Figure 5 5: Total Opex Estimates

5.5.1 Abandonment Costs

Abandonment cost estimates have been included in the evaluation. As no estimates of abandonment costs were available from the Operator, RPS has derived estimates based on RPS experience, as for previous years' reserves estimates. The costs are shown along with the capex and opex in Tables 5.8 to 5.17.

5.6 Fuel Gas

An allowance has been made for fuel gas volumes and shrinkage at the Mnazi Bay facilities. The gas is very dry and, until compression is installed, pressure through the plant will remain above 1450 psia with negligible shrinkage. For compression, the Operator has estimated a fuel gas requirement of 1.0 MMscf/d. Since the fuel usage will be dependent on flowrate, RPS has converted this to an allowance of 1% shrinkage from raw to sales gas to include compression fuel gas.

In addition, TPDC has requested gas fuel supply for its Madimba facility. The commercial agreement for this fuel gas has yet to be finalized but the present proposal by the Operator is for this gas to be sold at the contract price and the payments made as part of the cost pool recovery. A daily maximum of 1.4 MMcf/d has been proposed. For the purpose of the economic evaluation, this gas is assumed to be sold at the contract price as part of the production stream.

5.7 Taxation

Tanzanian income tax is payable to the GOT at 30% of taxable income. Taxable income is defined as the gross revenue less allowances. The allowances include operating costs and depreciation of capital assets (property, plant & equipment, and exploration & evaluation). The capital allowances were calculated based on 5-year straight-line depreciation. A minor amount of previous expenditure is also depreciated on a declining balance basis and the residual values and rates provided by the operator were used in the evaluation for these. Accumulated tax losses are carried forward indefinitely for the calculation of tax.

Local taxes are also payable to EWURA (Energy and Water Utilities Regulatory Authority) at approximately 1% of gross revenue and through a city levy of 0.3% of gross revenue.

5.8 Existing Cost, Tax and TPDC Financing Pools

Estimates have been made by the Company, as of December 31, 2019, as to the status of the various carried-forward balances for cost oil, tax and repayments by TPDC for its carry (prior to development), as follows:

Cost Oil: Total value for the licence, remaining to be recovered from previous expenditures up to 2019-12-31 is US$180.76 million. This amount is shared between the Companies (including TPDC for development and operations but not exploration) according to historical expenditures and recoveries from the beginning of the PSA. The status at year end 2019 is; TPDC US$36.08million, Wentworth Resources (including Wentworth's portion of CMBL share), US$56.78 million and M&P (including M&P's portion of CMBL share), US$87.9 million. The total allowable cost oil repayment each year is apportioned to each company based on the outstanding totals.

Tax: Each company reports a different GOT income tax position dependent on the history of its involvement in the concession. RPS has been advised by Maurel et Prom that its tax loss carry forward amount balance is zero as at year end 2019. The M&P has also advised RPS that the tax loss carry forward balance for CMBL, in which M&P and Wentworth hold 60.075% and 39.925% interests respectively has also been reduced to zero as of year end 2019. Wentworth has advised that its total tax loss carry forward balance at year end 2019 is US$165 million.

Since tax is paid by way of the Adjustment Factor, the actual taxation has no effect on the final ("after-tax") NPV but does enter into the Net Reserves calculation.

Financing of TPDC Costs:

Previously, both Maurel et Prom and Wentworth held outstanding balances of receivables from TPDC in relation to the costs of carrying TPDC's interests in the historical development and operation expenses of the project. The carry balances were repayable by assignment of a TPDC share of revenue. RPS has been advised by both M&P and Wentworth that the TPDC carry balances owing as at December 31, 2019 have been reduced to zero.

Additional Profits Tax ("APT"):

The PSA contains provisions for payment of APT payable to the GOT on an annual basis, based on the real rate of return of the project's net cash flow as compared to an indexed rate of return based on the United States Industrial Goods Producer Price Index. RPS has been advised by the Company that the threshold rates of return which would trigger payment of the APT have not yet been achieved and are not expected to be achieved in the future, based on projections of future production rates and net cash flow. Therefore, no APT has been applied to the cash flow projections.

Forecast of Prices and Inflation

Gas Price Forecast 2020.01.01, Nominal Values

Year	Oil Benchmarks		Inflation Rate
	Madimba Gas Charge (A)	Mtwara Power Generation	
	US$/bbl	US$/bbl	%/annum
2020	3.24	5.36	2.0
2021	3.30	5.36	2.0
2022	3.37	5.36	2.0
2023	3.43	5.36	2.0
2024	3.50	5.36	2.0
2025	3.57	5.36	2.0
2026	3.64	5.36	2.0
2027	3.72	5.36	2.0
2028	3.79	5.36	2.0
2029	3.87	5.36	2.0
2030	3.94	5.36	2.0
2031	4.02	5.36	2.0
2032	4.10	5.36	2.0
2033	4.19	5.36	2.0
2034	4.27	5.36	2.0
2035	4.36	5.36	2.0
2036	4.44	5.36	2.0
2037	4.53	5.36	2.0
2038	4.62	5.36	2.0
2039	4.71	5.36	2.0
2040	4.81	5.36	2.0

Currency Abbreviations	$US : American Dollar

Table 5 7: Gas Price and Inflation forecast (2020.01.01) Nominal Values

5.9 Reserves and Economics Results

The economic model was used to generate cash flow forecasts for each of the reserve case scenarios and to determine the economically recoverable reserves for each case. Detailed cash flow output summaries are presented for the four reserve levels in Tables 5.13 to 5.17 for Maurel et Prom working interest.

The reserve volumes and NPV for Wentworth's interest in the Mnazi Bay Field are summarized in the tables below:

Wentworth Resources Working Interest Reserves for Mnazi Bay
as at December 31, 2019
RPS Forecast 2020-01-01

Reserve Category	Gross Reserves				Net Reserves			
	Oil (MMstb)	Sales Gas (Bscf)	NGL& $C5^+$ (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (Bscf)	NGL& $C5^+$ (MMbbl)	BOE (MMbbl)
PROVED								
Producing	-	*18.5*	-	*3.1*	-	*15.1*	-	*2.5*
Non Producing	-	*22.3*	-	*3.7*	-	*18.0*	-	*3.0*
Undeveloped	-	*51.3*	-	*8.5*	-	*29.8*	-	*5.0*
Total Proved	**-**	**92.1**	**-**	**15.3**	**-**	**63.0**	**-**	**10.5**
Probable	-	*57.7*	-	*9.6*	-	*32.1*	-	*5.3*
PROVED + PROBABLE	**-**	**149.8**	**-**	**25.0**	**-**	**95.1**	**-**	**15.8**
Possible	-	*82.0*	-	*13.7*	-	*43.7*	-	*7.3*
PROVED + PROBABLE + POSSIBLE	**-**	**231.8**	**-**	**38.6**	**-**	**138.7**	**-**	**23.1**

Table 5 5: Wentworth's Working Interest Reserves by Reserves Category

The Net Present Value before and after tax for Wentworth's interest in the Mnazi Bay Field, also shown in the cash flow summary tables, are shown below:

Wentworth Resources Working Interest Reserves for Mnazi Bay
as at December 31, 2019
RPS Forecast 2020-01-01

Reserve Category	NPV Before Tax Million US$					NPV After Tax Million US$				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
PROVED										
Producing	*10.1*	*10.8*	*10.8*	*10.5*	*10.1*	*8.9*	*9.8*	*10.0*	*9.7*	*9.4*
Non Producing	*61.0*	*53.7*	*47.9*	*43.2*	*39.4*	*56.0*	*49.4*	*44.1*	*39.8*	*36.3*
Undeveloped	*71.7*	*51.4*	*37.8*	*28.4*	*21.8*	*66.5*	*47.5*	*34.8*	*26.1*	*19.9*
Total Proved	**142.8**	**115.9**	**96.5**	**82.2**	**71.2**	**131.4**	**106.7**	**88.9**	**75.7**	**65.6**
Probable	*71.4*	*46.2*	*32.3*	*24.4*	*19.8*	*64.9*	*42.3*	*29.7*	*22.5*	*18.3*
PROVED + PROBABLE	**214.2**	**162.2**	**128.9**	**106.6**	**91.0**	**196.3**	**149.0**	**118.6**	**98.2**	**83.9**
Possible	*106.4*	*68.1*	*48.0*	*36.9*	*30.2*	*97.3*	*62.6*	*44.2*	*34.0*	*27.8*
PROVED + PROBABLE + POSSIBLE	**320.6**	**230.2**	**176.9**	**143.5**	**121.3**	**293.6**	**211.6**	**162.8**	**132.2**	**111.8**

Table 5 6: Wentworth's Working Interest NPV by Reserves Category

Reconciliation:

The change in reserves volumes from year end 2018 are shown in the table below:

Reserves Reconciliation Year End 2019 Wentworth Resources Ltd - 31.94% WI **Gross Reserves - Gas - Company WI**								
Tunisia	Proved Developed Producing (Bscf)	Proved Non-Developed Producing (Bscf)	Proved Undeveloped (Bscf)	**Proved (Bscf)**	Probable (Bscf)	**Proved + Probable (Bscf)**	Possible (Bscf)	**Proved + Probable + Possible (Bscf)**
Opening Balance (Dec. 31, 2018)	27.4	13.9	51.3	92.6	61.3	153.9	89.2	243.1
Extension & Improved Recovery								
Technical Revisions	**- 1.8**	**9.5**	**- 0.0**	**7.7**	**3.2**	**10.9**	**- 15.8**	**- 4.9**
Reclassifications								
Discoveries								
Acquisitions								
Dispositions								
Economic Factors	**1.0**	**- 1.0**			**- 6.8**	**- 6.8**	**8.5**	**1.7**
Production	**- 8.2**			**- 8.2**		**- 8.2**		**- 8.2**
Closing Balance (Dec. 31, 2019)	18.5	22.3	51.3	92.1	57.7	149.8	82.0	231.8

Capex Summary (Real 2020 US$)		December 31, 2019 Mnazi Bay Reserve Review - Proved Developed Producing Case																					
		Totals	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Drilling																								
Future Wells																								
MB-5		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Total	-	-	-	-	-	-	-	-	-	-	-	-	-										
Existing Wells																								
MB-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MB-2	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MB-3	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MSX-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Wells Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-										
Facilities																								
Compression		-	-	-	-	-	-	-	-	-	-	-	-	-										
Madimba Facilities Upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Facilities & Other Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-										
Studies (G&G and Eng) Total		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Total Capex (Real 2020 US$)	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Abandonment Cost (Real 2020 US$)	15.48	-	-	-	-	-	-	-	-	-	-	-	15.48										

Opex Summary (Real 2020 US)														
Field Fixed (including G&A)		109.57	12.49	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83
		-												
Field Variable														
	Well count based ($/well/year)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Prod based ($/Mscf)	-	-	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
		-												
	Total Variable Opex (Real 2020 US$)	9.79	-	1.43	1.09	0.98	0.91	0.87	0.82	0.79	0.76	0.74	0.71	0.69
		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Opex (Real 2020 US $)	119.36	12.49	10.26	9.92	9.80	9.74	9.70	9.64	9.61	9.59	9.56	9.54	9.52

Table 5 8: Total Cost Summary Proved Developed Producing

Capex Summary (Real 2020 US$)		December 31, 2019 Mnazi Bay Reserve Review - Proved Developed Producing Case																					
		Totals	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Drilling																								
Future Wells																								
MB-5		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Total	-	-	-	-	-	-	-	-	-	-	-	-	-										
Existing Wells																								
MB-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MB-2	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MB-3	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
MSX-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Wells Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-										
Facilities																								
Compression		-	-	-	-	-	-	-	-	-	-	-	-	-										
Madimba Facilities Upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Facilities & Other Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-										
Studies (G&G and Eng) Total		-	-	-	-	-	-	-	-	-	-	-	-	-										
	Total Capex (Real 2020 US$)	-	-	-	-	-	-	-	-	-	-	-	-	-										
	Abandonment Cost (Real 2020 US$)	15.48	-	-	-	-	-	-	-	-	-	-	-	15.48										

Opex Summary (Real 2020 US)														
Field Fixed (including G&A)		109.57	12.49	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83
		-												
Field Variable														
	Well count based ($/well/year)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Prod based ($/Mscf)	-	-	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
		-												
	Total Variable Opex (Real 2020 US$)	9.79	-	1.43	1.09	0.98	0.91	0.87	0.82	0.79	0.76	0.74	0.71	0.69
		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Opex (Real 2020 US $)	119.36	12.49	10.26	9.92	9.80	9.74	9.70	9.64	9.61	9.59	9.56	9.54	9.52

Table 5 9: Total Cost Summary Proved Developed

Capex Summary (Real 2020 US$)		December 31, 2019 Mnazi Bay Reserve Review - Total Proved (1P) Case												
		Totals	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Drilling														
Future Wells														
MB-5		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Wells														
MB-1	Work-overs	5.41	-	-	5.41	-	-	-	-	-	-	-	-	-
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-
MB-2	Work-overs	5.41	-	-	5.41	-	-	-	-	-	-	-	-	-
	Re-perforations	0.21	-	0.21	-	-	-	-	-	-	-	-	-	-
MB-3	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	0.21	-	0.21	-	-	-	-	-	-	-	-	-	-
MSX-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	0.64	0.21	-	0.42	-	-	-	-	-	-	-	-	-
	Wells Subtotal	11.89	0.21	0.42	11.25	-	-	-	-	-	-	-	-	-
Facilities														
Compression		47.57	9.51	23.79	14.27	-	-	-	-	-	-	-	-	-
Madimba Facilities Upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-
	Facilities & Other Subtotal	47.57	9.51	23.79	14.27	-	-	-	-	-	-	-	-	-
Studies (G&G and Eng) Total		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Capex (Real 2020 US$)	59.46	9.73	24.21	25.52	-	-	-	-	-	-	-	-	-
	Abandonment Cost (Real 2020 US$)	15.48	-	-	-	-	-	-	-	-	-	-	-	15.48

Opex Summary (Real 2020 US)														
Field Fixed (including G&A)		117.57	12.49	8.83	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63
Field Variable														
	Well count based ($/well/year)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Prod based ($/Mscf)	-	-	0.21	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
	Total Variable Opex (Real 2020 US$)	66.18	-	6.30	7.81	7.81	7.82	7.81	7.54	6.24	5.04	4.05	3.23	2.53
		-	-	-	-	-	-	-						
	Total Opex (Real 2020 US $)	183.75	12.49	15.13	17.43	17.44	17.44	17.43	17.16	15.86	14.67	13.68	12.85	12.16

Table 5 10: Total Cost Summary Total Proved (1P)

Capex Summary (Real 2020 US$)		December 31, 2019 Mnazi Bay Reserve Review - Proved + Probable (2P) Case																						
		Totals	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Drilling																								
Future Wells																								
MB-5		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Wells																								
MB-1	**Work-overs**	**5.41**	-	-	-	-	5.41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MB-2	**Work-overs**	**5.41**	-	-	-	-	5.41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	**0.21**	-	-	-	0.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MB-3	**Work-overs**	**5.41**	-	-	-	5.41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	**0.21**	-	-	0.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MSX-1	**Work-overs**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	**0.64**	-	-	0.21	0.42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wells Subtotal	**17.30**	-	-	**0.42**	**6.05**	**10.82**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Facilities																								
Compression		**47.57**	-	-	9.51	23.79	14.27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Madimba Facilities Upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Facilities & Other Subtotal	**47.57**	-	-	**9.51**	**23.79**	**14.27**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Studies (G&G and Eng) Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Capex (Real 2020 US$)	**64.87**	-	-	**9.94**	**29.84**	**25.10**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Abandonment Cost (Real 2020 US$)	**15.48**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.48

Opex Summary (Real 2020 US)																								
Field Fixed (including G&A)	**212.22**	12.49	8.83	8.83	8.83	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63
	-																							
Field Variable																								
Well count based ($/well/year)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prod based ($/Mscf)	-	-	0.21	0.21	0.21	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
	-																							
Total Variable Opex (Real 2020 US$)	**108.87**	-	7.09	7.06	7.07	8.74	8.75	8.74	8.74	8.49	7.41	6.40	5.54	4.78	4.12	3.51	3.00	2.53	2.09	1.70	1.36	1.03	0.73
	-	-	-	-	-	-	-																	
Total Opex (Real 2020 US $)	**321.09**	**12.49**	**15.92**	**15.89**	**15.89**	**18.37**	**18.37**	**18.37**	**18.37**	**18.11**	**17.03**	**16.03**	**15.16**	**14.41**	**13.74**	**13.13**	**12.62**	**12.15**	**11.72**	11.33	10.98	10.65	10.36

Table 5 11: Total Cost Summary Proved + Probable

Capex Summary (Real 2020 US$)		December 31, 2019 Mnazi Bay Reserve Review - Proved + Probable + Possible 3P Case																												
		Totals	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Drilling																															
Future Wells																															
MB-5		31.84	-	-	-	31.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	31.84	-	-	-	31.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Wells																															
MB-1	Work-overs	10.82	-	-	-	10.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MB-2	Work-overs	5.41	-	-	5.41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	0.21	-	-	0.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MB-3	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	0.21	-	0.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MSX-1	Work-overs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Re-perforations	0.64	-	0.21	0.42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wells Subtotal	49.13	-	0.42	6.05	42.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Facilities																															
Compression		47.57	-	-	9.51	23.79	14.27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Madimba Facilities Upgrade		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Facilities & Other Subtotal	47.57	-	-	9.51	23.79	14.27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Studies (G&G and Eng) Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Capex (Real 2020 US$)	96.71	-	0.42	15.56	66.45	14.27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Abandonment Cost (Real 2020 US$)	24.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.21
Opex Summary (Real 2020 US)																															
Field Fixed (including G&A)		212.50	12.78	8.83	8.83	8.83	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63	9.63
		-																													
Field Variable																															
	Well count based ($/well/year)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Prod based ($/Mscf)	-	-	0.21	0.21	0.21	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
	Total Variable Opex (Real 2020 US$)	160.80	-	9.91	9.91	9.92	12.30	12.28	12.29	12.19	11.19	9.94	8.84	8.20	7.00	6.26	5.59	4.98	4.42	3.96	3.49	3.07	2.70	2.35	2.08	1.80	1.52	1.30	1.17	0.99	0.88
		-	-	-	-	-	-	-																							
	Total Opex (Real 2020 US $)	373.30	12.78	18.74	18.74	18.75	21.92	21.90	21.91	21.82	20.81	19.56	18.46	17.83	16.63	15.89	15.22	14.60	14.05	13.58	13.12	12.70	12.33	11.98	11.70	11.42	11.14	10.93	10.79	10.62	10.51

Table 5 12: Total Cost Summary Proved + Probable + Possible

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Production Forecast:
Proved Developed Producing
RPS Forecast 2020-01-01

COMPANY: Wentworth Resources
OPERATOR: Maurel et Prom
FIELD: Mnazi Bay
COMPANY SHARE: 31.94%

Reserves Level: Proved Developed Producing
Price Forecast Case: RPS Forecast 2020-01-01
Average Annual Cost Inflation: 2.00%
Effective Date: 2019-12-31

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(BCF)	57.9	50.6	18.5	15.1
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	9.6	8.4	3.1	2.5

PRESENT VALUE - COMPANY SHARE (Million US$)

Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	71.9	56.9	46.8	39.7	34.5
Net Revenue	58.9	46.5	38.2	32.3	28.1
Operating Costs	42.5	32.1	25.2	20.5	17.1
Capital Costs	-	-	-	-	-
Cash Flow Before Tax	10.1	10.8	10.8	10.5	10.1
Cash Flow After Tax	8.9	9.8	10.0	9.7	9.4

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million US$): 6.15
Year: 2031

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+
PRODUCT PRICES (US$)																						
Field Prices																						
Crude Oil	(US$/stb)																					
Sales Gas	(US$/MMbtu)	3.37	3.52	3.65	3.74	3.81	3.89	3.97	4.04	4.11	4.18	4.25	4.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NGL	(US$/bbl)																					
Condensate	(US$/bbl)																					
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Production Wellcount (#)		5	5	2	2	2	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0		
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(BCF)	3.58	2.18	1.66	1.49	1.39	1.32	1.24	1.20	1.16	1.12	1.08	1.05	-	-	-	-	-	-	-	-	-	18.48
NGL	(MMbbl)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million US$/year)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Gross Production Revenue	12.4	7.8	6.2	5.7	5.4	5.3	5.0	4.9	4.9	4.8	4.7	4.6	-	-	-	-	-	-	-	-	-	71.87
Effective Royalty	2.6	1.3	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	-	-	-	-	-	-	-	-	-	13.01
Net Production Revenue	9.8	6.5	5.1	4.7	4.5	4.4	4.2	4.1	4.0	3.9	3.9	3.8	-	-	-	-	-	-	-	-	-	58.86
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A, Local Taxes	4.0	3.4	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.7	3.7	3.8	-	-	-	-	-	-	-	-	-	42.66
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	6.1	-	-	-	-	-	-	-	-	-	6.15
Op. Cash Inc. Before Tax	5.7	3.1	1.8	1.4	1.1	0.9	0.7	0.5	0.4	0.3	0.1	(6.1)	-	-	-	-	-	-	-	-	-	10.05
Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TPDC Past Capital Repayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Before Tax	5.7	3.1	1.8	1.4	1.1	0.9	0.7	0.5	0.4	0.3	0.1	(6.1)	-	-	-	-	-	-	-	-	-	10.05
Income Tax	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	1.15
Cash Flow After Tax	5.4	2.9	1.7	1.3	1.0	0.8	0.6	0.5	0.4	0.2	0.1	(6.1)	-	-	-	-	-	-	-	-	-	8.91

Table 5 13: Cash Flow Summary Proved Developed Producing (Wentworth)

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Production Forecast:
Proved Developed Producing and Non-Producing
RPS Forecast 2020-01-01

COMPANY: Wentworth Resources
OPERATOR: Maurel et Prom
FIELD: Mnazi Bay
COMPANY SHARE: 31.94%

Reserves Level: Proved Developed Producing and Non-Producing
Price Forecast Case: RPS Forecast 2020-01-01
Average Annual Cost Inflation: 2.00%
Effective Date: 2019-12-31

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(BCF)	127.7	111.8	40.8	33.2
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	21.3	18.6	6.8	5.5

PRESENT VALUE - COMPANY SHARE (Million US$)

Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	147.9	125.5	108.9	96.2	86.3
Net Revenue	120.2	101.8	88.1	77.7	69.6
Operating Costs	42.8	33.5	27.1	22.5	19.1
Capital Costs	-	-	-	-	-
Cash Flow Before Tax	71.1	64.5	58.8	53.8	49.5
Cash Flow After Tax	64.9	59.2	54.1	49.6	45.7

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million US$): 6.03
Year: 2030

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+
PRODUCT PRICES (US$)																						
Field Prices																						
Crude Oil	(US$/stb)																					
Sales Gas	(US$/MMbtu)	3.30	3.36	3.44	3.53	3.62	3.71	3.82	3.93	4.11	4.20	4.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NGL	(US$/bbl)																					
Condensate	(US$/bbl)																					
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Production Wellcount (#)		5	5	5	4	4	3	3	2	2	2	2	0	0	0	0	0	0	0	0	0		
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(BCF)	8.11	8.27	6.15	4.68	3.63	2.94	2.33	1.83	1.15	1.05	0.66	-	-	-	-	-	-	-	-	-	-	40.80
NGL	(MMbbl)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million US$/year)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Gross Production Revenue	27.4	28.4	21.7	16.9	13.5	11.2	9.1	7.4	4.8	4.5	3.0	-	-	-	-	-	-	-	-	-	-	147.86
Effective Royalty	5.9	5.6	4.0	3.1	2.4	1.9	1.5	1.2	0.8	0.8	0.5	-	-	-	-	-	-	-	-	-	-	27.71
Net Production Revenue	21.5	22.8	17.6	13.9	11.1	9.3	7.6	6.1	4.0	3.7	2.5	-	-	-	-	-	-	-	-	-	-	120.15
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A, Local Taxes	4.0	4.7	4.3	4.1	3.9	3.8	3.7	3.7	3.6	3.6	3.6	-	-	-	-	-	-	-	-	-	-	43.02
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	6.0	-	-	-	-	-	-	-	-	-	-	6.03
Op. Cash Inc. Before Tax	17.5	18.2	13.3	9.8	7.2	5.4	3.8	2.4	0.4	0.1	(7.2)	-	-	-	-	-	-	-	-	-	-	71.10
Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TPDC Past Capital Repayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Before Tax	17.5	18.2	13.3	9.8	7.2	5.4	3.8	2.4	0.4	0.1	(7.2)	-	-	-	-	-	-	-	-	-	-	71.10
Income Tax	1.0	1.3	1.1	0.9	0.7	0.5	0.4	0.2	0.1	0.0	-	-	-	-	-	-	-	-	-	-	-	6.20
Cash Flow After Tax	16.5	16.9	12.2	8.9	6.5	4.9	3.5	2.2	0.4	0.0	(7.2)	-	-	-	-	-	-	-	-	-	-	64.89

Table 5 14: Cash Flow Summary Proved Developed (Wentworth)

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Production Forecast:
Total Proved
RPS Forecast 2020-01-01

COMPANY: Wentworth Resources
OPERATOR: Maurel et Prom
FIELD: Mnazi Bay
COMPANY SHARE: 31.94%

Reserves Level: Total Proved
Price Forecast Case: RPS Forecast 2020-01-01
Average Annual Cost Inflation: 2.00%
Effective Date: 2019-12-31

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(BCF)	288.3	252.3	92.1	63.0
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	48.1	42.0	15.3	10.5

PRESENT VALUE - COMPANY SHARE (Million US$)

Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	339.4	266.0	215.3	179.1	152.4
Net Revenue	232.2	185.2	152.4	128.7	111.0
Operating Costs	65.3	49.3	38.6	31.2	25.9
Capital Costs	17.7	16.3	15.1	14.0	13.1
Cash Flow Before Tax	142.8	115.9	96.5	82.2	71.2
Cash Flow After Tax	131.4	106.7	88.9	75.7	65.6

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million US$): 6.15
Year: 2031

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+
PRODUCT PRICES (US$)																						
Field Prices																						
Crude Oil	(US$/stb)																					
Sales Gas	(US$/MMbtu)	3.29	3.35	3.42	3.48	3.55	3.62	3.69	3.77	3.85	3.94	4.03	4.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NGL	(US$/bbl)																					
Condensate	(US$/bbl)																					
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Production Wellcount (#)		5	5	5	5	5	5	5	5	5	5	5	5	0	0	0	0	0	0	0	0		
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(BCF)	9.63	9.58	9.50	9.50	9.53	9.49	9.17	7.59	6.15	4.93	3.93	3.08	-	-	-	-	-	-	-	-	-	92.09
NGL	(MMbbl)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million US$/year)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Gross Production Revenue	32.4	32.9	33.2	33.9	34.6	35.2	34.6	29.3	24.2	19.9	16.2	13.0	-	-	-	-	-	-	-	-	-	339.42
Effective Royalty	6.9	6.5	6.7	6.9	7.1	15.6	16.5	13.4	10.6	8.2	6.1	2.8	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	-	107.23
Net Production Revenue	25.5	26.4	26.6	27.0	27.6	19.6	18.1	15.8	13.6	11.7	10.1	10.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	232.19
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A, Local Taxes	4.0	4.9	5.8	5.9	6.0	6.2	6.2	5.8	5.5	5.2	5.0	4.8	-	-	-	-	-	-	-	-	-	65.54
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	6.1	-	-	-	-	-	-	-	-	-	6.15
Op. Cash Inc. Before Tax	21.5	21.4	20.8	21.0	21.5	13.4	12.0	10.0	8.1	6.5	5.0	(0.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	160.50
Capital	3.1	7.9	6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.68
TPDC Past Capital Repayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Before Tax	18.4	13.5	14.1	21.0	21.5	13.4	12.0	10.0	8.1	6.5	5.0	(0.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	142.82
Income Tax	1.2	1.4	1.4	1.4	1.4	1.0	0.9	0.8	0.7	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	11.44
Cash Flow After Tax	17.2	12.1	12.7	19.6	20.1	12.4	11.1	9.2	7.4	5.9	4.6	(0.8)	-	-	-	-	-	-	-	-	-	131.38

Table 5 15: Cash Flow Summary Total Proved (Wentworth)

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Production Forecast:
Total Proved + Probable
RPS Forecast 2020-01-01

COMPANY: Wentworth Resources
OPERATOR: Maurel et Prom
FIELD: Mnazi Bay
COMPANY SHARE: 31.94%

Reserves Level: Total Proved + Probable
Price Forecast Case: RPS Forecast 2020-01-01
Average Annual Cost Inflation: 2.00%
Effective Date: 2019-12-31

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(BCF)	468.9	410.3	149.8	95.1
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	78.1	68.4	25.0	15.8

PRESENT VALUE - COMPANY SHARE (Million US$)

Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	581.6	402.8	299.1	234.3	191.2
Net Revenue	369.1	260.3	197.7	158.5	132.3
Operating Costs	124.9	76.9	52.2	38.3	29.8
Capital Costs	22.1	18.4	15.5	13.2	11.3
Cash Flow Before Tax	214.2	162.2	128.9	106.6	91.0
Cash Flow After Tax	196.3	149.0	118.6	98.2	83.9

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million US$): 7.50
Year: 2041

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+
PRODUCT PRICES (US$)																						
Field Prices																						
Crude Oil	(US$/stb)																					
Sales Gas	(US$/MMbtu)	3.28	3.35	3.41	3.48	3.54	3.61	3.68	3.75	3.83	3.91	3.99	4.07	4.15	4.24	4.33	4.42	4.51	4.61	4.71	4.81	0.38
NGL	(US$/bbl)																					
Condensate	(US$/bbl)																					
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Production Wellcount (#)		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5		
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(BCF)	10.81	10.78	10.74	10.75	10.66	10.64	10.63	10.63	10.35	9.01	7.79	6.73	5.83	5.01	4.27	3.65	3.08	2.55	2.07	1.65	2.14	149.76
NGL	(MMbbl)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million US$/year)

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Gross Production Revenue	36.3	36.9	37.5	38.2	38.7	39.3	40.1	40.9	40.6	36.0	31.8	28.1	24.8	21.7	18.9	16.5	14.2	12.0	10.0	8.1	10.9	581.59
Effective Royalty	7.8	7.3	7.3	7.5	12.0	19.2	19.7	20.1	19.8	17.1	14.7	12.6	10.8	9.0	7.4	6.1	4.8	3.5	2.4	1.5	2.0	212.47
Net Production Revenue	28.6	29.6	30.2	30.8	26.7	20.1	20.4	20.8	20.8	19.0	17.1	15.5	14.0	12.7	11.5	10.4	9.4	8.5	7.6	6.6	8.9	369.11
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A, Local Taxes	4.0	5.2	5.3	5.4	6.4	6.5	6.6	6.8	6.8	6.5	6.3	6.0	5.9	5.7	5.6	5.4	5.3	5.3	5.2	5.1	10.1	125.31
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.5	7.50
Op. Cash Inc. Before Tax	24.6	24.4	24.9	25.4	20.3	13.6	13.7	14.0	14.0	12.4	10.9	9.5	8.2	7.0	5.9	5.0	4.1	3.2	2.4	1.5	(8.7)	236.31
Capital	-	-	3.3	10.1	8.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22.09
TPDC Past Capital Repayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Before Tax	24.6	24.4	21.6	15.3	11.7	13.6	13.7	14.0	14.0	12.4	10.9	9.5	8.2	7.0	5.9	5.0	4.1	3.2	2.4	1.5	(8.7)	214.21
Income Tax	1.4	1.8	1.9	1.8	1.4	0.9	0.8	0.8	0.9	1.0	0.9	0.8	0.7	0.6	0.5	0.4	0.4	0.3	0.2	0.2	0.0	17.90
Cash Flow After Tax	23.1	22.6	19.7	13.4	10.2	12.7	12.9	13.2	13.0	11.5	10.0	8.6	7.5	6.4	5.4	4.5	3.7	2.9	2.2	1.4	(8.8)	196.31

Table 5 16: Cash Flow Summary Proved + Probable (Wentworth)

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Production Forecast:
Total Proved + Probable + Possible
RPS Forecast 2020-01-01

COMPANY: Wentworth Resources
OPERATOR: Maurel et Prom
FIELD: Mnazi Bay
COMPANY SHARE: 31.94%

Reserves Level: Total Proved + Probable + Possible
Price Forecast Case: RPS Forecast 2020-01-01
Average Annual Cost Inflation: 2.00%
Effective Date: 2019-12-31

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(BCF)	725.7	635.0	231.8	138.7
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	120.9	105.8	38.6	23.1

PRESENT VALUE - COMPANY SHARE (Million US$) Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	923.9	600.5	431.5	332.5	269.2
Net Revenue	552.9	362.6	265.8	209.7	173.8
Operating Costs	185.6	101.1	64.3	45.6	34.9
Capital Costs	32.8	27.7	23.5	20.2	17.5
Cash Flow Before Tax	320.6	230.2	176.9	143.5	121.3
Cash Flow After Tax	293.6	211.6	162.8	132.2	111.8

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million US$): 13.46
Year: 2048

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+
PRODUCT PRICES (US$)																						
Field Prices																						
Crude Oil	(US$/stb)																					
Sales Gas	(US$/MMbtu)	3.27	3.33	3.40	3.46	3.53	3.60	3.67	3.74	3.82	3.90	3.98	4.05	4.14	4.22	4.31	4.39	4.48	4.57	4.66	4.75	1.81
NGL	(US$/bbl)																					
Condensate	(US$/bbl)																					
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Production Wellcount (#)		5	5	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6		
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(BCF)	15.18	15.07	15.08	15.09	15.00	14.93	14.94	14.83	13.64	12.09	10.75	9.98	8.54	7.61	6.80	6.05	5.39	4.81	4.25	3.74	18.00	231.77
NGL	(MMbbl)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million US$/year) Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040+	Total
Gross Production Revenue	50.8	51.4	52.5	53.5	54.2	55.1	56.2	56.8	53.3	48.2	43.7	41.4	36.2	32.9	30.0	27.2	24.7	22.5	20.3	18.2	94.6	923.93
Effective Royalty	10.9	10.3	18.9	12.7	24.1	28.0	28.7	29.0	26.7	23.7	21.2	19.9	16.9	15.1	13.5	11.9	10.5	9.3	8.0	6.8	24.9	371.01
Net Production Revenue	39.9	41.2	33.5	40.8	30.1	27.1	27.5	27.9	26.6	24.5	22.6	21.6	19.2	17.8	16.5	15.3	14.2	13.2	12.3	11.4	69.8	552.92
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A, Local Taxes	4.1	6.1	6.2	6.4	7.6	7.7	7.9	8.0	7.8	7.5	7.2	7.1	6.8	6.6	6.4	6.3	6.2	6.1	6.0	5.9	52.2	186.11
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.5	13.46
Op. Cash Inc. Before Tax	35.8	35.1	27.3	34.4	22.5	19.3	19.6	19.8	18.8	17.0	15.4	14.5	12.5	11.2	10.1	9.0	8.0	7.2	6.3	5.5	4.1	353.35
Capital	-	0.1	5.2	22.5	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32.77
TPDC Past Capital Repayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow Before Tax	35.8	34.9	22.1	11.9	17.6	19.3	19.6	19.8	18.8	17.0	15.4	14.5	12.5	11.2	10.1	9.0	8.0	7.2	6.3	5.5	4.1	320.59
Income Tax	2.1	2.6	2.2	2.3	1.6	1.2	1.1	1.1	1.4	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.6	0.5	0.5	1.7	26.96
Cash Flow After Tax	33.8	32.3	19.9	9.6	16.0	18.1	18.5	18.7	17.5	15.7	14.1	13.3	11.4	10.3	9.2	8.2	7.4	6.5	5.7	5.0	2.4	293.63

Table 5 17: Cash Flow Summary Proved + Probable + Possible (Wentworth)

Appendix A
Glossary of Technical Terms

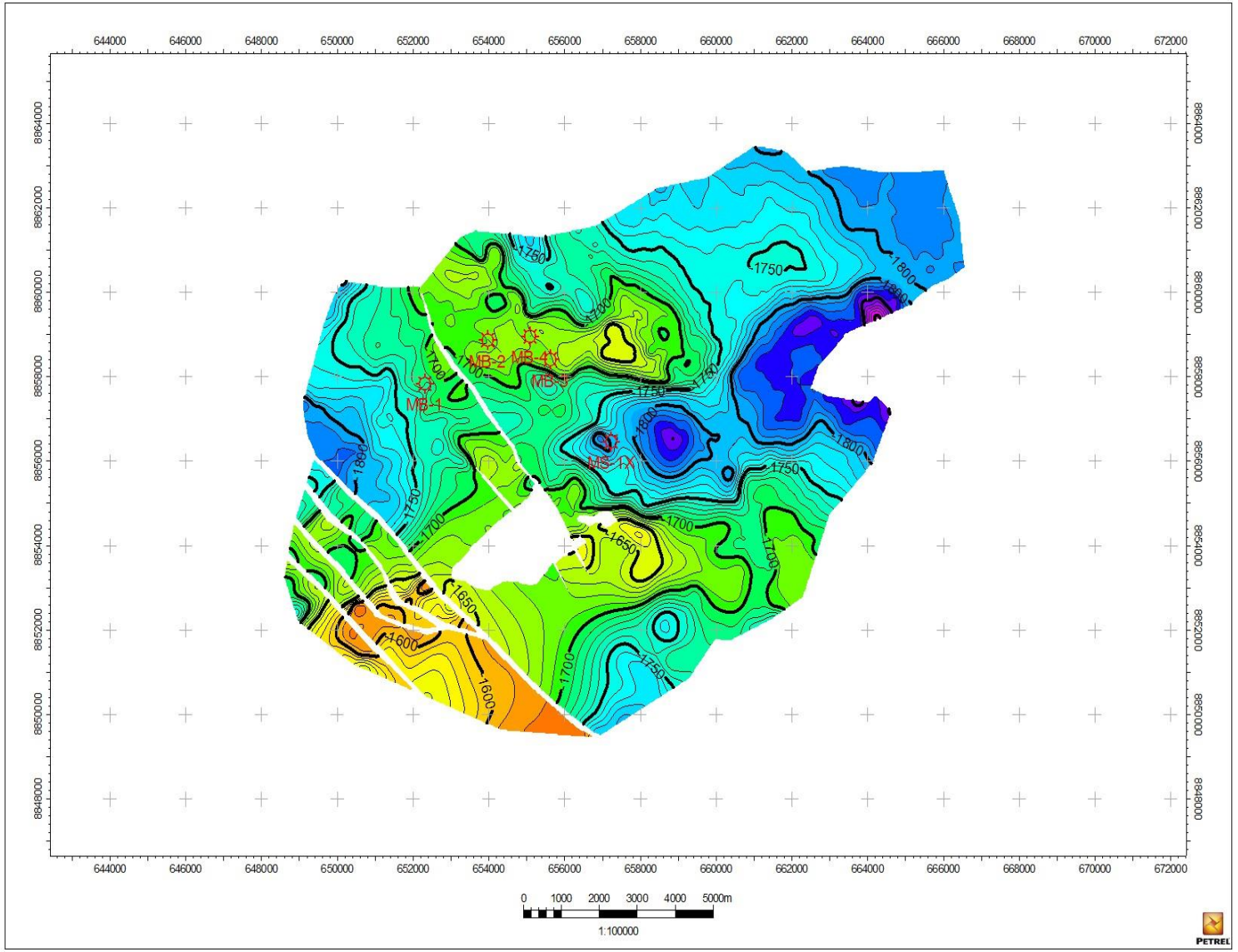
Glossary of Terms and Abbreviations	
AOF	Absolute Open Flow
API	Oil gravity in American Petroleum Institute (API) units
AVO	Amplitude vs Offset
B	Billion (10^9)
bbl	Barrels
Bscf	billions of standard cubic feet
boe	barrels of oil equivalent
bopd	barrels of oil per day
bpd	barrels per day
CPF	Central Processing Facility
CPI	Computer-Processed Interpretation
d	Day
DST	Drill Stem Test
E	Gas Expansion Factor (surface volume / reservoir volume)
EUR	Estimated Ultimate Recovery
EWT	Extended Well Test
ft	feet
FWL	Free Water Level
GDT	Gas-Down-To
GIIP	Gas Initially-In-Place
GOC	Gas-Oil-Contact
GOR	Gas/Oil Ratio
GRV	Gross Rock Volume
GSA	Gas Sales Agreement
GWC	Gas-Water Contact
IPR	Inflow performance relationship
1P	Proved
2P	Proved + Probable
3P	Proved + Probable + Possible
km	kilometres
Gp	Cumulative gas produced
HCIIP	Hydrocarbons Initially in Place

Glossary of Terms and Abbreviations	
LOF	Life of Field
m	metres

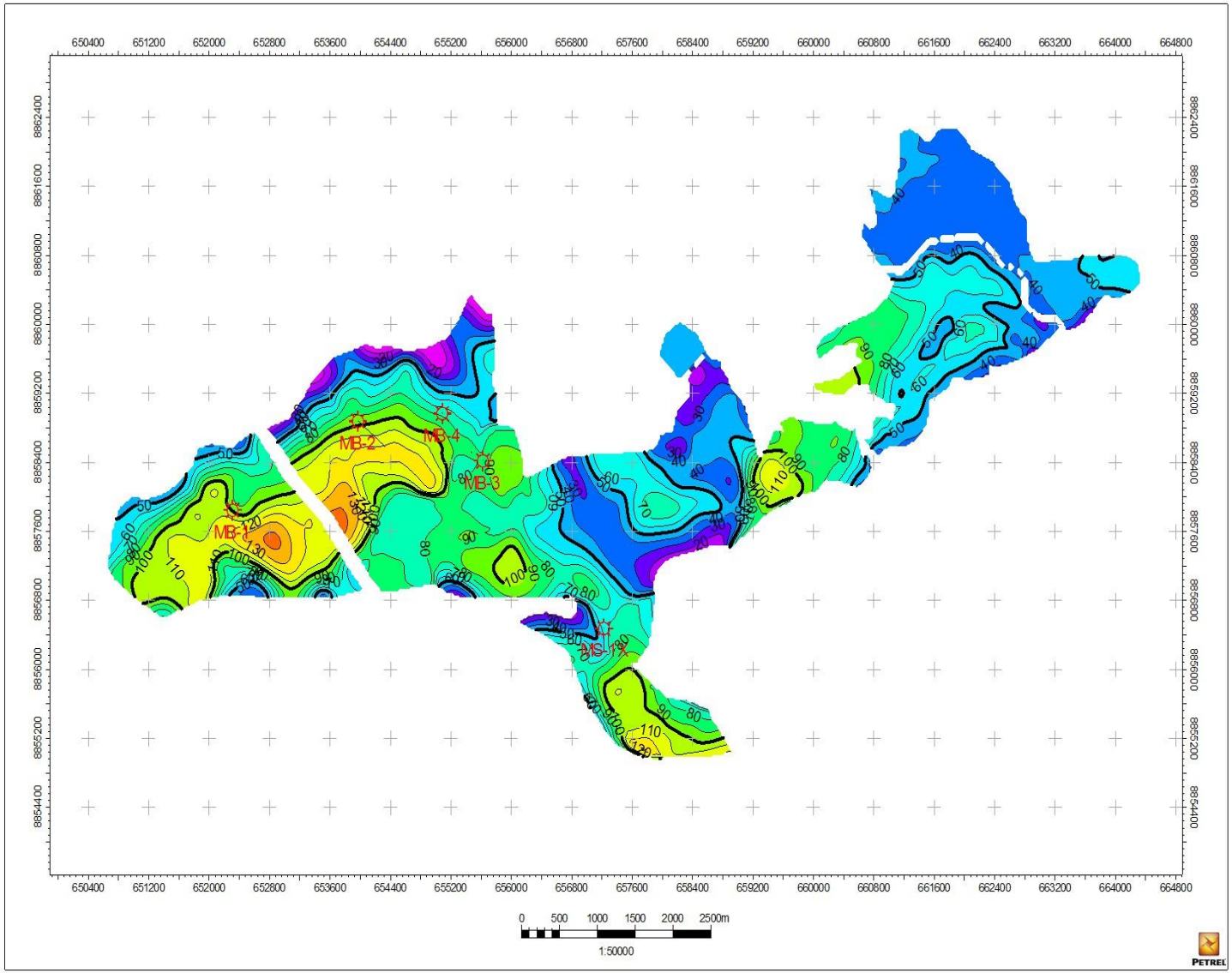
Appendix B

Mnazi Bay/Msimbati Structure and Isopach Maps

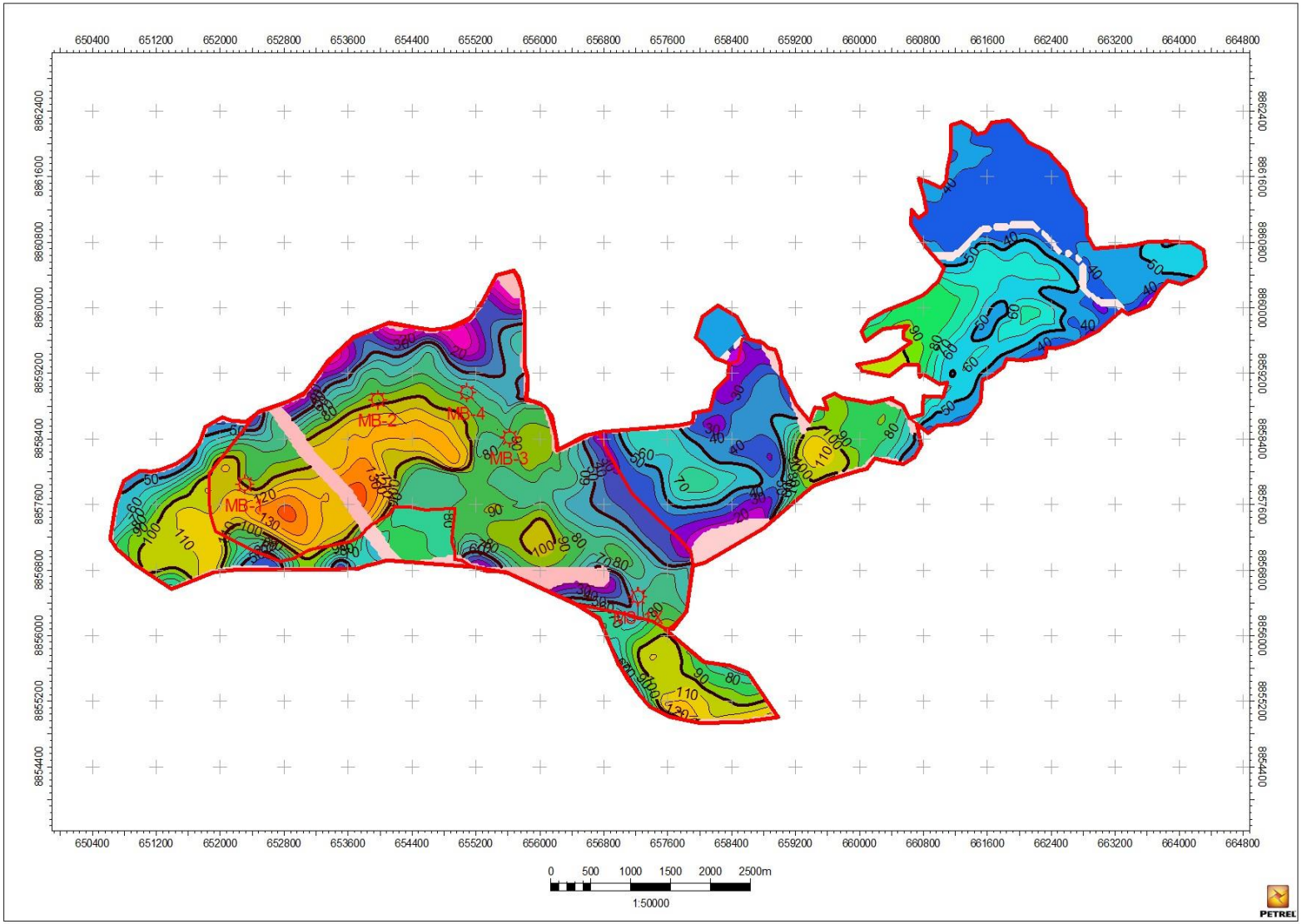
Appendix B: MB UPPER SANDS DEPTH MAP



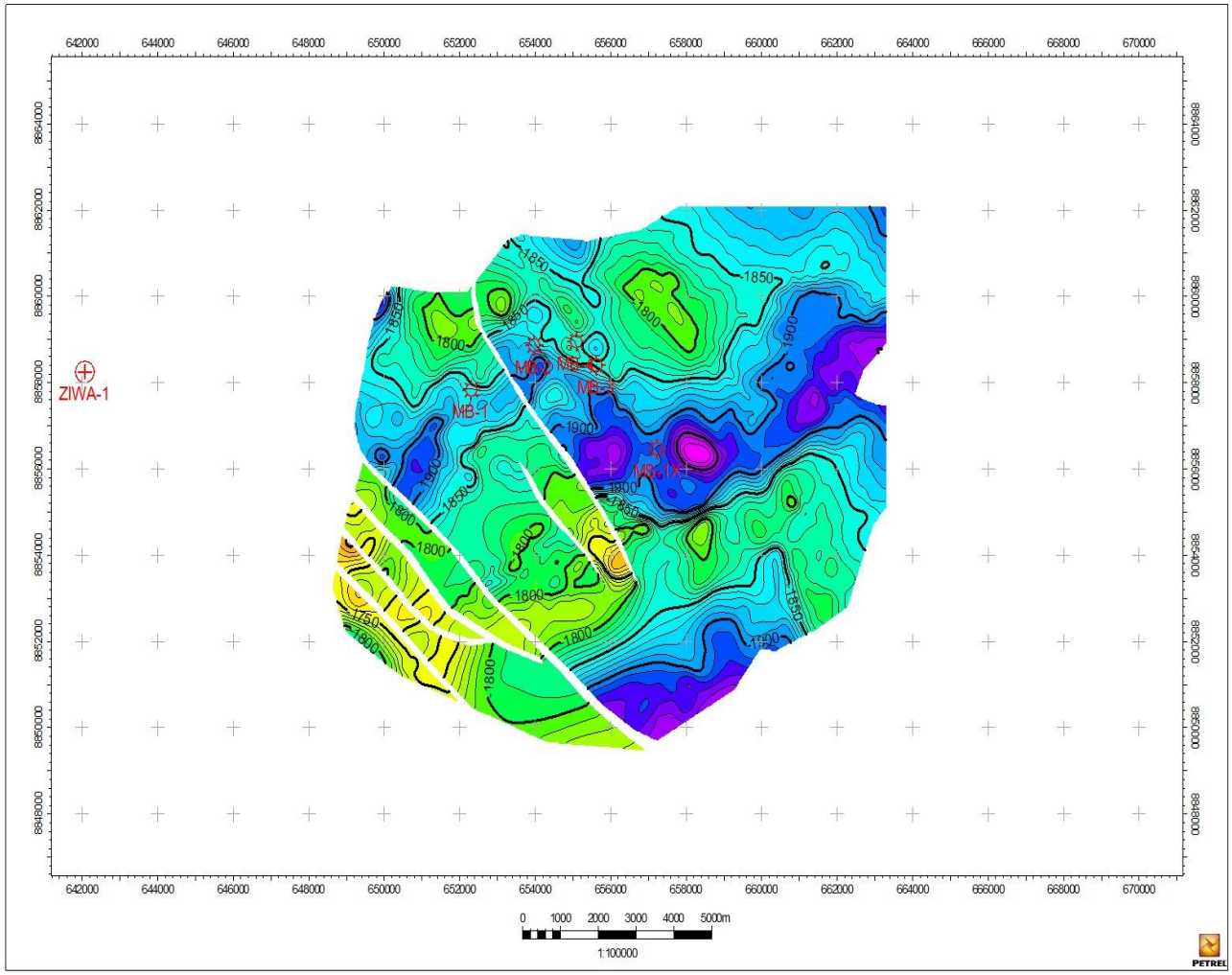
APPENDIX B: MB UPPER SANDS GROSS ROCK VOLUME ABOVE GAS-WATER CONTACT (1864M)



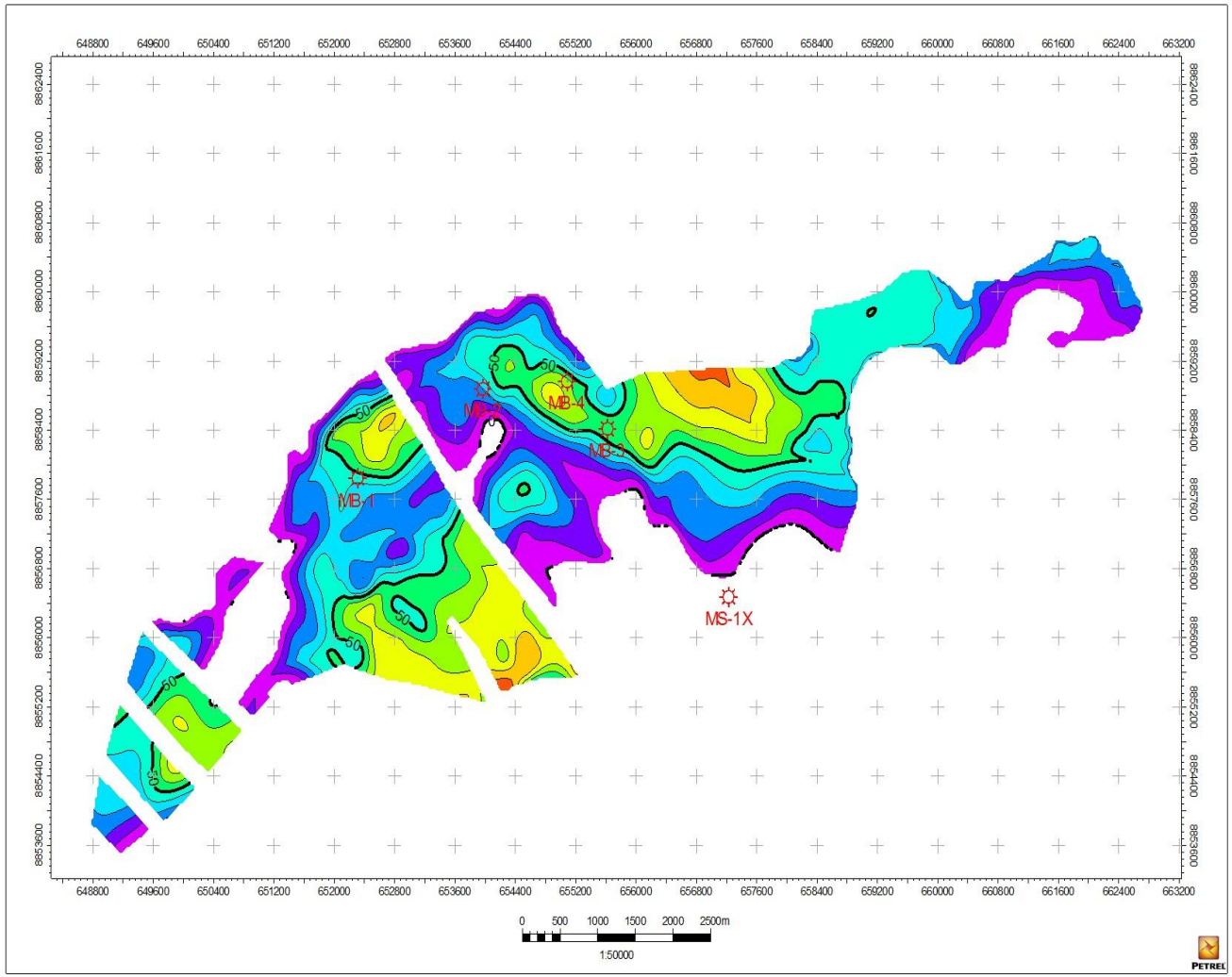
APPENDIX B: MB UPPER SANDS P10, P50 & P90 AREAS



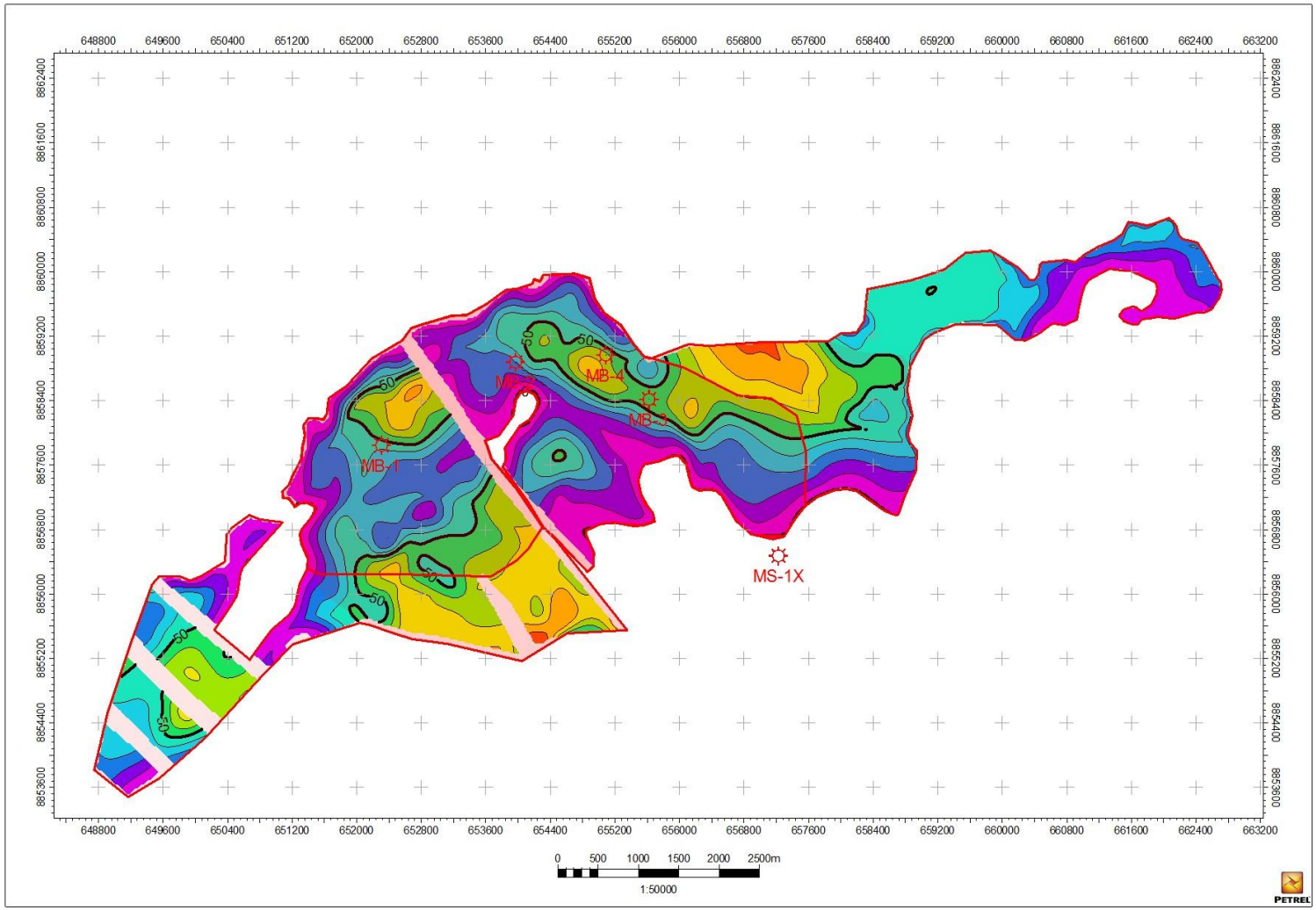
APPENDIX B: MB LOWER SANDS DEPTH MAP



APPENDIX B: MB LOWER SANDS GROSS ROCK VOLUME ABOVE GAS-WATER CONTACT (1905M)



APPENDIX B: MB LOWER SANDS P10, P50 & P90 AREAS



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