PROJECT
OIL KENYA

SOUTH LOKICHAR BASIN
FIELD DEVELOPMENT PLAN

SEPTEMBER 2025

gulf
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SUBMISSION

This Field Development Plan has been submitted to Energy and Petroleum Regulatory Authority by Gulf Energy E&P BV on the **30th Day of September 2025** in accordance with **clause 20** of the Block T6 (10BB) and Block T7(13T) PSCs and **Section 30(3)** of the **Petroleum Act (Cap 308)**,

Paul Limoh

Chief Executive Officer

THE NATIONAL ASSEMBLY
PAPERS LAID
DATE: 27 NOV 2025
DAY. Thursday
TABLED BY: Hon. Naomi Waqo, MP
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UNITS OF MEASURE

Unit	Definition
AMSL	Above Mean Sea Level
bara	Bar absolute
BCF	Billion Cubic Feet
blpd	Barrels Liquid Per Day
stb/d	Stock tank barrels per day
bwpd	Barrels of water per day
km	Kilometres
m	Metres
MMbbls	Millions of barrels
MMscf/d	Million standard cubic feet per day
MMstb	Million stock tank barrels
MW	Mega Watts
psia	Pounds per square inch absolute
TVDSL	True vertical depth sub lake
TVDSS	True vertical depth sub sea

ABBREVIATIONS AND KEY WORDS

Abbreviation	Definition
10BB	means the new Block T6, previously Block 10BB
13T	means the new Block T7, previously Block 13T
ACCE	Advance Collaboration and Control Environment
AGC	Automatic Gain Control
AGI	Above ground installation
AGO	Automotive Gas Oil
AICD	Autonomous Inflow Control Devices
ALARP	As Low As Reasonably Practicable
AMS	Asset Management System
amsl	Above mean sea level
AOC	Africa Oil Turkana Limited, Africa Oil Kenya BV
AOI	Area of Interest
API	American Petroleum Institute
BCC	Backup Control Centre
BLPD	Barrels Liquid Per Day
BOP	Blow Out Preventer
BS&W	Basic Sediment & Water
BTC	Buttress Thread and Coupling
CAPEX	Capital Expenditure
CCR	Central Control Room
CCTV	Closed Circuit Television

Abbreviation	Definition
CDA	Common Development Agreement
CDP	Common Depth Point
CFA	Central Facilities Area
CGG	Compagnie Générale de Géophysique
CIA	Cumulative Impact Assessment
Contractor	PSC Licensee Gulf Energy E&P B.V.
CPF	Central Processing Facility
CPI	Computer Processed Interpretation
CPR	Competent Person's Report
CRA	Corrosion Resistant Alloy
CSPO	Control Share of Profit Oil
CT	Coil Tubing
D&C	Drilling and Completion
DA	Development Area
DICL	Ductile Iron Cement Lined
DP	Development Plan
DST	Drill Stem Test
E&A	Exploration and Appraisal
EEI	Extended Elastic Impedance
EHS	Environment, Health and Safety
EIA	Environmental Impact Assessment
EIT	Electrical, Instrumentation and Telecommunication
EMT	Electro Magnetic Telemetry
ENVID	Environmental Impact Identification
EOPS	Early Oil Pilot Scheme
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
EPCC	Engineering, Procurement, Construction and Commissioning
EPF	Early Production Facility
EPRA	Energy Petroleum Regulatory Authority
ERC	Energy Regulatory Commission
ERP	Emergency Response Plan
ESD	Emergency Shutdown System
ESIA	Environment and Social Impact Assessment
ESMP	Environmental and Social Management Plan
ESMS	Environmental and Social Management System
ESP	Electrical Submersible Pump
EWT	Extended Well Test
FEED	Front End Engineering and Design
FGS	Fire and Gas System
FID	Final Investment Decision
FOB	Free On Board
FOC	Fibre Optic Cable
FTG	Full Tensor Gravity

Abbreviation	Definition
FVF	Formation Volume Factors
FWL	Free Water Levels
GEBV	Gulf Energy E&P B.V.
GIIP	Gas Initially In Place
GMPP	General Marked Point Process
GOK	Government of Kenya
GOP	Good Oilfield Practice
GOR	Gas Oil Ratio
GRV	Gross Rock Volume
GTG	Gas Turbine Generator
GVF	Gas Volume Fraction
HAFWL	Height Above Free Water Level
HAZID	Hazard Identification
HAZOP	Hazard and Operability
HCPV	Hydrocarbon Pore Volume
HDPE	High Density Polyethylene
HFO	Heavy Fuel Oil
HMI	Human Machine Interface
HRP	Hydraulic rod pump
HSE	Health, Safety and Environment
HVAC	Heating, Venting, Air Conditioning
IAP	Integrated Activity Plan
ICD	Inflow Control Device
ICSS	Integrated Control and Safety System
IDF	Input Declaration Fee
IFC	International Finance Corporation
IGF	Induced Gas Flotation
IPS	Integrated Production System
IRR	Internal Rate of Return
ISD	Inherently Safer Design
ISO	International Organisation for Standardisation
IT	Information Technology
IWMF	Integrated Waste Management Facility
JDA	Joint Development Agreement
JOA	Joint Operating Agreement
KeNHA	Kenya National Highways Authority
KETRACO	Kenya Electricity Transmission Company
KPRL	Kenya Petroleum Refineries Limited
KVDA	Kerio Valley Development Authority
LARF	Land Access and Resettlement Framework
LCC	Logistics Coordination Centre
LCM	Lost Circulation Material
LCP	Local Content Plan
LEF	Lokichar Export Facility

Abbreviation	Definition
LKT	Prefix to Seismic Horizons (i.e. LKT60)
LMT	Lamu Marine Terminal
LOF	Load Out Facility
LOPA	Layer of Protection Analysis
LPG	Liquefied Petroleum Gas
LWD	Logging While Drilling
MCC	Main Control Centre
MDT	Modular Dynamic Tester
MGR	Meter Gauge Railway
MICP	Mercury Injection Capillary Pressure
MLA	Marine Loading Arm
MOE	Ministry of Energy
MOEP	Ministry of Energy & Petroleum
MOPM	Ministry of Petroleum & Mining
MOV	Motor Operated Valve
MPFM	Multi Phase Flow Meter
MTBF	Mean Time Between Failure
NCF	Net Cash Flow
NEAT	Ngamia, Ekales, Amosing and Twiga
NEMA	National Environment Management Authority
NLC	National Land Commission
NOCK	National Oil Corporation of Kenya
NTG	Net To Gross
ODT	Oil Down To
OHTL	Overhead transmission lines
OP	Operations Framework
OPEX	Operating Expenditure
OSCP	Oil Spill Contingency Plan
OWC	Oil Water Contacts
PBU	Pressure Build-Up
PCP	Progressive Cavity Pump
PCS	Process Control System
PI	Production Information
Pipeco	Pipeline Company
PLT	Production Logging Tool
PMC	Project Management Contractor
PMS	Premium Motor Spirit
PostSTM	Post-Stack Time Migration
PreSDM	Pre-Stack Depth Migration
PreSTM	Pre-Stack Time Migration
PRS	Pressure Regulating Station
PSC	Production Sharing Contract
PVT	Pressure Volume Temperature
PWRI	Produced water re-injection

Abbreviation	Definition
QRA	Quantitative Risk Assessment
RAP	Relative Amplitude Processing
RCA	Routine Core Analysis
RCI	Reservoir Characterization Instrument
RDL	Railway Development Levy
RTU	Remote Terminal Unit
SBM	Synthetic Based Mud
SCAL	Special Core Analysis Laboratory
SDM	Stack Depth Migration
SEF	Stakeholder Engagement Framework
SEP	Stakeholder Engagement Plan
SGR	Standard Gauge Railway
SGR	Standard Gauge Railway
SIL	Safety Integrity Level
SIMOPS	Simultaneous Operations
SIS	Sequential Indicator Simulation
SMP	Name of a drilling rig provider
SOBM	Synthetic Oil Based Mud
SPM	Side Pocket Mandrel
SPM	Side Pocket Mandrel
SRO	Surface Read Out
SSD	Sliding Side Door
SSEA	Safety Sustainability and External Affairs
STM	Stack Time Migration
STOIIP	Stock Tank Oil Initially in Place
SWCT	Single Well Chemical Tracer
SWTT	Single Well Tracer Test
TAN	Twiga Amosing Ngamia
TAPS	Technology Assisted Production System
TCP	Tubing Conveyed Perforating
TLE	Tullow Kenya BV
TOC	Total organic carbon
Total	Total E&P International K2 Ltd, Total E&P International K3 Ltd and Tullow Kenya BV
TVD	True Vertical Depth
TVP	True Vapour Pressure
TWT	Two-way travel
UPDA	Upstream Phased Development Addendum
UPS	Uninterruptible Power Supply
UR	Ultimate Recovery
VR	Valve Removal
VSAT	Very Small Aperture Terminal
VSP	Vertical Seismic Profile
WAA	Water Abstraction Area
WAT	Wax Appearance Temperature

Abbreviation	Definition
WBM	Water Based Mud
WDT	Wax Dissolution Temperature
WHRU	Waste Heat Recovery Unit
WIT	Water Injection Trials
WP	Wellhead Pressure
WRMA	Water Resources Management Authority
WRMP	Well & Reservoir Management Plan
WUT	Water Up To
XRD	X-ray Diffraction Method

1 EXECUTIVE SUMMARY

This Field Development Plan (FDP) describes the strategy to fully develop six key discoveries within the Block 10BB-13T license areas (Figure 1-1) as well as the further appraisal and exploration activities that will be conducted to maximize resource recovery within the Development Area.

The development strategy uses a phased approach, beginning with the largest and most technically mature reservoirs. To achieve first oil and support an initial plateau of 20,000 stb/d of oil, 48 wells in the Ngamia and Amosing fields will be used and produced through Early Production Facilities. The data gathered through this phase will be used to optimise a second phase of development which plans to execute further drilling in Ngamia and Amosing whilst adding production from the Twiga, Ekales, Agete and Etom fields. The second phase of the development will utilise a Central Production Facility to increase the oil plateau to some 50,000 stb/d.

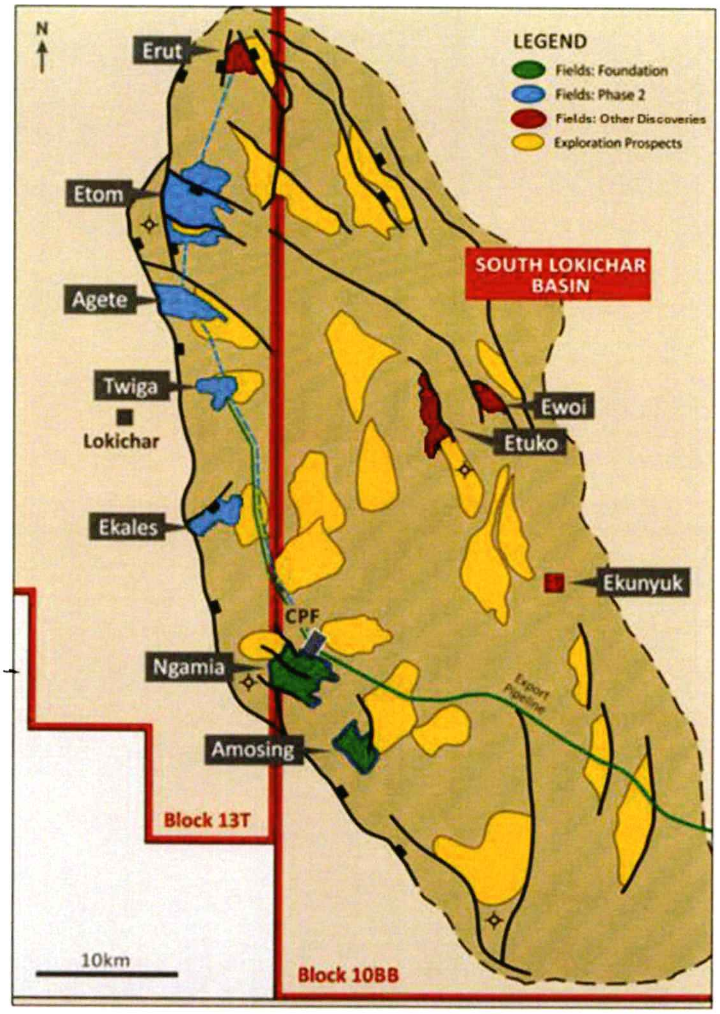
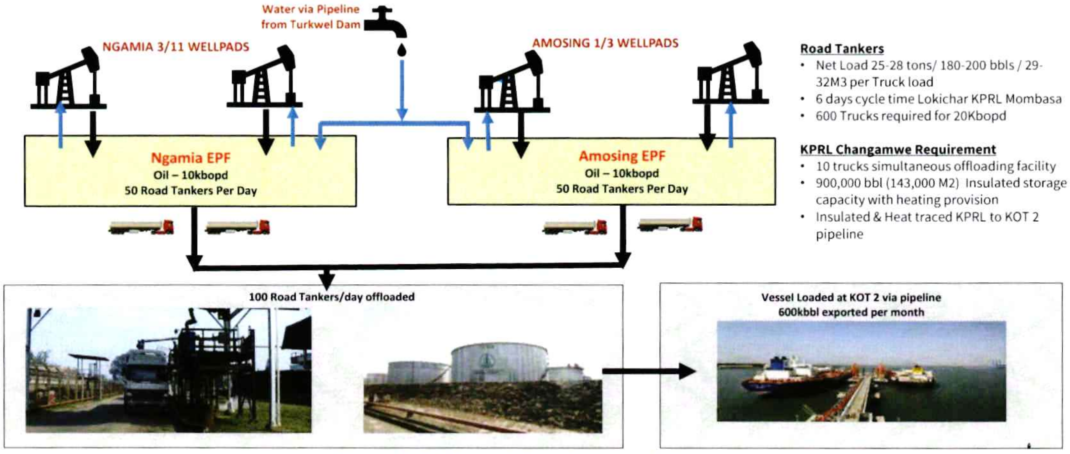


Figure 1-1: Basin Discoveries & Exploration Prospects

Following first oil, an Exploration and Appraisal Plan will be undertaken with the objective of extending the plateau period by de-risking contingent resources and adding new discoveries. Section 5 in this document details the proposed Exploration and Appraisal plan. The Development Area may be extended for a five-year period if a subsequent Exploration & Appraisal Plan is approved by the Government of Kenya, alternatively the size of the Development Area will reduce in phases.

The phased approach to the development will initially start with the infrastructure shown in Figure 1-2. To achieve an accelerated first oil date and to allow for early data gathering to further optimise later developments in the basin production will initially be through rental EPFs. Crude will be trucked through KPRL Changamwe and exported through Mombasa port.

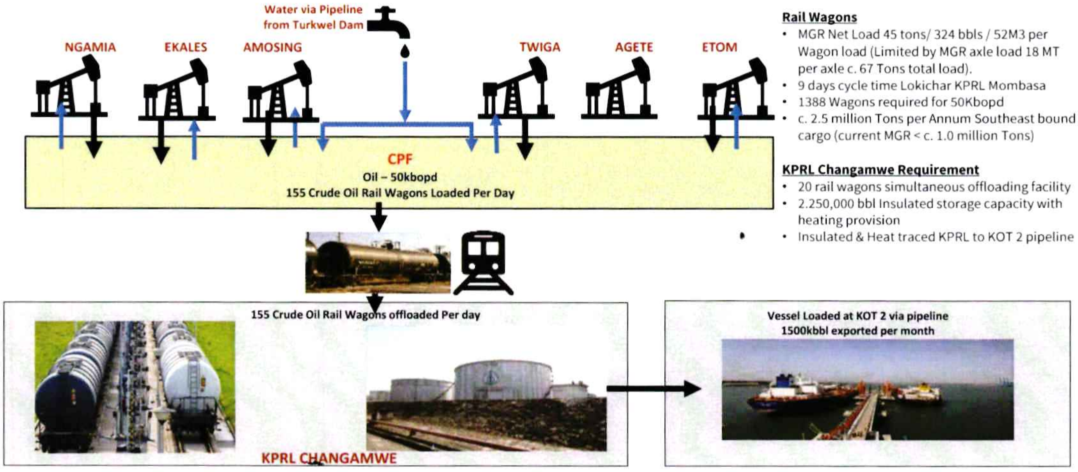


Road Tankers
- Net Load 25-28 tons/ 180-200 bbls / 29-32M3 per Truck load
- 6 days cycle time Lokichar KPRL Mombasa
- 600 Trucks required for 20Kbopd

KPRL Changamwe Requirement
- 10 trucks simultaneous offloading facility
- 900,000 bbl (143,000 M2) Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 1-2: Phase 1 Development Schematic

Phase 2 of the development will entail a larger drilling campaign across the Amosing, Ngamia, Twiga, Ekales, Agete and Etom fields (Figure 1-3). The higher production plateau of 50 kstb/d is planned to be exported through the rail network, with final export also through Mombasa.



Rail Wagons
- MGR Net Load 45 tons/ 324 bbls / 52M3 per Wagon load (Limited by MGR axle load 18 MT per axle c. 67 Tons total load).
- 9 days cycle time Lokichar KPRL Mombasa
- 1388 Wagons required for 50Kbopd
- c. 2.5 million Tons per Annum Southeast bound cargo (current MGR < c. 1.0 million Tons)

KPRL Changamwe Requirement
- 20 rail wagons simultaneous offloading facility
- 2.250,000 bbl Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 1-3: Phase 2 Development Schematic

The development targets a discovered Stock Tank Oil Initially in Place ("STOIIP") range of 1,192 – 1,952– 3,419 MMstb and a best estimate recovery of 326 MMstb of Contingent Resources during the 25-year contract period as shown in the resource summary in Figure 1-4.

9 Fields | 1.95 billion barrels STOOIP | 429 mmbo 2C LOF | 326 mmbo 2C In-License | 829 mmbo 3C LOF

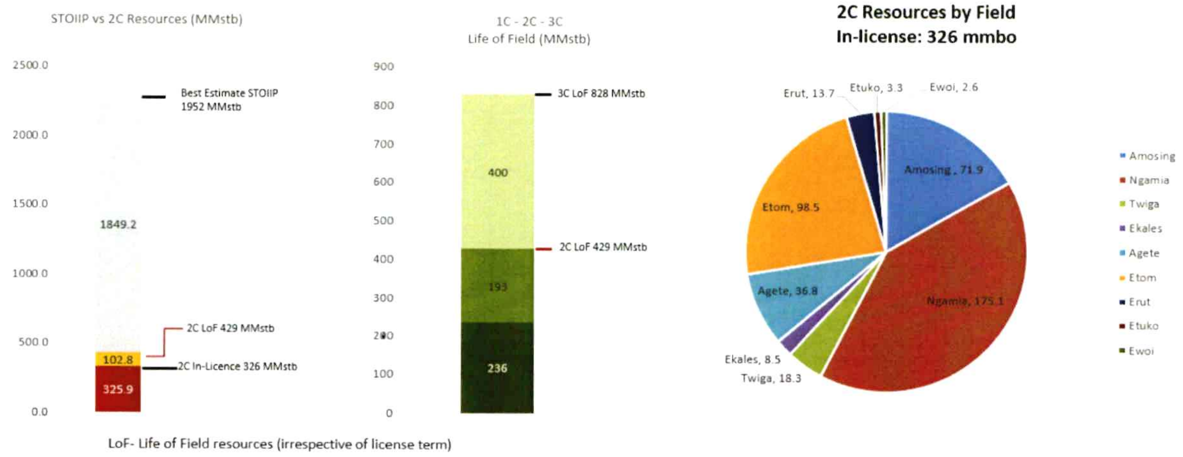


Figure 1-4: Resource Summary

The 50,000 stb/d plateau period is estimated to extend for approximately five years as the existing 6 discoveries are tied back to the central facility before steadily declining over the balance of the license period. However, the plateau period is expected to be further extended via the development of additional resources appraised and discovered in the E&A program or potential Enhanced Oil Recovery (EOR) programs.

The production profile over the initial license period is shown in Figure 1-5.

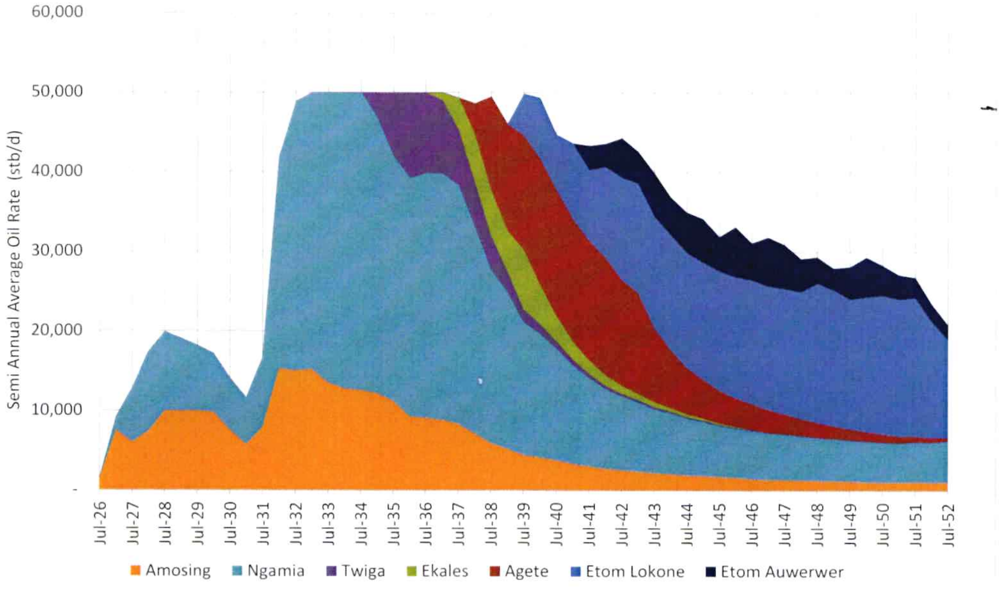


Figure 1-5: Production Profile

An exploration and appraisal program will be conducted during early production with the objective of lengthening the plateau period by arresting decline. The program will focus initially on near field appraisal within the Ngamia and Amosing fields, with the potential to convert significant 3C resources into 2C resources once production commences or allow for the pattern flood to be extended in currently prospective areas.

Additional appraisal exists outside the fields in existing discoveries with the objective of adding additional 2C resource. Secondary reservoirs within the Lokone Formation provide another significant development target if planned appraisal efforts are successful.

The commercial evaluation is based on 326 million stb of development pending 2C resources as the current evaluation of Etuko, Ewoi and Erut does not reach this threshold. Resources in the lower quality Ngamia Lokone formation are also not included at the current time. Prior to developing the smaller discoveries, specific appraisal activities are required to confirm the technical and commercial merits and to de-risk the investment decisions.

The de-risking activities and associated investments required will follow first oil are described in detail in the Exploration and Appraisal Plan, contained in Section 5. This plan will be timed to offset decline, take advantage of available facility capacity, and further lengthen the plateau.

The Exploration and Appraisal Plan is designed to add resources through near field appraisal and also includes plans to drill three high-potential exploration prospects; Lopara North, Lopara-1 and Amosing Fan-1, which are close to Amosing Field and could be added quickly to the development plan. A material success in any of these prospects will likely lead to similar targets within the Development Area.

The baseline project execution schedule for the Phase 1 project is presented in Figure 1-6.

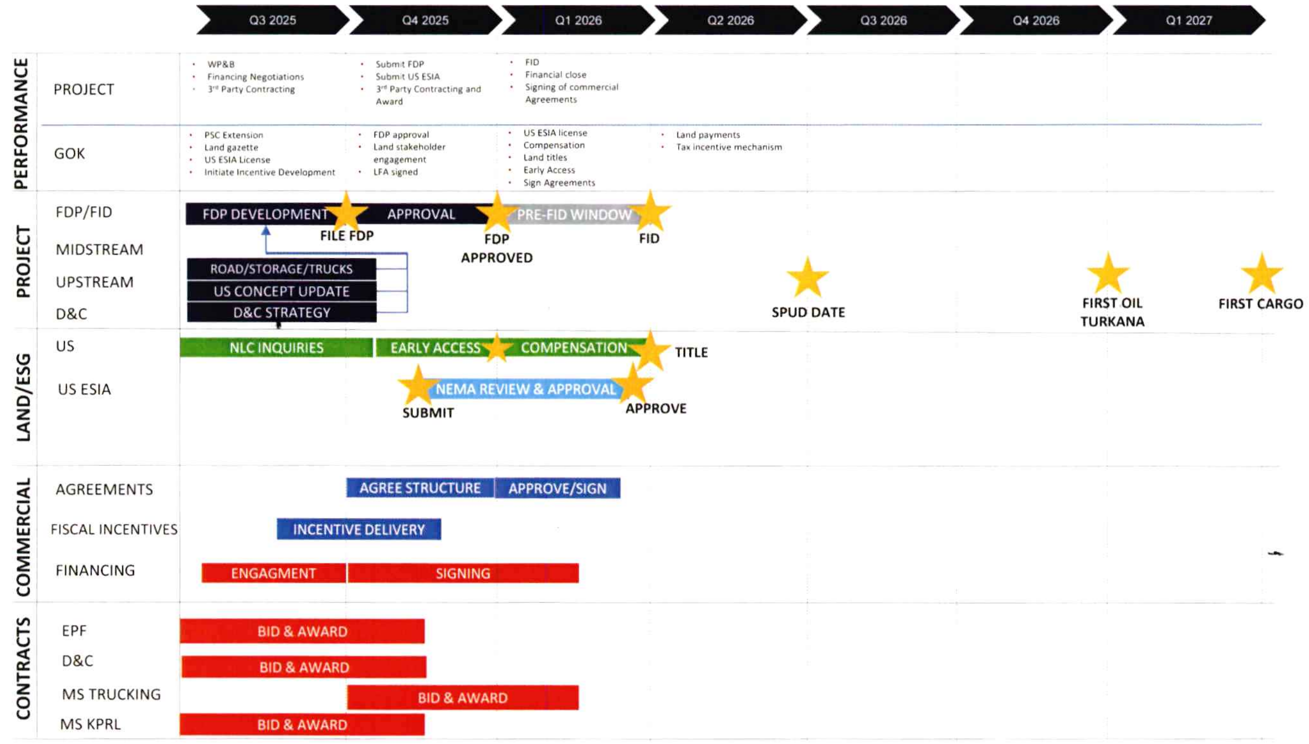
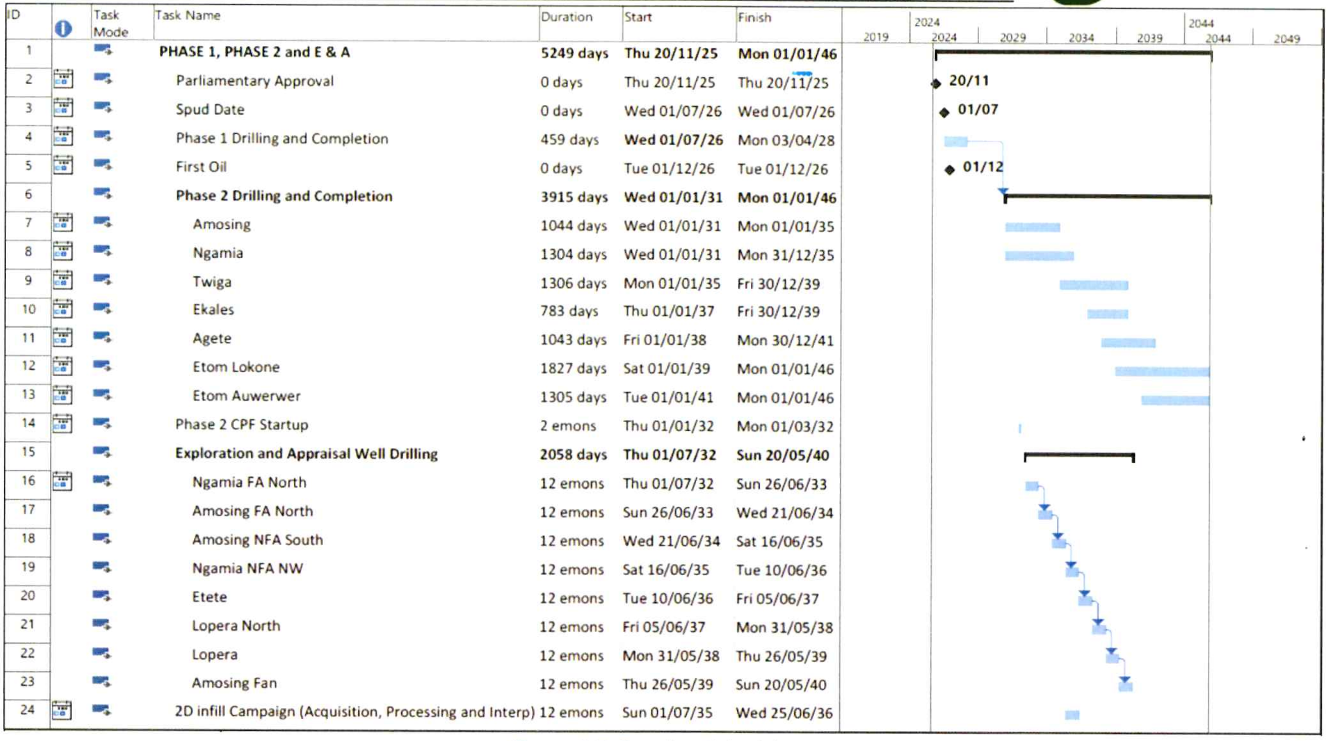


Figure 1-6: Phase 1 Baseline Schedule

A high level schedule for Phase 1, Phase 2 and the E&A drilling plan is presented in Figure 1-7



ID	ⓘ	Task Mode	Task Name	Duration	Start	Finish
1		➜	**PHASE 1, PHASE 2 and E & A**	**5249 days**	**Thu 20/11/25**	**Mon 01/01/46**
2	▦	➜	Parliamentary Approval	0 days	Thu 20/11/25	Thu 20/11/25
3	▦	➜	Spud Date	0 days	Wed 01/07/26	Wed 01/07/26
4	▦	➜	Phase 1 Drilling and Completion	459 days	**Wed 01/07/26**	Mon 03/04/28
5	▦	➜	First Oil	0 days	Tue 01/12/26	Tue 01/12/26
6		➜	**Phase 2 Drilling and Completion**	**3915 days**	**Wed 01/01/31**	**Mon 01/01/46**
7	▦	➜	Amosing	1044 days	Wed 01/01/31	Mon 01/01/35
8	▦	➜	Ngamia	1304 days	Wed 01/01/31	Mon 31/12/35
9	▦	➜	Twiga	1306 days	Mon 01/01/35	Fri 30/12/39
10	▦	➜	Ekales	783 days	Thu 01/01/37	Fri 30/12/39
11	▦	➜	Agete	1043 days	Fri 01/01/38	Mon 30/12/41
12	▦	➜	Etom Lokone	1827 days	Sat 01/01/39	Mon 01/01/46
13	▦	➜	Etom Auwerwer	1305 days	Tue 01/01/41	Mon 01/01/46
14	▦	➜	Phase 2 CPF Startup	2 emons	Thu 01/01/32	Mon 01/03/32
15		➜	**Exploration and Appraisal Well Drilling**	**2058 days**	**Thu 01/07/32**	**Sun 20/05/40**
16	▦	➜	Ngamia FA North	12 emons	Thu 01/07/32	Sun 26/06/33
17		➜	Amosing FA North	12 emons	Sun 26/06/33	Wed 21/06/34
18		➜	Amosing NFA South	12 emons	Wed 21/06/34	Sat 16/06/35
19		➜	Ngamia NFA NW	12 emons	Sat 16/06/35	Tue 10/06/36
20		➜	Etete	12 emons	Tue 10/06/36	Fri 05/06/37
21		➜	Lopera North	12 emons	Fri 05/06/37	Mon 31/05/38
22		➜	Lopera	12 emons	Mon 31/05/38	Thu 26/05/39
23		➜	Amosing Fan	12 emons	Thu 26/05/39	Sun 20/05/40
24	▦	➜	2D infill Campaign (Acquisition, Processing and Interp)	12 emons	Sun 01/07/35	Wed 25/06/36

Figure 1-7: Baseline Schedule

Schedule Notes

1. All durations are subject to final tendering and award of major contracts for the wells, upstream and midstream

The Class 3 upstream capital cost estimate to develop the first six discoveries is shown in Table 1-1. The CAPEX is based on a combination of tender, vendor and historical database information. The final cost may vary and is contingent on receiving final bids including, but not limited to, drilling services, materials and EPCC contracts.

Table 1-1: Upstream Development CAPEX

CAPEX ($M)	Phase 1	Phase 2	Total
Surface Facilities	36.8	430.8	467.6
Drilling and Completions	215.8	5,021.8	5,237.6
Project Owners Costs	11.3	-	11.3
Project Total	263.9	5,452.6	5,716.5
Decommissioning	-	-	343.0
Exploration and Appraisal	-	77.5	-

The project's economics have been prepared using the recoverable resources, costs and timing contained within this FDP. The Project Specific Fiscal Terms ("PSFT"), including certain tax exemptions are available under law to high-value capital investments of this magnitude and are subject to application to the National Treasury.

Following adoption of the FDP by the Government of Kenya, certain activities must be completed before a Final Investment Decision (FID) may be taken. These activities include validating costs through a competitive bid process, engaging EPC contractors, finalising land access and execution of key commercial agreements.

2 INTRODUCTION

This document is presented to the Government of Kenya by Gulf Energy E&P B.V. and it replaces in its entirety the Field Development Plan submitted to Energy Petroleum Regulatory Authority (EPRA) by KJV on March 3, 2023.

The document has been prepared using sound engineering principles in accordance with good international petroleum industry practice and in keeping with the principles of the Block 13T and Block 10BB Production Sharing Contracts.

The Production Sharing Contracts (PSC) set out the requirements for the contents of the Field Development Plan as provided in this document, as follows:

(a) proposals for the development and production, initially from Ngamia and Amosing fields and subsequently from Twiga, Agete, Etom and Ekales fields, with the objective of maintaining the plateau over multiple years

(b) a detailed description of the geology, geophysics and reservoir engineering of the South Lokichar Basin and an analysis of the volumetric of the discoveries

(c) details on the drilling and completion of wells, the production facilities required, construction and operating philosophy to be adopted

(d) details of the proposed development area, that contains commercial accumulations, declared discoveries, future appraisal areas as well as exploration prospects and leads

(e) proposals relating to the spacing, drilling and completion of the wells and the facilities and installations required for the production, storage and transportation of petroleum including:

(f) the estimated number of production wells

(g) the particulars of production equipment and facilities

(h) the particulars of feasible alternatives for transportation of petroleum including pipelines

(i) a production forecast and an estimate of the investment and expenses involved

(j) an estimate of the time required to complete each phase of the development plan

(k) proposed plan for the adherence to all regulatory and other measures to ensure the health and safety of all stakeholders and that the environment is fully protected. We take cognizance of the fact that delivering the field development safely and with respect for the local environment is key to a successful outcome

(l) an outline of the proposed strategies in relation to employment and training of national staff and contractors, supplier development and overall development of National Content to support the development

(m) the assumptions related to deliverables from the Government of Kenya that embedded in the development strategy to ensure the economic and commercial viability of the South Lokichar Project

3 PRODUCTION SHARING CONTRACTS & LEGAL FRAMEWORK

On 25th October 2007 Turkana Drilling Consortium (Kenya) signed a Production Sharing Contract (PSC) for a 100% working interest in newly designated Block 10BB. On 17th September 2008 Platform Resources Inc. signed a PSC for a 100% working interest in newly designated Block 13T. In 2009 Africa Oil Turkana Ltd (a wholly owned subsidiary of Africa Oil Corporation) acquired Turkana Drilling Consortium. In 2010 Africa Oil Kenya B.V. acquired Platform Resources Inc. giving Africa Oil a 100% interest in both Blocks 10BB and 13T.

On 26th January 2011 Tullow Kenya B.V. completed a farm-in to Blocks 10BB and 13T acquiring a 50% interest and Operatorship of both blocks. On 1st March 2016 Africa Oil farmed down a further 25% of their remaining equity in Blocks 13T and 10BB to Maersk Oil and Gas.

On 21st August 2017 Total S.A. acquired 100% of Maersk Oil and Gas thus acquiring all Maersk Oil and Gas participating interests in Block 10BB and Block 13T giving subsidiaries Total E&P International K2 LTD and Total E&P International K3 LTD a 25% interest in each of the said Block 10BB and Block 13T PSCs, respectively.

On July 21, 2025, Tullow Overseas Holding BV, a wholly owned subsidiary of Tullow Oil plc (Tullow) and Auron Energy E&P Limited, an affiliate of Gulf Energy Limited (GEL), signed a sale and purchase agreement. for the purchase of Tullow Kenya B.V. (TKBV). The transaction, which constitutes a corporate share transfer, involved the acquisition of 100% of Tullow Kenya BV, as a going concern, by Auron Energy E&P Limited, an affiliate of Gulf Energy Limited, from its current parent company, Tullow Overseas Holdings BV giving the subsidiary Gulf Energy E&P BV a 100% interest in each of the said Block 10BB and Block 13T PSCs, respectively.

Gulf Energy E&P BV holds a 100% interest in each of the said Block 10BB and Block 13T PSCs.

3.1 Block 13T

3.1.1 Initial Exploration Period

The Initial Exploration Period ran from 17th December 2008 to 17th September 2012 including a one-year extension granted by the Minister of Energy and Petroleum. During the Initial Exploration Period all the legacy 2D seismic and gravity data from the Shell-Amoco campaign were reviewed, re-processed and reinterpreted. Geological field mapping was also carried out.

In addition, 5,648 km^2 of high-resolution Full Tensor Gravity Gradiometry (FTG) data were acquired. This data was used to guide the acquisition of a further 1,031 km of 2D seismic data. After satisfying the Initial Exploration Period work programme the Contractor elected to enter the First Additional Exploration Period after the mandatory 25% relinquishment.

3.1.2 First Additional Exploration Period

The First Additional Exploration Period ran from 18th September 2012 to 18th September 2015 including a one-year extension granted by the Minister of Energy and Petroleum on 11th July 2014. During the First Additional Exploration Period the Contractor acquired a further 265 km of 2D seismic data, 481 km^2 of 3D seismic data and drilled 10 exploration and appraisal wells. After satisfying the First Additional Exploration Period work programme the Contractor elected to enter the Second Additional Exploration Period after the mandatory 25% relinquishment.

3.1.3 Second Additional Exploration Period

The Second Additional Exploration Period initially ran from 19th September 2015 to 18th September 2020 including a three-year extension granted by the Minister of Energy and Petroleum. Pursuant to the Ministry of Petroleum and Mining letters dated 1st September 2020 and 2nd December 2020 respectively, the Second Additional Exploration Period expired on 31st December 2021 following the submission of the first version of the Field Development Plan on 10th December 2021.

During the Second Additional Exploration Period the Contractor has drilled six (6) exploration and appraisal wells.

3.2 Block 10BB

3.2.1 Initial Exploration Period

The Initial Exploration Period ran from 25th January 2008 to 24th July 2012 including extensions granted by the Minister of Energy and Petroleum. During the Initial Exploration Period all the legacy 2D seismic and gravity data from the Shell-Amoco campaign were reviewed, reprocessed and reinterpreted.

Geophysical, geological and geochemical studies were also conducted including geological field mapping. In addition, 10,422 km^2 of high-resolution Full Tensor Gravity Gradiometry (FTG) data were acquired. These data were used to guide the acquisition of 1,743 km of 2D seismic data. One exploration well was drilled. After satisfying the Initial Exploration Period work programme the Contractor elected to enter the First Additional Exploration Period after the mandatory 30% relinquishment.

3.2.2 First Additional Exploration Period

The First Additional Exploration Period ran from 25th July 2012 to 24th July 2015 including a one-year extension granted by the Minister of Energy and Petroleum. During the First Additional Exploration Period the Contractor acquired a further 1,880 km of 2D seismic data, 471 km^2 of 3D seismic and drilled 20 exploration and appraisal wells. After satisfying the First Additional Exploration Period work programme the Contractor elected to enter the Second Additional Exploration Period after the mandatory 30% relinquishment.

3.2.3 Second Additional Exploration Period

The Second Additional Exploration Period initially run from 25th July 2015 to 18th September 2020 including a three-year extension granted by the Minister of Energy and Petroleum on 11th July 2014. Pursuant to the Ministry of Petroleum and Mining letters dated 1st September 2020 and 2nd December 2020 respectively, the Second Additional Exploration Period expired on 31st December 2021 following submission of the first version of the Field Development Plan on 10th December 2021.

During the Second Additional Exploration Period the Contractor has drilled 4 exploration and appraisal wells, undertaken extended well testing activities and a waterflood pilot project on the Ngamia discovery.

3.3 Notices of Discovery

Exploration drilling across Blocks 13T and 10BB has resulted in the discovery of hydrocarbons in ten separate structures in the South Lokichar Basin.

On 27th February 2013 the Contractor proposed to MOEP, to establish an AOI over sections of Blocks 10BB and 13T. The rationale for establishing the AOI was to allow for a coordinated approach to the exploration and evaluation of discoveries in Blocks 10BB and 13T to enable the Contractor to determine the commerciality of the reserves on a basin-wide approach. MOEP granted its approval on 28th February 2013.

On 23rd May 2014, the Contractor requested an expansion of the AOI to include additional discoveries (Etuko, Ewoi and Ekunyuk). MOEP granted its approval on 4th September 2015.

Notices of Discovery have been submitted to MOEP as follows (Table 3-2).

Table 3-1: Notices of Discovery

Discovery	Date of Notice
Twiga	22nd February 2013
Ngamia	15th July 2013
Ekales	14th April 2014
Etuko	15th April 2014
Agete	4th December 2014
Ewoi	4th December 2014
Etom	18th December 2014
Amosing	22nd December 2014
Ekunyuk	22nd December 2014
Erut	17th January 2017

3.4 Area of Interest

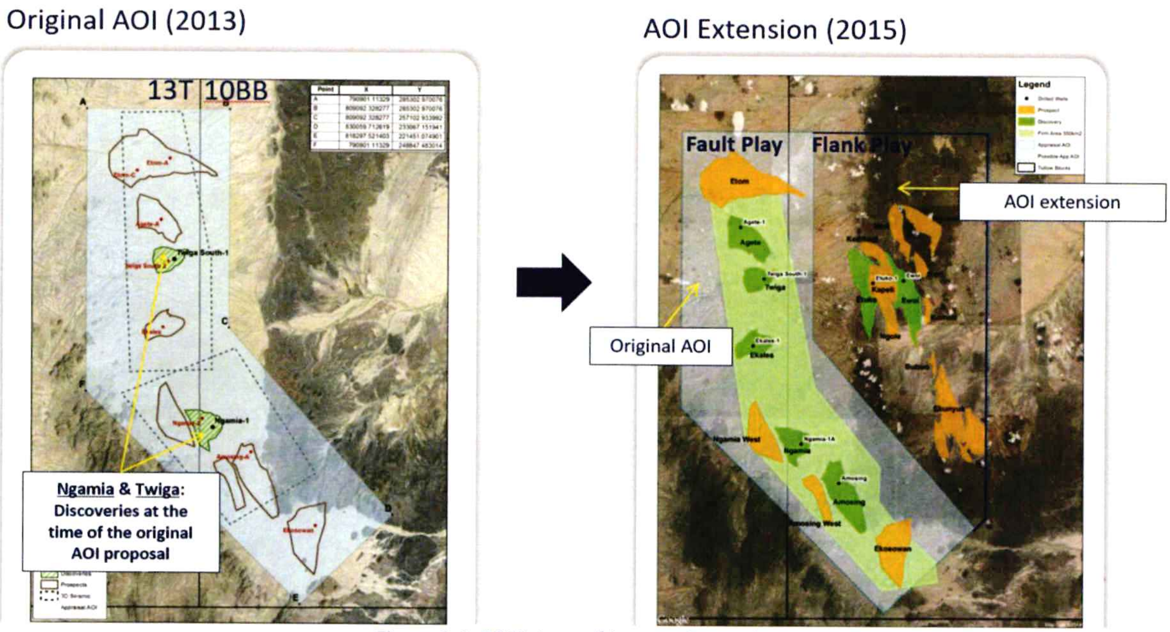
In February 2013, the Contractor parties proposed the establishment of an Area of Interest (AOI) covering portions of Blocks 10BB and 13T to enable a coordinated evaluation of discoveries within the South Lokichar Basin. This proposal was formally approved by the Cabinet Secretary for Energy and Petroleum, with subsequent expansion approved in 2015 to include additional discoveries on the eastern flank of the Basin (Figure 3-1).

The AOI framework was designed to facilitate a basin-wide assessment of commerciality, allowing discoveries to be evaluated collectively rather than individually under the strict timelines of the respective PSCs.

This integrated approach, which has been adopted in the tenure of the petroleum operations, enables synchronized development planning across Blocks 10BB and 13T, promotes cost efficiency, and supports optimal resource utilization.

The AOI was validly established under the now repealed Petroleum (Exploration and Production) Act Cap 308, with approvals granted by both the Cabinet Secretary and the Principal Secretary, who are duly authorized under Kenyan law to bind the Government

The AOI does not alter other PSC provisions but provides a regulatory basis for a phased, coordinated, and commercially sound development strategy for the Basin.


Original AOI (2013)

AOI Extension (2015)

Ngamia & Twiga: Discoveries at the time of the original AOI proposal

Original AOI

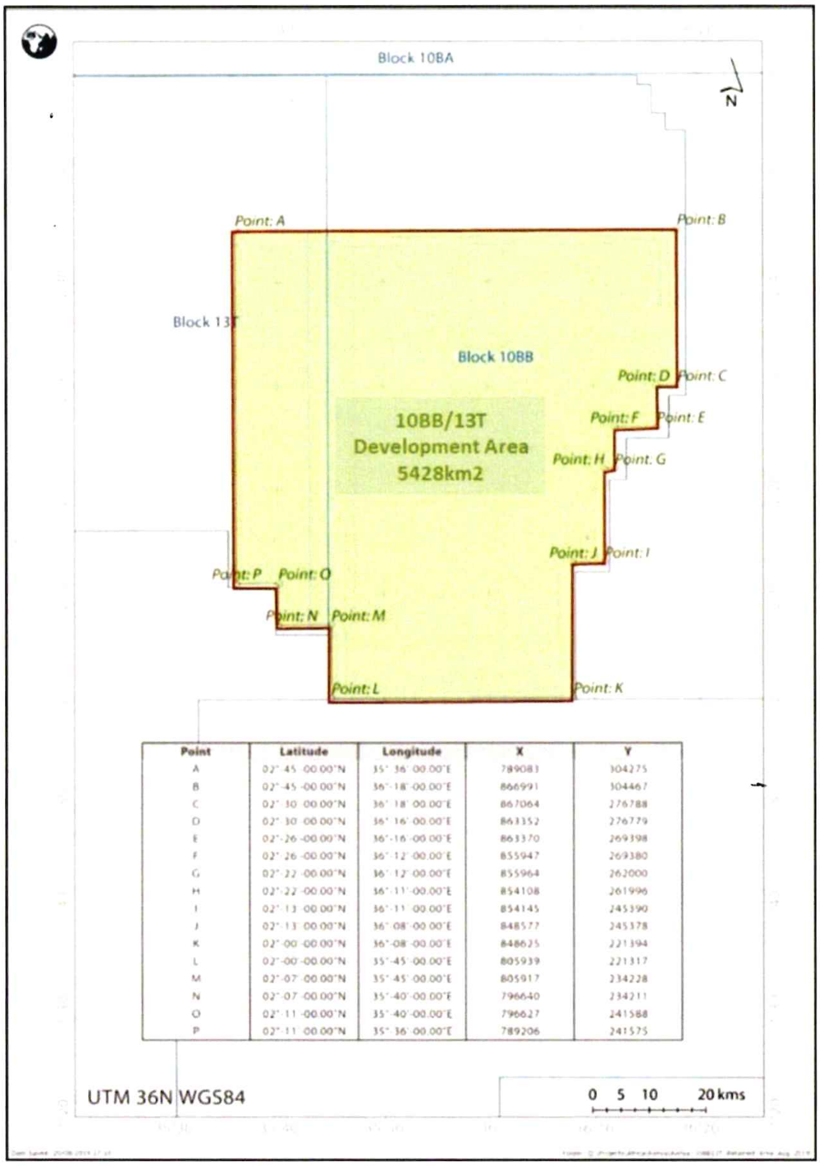
AOI extension

Figure 3-1: 2015 Area of Interest Expansion

3.5 Development Area

In keeping with the principles of Clause 20 of the Production Sharing Contracts, the Contractor proposes a Development Area, to be defined inclusive of an integrated development concept for commercial accumulations, declared discoveries, appraisal areas as well as future exploration prospects and leads, as initially described in Section 5.

The coordinates for the proposed Development Area are set out in Figure 3-2.



Point	Latitude	Longitude	X	Y
A	02°-45'-00.00"N	35°-36'-00.00"E	789083	304275
B	02°-45'-00.00"N	36°-18'-00.00"E	866991	304467
C	02°-30'-00.00"N	36°-18'-00.00"E	867064	276788
D	02°-30'-00.00"N	36°-16'-00.00"E	863352	276779
E	02°-26'-00.00"N	36°-16'-00.00"E	863370	269398
F	02°-26'-00.00"N	36°-12'-00.00"E	855947	269380
G	02°-22'-00.00"N	36°-12'-00.00"E	855964	262000
H	02°-22'-00.00"N	36°-11'-00.00"E	854108	261996
I	02°-13'-00.00"N	36°-11'-00.00"E	854145	245390
J	02°-13'-00.00"N	36°-08'-00.00"E	848577	245378
K	02°-00'-00.00"N	36°-08'-00.00"E	848625	221394
L	02°-00'-00.00"N	35°-45'-00.00"E	805939	221317
M	02°-07'-00.00"N	35°-45'-00.00"E	805917	234228
N	02°-07'-00.00"N	35°-40'-00.00"E	796640	234211
O	02°-11'-00.00"N	35°-40'-00.00"E	796627	241588
P	02°-11'-00.00"N	35°-36'-00.00"E	789206	241575

Figure 3-2: Proposed Development Area Coordinates

3.6 Legal Framework

Blocks 13T and 10BB are governed by separate PSCs. As the discoveries will be developed together, the PSCs must be combined in certain respects.

As indicated in Section 3.4, the integrated development of the discoveries in the AOI does not alter other PSC provisions but provides a regulatory basis for a phased, coordinated, and commercially sound development strategy for the Basin This integrated approach, which has been adopted in the tenure of the petroleum operations, enables synchronized development planning across Blocks 10BB and 13T, promotes cost efficiency, and supports optimal resource utilization. The AOI approach was formally approved by the Cabinet Secretary for Energy and Petroleum, with subsequent expansion approved in September 2015 to include additional discoveries on the eastern flank of the Basin

Common Facilities must be constructed and operated to process oil produced from both Blocks, and the costs of these facilities must be shared between the PSCs in proportion to the amount of oil anticipated to be produced from each Block. The 'Common Facilities', which are those facilities utilized by both blocks for production and development, will be funded by allocating costs of the Common Facilities between the Block 10BB parties and the Block 13T parties in accordance with an agreed allocation percentage.

GEBV and the Government will agree on an appropriate legal framework to take into account specific enabling project agreements and any proposed changes to the PSCs, including those related to the development and production in the Development Area. These will be facilitated through either an amendment to the existing Blocks 10BB and 13T PSCs or specific enabling project agreements

The contractual framework described above is subject to the provisions of the Petroleum Act 2019 to the extent they apply to the project development.

4 SUBSURFACE

4.1 Introduction

4.1.1 Well/Seismic Database

After the Shell-operated original South Lokichar Basin hydrocarbon discovery Well Loperot-1 was drilled in 1992, no further wells were drilled until 2012. Since further drilling began in the basin in early 2012, a total of 41 exploration and appraisal wells have been drilled in the basin (Section 14). Fourteen of the wells were classified as exploration wells with the remainder classified as appraisal wells. The fourteen exploration wells led to ten declared discoveries and four dry holes. Seventeen of the wells have been completed and perforated for flow testing. Timing of the data acquisition in the South Lokichar Basin is illustrated in Figure 4-1.

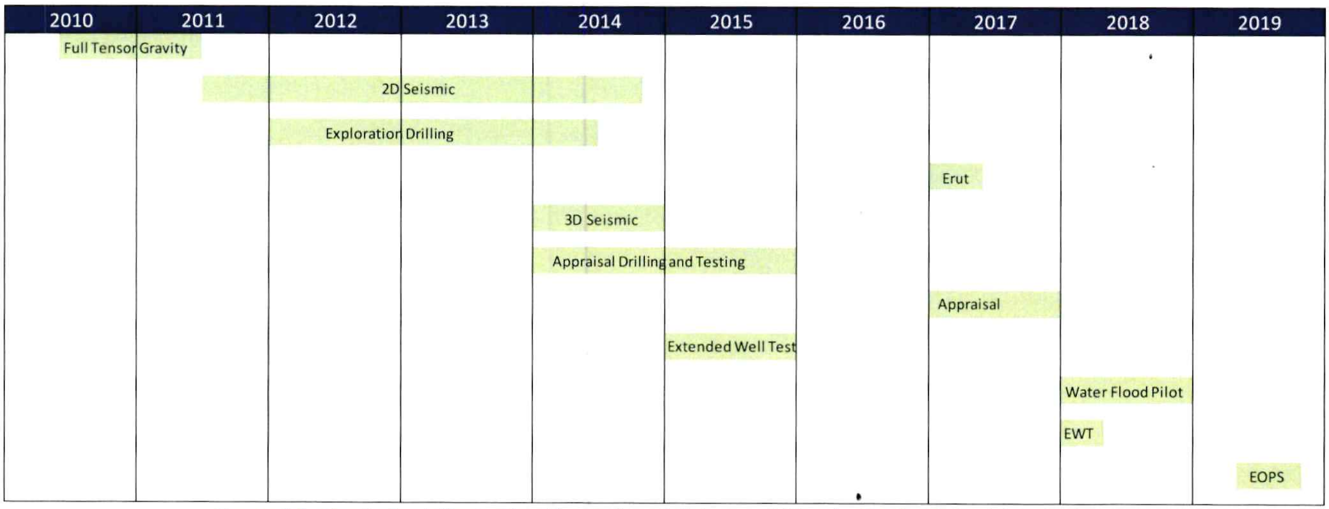


Figure 4-1: Gantt chart illustrating the timing of data acquisition in the South Lokichar Basin

The drilling of the forty-one recent wells in the South Lokichar Basin results in an extensive database available for analysis. This data includes logging while drilling (LWD), wireline logs, vertical seismic profiles, conventional and sidewall cores, formation pressures, fluid samples and as post-drilling dynamic flowing and injection data.

In 2011, the Contractor conducted airborne Full Tensor Gravity Gradiometry (FTG) surveys covering 16,070 km^2 of Blocks 10BB and 13T. In frontier exploration provinces, FTG provides a high-resolution measurement of the earth's gravitational field allowing the identification of basement lows. Basement lows are interpreted as potential sedimentary basin depocenters which are then the targeted areas for reconnaissance 2D seismic acquisition.

All the legacy 2D seismic data from Shell-Amoco were reprocessed by the Contractor. In addition, between 2011 and 2014 as part of the license commitments, the Contractor acquired an additional 4,919 km of 2D seismic data across Blocks 10BB and 13T. These data were almost exclusively acquired using a cable recording system with a vibroseis truck-mounted source. The 2D seismic data were used to plan the early exploration wells and many of the initial appraisal wells between 2012 and late 2014.

In 2014 two 3D seismic surveys were acquired on the western side of the South Lokichar Basin. The first survey of 550 km^2 was acquired over the Agete-Twiga-Ekales-Ngamia-Amosing area. The second survey of 400 km^2 was acquired over the Etom area. This data was acquired with vibroseis sources (flip-flop & slip-sweep) using nodal (cable-less) geophone technology with using a source to receiver spacing of 25 m, source and receiver line increments of 100 m, with a nominal CDP (Common Depth Point) fold of 250.

4.1.2 Exploration History

Fifteen exploration wells have been drilled in the Lokichar Basin including the original discovery well, Loperot-1, drilled by Shell in 1992 (Figure 4-2). There have been ten declared discoveries in the basin resulting from the drilling campaigns. This document will discuss these discoveries briefly but will focus on the discoveries which are currently planned to be developed in the earliest stages of the project (referred to as Phase 1 and Phase 2).

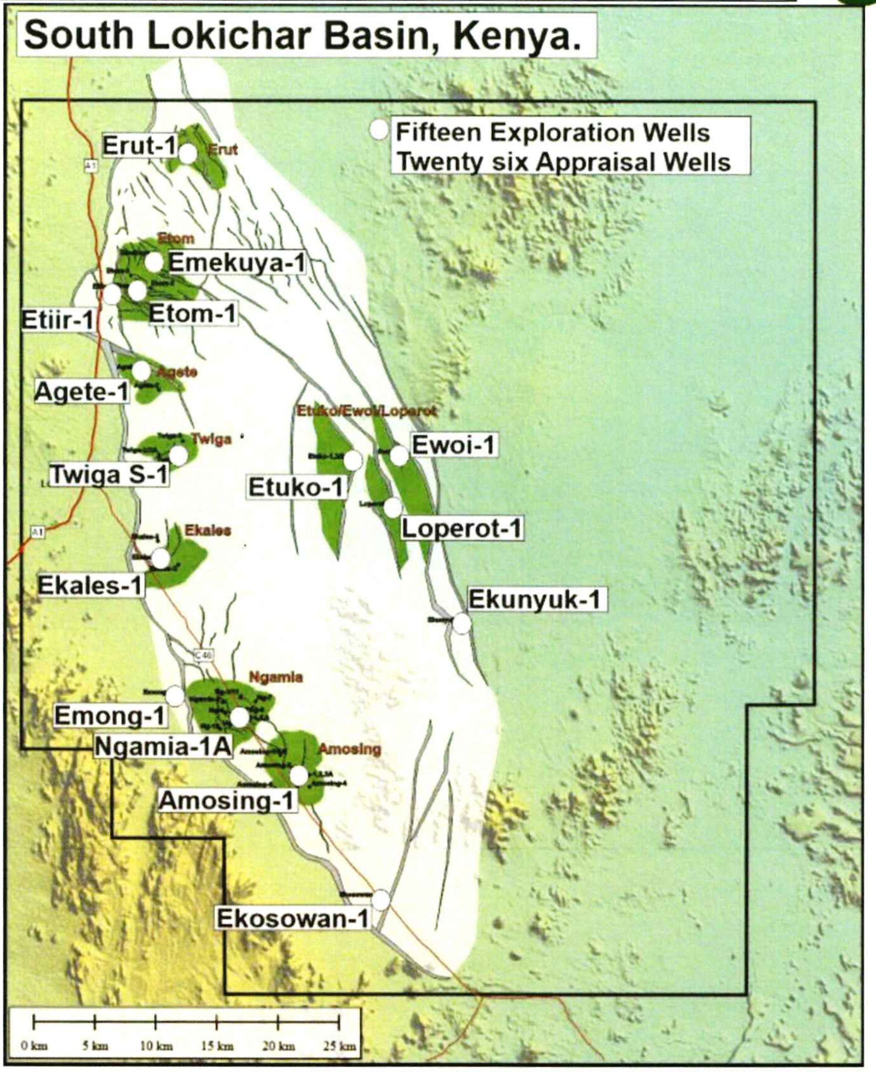


Figure 4-2: Exploration wells in the South Lokichar Basin

In late 2011, the Contractor mobilized the Weatherford 804 drilling rig into Turkana County to begin exploration drilling. The first well, on the Ngamia prospect, was spudded on 24th January 2012. The well was located 23 km southeast of the provincial town of Lokichar and 21 km southwest of the 1992 Shell exploration well Loperot-1. After a mechanical sidetrack, Ngamia-1A was drilled to total depth of 2,340 mMD (-2,336 mTVDKB). The well encountered several hundred meters of gross oil-bearing sandstones in the Miocene Lower Auwerwer and Lokone Sandstone Formations and was announced as an oil discovery in March 2012.

The Weatherford 804 was then moved to the Twiga prospect location, 22 km northwest of Ngamia, with exploration well Twiga South-1 spudded on 21st August 2012. The well was drilled to a total depth of 3,250 mMD (-3,250 mTVDKB) and encountered several hundred meters of gross oil-bearing sandstones in the Lower Auwerwer Formation and Lokone Sandstone Formation. The well was suspended and announced as an oil discovery in November 2012.

The Etuko-1 exploration well commenced drilling on May 11, 2013, from the Sakson PR5 rig. The well is on the eastern side of the Lokichar Basin and is located 5 km northwest of the Loperot-1 discovery well. The Etuko-1 well drilled to a total depth of 3,100 mMD (-3,097 mTVDKB) and encountered several oil and gas bearing zones within the Lokone Shale and Lokone Sand Formations. The well was suspended and announced as a discovery in April 2014.

The Ekales-1 exploration well spud on July 22, 2013, from the Weatherford 804 drilling rig. The well is located between the Ngamia and Twiga oil discoveries on the western side of the basin. The well drilled to a total depth of 2,554 mMD (-2,554 mTVDKB) and discovered oil-bearing sandstones in the Lower Auwerwer Formation. The well was suspended and announced as a discovery in April 2014.

Following the drilling of the Etuko-1 well, the Sakson PR5 well moved to the Agete prospect where the Agete-1 well was spudded on September 17, 2013. The well is located 8 km north of the Twiga discovery. The well was drilled to a total depth of 1,930 mMD

(-1,930 mTVDKB) and discovered several pools of oil-bearing sandstones in the Lower Auwerwer Formation. The well was suspended and announced as a discovery in December 2014.

The Weatherford 804 rig commenced exploration drilling at Amosing-1 on 25th November 2013 and drilled to a measured depth of 2,531 mMD (-2,531 mTVDKB). The well encountered up to 200 m of gross oil-bearing sandstone in the Lower Auwerwer Formation and was announced as the sixth oil discovery in January 2014.

The Ewoi-1 well is located on the eastern side of the Lokichar Basin and was spudded on December 16, 2013, with the Sakson PR5 drilling rig. The well is located 4 km east of the Etuko-1 well. The well drilled to a total depth of 1,911 mMD (-1,911 mTVDKB) and discovered oil-bearing sandstones within the Lokone Shale Formation. The well was suspended and announced as a discovery in December 2014.

The Etom Field, located north of the Agete Field, was discovered by two exploration wells, Etom-1, and Emekuya-1. The Etom-1 well was drilled with the Weatherford 804 drilling rig, spudding on July 13, 2014. The well drilled to a total depth of 2,000 mMD (-2,000 mTVDKB) and encountered hydrocarbons in the Lower Auwerwer Formation as well as sandstones equivalent in age to the Lokone Shale Formation. The Emekuya-1 well was drilled with the Marriot 46 drilling rig spudding on April 25, 2017. The well was drilled to a total depth of 1,356 mMD (-1,356 mTVDKB) and found oil bearing sandstone in the Lower Auwerwer Formation and the Lokone Shale Formation. The Etom field was announced as a discovery in December 2014.

The Erut-1 well is located 12 km northeast of the Etom Field and was spudded on December 19, 2016, by the Marriot 46 drilling rig. The well drilled to a total depth of 1,317 mMD (-1,317 mTVDKB) and discover oil bearing sandstone in the Lokone Shale Formation and evidence of hydrocarbons in the Lower Auwerwer Formation. The well was suspended and announced a discovery in January 2017.

Four unsuccessful exploration wells were drilled in the Lokichar basin: Emong-1, Ekunyuk-1, Ekosowan-1, and Etir-1 did not provide material indications of hydrocarbons and were abandoned and classified as dry holes.

4.1.3 Appraisal

In 2014, the appraisal and delineation of the fields discovered in the South Lokichar Basin during the main exploration phase began. The primary purpose of the appraisal program was to gain further information and confidence in reservoir and non-reservoir facies distributions, structural configuration, fluid contacts and reservoir and fluid properties. To date, twenty-six appraisal wells have been drilled in the South Lokichar Basin (Section 14 / Section 15).

During the appraisal drilling phase, additional data including conventional and sidewall cores, formation pressures and samples, and conventional wireline logs were acquired to help uncertainties identified in the exploration phase. Later in the appraisal phase, less time consuming and less expensive data acquisition techniques such as replacing wireline logging tools with logging while drilling (LWD) data acquisition were employed which will be carried forward into the development phase.

In addition to drilling appraisal wells, another part of the appraisal program was the acquisition of 3D seismic to reduce uncertainties in the structural configuration of the fields. A more detailed discussion on the 3D seismic acquisition is provided in the geophysics section. As will be discussed in the individual field description sections, there are still uncertainties that exist in the different fields and further appraisal in conjunction with early development activities may be warranted.

4.2 Geology

4.2.1 Regional Structural and Stratigraphic Setting

The South Lokichar Basin is a NNW-SSE trending asymmetrical half graben within the Turkana Rift of the Great East African Rift System. The South Lokichar Basin is approximately 70 km long and 35 km wide at its maximum extent and covers an area of approximately 1700 km^2.

The South Lokichar Basin has a straightforward half-graben geometry with Lower to Middle Miocene syn-rift sediments thickening westwards towards the basin bounding north-south trending Lokichar Fault (Figure 4-3 and Figure 4-4). Displacement along the east dipping basin bounding Lokichar Fault dies out along strike to the north and south with the maximum displacement located near the centre of the fault. The syn-rift sediments thicken along this north-south trend towards the centre of the basin as shown in Figure 4-5. The depositional centre of the basin is offset from the Ekales field where the thickest section of syn-rift sediments is present, as shown in Figure 4-6. The basin is bounded to the east on the flexural margin by the Lokone Horst bringing Pre-Cambrian aged crystalline metamorphic rocks to surface.

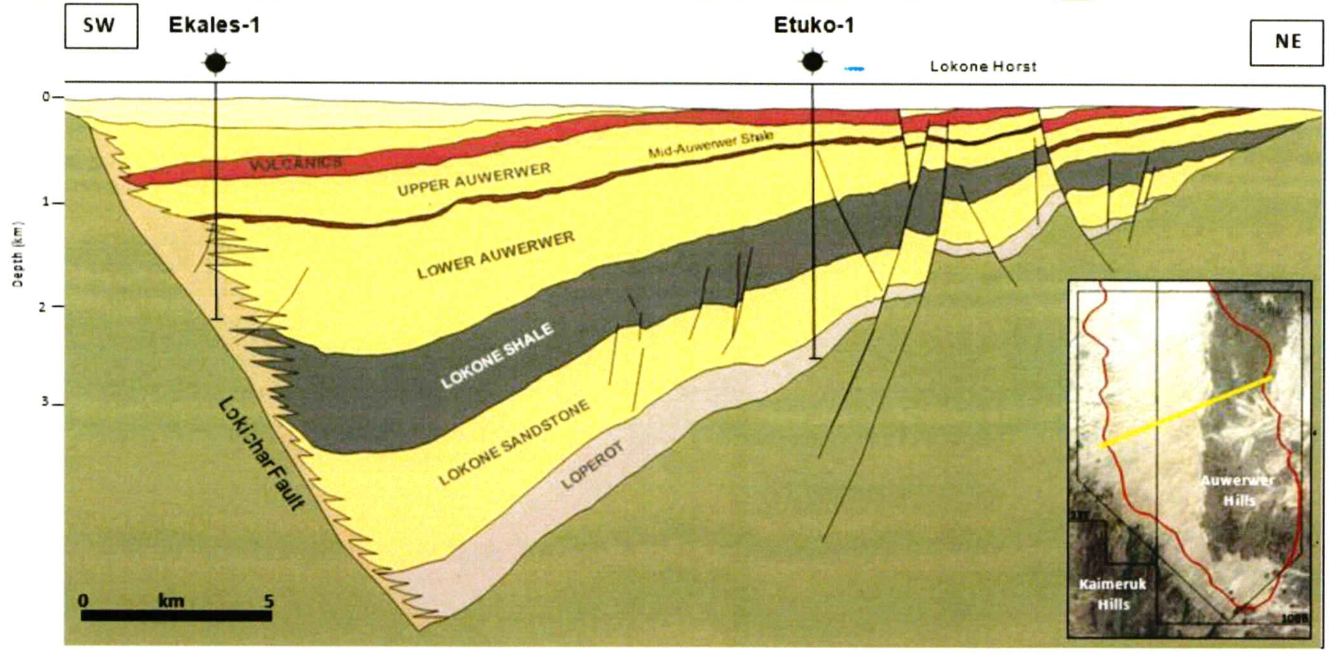


Figure 4-3: Stratigraphic Cross-Section, Lokichar Basin

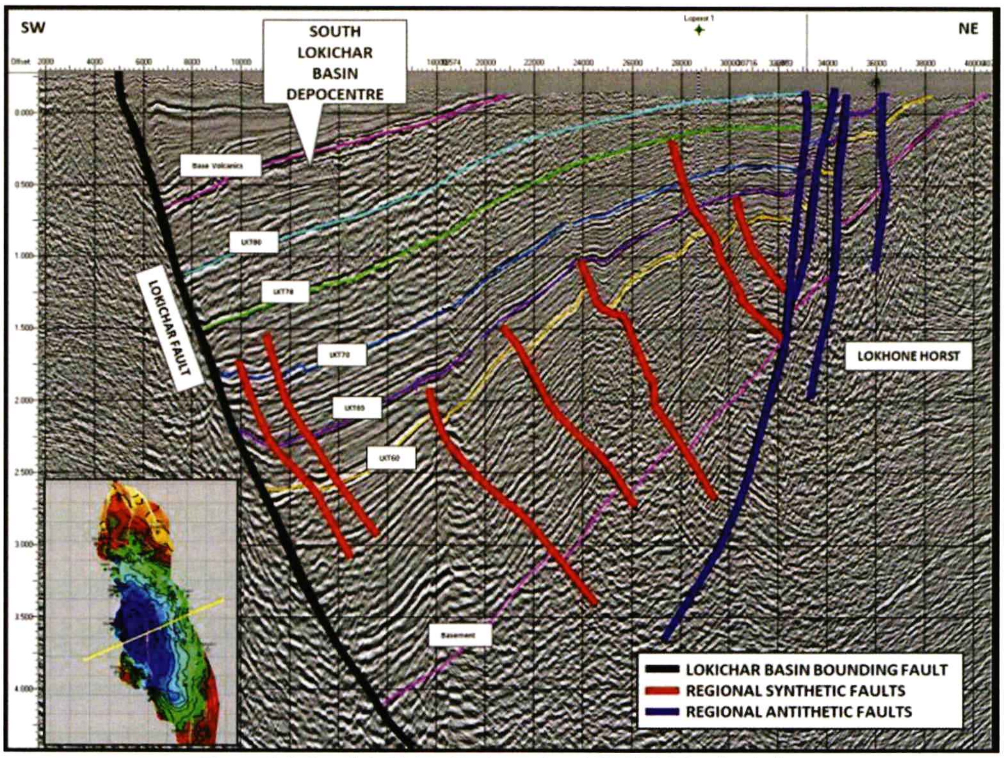


Figure 4-4: South Lokichar Basin regional SW-NE 2D seismic line

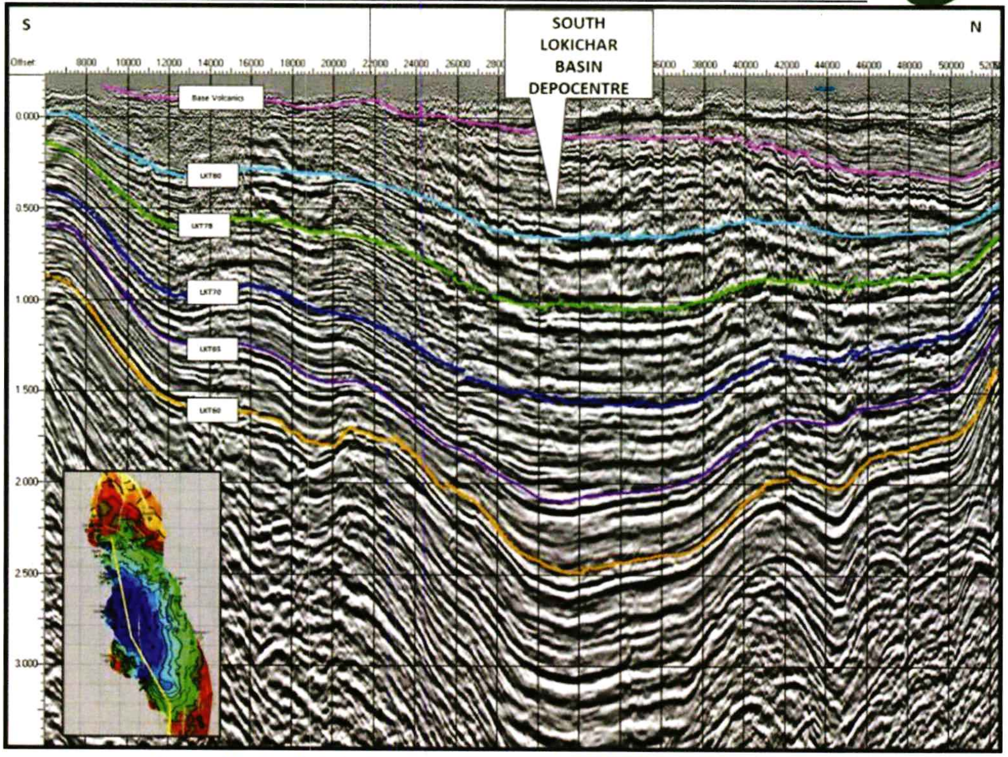


Figure 4-5: South Lokichar Basin Regional S-N 3D RAP PreSTM seismic line

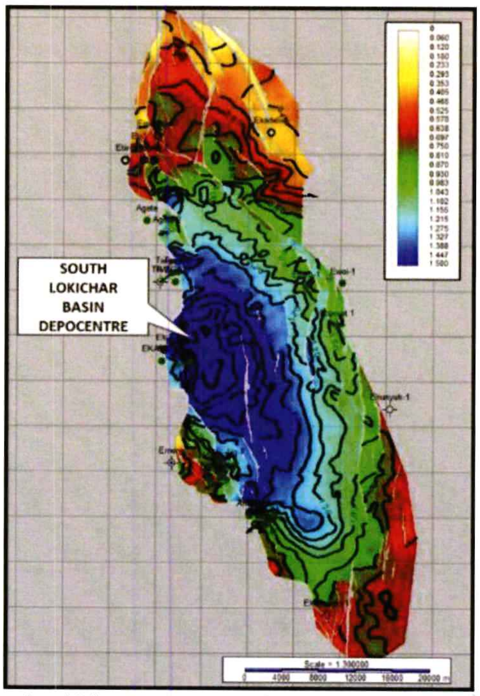


Figure 4-6: South Lokichar Basin Regional LKT60 to LKT80 isochron (seconds)

The basin stratigraphy can be described in terms of a series of pre-rift, syn-rift and post-rift sequences. The pre-rift sequence is composed of Pre-Cambrian crystalline metamorphic rocks consisting of heterogeneous and highly tectonisized units of amphibolite, gneissen, schists and migmatites dated between 500 and 600 million years. The overlying syn-rift sequence of up to 5 km in thickness consists of fluvial-lacustrine sediments biostratigraphically dated as Lower to Middle Miocene. This sequence is capped by phonolitic basalts dated 12 to 16 million years. The post-rift sequence, above the Miocene Unconformity, consists mainly of Pliocene to Holocene alluvium, fluvial and loess deposits.

The primary reservoirs in the South Lokichar Basin are in the Lower Auwerwer and Lokone Formations (Figure 4-7). The Lokone Formation is separated into two units, the Lokone sandstone and overlying Lokone Shale. Reservoirs in the Lokone Sandstone unit are described as gravity flow deposits shed into a lacustrine system with the intervening shales being lacustrine shales. The reservoirs within the Lokone Shale unit are also gravity flow deposits into a lacustrine setting, with these sandstones, completely encased in shales, commonly appearing to be overpressured. The Lower Auwerwer reservoir sandstones are a series of stacked fluvial deposits interbedded with mud and silt-dominated alluvial plain deposits. These finer grained layers act as intraformational seals generating a series of stacked hydrocarbon pools.

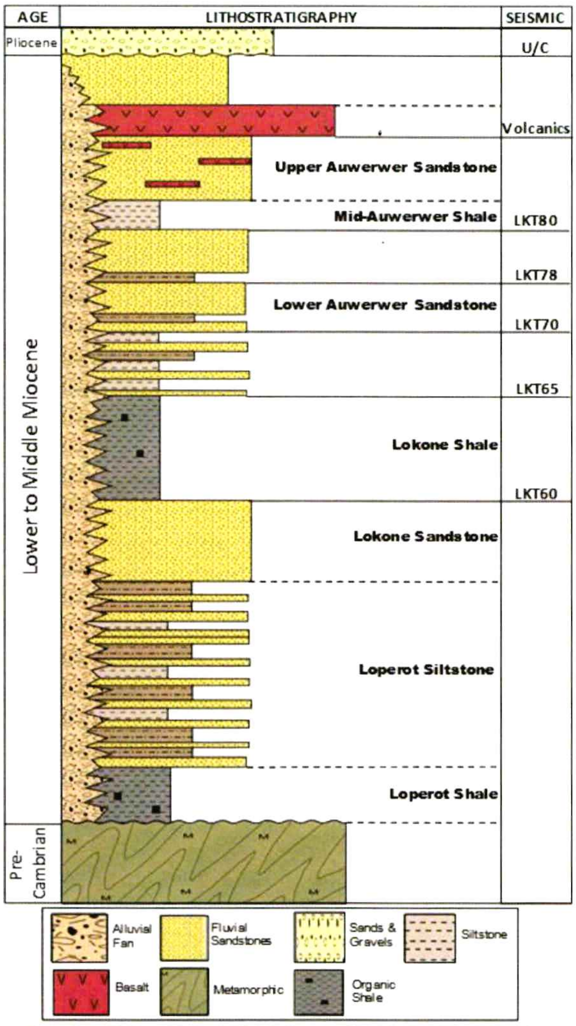


Figure 4-7: Stratigraphic Column, South Lokichar Basin

Figure 4-7 also shows seismic picks associated with the lithostratigraphy of the South Lokichar Basin. These seismic picks are based on events described below.

- Volcanics – marks the transition of the volcanic sequence to stacked fluvial sandstones of the Upper Auwerwer Formation. The thickness of the volcanic sequence varies across the South Lokichar Basin and is completely eroded on the eastern side of the basin. The volcanic sequence is a key layer in the depth conversion stage of the seismic horizons due to the high seismic velocity and density and variable thickness of the unit. The base volcanic is a good regional seismic marker across the basin.
- LKT80 – marks the base of the Mid Auwerwer Shale which is a basin wide lacustrine shale and the top of the Lower Auwerwer Formation. The Lower Auwerwer Formation consists of interbedded fluvial sandstones and thin alluvial plane shales.
- LKT78 – marks the base of a thin basin wide shale that may have been the result of a major flooding event throughout the South Lokichar Basin.

- LKT70 – marks the base of the Lower Auwerwer Formation as it transitions into the lacustrine shales of the Lokone Formation. The quality of the LKT 70 seismic marker varies from poor to good across the South Lokichar Basin due to the transitional nature.
- LKT65 – marks the top of the Lokone Shale formation. It comprises lacustrine shale deposits with interbedded sandstone gravity flow deposits. The quality of the LKT 70 seismic marker varies from poor to good across the South Lokichar Basin.
- LKT60 – marks the base of the Lokone Shale Formation as it transitions into the gravity flow sandstones interbedded with lacustrine shales of the Lokone Sandstone Formation. The quality of the LKT60 seismic marker varies from poor to good across the South Lokichar Basin due to the transitional nature of the Lokone Sandstone Formation.

The South Lokichar Basin internal regional structural geometry is dominated by a series of synthetic and antithetic normal faults that are parallel or sub-parallel to the NNW-SSE trending basin bounding Lokichar Fault. Examples of the regional synthetic and antithetic faults are shown on the NE-SW 2D seismic line in Figure 4-4. Timing of the synthetic faults, for the most part, was during deposition of the LKT70 source rock. Thickening of the LKT70 source rock in the hanging wall of the synthetic faults is evident. Displacement of formations above the LKT70, along the fault trends are minimal or non-existent as shown in Figure 4-4. Timing of the antithetic fault trends tends to be post syn-rift deposition and, for the most part, is associated with the late uplift of the Lokone Horst on the east side of the basin as shown in (Figure 4-4). The South Lokichar Basin is dominated by extensional roll-over anticlinal structures within the hanging wall of the basin-bounding Lokichar Fault and horst and graben style block faulting structures on the flexural margin of the east side. Many of the hanging wall roll-over anticlinal structures exhibit a late stage crestal collapse consisting of both synthetic and antithetic faults as shown in Figure 4-3.

4.2.2 Environment of Deposition

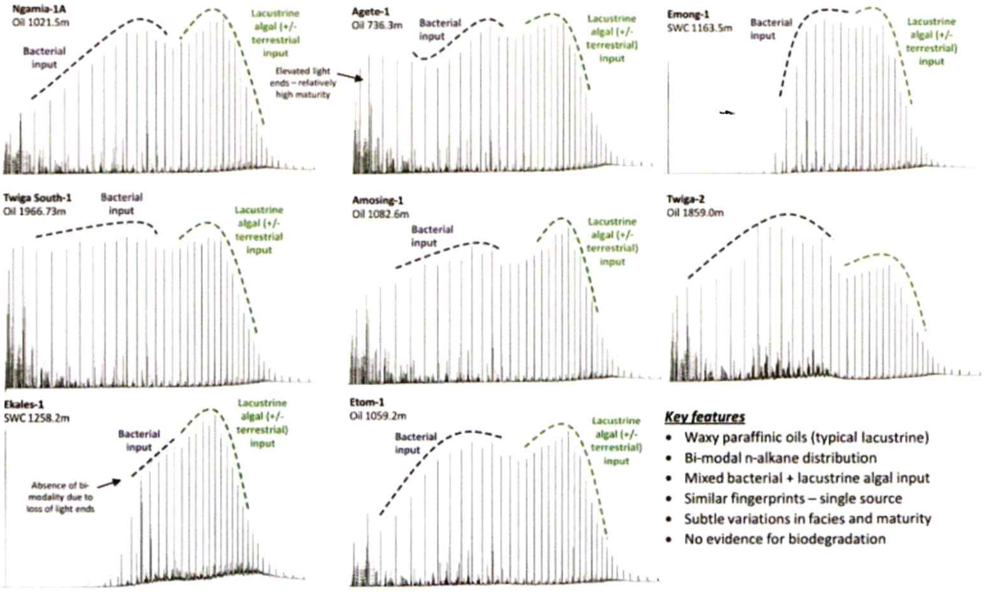
The depositional environment in the South Lokichar Basin during Miocene time is interpreted as terrestrial with predominantly fluvial, lacustrine, alluvial plain, and alluvial fan deposits.

The lower most reservoir of the Lokone sandstones are interpreted as gravity flow deposits generated by near floor sandstone being deposited out into the lacustrine setting during storm events. These deposits become less common into the lower part of the Lokone shale section as the basin subsided and relative lake level rose. It is during this time in the early phase of the Lokone shale deposition that the primary lacustrine source rock was deposited. Later in the development of the Lokone shales, gravity flow deposits returned and are present in the upper part of this section as part of the gradual transition from the Lokone shale into the Lower Auwerwer Formation. This transition sees sediment deposition changing from predominantly lacustrine to mainly alluvial plain with stacked fluvial deposits that make up the primary reservoir in the basin. This section of alluvial and fluvial deposits is capped by the lacustrine shales of the mid-Auwerwer. On the western side of the basin adjacent to the rift bounding fault, alluvial fan deposits are encountered. These deposits tend to be very immature in nature and are non-reservoir in every location it has been encountered to date.

4.2.3 Geochemistry/Source Rocks/Maturation

The main source rock interval in the South Lokichar Basin is the Lokone Shale which contains an average 3.5% total organic carbon (TOC). The maceral composition of the organic matter is dominated by lipinite rich Type I kerogen. Type I kerogens are typically found in lacustrine environments and yield low gas-oil-ratio, waxy crude oils. Secondary source rock potential has also been identified in the older Loperot Shale with residual total organic carbon values of up to 4.5%. The Lokone Shale is estimated to be more than one kilometer in thickness in the center of the basin. Maturation studies confirm that the Loperot Shale is in the oil window in the center of the basin, present-day. The Loperot Shale has higher maturity and is at the end of its oil- generation phase or entering a gas-generation phase in the deepest parts of the basin.

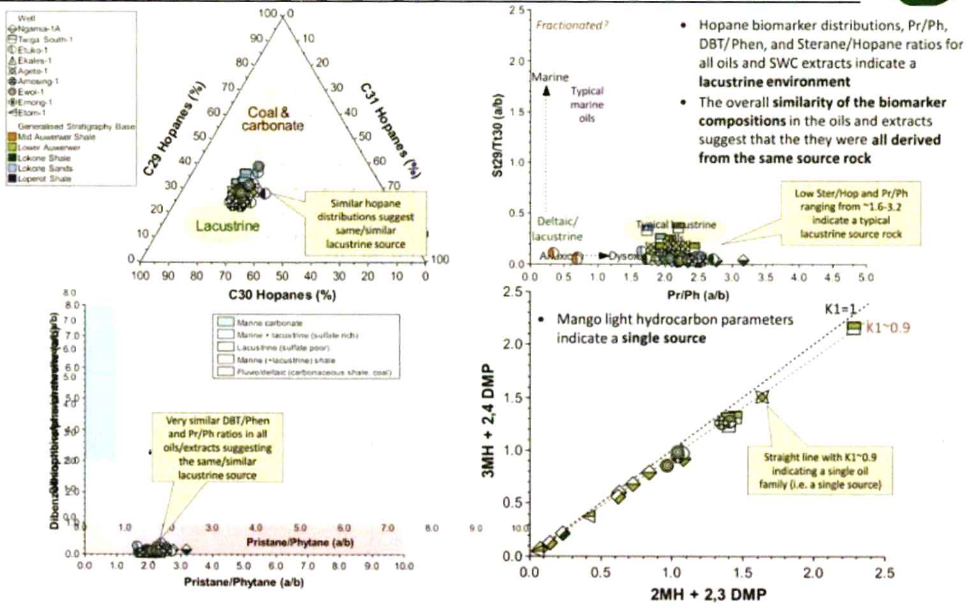
Figure 4-8 and Figure 4-9 illustrate geochemical properties of oils from the South Lokichar Basin. The data illustrates that the oil analyzed from the different wells is from the same source rock. The source rocks are the lacustrine shales of the Lokone Shale. The maturity of the source rock is illustrated in Figure 4-10. While oil is the dominant hydrocarbon in the basin, some of the Lokone source rock has entered the gas generation window. The oil in the South Lokichar Basin typically has a low gas oil ratio (GOR), however there have been zones with free gas identified in many of the fields in both the Lower Auwerwer and Lokone reservoirs.



Key features

- Waxy paraffinic oils (typical lacustrine)
- Bi-modal n-alkane distribution
- Mixed bacterial + lacustrine algal input
- Similar fingerprints – single source
- Subtle variations in facies and maturity
- No evidence for biodegradation

Figure 4-8: Whole oil gas chromatograph data from South Lokichar oil samples



Similar hopane distributions suggest same/similar lacustrine source

- Hopane biomarker distributions, Pr/Ph, DBT/Phen, and Sterane/Hopane ratios for all oils and SWC extracts indicate a **lacustrine environment**
- The overall **similarity of the biomarker compositions** in the oils and extracts suggest that the they were **all derived from the same source rock**

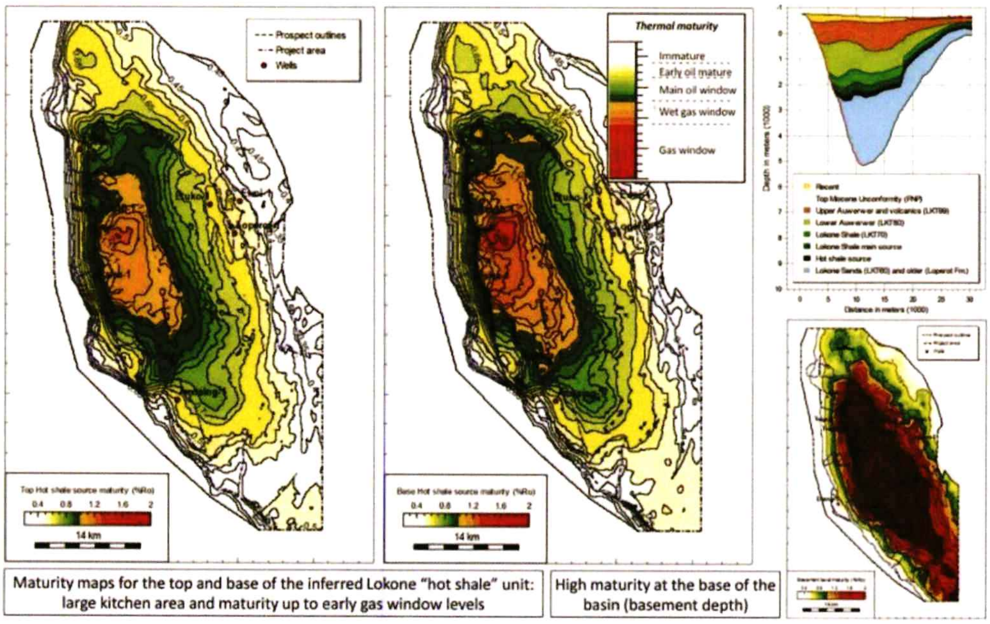
Low Ster/Hop and Pr/Ph ranging from ~1.6-3.2 indicate a typical lacustrine source rock

Very similar DBT/Phen and Pr/Ph ratios in all oils/extracts suggesting the same/similar lacustrine source

- Mango light hydrocarbon parameters indicate a **single source**

Straight line with K1~0.9 indicating a single oil family (i.e. a single source)

Figure 4-9: Geochemistry of oils in the South Lokichar Basin



Maturity maps for the top and base of the inferred Lokone "hot shale" unit: large kitchen area and maturity up to early gas window levels

High maturity at the base of the basin (basement depth)

Figure 4-10: Source rock maturity maps of the South Lokichar Basin

4.3 Geophysics

4.3.1 Full Tensor Gradiometry

In 2011, Full Tensor Gradiometry (FTG) surveys were conducted, covering the South Lokichar Basin as shown in Figure 4-11. FTG provides a measurement of the earth's gravitational field, allowing the identification of basement highs (red colour on the map) and basement lows (blue colour on the map). Basement lows are interpreted as possible sedimentary basin depocenters where sediments accumulate over time.

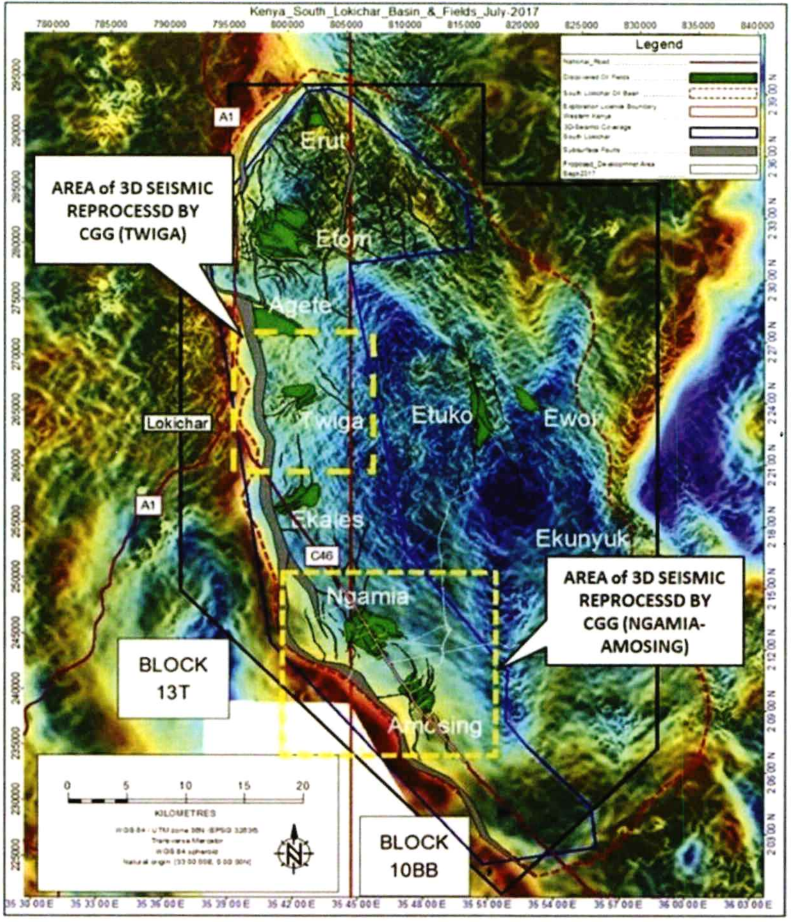


Figure 4-11: Full Tensor Gradiometry survey and 3D seismic coverage within the South Lokichar Basin

4.3.2 2D Seismic Data

There is about 1600 km of 2D legacy seismic data within the Lokichar Basin. The 2D legacy seismic data was used to define structures and trends within the South Lokichar Basin and for layout and planning of an additional 2000 km of 2D seismic acquisition in basin. The 2D seismic data were used to plan the early exploration wells and many of the initial appraisal wells between 2012 and late 2014. The data was also used to define the key structural and stratigraphic elements of the South Lokichar Basin and helped with the layout and design of the 2014 3D seismic program. The 2D seismic dataset within Blocks 10BB and 13T is shown in Figure 4-12.

4.3.3 3D Seismic Data

Figure 4-12 shows the outline of the 950 km^2 of 3D data acquired on the western side of the South Lokichar Basin. It was acquired in two segments: a southern area over Agete, Twiga, Ekales, Ngamia and Amosing and a second area over Etom and Erut.

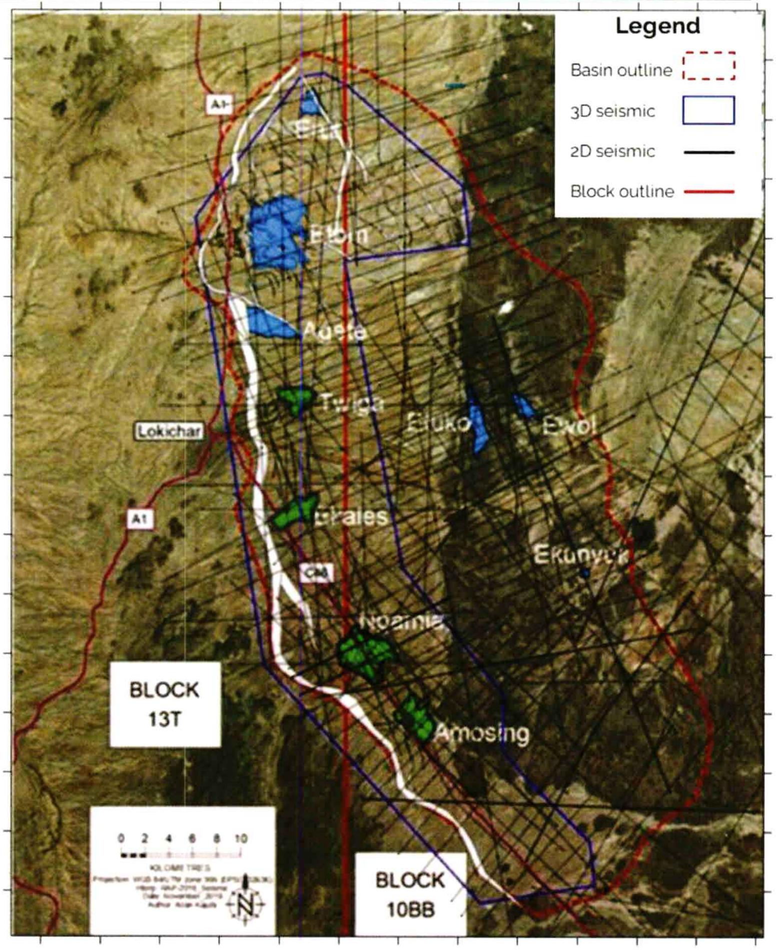


Figure 4-12: 3D seismic coverage (blue polygon) and 2D seismic lines (black lines) in the South Lokichar Basin

The following 3D seismic processing phases were undertaken by Tullow Oil's Geophysical Technology Group between 2014 and 2016:

Fast-track seismic processing sequence with a complete Post Stack Time Migration (PostSTM) dataset delivered in Q2 2015. The full 950 km^2 3D seismic data was merged and processed through a more complex processing flow with linear and random noise attenuation, refraction statics and deconvolution. A final Pre-Stack Time Migration (PreSTM) product was generated in Q3 2015. The 3D PreSTM data set was used to interpret the horizon inputs for the first iteration of the subsurface modelling carried out in 2015. The 3D Pre STM data set was not processed with a surface consistent amplitude correction and is not suitable for quantitative data analysis such as amplitude versus offset analysis.

In 2016, an additional processing phase was undertaken on the full 950 km^2 3D seismic data set to generate surface consistent processed outputs in a Relative Amplitude Processing (RAP) workflow. The main additional processing steps applied in this phase were improved refraction statics, additional linear denoise, demultiplex and surface consistent amplitude correction. Updated stacking velocity analysis was undertaken with a focus on stratigraphic consistency. Also, a larger offset range was input to the pre-stack time migration. This RAP PreSTM was used to interpret new horizon inputs for iteration second subsurface modelling in 2016.

Following a review of the RAP PreSTM 3D processing in Q4 2016, reprocessing of 300 km2 of the 3D seismic data set commenced over the Ngamia and Amosing fields. The objective of the reprocessing was to make improvements to the pre-processing techniques addressing ground roll related noise removal. This reprocessing project was undertaken by CGG in during 2017, with the aim to leverage a more sophisticated denoise workflow to maximize signal-to-noise ratio of data input to an azimuthally sectored PreSTM as well as a Pre-Stack Depth Migration (Pre SDM). The PreSTM data was utilized for comparison with subsurface models and to better understand variation in GRV. The final PreSDM product will be used to assess changes in the structural and stratigraphic interpretation of the Ngamia and Amosing fields and execute phase well planning at pad scale.

4.3.4 Synthetic Well Ties to RAP PreSTM 3D Seismic Data

Synthetic gathers were generated for a series of wells drilled in the South Lokichar Basin. This allowed correct correlation of the available well log data used to create the synthetic gathers and the RAP PreSTM seismic data. The synthetic well ties were generally good throughout the South Lokichar Basin but the reliability of the synthetic well ties to the RAP PreSTM seismic data varies as a function of borehole deviation, seismic data quality, level of structural complexity and near surface multiples.

An example of a synthetic well tie to the RAP PreSTM seismic data is demonstrated for the Ngamia-3 well in Figure 4-13. The last track in Figure 4-13 shows a good quality match between the synthetic trace and the RAP PreSTM at all LKT seismic markers.

The seismic has SEG normal polarity, where an increase in amplitude impedance corresponds to a positive amplitude (peak).

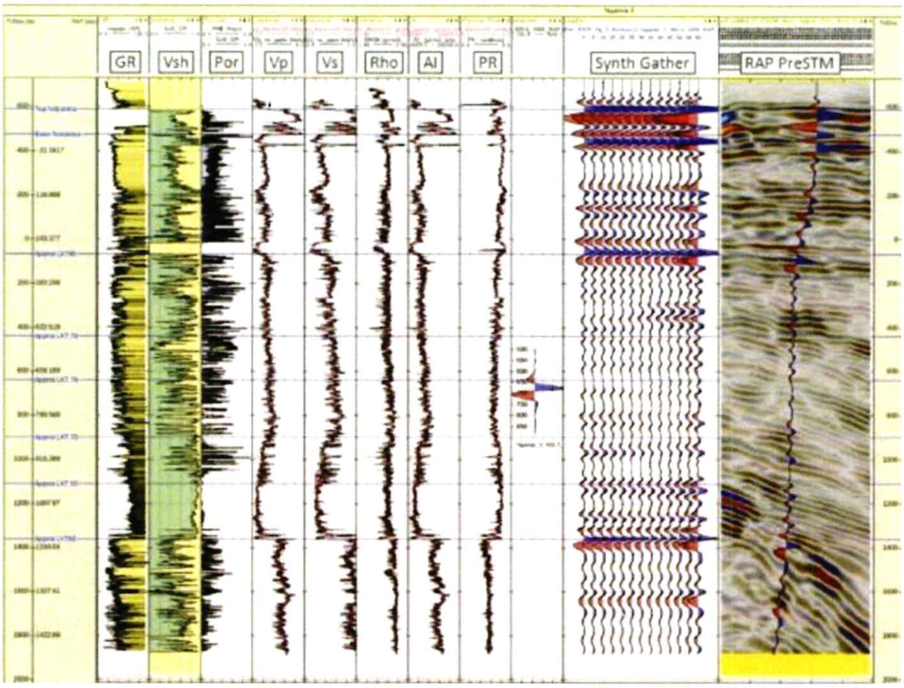


Figure 4-13: Synthetic well tie and synthetic gather at Ngamia-3

4.4 Petrophysics

This section documents the logging and coring programs conducted in both the exploration and appraisal wells in the South Lokichar Basin. The petrophysical analysis of the data and subsequent interpretations of rock quality and fluid contents are challenging in the South Lokichar Basin. Key difficulties include the determination of the volume of shale in the reservoir sections and determination of water saturation.

4.4.1 Data Acquisition Program

Since the drilling of the first South Lokichar Basin Well (Ngamia 1/1A) in 2012, to the latest well (Amosing-7) in 2017, data acquisition has evolved through changes in drilling practices, mud systems, and continued attempts to reduce well costs (Section 14). A data acquisition programme has been carried out in all wells with wireline logs, wireline downhole pressure and fluid samples, core and rotary side-wall-cores. Digital log data has been acquired on pipe with the deployment of advanced logging while drilling tools (LWD). Early wells in the basin were drilled with water-based mud systems (WBM) but, due to hole stability issues, later wells have been drilled with an oil-based mud system.

The basic set of data required for the petrophysical analysis are gamma ray, sonic, neutron-density and resistivity logs. Early wells acquired the gamma ray and resistivity logs while drilling and the sonic and neutron density logs on wireline but in later appraisal wells these logs were all acquired while drilling. Other logs, such as nuclear magnetic resonance and image logs, were acquired in some early wells but typically not present in the later appraisal wells.

The log database is summarised in Table 4-1.

Table 4-1: Exploration and Appraisal Well Log Inventory

	LWD			Wireline																
	GR	Den Neu	RES	SGR	SP	RES	Micro LL	Cali	STAR FMI	EI OBMI	CBIL	ECS FLeX	CMR MReX	Den Neu	Sonic	MDT RCI	VSP	SBT CBL	SWC	RSWC
Agete-1	x		x	x	x	x	x	x	x				x	x	x	x	x	x	x	
Agete-2	x		x		x									x						
Amosing-1	x		x	x		x	x	x	x		x		x	x	x	x	x	x	x	x
Amosing-2				x		x		x		x	x	x	x	x	x	x	x			
Amosing-2A	x		x	x		x		x		x	x	x	x	x	x	x	x	x		
Amosing-3	x		x	x		x		x		x	x		x	x	x	x	x	x		
Amosing-4	x			x		x		x					x	x	x	x	x	x		
Amosing-5	x			x		x		x		x				x	x	x	x	x		
Amosing-5A	x			x		x		x						x	x	x		x		
Amosing-6	x	x	x	x		x		x		x				x	x	x	x	x		
Amosing-7	x	x	x	x		x		x						x	x	x	x	x		
Cheptuket-1	x			x		x		x		x	x			x	x	x	x	x		x
Ekales-1	x		x	x	x	x		x	x				x	x	x	x	x	x	x	x
Ekales-2	x			x		x		x		x			x	x	x	x	x	x		x
Ekales-3	x	x	x			x		x						x	x	x	x	x		
Ekosowan-1	x		x	x	x	x		x		x	x		x	x	x	x	x			x
Ekunyuk-1	x		x	x	x	x	x	x	x				x	x	x	x		x		
Emesek-1	x			x		x		x						x	x	x	x			x
Emong-1	x		x	x	x	x	x	x	x				x	x	x	x	x	x	x	x
Engomo-1	x			x		x		x						x	x	x	x			x
Epir-1	x			x		x		x					x	x	x	x	x	x	x	x
Erut-1	x			x		x		x		x				x	x	x	x	x		x
Etbir-1	x			x		x		x						x	x	x	x	x		x
Etom-1	x		x	x	x	x	x	x	x				x	x	x	x	x			x
Etom-2	x			x		x		x			x		x	x	x	x	x	x		x
Etom-3	x	x	x	x		x		x		x				x	x	x	x	x		x
Etuko-1	x		x	x	x	x		x	x				x	x	x	x	x			x
Etuko-2A	x		x	x	x	x	x	x	x				x	x	x	x				
Ewoi-1	x		x	x	x	x	x	x	x				x	x	x	x	x		x	x
Kodos-1	x		x	x	x	x		x	x				x	x	x	x	x	x		x
Ngamia-1A	x		x	x	x	x	x	x	x			x	x	x	x	x	x	x	x	
Ngamia-2	x		x	x		x	x	x		x	x	x	x	x	x	x	x	x		x
Ngamia-3	x		x	x		x		x		x	x	x	x	x	x	x	x	x		x
Ngamia-4	x		x	x		x		x		x	x	x	x	x	x	x		x		
Ngamia-5	x	x	x	x		x		x		x	x	x	x	x	x	x	x	x		
Ngamia-6	x	x	x	x		x		x					x	x	x	x	x	x		
Ngamia-7	x			x		x		x					x	x	x	x	x	x		
Ngamia-8	x			x		x		x					x	x	x	x	x	x		
Ngamia-9	x			x		x		x					x	x	x	x	x			
Ngamia-10	x	x	x	x		x		x		x				x	x	x	x	x		
Ngamia-11	x	x	x	x		x		x		x				x	x	x		x		
Paipai-1	x			x	x	x		x	x			x	x	x	x	x	x	x	x	x
Twiga-1	x		x	x	x	x	x	x	x			x	x	x	x	x	x		x	x
Twiga-2	x		x	x		x	x	x		x		x	x	x	x	x	x	x		x
Twiga-2A	x		x	x		x		x		x	x			x	x	x				
Twiga-3	x			x	x	x		x		x	x		x	x	x	x		x		

🟨	SOBM
🟧	K2SiO3 WBM
🟦	Polymer WBM

GR	Gamma Ray	**SP**	Spontaneous Potential	**WLPS**	Wireline Pressure and Sampling
DEN	Density	**CALI**	Calliper	**VSP**	Vertical Seismic Profile
NEU	Neutron	**Image RES**	Micro-Resistivity image log	**CBL**	Cement Bond Log
SONIC	Sonic	**Image ACOUSTIC**	Acoustic image log	**SWC**	Side Wall Core - Percussion
RES	Resistivity	**ES**	Elemental Spectroscopy	**RSWC**	Rotary Side Wall Core
SGR	Spectral Gamma Ray	**NMR**	Nuclear Magnetic Resonance		

Formation pressures and samples were taken with repeat formation testing tools on wireline. This data is used to interpret hydrocarbon contacts as well as provide additional information on formation quality through estimates of fluid mobility in the reservoir. Fluid samples were acquired to provide quick look analysis at the well site as well as further PVT analysis on pressurized and non-pressurized samples in the laboratory environment.

Vertical seismic profiles (VSP) were acquired in all the exploration wells and many of the appraisal wells. This data is used to tie the geological formation tops to the seismic data.

4.4.2 Core Data

Forty-five conventional whole cores have been taken from 15 exploration and appraisal wells of which 73% of samples taken have been taken from the Lower Auwerwer Formation. A breakdown of core acquired by well and reservoir can be seen in Table 4-2. In addition, a total of 1,049 sidewall cores, both percussion and rotary type, have been taken from 21 wells.

In Q1 2016, in keeping with the principles of Clause 14 PSCs the Contractor repatriated a representative part of the cores (the 1/3 cut) to be stored at the NOCK facility in Nairobi.

A total of forty-seven conventional cores from 15 wells were acquired during the exploration and appraisal period of the Lokichar Basin. In addition to the conventional full diameter cores, hundreds of both percussion and rotary sidewall cores were also taken from eighteen wells.

Table 4-2: Whole core database (Source: Tullow Oil)

Well	Cores	Core Thickness (m)	Core Thickness (m)	
			Auwerwer	Lokone
Agete-1	1	52.3	52.3	
Amosing-2	1	10.9	10.9	
Amosing -2A	4	212.9	159.9	53.0
Amosing-6	3	94.9	94.9	
Amosing-7	1	54.3		54.3
Ekales-1	3	39.0	39.0	
Emekuya-1	3	109.6	55.0	54.6
Etuko-1	5	74.7		74.7
Etuko-2A	4	54.2	55.2	
Ngamia-2	7	263.2	232.2	31.0
Ngamia-3	3	162.6	162.5	
Ngamia-4	1	55.0	55.0	
Ngamia-5	2	81.6	53.7	27.9
Ngamia-10	1	46.9		46.9
Twiga South-1	6	121.7	41.9	79.8
Total	**45**	**1433.8**	**1012.5**	**422.2**

Plugs taken from the conventional full diameter cores have been analysed for routine core analysis measurements including porosity, permeability, and grain density. Dean-Stark analysis was also conducted on numerous plugs to give an estimate of in-situ fluid saturations. Some of the rotary sidewall cores acquired were also analysed for basic porosity, permeability, and grain density. Select plugs had thin sections cut and were reviewed petrographically to aid in describing the reservoir quality and components. Some special core analysis (SCAL) was performed on both full diameter preserved sections of the core as well as plugs. Most of this analysis was conducted for production or reservoir engineering purposes.

Figure 4-14 shows a porosity-permeability plot for all plugs analysed from conventional full diameter cores in the South Lokichar Basin (except Amosing-7). The data displayed includes data from all formations, reservoir, and non-reservoir rock types.

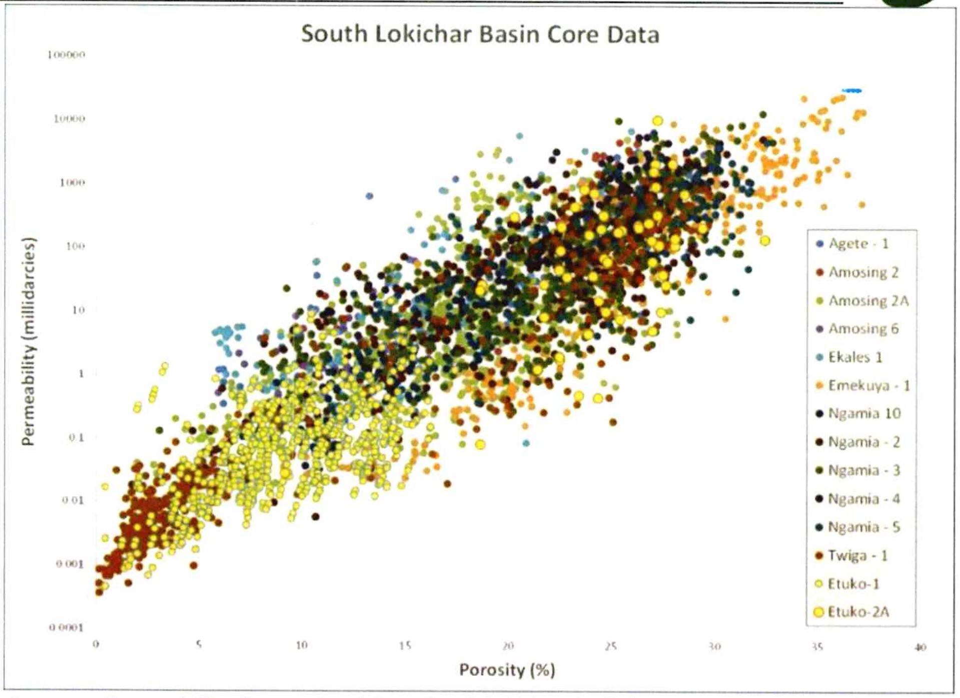


Figure 4-14: Porosity versus Permeability, Conventional Core, South Lokichar Basin (Note: Amosing-7 core data not included as found to be non-reservoir)

Figure 4-15 is a plot showing the relationship of porosity versus depth. While there is a general trend of porosity with depth, the main ranges of porosity are primarily controlled by facies changes and diagenesis of the different rock types.

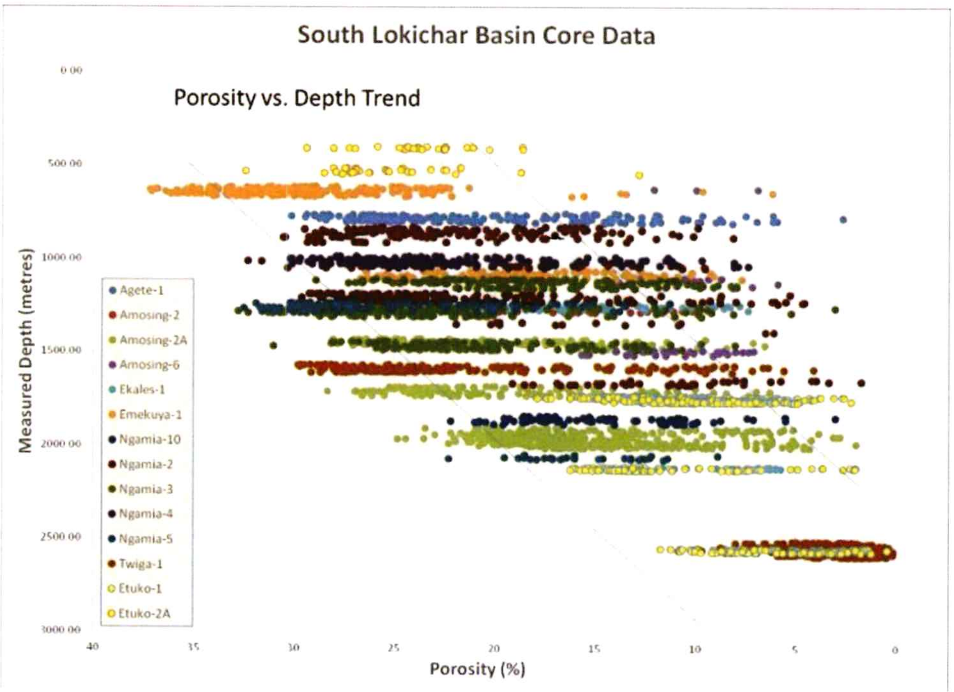


Figure 4-15: Porosity versus Depth Plot, Conventional Core Data, South Lokichar Basin

An extensive reservoir fluid sampling campaign has been conducted during exploration and appraisal drilling and testing. Three hundred and seventy-six fluid oil samples have been acquired from 31 wells across the majority of hydrocarbon bearing reservoirs in nine out of the ten discoveries. Pressurised samples were taken using downhole wireline samplers during logging operations and during flow testing operations (both DST and EWT) for PVT laboratory experiments. Atmospheric (dead oil) samples were taken for crude assay and production technology fluid characterisation. A listing of the acquired samples is shown in Table 4-3 and Figure 4-16. It should be noted that a subset of these have been retained in the UK for ongoing and future analysis.

Table 4-3: Oil sample inventory

Well	Wireline	Flow Test	Atmospheric	Pressurised
Agete	14	20	11	23
Amosing	43	10	3	50
Ekales	15	4	6	13
Erut	17	0	11	6
Etom	23	0	0	23
Etuko	19	16	1	34
Ewoi	20	0	0	20
Ngamia	81	38	20	99
Twiga	24	32	12	44
Totals	**256**	**120**	**64**	**312**

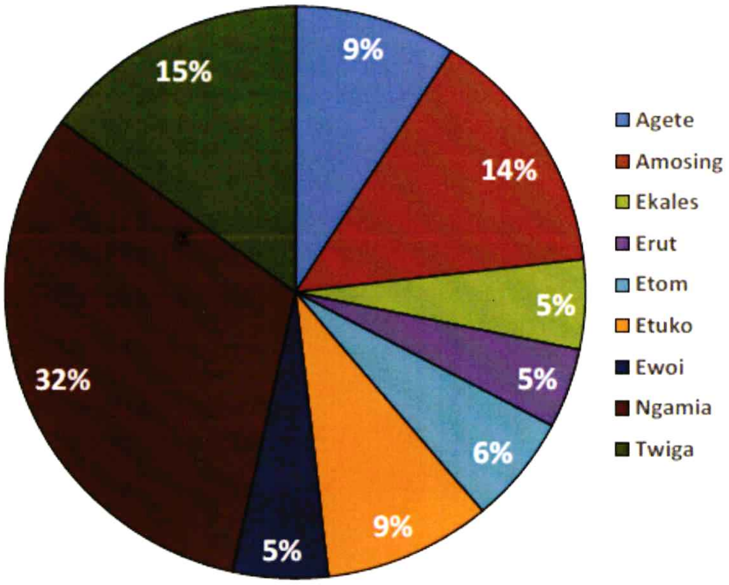


Figure 4-16: Oil sample inventory (%) (Source: Tullow Oil)

4.4.3 Calibration of Log to Core Data

An integrated petrophysical interpretation has been caried out across all wells. The data has been conditioned, depth shifted and logs curves spliced where necessary. Bad hole sections were identified. Log data has been calibrated to core for the determination of porosity, volume of clay and water saturation. This calibration has then been carried forward into the static modelling, especially with regards to water saturation which is populated in the model using a saturation height function.

4.4.4 Petrophysical Methodology

An integrated petrophysical interpretation has been caried out across all wells. The main purposes of the petrophysical workflow are to characterise the reservoir components and quality, and to describe rock facies by using core analysis and log data acquired from the well bores. This analysis is used in the calculation of hydrocarbons in place as well as representing the dynamic potential of these resources. The primary inputs to the analysis are the log, core and dynamic flow data acquired during the exploration and appraisal phase of the project. The main deliverables for the petrophysical analysis are to generate a representative volume shale, porosity, permeability and water saturation. A visual illustration of the petrophysical workflow can be seen in Figure 4-17. The key steps can be summarised to:

- Raw data management, preparation and zonation

- Generation of Volume of Shale (Vsh), porosity, permeability and water saturation
- Integration of fluid data and calibration to core
- Integration of petrophysical analysis to static modelling
- Cut-off analysis and interpretation management.

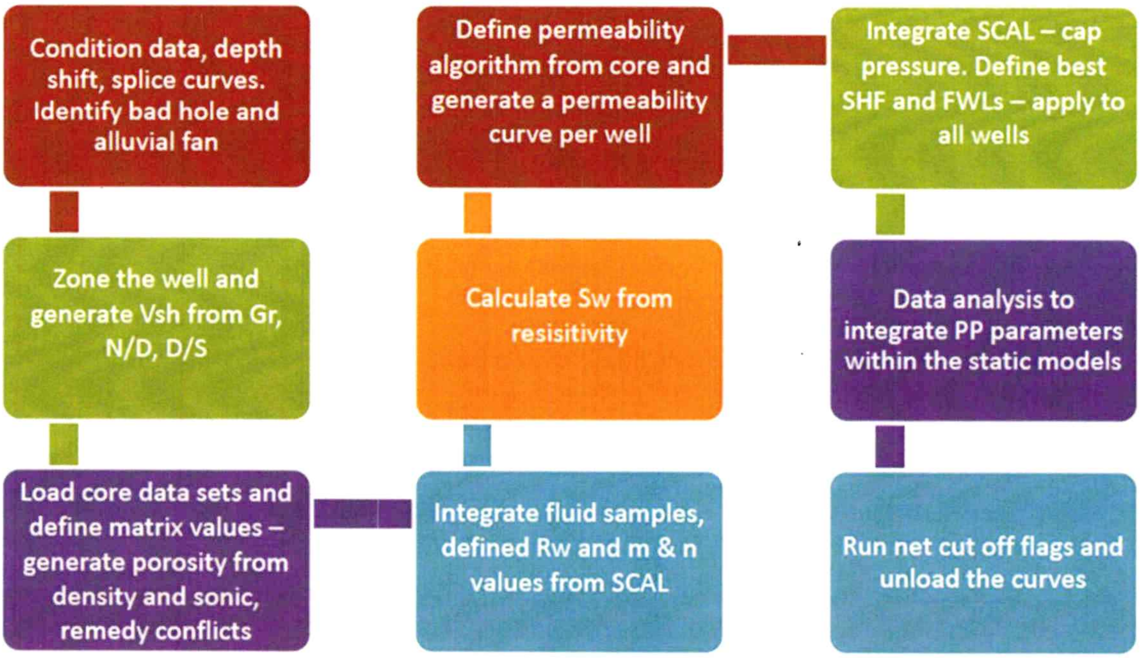


Figure 4-17: Petrophysical workflow summary

A consistent petrophysical methodology has been adopted across all wells with modifications to key input parameters which capture local variations between the fields. Such examples include the permeability model, net cut-offs and saturation height function modelling.

The Total Porosity approach was used for all petrophysical analysis. To have the most confidence in log evaluations, the core derived measurements should agree with those from the wireline logs. Since it is not possible to measure effective porosities in a reliable and repeatable manner, calibration with core analyses is best achieved by measuring total porosities on core plugs and comparing these with total porosities estimated from logs. This process also simplifies the interpretation as the necessity for shale fraction used in effective porosity calculation becomes redundant.

4.4.4.1 Volume of shale (Vsh)

Volume of shale (Vsh) can be calculated using several methodologies. In the Lokichar basin, Vsh has been derived using the density-neutron logs where borehole quality is good and by using the gamma ray log where the borehole quality is bad. Nuclear magnetic resonance logs (present in the early exploration wells) were used to quality control the results from these methodologies.

A wide range in shale volume estimates was calculated. To refine these values a detailed X-ray diffraction (XRD) study was commissioned with 236 samples selected from Ngamia and Amosing cores.

The samples were taken across major reservoir units, in addition to the top and base of the units to characterise the shoulder effects. Figure 4-18 illustrates the types and proportions of clays seen in the Ngamia and Amosing cores analysed. The average dry clay component of the samples analysed is around 13% which will equate to approximately 22% Vshale. Figure 4-19 shows the mineralogy of the samples analysed (excluding the clays in Figure 4-18).

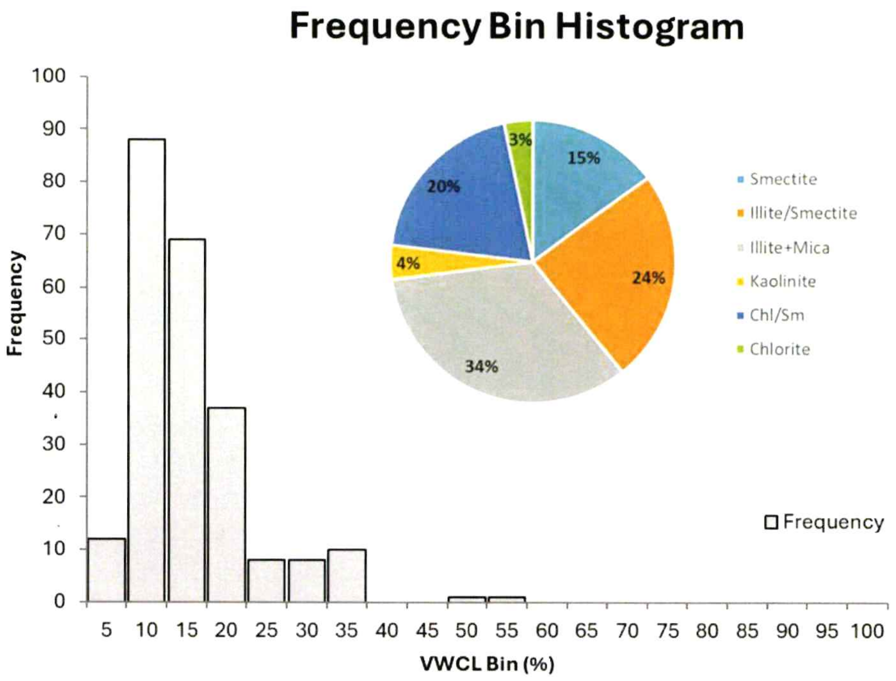


Figure 4-18: Types and proportions of clays in Ngamia and Amosing cores

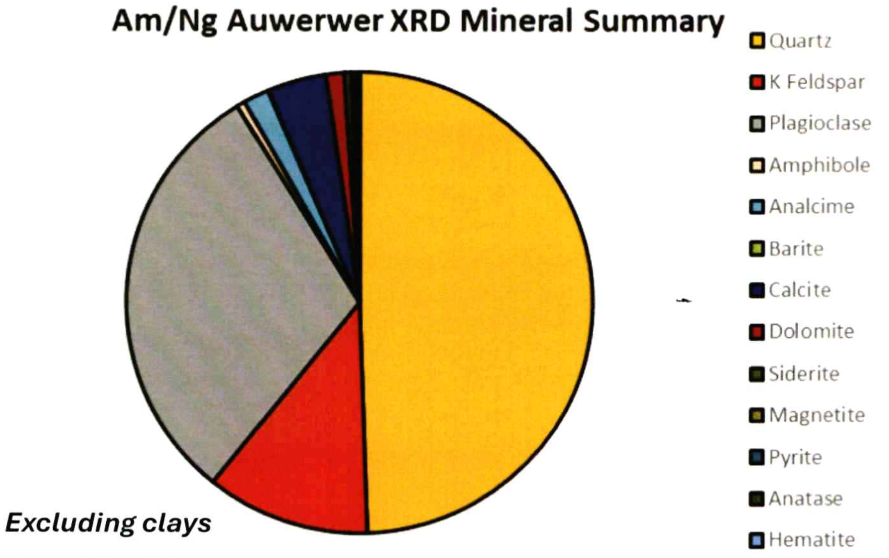


Figure 4-19: Mineralogy of Ngamia and Amosing samples analyzed in the XRD study, excluding clays

The clay to shale ratio was set at 55% as indicated by the maximum levels of clay seen within the XRD study shown in Figure 4-18. The ratio is an important parameter when computing water saturation from shaley sand equations since it is the clays that act as the key contributor to excessive conductivity and therefore important this parameter is accurately defined. Where XRD data was available, comparisons were made back to the predicted Vshale curve and acted as a hard calibration point.

The results of the XRD measurements were compared against the various methods described above. It was determined that Vshale calculated from the neutron-density logs was both the best match to the XRD data and had the best vertical resolution. In poor hole conditions the gamma ray derived Vshale is used in place of the neutron-density measurements.

The shale fraction has been used primarily for lithology identification, sonic porosity correction through shales and reservoir cut off determination.

4.4.4.2 Porosity/Permeability (Ø, K)

Porosity can be determined through various methods using neutron-density, sonic or nuclear magnetic resonance logs. The standard methodology for this project is using the single density methodology.

The porosity measurements derived from the nuclear magnetic resonance tools were compromised due to incorrect running speed causing an underestimate of porosity values. Porosity calculated from the nuclear magnetic resonance tools were therefore not used in any of the static or dynamic models.

Porosity (PHIT) is calculated primarily from the single density method using a hydrocarbon density of 0.85-0.95g/cc (dependent on mud type), and a variable grain density (dependent on clay and sand volume). Clay parameters are varied by petrophysical zonation with dry clay values ranging from of 2.7-2.75g/cc across the field. Dry sand matrix was set to 2.68 g/cc as determined from the average grain density during the RCA program and shown below in Figure 4-20. Log porosity is calibrated against core porosity which is accepted as being equivalent to the total porosity. In areas of wash-out, the compressional sonic curve was used to compute the total porosity based on the Wyllie equation as it is less sensitive to borehole conditions.

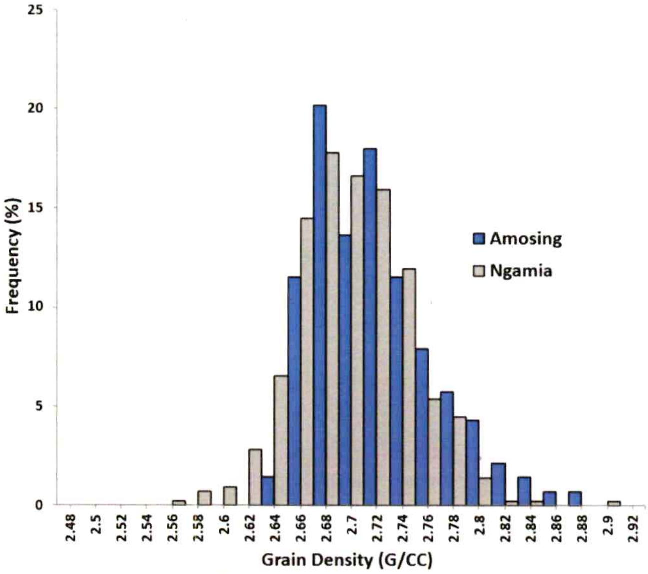


Figure 4-20:RCA Grain density across Ngamia & Amosing

XRD, thin sections and SEM data all show minerals such feldspars, plagioclase, calcite, dolomite, and pyrite which explain the elevated grain densities.

A comparison of core and log porosities can be found in Figure 4-21.

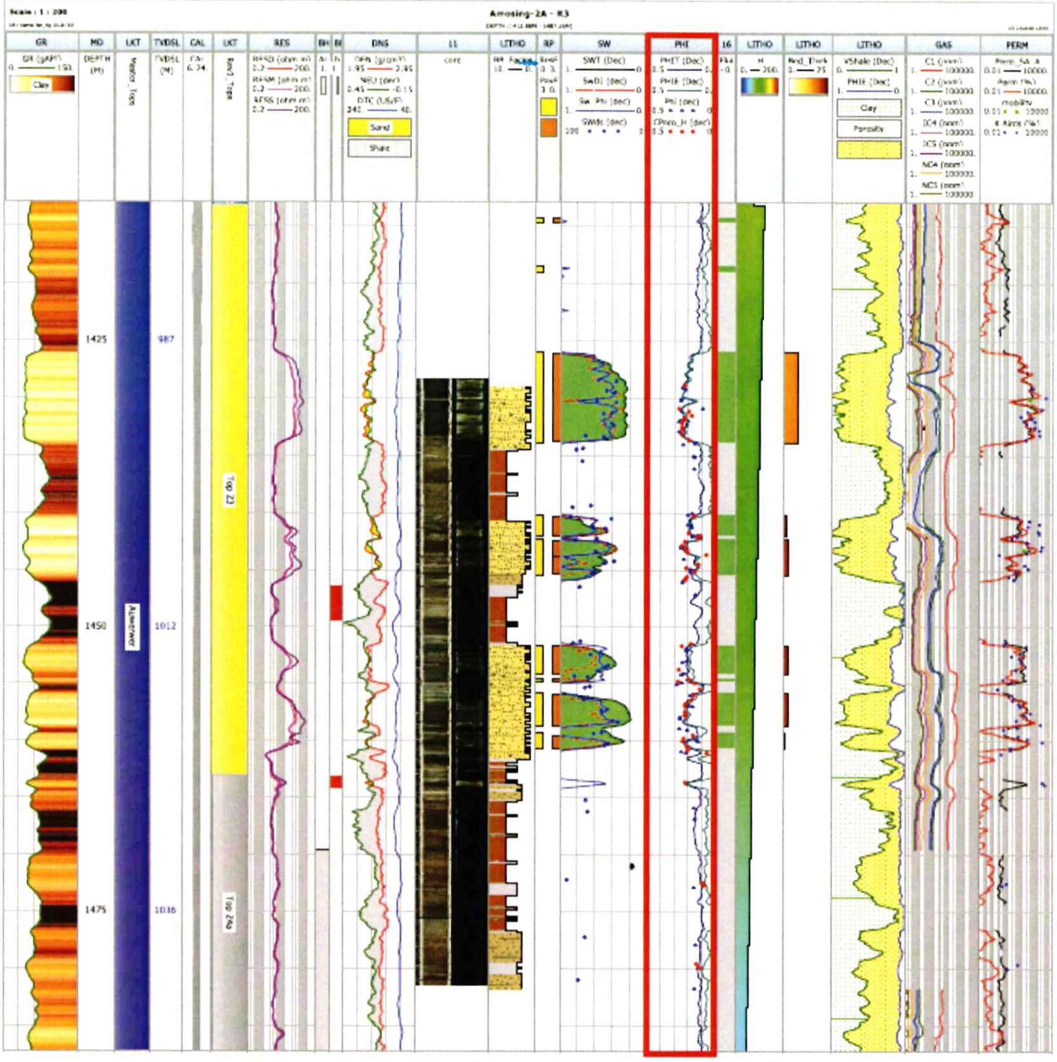


Figure 4-21: Porosity calibration: Example Amosing-2A Z3/4a

The core data has been used to define a permeability algorithm. As all the core analysis across both Amosing and Ngamia is referenced to air permeability, it was decided to model air permeability within the petrophysical model. Furthermore, as many of the SCAL measurements such as capillary pressure data reference air permeability, it was important to remain in this domain, with all liquid corrections carried in the dynamic uncertainty.

The XRD study allows the use of the total clay volume from XRD to compare to core permeability. Porosity and clay volume show strong controls on permeability, as seen in Figure 4-22.

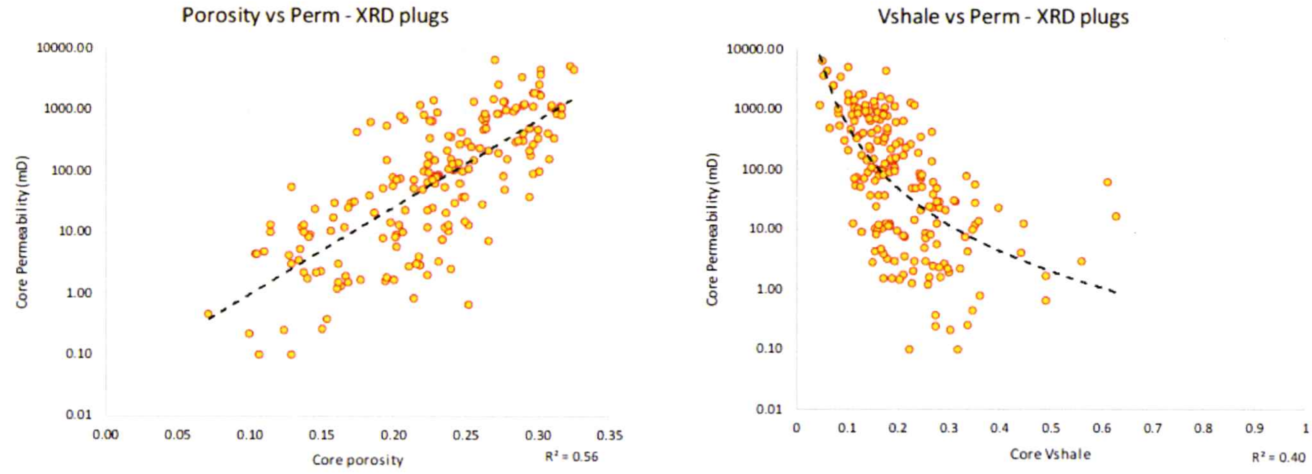


Figure 4-22: Permeability relationship to porosity and clay

Porosity to Vshale ratio is a useful method for combining two petrophysical parameters into one term for permeability prediction. A value of 1 exists where porosity is equal to Vshale, with a value of 2 where porosity is two times greater than Vshale. Figure 4-23 shows a comparison of the Phi/ Vshale ratio to permeability from the XRD plugs. The cleaner, well sorted, large pore throat plugs sit towards the top right of the plot, with a high Phi/ Vshale ratio. The shaley, poorly sorted and smaller pore throat plugs sit towards the bottom left, with low Phi/ Vshale values. The close relationship of Phi/ Vshale further enhances the reliability of using these inputs into the permeability algorithm.

Mercury injection capillary pressure pore throat radii distributions have been superimposed on Figure 4-23. The lower Phi/ Vshale ratio plugs have much smaller pore throats dominated by the peak on the left giving it a bimodal distribution. As the Phi/ Vshale ratio increases as does the pore throat radius leading to a higher Phi/ Vshale ratio and permeability.

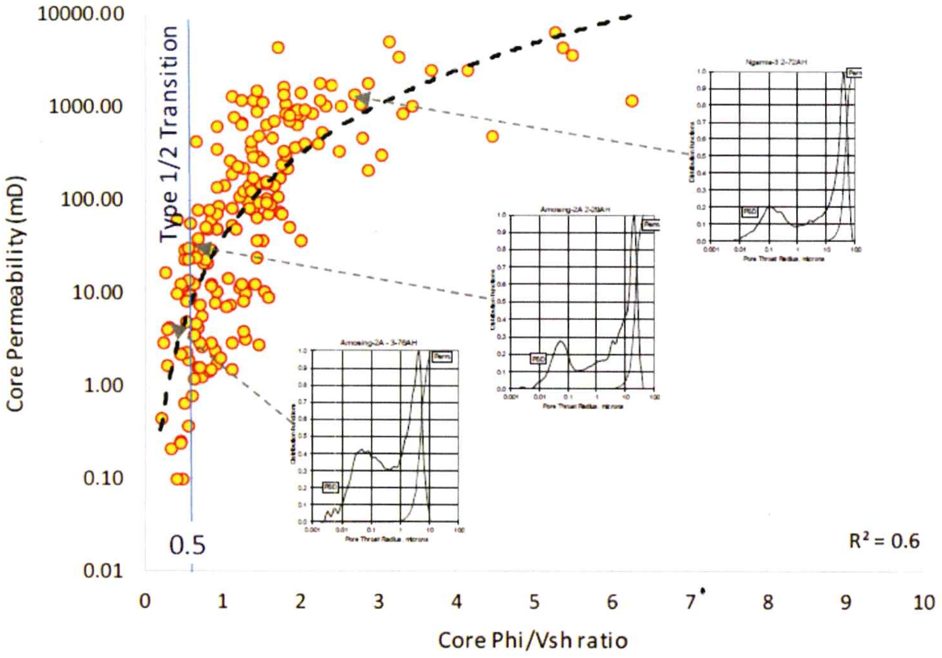


Figure 4-23: Phi/Vsh ratio vs permeability

As reported in, Ngamia and Amosing share some common petrophysical characteristics, but there is enough variation within Vshale and Porosity across the two fields that they warrant separate permeability models.

4.4.4.3 Water Saturation (Sw)

Water saturation is a key component of determining hydrocarbons in place. It was recognised early in the appraisal phase of the South Lokichar Basin that accurate water saturation estimation would be challenging. The low salinity of the reservoir's formation water means there is little resistivity contrast between oil-bearing and water-bearing formations; the Archie equation cannot be used to derive water saturation in the Lokichar Basin.

Other difficulties in deriving water saturation in the Lokichar Basin include a high clay conductance (resulting in a large BOV) and residual oil in water legs.

For the purposes of reservoir modelling and determining hydrocarbon volumes in place, the decision was made to use saturation height functions tied to reservoir quality rather than populating the static model with log-derived water saturation. These functions have been determined from core derived capillary pressure data including:

- 105 Mercury Injection Capillary Pressure (MICP) measurements;
- 6 Air-Brine stressed Centrifuge Capillary Pressure measurements from Amosing.
- 13 Air-Brine stressed Porous Plate measurements, 7 from Amosing & 6 from Ngamia.

Prior to use, the MICP data were corrected for closure, clay-bound water, and to stress. All three data sources were corrected to reservoir conditions. Default reservoir values for contact angle (30deg) and interfacial tension (30 dynes/cm) were applied. The Pc data was corrected for height above the FWL using water density of 1 gm/cc and a hydrocarbon density of 0.8gm/cc.

The saturation height function (SHF) expresses oil saturations as a function of height above the fluid contact and thus aims to model the "transition" zone as well as the irreducible water saturation higher up in the oil column. A dependency on porosity and permeability is used to account for variations in rock quality. Since the fields have different permeability models, reservoir cut-offs and subtle differences in capillary pressure; each field was assigned its own specific saturation height function.

Leverett-J models were created since these are most readily implemented in static and dynamic models. Note that these models use both porosity and permeability as inputs along with height above the FWL. The process of building the function is iterative whereby after each iteration, the data is checked back to the input data to define how well this was predicted back as shown in Figure 4-24.

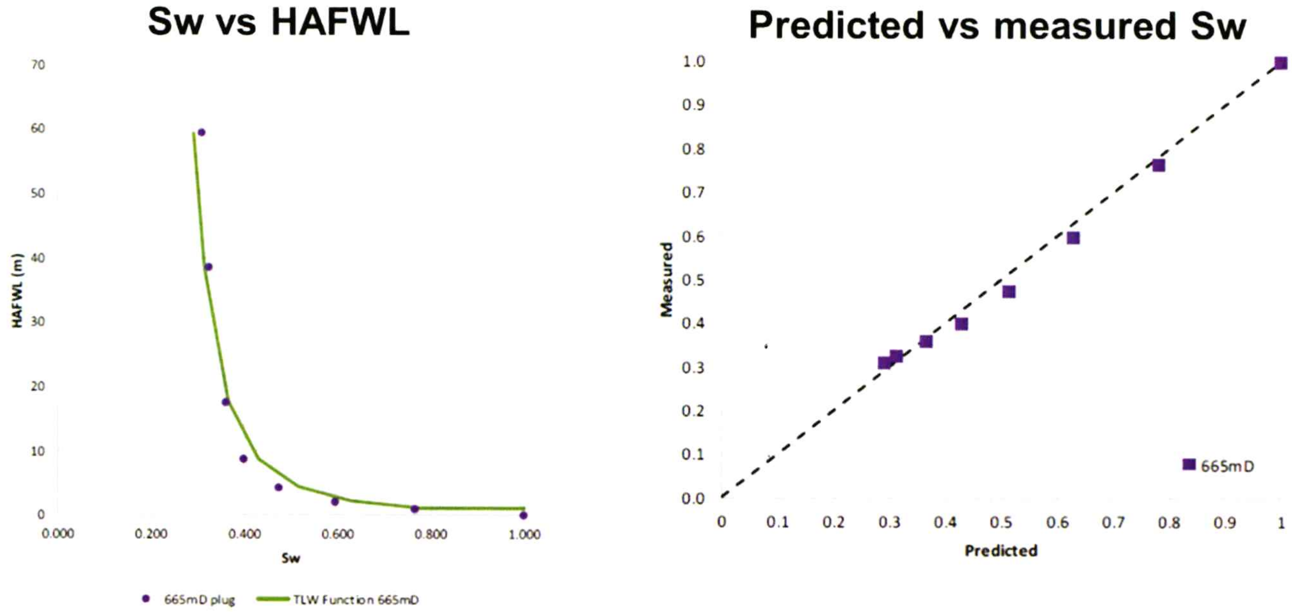
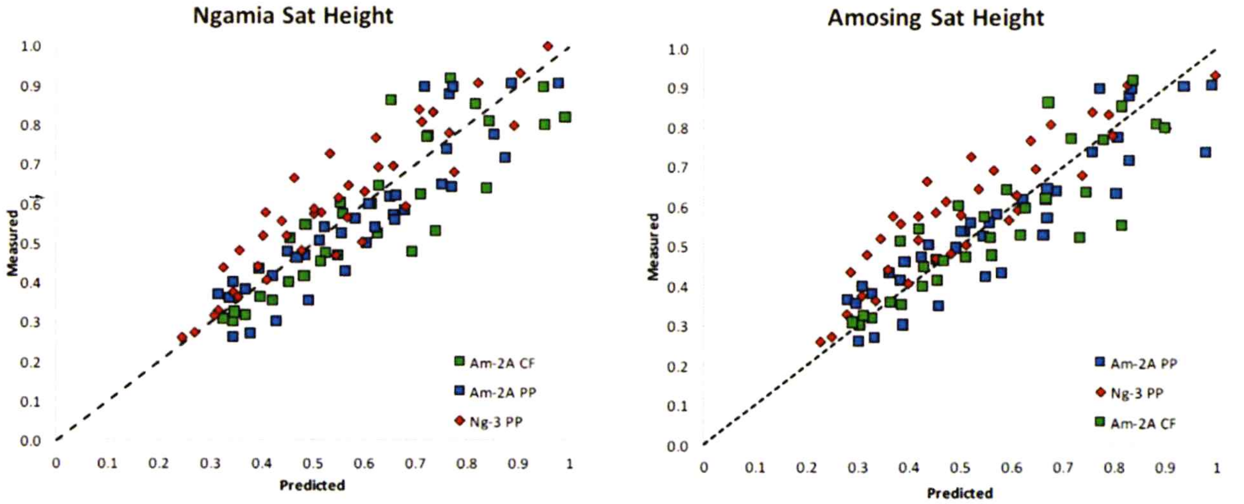


Figure 4-24: Saturation height curve fitting

The final matches for the input (measured) versus output (predicted) for the SHF are shown in Figure 4-25. Centrifuge and porous plate data were used across both fields, with each field specifically weighted to its dataset hence the variation in the equation coefficients. The SHF was compared back to Dean Stark and log derived resistivity SwT to ensure consistency across the results, which was overall a good match.



$SwDJ = 0.55*K^{-0.175} + 0.475*J^{-0.325}$ $SwDJ = 0.35*K^{-0.105} + 0.500*J^{-0.420}$

where $J = P/26 \cdot (PERM/PHIT)^{0.5}$ and $P = HUC*9.81*(1000-800)*0.00014508$ psi, HUC is the height above the FWL in metres, K is the permeability and PHIT is the total porosity

Figure 4-25: Saturation Height Function

Due to the fluvial nature of the Amosing and Ngamia reservoirs, some sands do not appear to receive charge. As the SHF populates HC above a given FWL, failure to capture these sands will lead to an overestimation in STOIIP and be problematic for perforations due to the presence of water in the production phase. A schematic on how these uncharged sands are visually identified is shown in Figure 4-26.

Non-charged sands have been identified from:

- Core fluorescence
- Samples and pressures

- Resistivity derived SwT
- Gas chromatograph

In Figure 4-26, the purple curve shows a typical SwT from resistivity, which sees HC in zone 3, but not zone 2 (water bearing). The SHF is shown in red, which shows above the FWL, all zones (3 and 2) get saturated with oil. Within every well, a flag has been generated following the same scheme here, with fluid 2 identified as "uncertain" pay. This is discussed further in the modelling section.

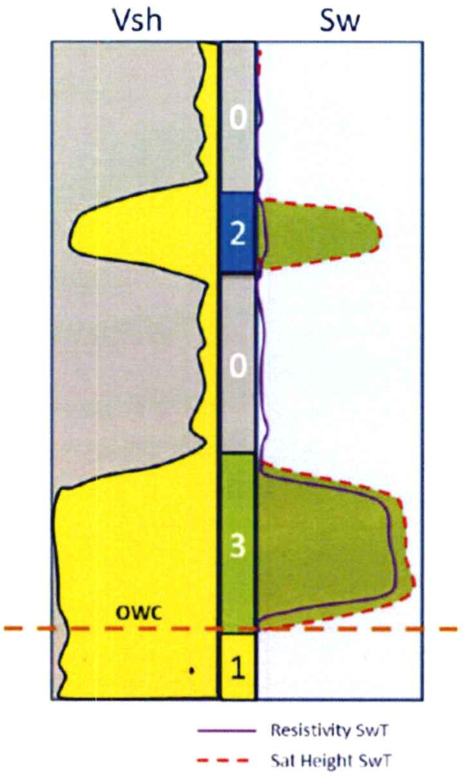
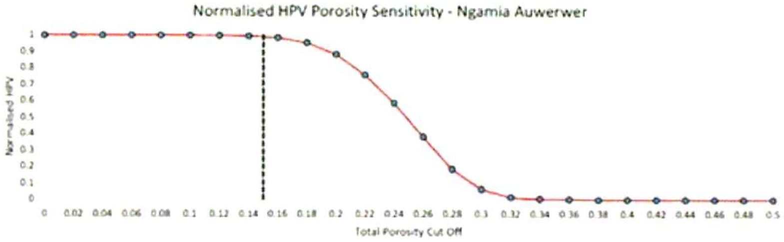


Figure 4-26: Schematic showing an uncharged zone

4.4.4.4 Cut-Offs/ Net Reservoir Definition

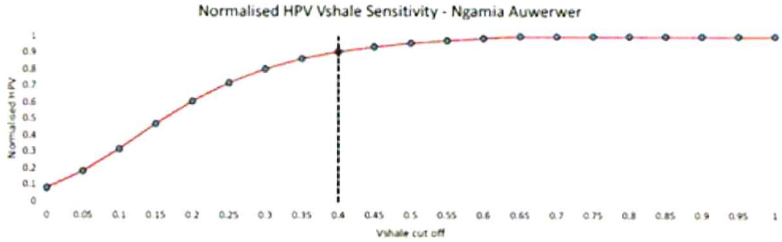
Net reservoir has been defined as rock that can store hydrocarbons. The primary cut-offs used to help define net reservoir are Vshale and porosity. The cut-offs used in the static geological models and the determination of net reservoir were established by reviewing all reservoir data acquired including core data, drill stem test data and other data such as mobility measurements from the wireline testing tools. The cut-offs therefore vary by field.

The primary method used to define the cut-offs is based on the cumulative hydrocarbon pore thickness (Phi*So*H) versus cut-offs. Variations in cut-offs are plotted against the hydrocarbon storage capacity and shown Figure 4-27, where the impact of the changing cut offs can be quantified. Typically, the P90 (90% of HPV captured) value is deemed a reasonable cut off. Additionally, core photographs were used to help define the cut offs. By examining the fluorescence from UV light, charging can be clearly observed and related back to the core petrophysical parameters.



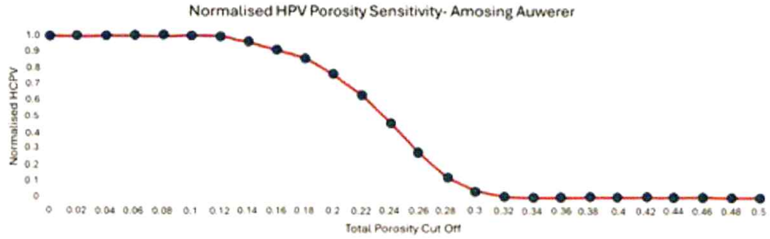
Normalised HPV Porosity Sensitivity - Ngamia Auwerwer

15% Porosity cut off used across Ngamia Auwerwer – captures 99% of HPV



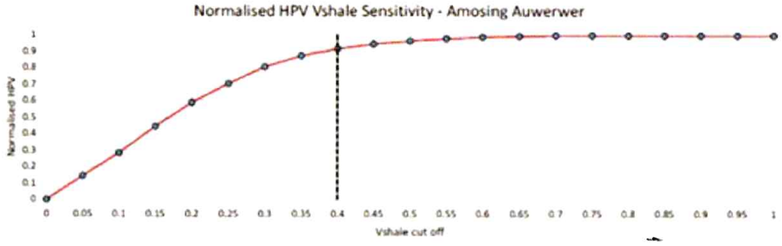
Normalised HPV Vshale Sensitivity - Ngamia Auwerwer

40% Vsh cut off used Ngamia Auwerer- captures 91% of HPV



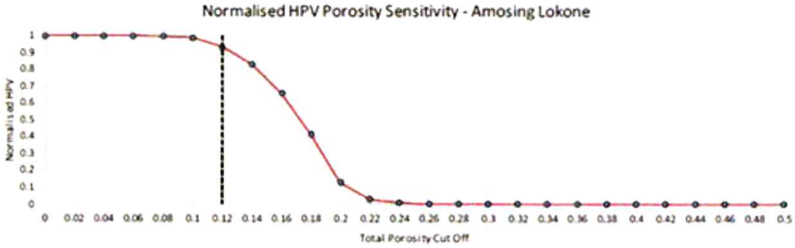
Normalised HPV Porosity Sensitivity- Amosing Auwerer

12% Porosity cut off used across Amosing Auwerer- captures 100% of HPV



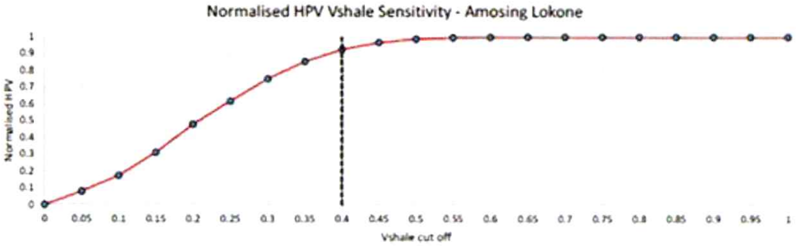
Normalised HPV Vshale Sensitivity - Amosing Auwerwer

40% Vsh cut off used across Amosing Auwerwer – captures 92% HPV



Normalised HPV Porosity Sensitivity - Amosing Lokone

12% Porosity cut off used across Amosing Lokone- captures 93% of HPV



Normalised HPV Vshale Sensitivity - Amosing Lokone

40% Vsh cut off used across Amosing Lokone- captures 93% of HPV

Figure 4-27: HPV vs cut-off for net definition

The Amosing Auwerwer and Lokone net reservoirs have been defined as having Vshale less than 40% and PHIT greater than 12%. The Ngamia Auwerwer net reservoir was defined as having Vshale less than 40% and PHIT greater than 15%. The Twiga Auwerwer net reservoir was defined as having Vclay less than 50% and PHIT greater than 15%. Twiga has a Vclay to Vshale ratio of 55%.

4.4.4.5 Rock Typing

Rock typing has been undertaken and incorporated into the modelling of the Amosing and Twiga Fields due to variations in porosity distributions compared to other fields. This is detailed further in the individual field Sections 4.6.2 and 4.6.3.

4.4.4.6 Fluid Distribution

Understanding and predicting where uncharged sands are located across the fields resided is important so as not to overestimate hydrocarbons in place.

As generally observed in the core data, the uncharged zones tend to be confined to the thinner bedded sands. As net reservoir flags are generated in each well, defining the thickness of each bed is a straightforward task, where thin (<1m), medium (1-3m) and thick (3m+) could be defined.

Filtering the bed thickness by petrofacies and fluid type provides a way to identify where these uncharged sands reside. Figure 4-28 shows two examples for Amosing and Ngamia. The thin beds tend to have the largest proportions of Type 1 facies, followed by the medium and lastly the thick beds. Thin and medium beds are much more prone to containing uncharged sands (water), where the thick beds are dominated by Type 2 facies, and are predominately oil prone.

This exercise was completed on both Amosing and Ngamia well data. The overall results are similar, but the proportions do vary. This has been captured in the static models.

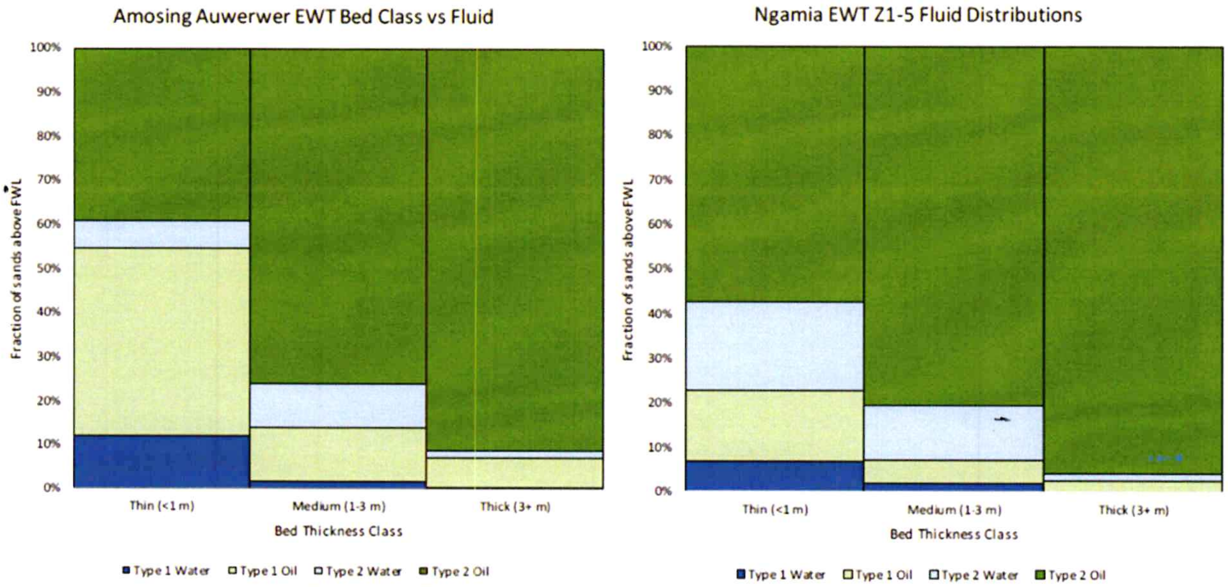


Figure 4-28: Fluid typing within bed thickness class and petrofacies

4.4.5 Petrophysical Summary

The key deliverable of the petrophysical workflow was to provide a set of petrophysical parameters that can be used to properly characterise the reservoir and accurately predict the volume of hydrocarbons in the reservoir from a static model. The value of an extensive dataset of log and core data has led to the creation of a dataset that has a high degree of confidence to be used in the static and dynamic modelling. This analysis provides the foundations for the facies and reservoir property development in the static and dynamic reservoir models.

4.5 STOIIP Calculation Methodology

4.5.1 Introduction

This section describes the methodology used to calculate stock tank oil initially in place (STOIIP) in each field. Note that only Phase 1 and Phase 2 fields are discussed, namely Ngamia Auwerwer, Amosing, Twiga Auwerwer, Etom, Agete, and Ekales.

Static geological models have been built for three fields: Ngamia Auwerwer, Amosing, and Twiga Auwerwer. The static model volumes produce deterministic STOIIP which are used in the reference/best/mid case scenario. A summary of static model methodology is discussed in Section 4.5.2 below. Low and high case volumes have also been estimated using a separate method which uses statistical analysis.

For Etom, Agete, and Ekales, a range of low, mid, and high case STOIIP have been estimated using a statistical, monte carlo evaluation. The mid case STOIIP is a result of a probabilistic evaluation between the low and high case inputs. The volumetrics methodology is summarised in Section 4.5.3 below.

4.5.2 Static Model Methodology Summary

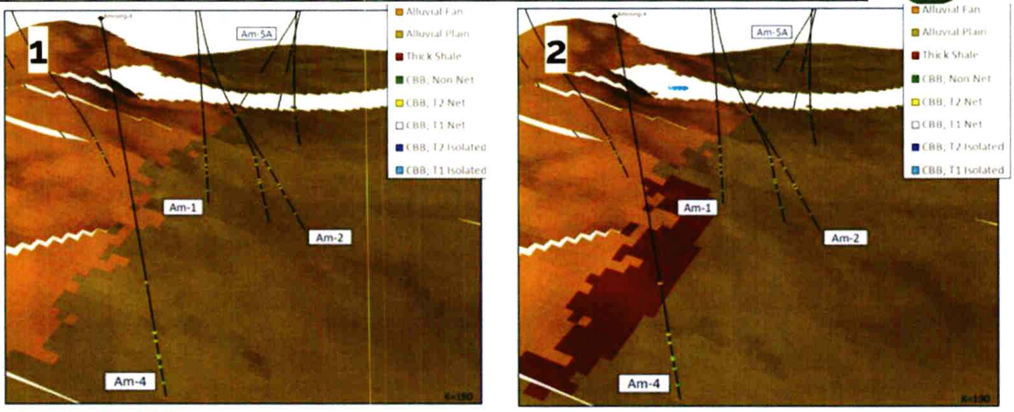
The static geological models for the Ngamia, Amosing, and Twiga fields have been built by integrating relevant sub-surface data and interpretations presented in the preceding sections. The structural interpretation from 3D seismic, sedimentological core descriptions, facies and paleocurrent interpretations from image logs, depositional models with sand body geometries and porosity and permeability derived from log and core analyses have all been integrated to build the fine-scaled static model.

A full-field 3D reservoir model has been constructed for each field using industry standard modelling software (Schlumberger Petrel).

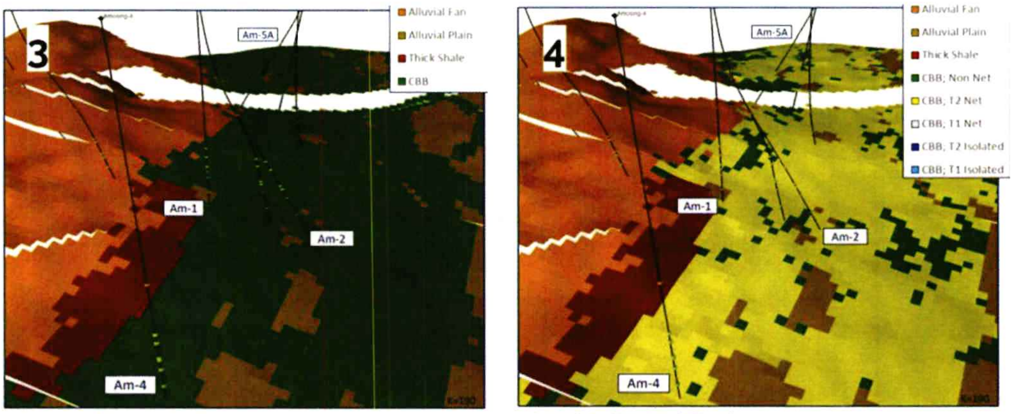
A summary of the modelling workflow is as below:

- Integration of depth maps of key mappable horizons
- Construction of detailed fault static model from seismic interpretation
- Zonation and layering of the 3D grid based on detailed well correlation
- Facies and property modelling
- Simulation grid design and upscaling of the fine scaled geological model for dynamic reservoir simulation

Facies modelling utilises a multi-step approach attempting to best model the interpreted and conceptualized depositional patterns. After identifying alluvial-fluvial boundary using polygon sets, alluvial fan facies and broadly fluvial facies are modelled. The next step involves populating of shales within the fluvial succession. Afterwards, channel belt bodies (CBBs) are modelled to create zonal fairways. Net sands are modelled within the CBBs to give NTG property. Example for Amosing is shown below. Porosity is modelled stochastically within the net sands and permeability is modelled using a poroperm transform function based on the core data on a field-by-field basis. Water saturation is modelled using saturation height functions derived from petrophysical interpretation.



Amosing: Alluvial Fan **Amosing: Thick Shales**



Amosing: Channel Belts **Amosing: Reservoir Sand**

Figure 4-29: Facies Modelling Workflow

4.5.3 Statistical Volumetrics Methodology Summary

For Etom, Agete, and Ekales fields, in place volumes have been calculated using a statistical methodology. The same method was also used to calculate low and high case STOIIP in Amosing, Ngamia, and Twiga.

Two-way time (TWT) grids were interpreted on a 3D seismic and depth conversion was performed to create depth grids. Depth grids were tied to formation top picks. Top and base depth grids, together with interpretation of fluid contacts and compartments were used to calculate a range of low and high gross rock volume (GRV). Mid case GRV is estimated based on a lognormal distribution between the low and high cases.

Petrophysical analysis was done using a series of low and high case cut-offs. Net-to-gross (NTG), porosity, and water saturation (Sw) inputs to volume estimation have been derived from the well sums and averages following petrophysical analysis as well as analogues. Fluid volume factors were estimated using fluid properties from PVT data. Mid case inputs were derived statistically from low and high case inputs. Details are discussed in each field's subsection in Section 4.6.

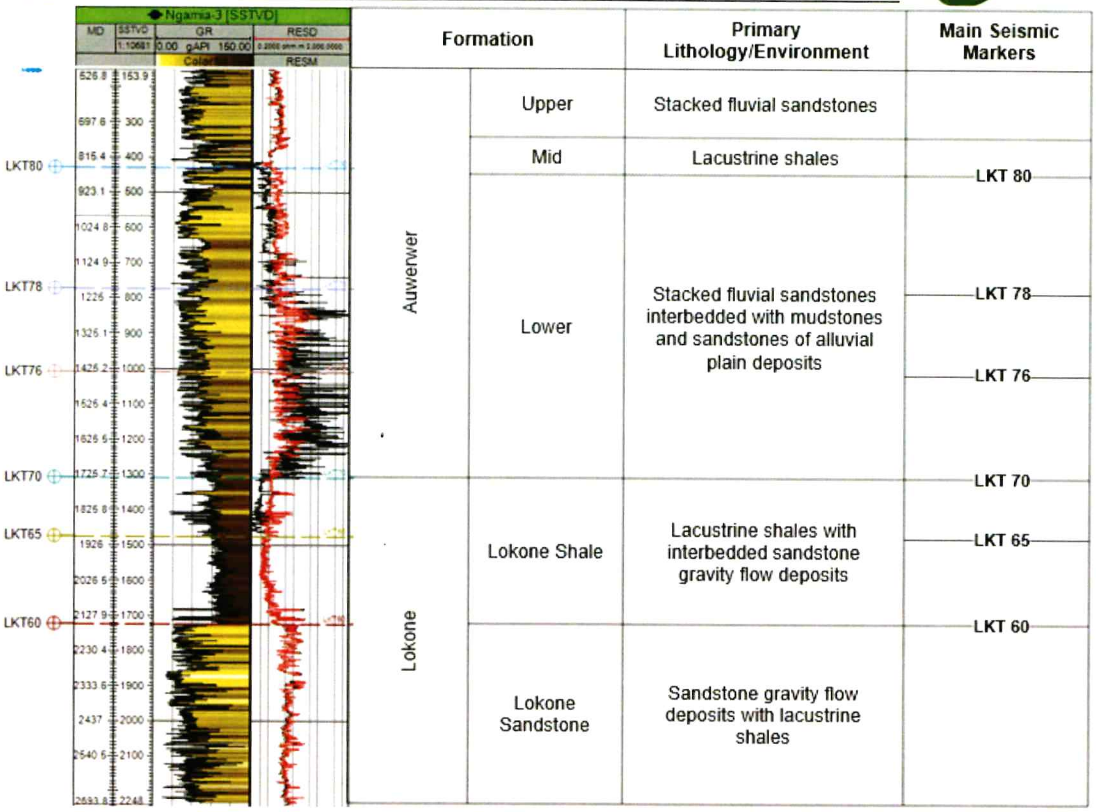
4.6 Field Descriptions

Phase 1 and 2 development of the South Lokichar Basin includes the following fields: Ngamia (Auwerwer), Amosing (Auwerwer), Twiga (Auwerwer), Ekales (Auwerwer), Etom (Auwerwer and Lokone), Agete (Auwerwer). The sections below provide further details on these fields. Phase 1 is limited to the Ngamia and Amosing fields.

4.6.1 Ngamia Auwerwer

4.6.1.1 Introduction

The Ngamia field was the first major discovery of hydrocarbons in the South Lokichar Basin. From both a geological and development standpoint, the field has been separated into two main stratigraphic sections, the Lower Auwerwer Formation and Lokone Formation (Figure 4-30). This part of the document will focus on the Lower Auwerwer formation.



Formation		Primary Lithology/Environment	Main Seismic Markers
Auwerwer	Upper	Stacked fluvial sandstones	
	Mid	Lacustrine shales	LKT 80
	Lower	Stacked fluvial sandstones interbedded with mudstones and sandstones of alluvial plain deposits	LKT 78 LKT 76 LKT 70
Lokone	Lokone Shale	Lacustrine shales with interbedded sandstone gravity flow deposits	LKT 65 LKT 60
	Lokone Sandstone	Sandstone gravity flow deposits with lacustrine shales	

Figure 4-30: Well Ngamia-3 Log Illustrating the Stratigraphy in the Ngamia Field

Following the discovery of hydrocarbons in Well Loperot-1 drilled by Shell in 1992/93 on the eastern side of the South Lokichar Basin, Well Ngamia-1/1A was the first exploration well drilled on the western side of the basin. The well was spudded in January of 2012 with the Weatherford 804 drilling rig. The well took over six months to drill and evaluate, primarily due to significant borehole stability issues, but also due to the significant sections of hydrocarbon bearing reservoirs that were encountered.

Well Ngamia-1/1A location was selected on 2D seismic data. The well was drilled mostly vertically in the sidetrack Ngamia-1A leg to a total depth of 2,340 mMD in the Lokone Sandstone Formation. Well Ngamia-1A encountered over 1,100 m of gross hydrocarbon bearing section in the Lower Auwerwer Formation, sandstones equivalent in age to the Lokone Shale Formation and the Lokone Sandstone Formation. The drilling rig was released from the location of the operation on July 6, 2012.

During the drilling of the well, logging while drilling measurements including gamma ray and resistivities were acquired. Conventional wireline logs were acquired at the end of the main hole sections and included a very robust selection of modern log measurements. Further rock samples were acquired through the acquisition of both percussion and rotary sidewall cores. Using the wireline formation testing tool, formation pressures were acquired throughout the well in addition to fluid samples.

Well Ngamia-1A was re-entered on March 22, 2013, with the Weatherford 804 drilling rig to complete a drill stem testing program. Six production tests were performed in the well. Since then, numerous other flow tests, production and injection trials, have been completed in the appraisal wells. The data acquired from this testing will be discussed in the reservoir engineering section.

The Ngamia field appraisal program consisted of an additional ten wells to date, Ngamia-2 through Ngamia-11. All wells drilled in the Ngamia field have encountered hydrocarbons in the Lower Auwerwer Formation. Well locations are shown in Figure 4-31 alongside the mid case hydrocarbon pore volume map. Eight of the appraisal wells (Ngamia-3, and Ngamia-5 through Ngamia-11), encountered hydrocarbon bearing zones similar in nature to Well Ngamia-1A. Two wells, Ngamia-2 and -4 encountered hydrocarbon discoveries that were overpressured in the Auwerwer compared to the rest of the field and do not appear to be communication with the regional water aquifer.

The Ngamia Lower Auwerwer oil resources make up the largest discovered oil accumulation in the South Lokichar Basin. Current estimates include a range of low at 459 MMstb, mid at 680 MMstb, and a high estimate of 984 MMstb STOIIP. The mid case estimate is based on a rigorous process of incorporating the geophysical, geological, petrophysical and reservoir engineering data and interpretations into a three-dimensional static model. The process of building this model will be described in the following sections. The low and high case estimates are based on statistical volumetrics methodology which incorporates a suitable range of uncertainty in the volumetric parameters and reservoir extent. This methodology is also discussed in the following sections.

4.6.1.2 Geology

The Ngamia Field is a moderately faulted, three-way dip closed anticlinal structure along the western margin of the South Lokichar Basin. The field is ultimately bounded to the west by the large, basin bounding fault, however the main accumulation appraised at Ngamia lies over three kilometers east of the main basin bounding fault (Figure 4-31).

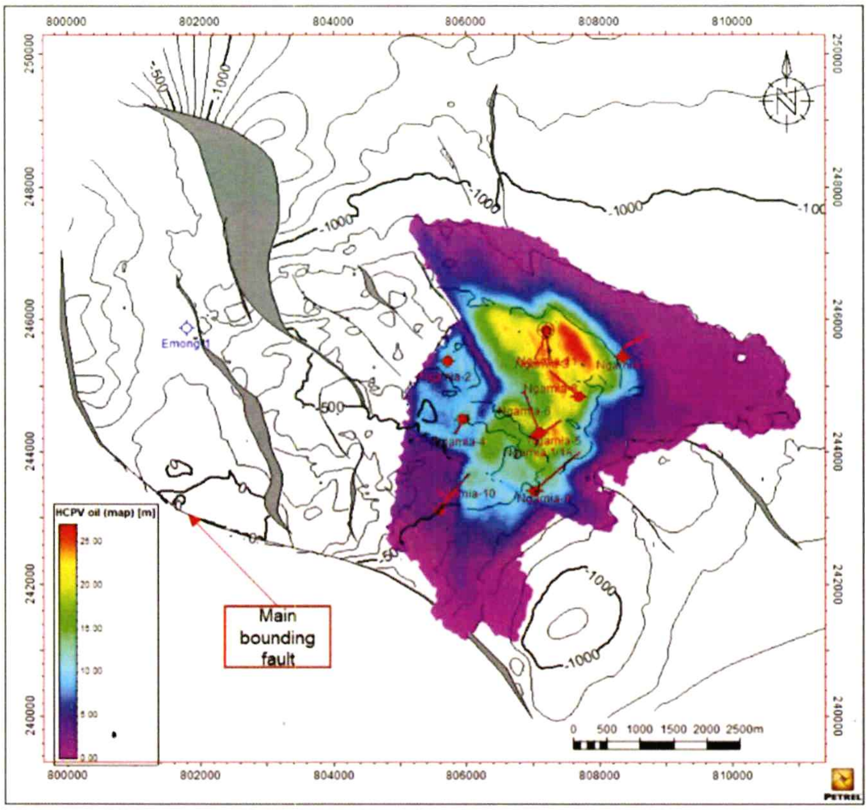
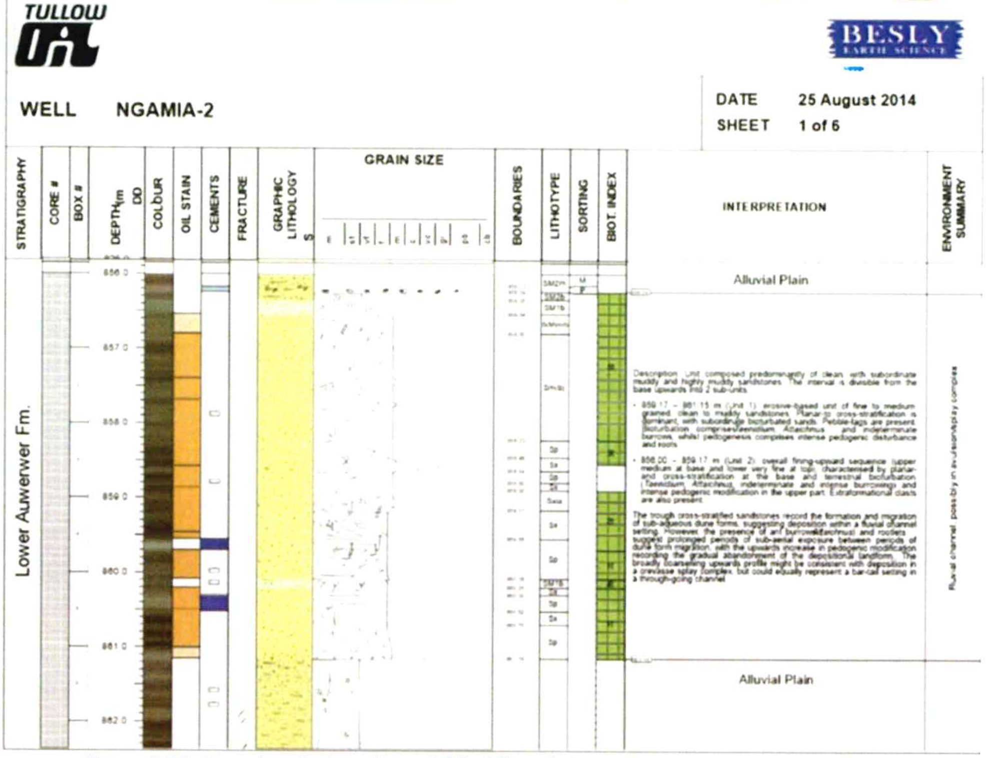


Figure 4-31: Ngamia (Auwerwer Fm.) Mid Case Oil Hydrocarbon Pore Volume (HCPV) and LKT78 Depth Grid and Faults

The sandstones of the Lower Auwerwer Formation are the main reservoirs in the Ngamia Field. These reservoir sandstones are primarily fluvial in origin (Figure 4-32 and Figure 4-33) with evidence of some poorer quality reservoir sandstones thought to be more alluvial in origin close to the main fault systems. The influence of this poorer quality non-reservoir alluvial facies has a small impact on resource volumes in the Ngamia field compared to Amosing and Twiga fields where the impact is much greater.

There is some level of structural complexity in the Ngamia field with seismically visible faults separating the field into segments (Figure 4-34). Faults, both synthetic and antithetic to the basin bounding fault, cut through the Lower Auwerwer section. Most of these faults have sufficient throw to provide at least some sealing capacity during production.

Hydrocarbon-bearing sandstones within the Lower Auwerwer Sandstone are individually sealed by laterally extensive mudstones within the sequence. The ultimate top seal to all the hydrocarbon discoveries is provided by the Mid-Auwerwer Shale at the base of the Upper Auwerwer Sandstone.



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WELL NGAMIA-2

DATE 25 August 2014

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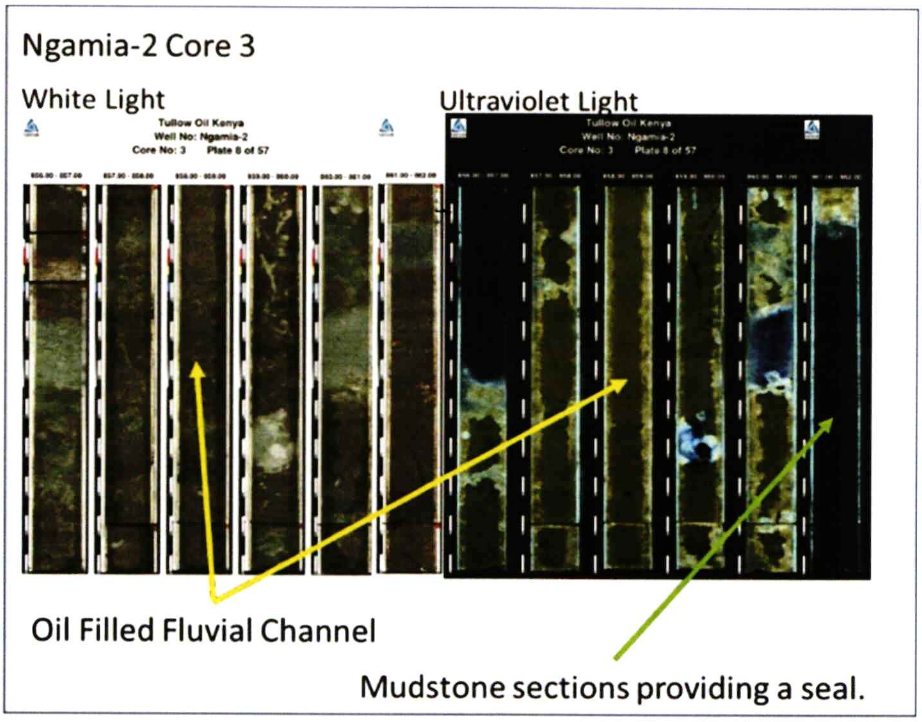
Description: Unit composed predominantly of clean, with subordinate muddy and highly muddy sandstones. The interval is divisible from the base upwards into 2 sub-units.

- 859.17 – 861.15 m (Unit 1): erosive-based unit of fine to medium grained, clean to muddy sandstones. Planar-to cross-stratification is dominant, with subordinate bioturbated sands. Pebble-lags are present. Bioturbation comprises Taenidium, Attaichnus and indeterminate burrows, whilst pedogenesis comprises intense pedogenic disturbance and roots.
- 856.00 – 859.17 m (Unit 2): overall fining-upward sequence (upper medium at base and lower very fine at top), characterised by planar- and cross-stratification at the base and terrestrial bioturbation (Taenidium, Attaichnus, indeterminate and intense burrowings) and intense pedogenic modification in the upper part. Extraformational clasts are also present.

The trough cross-stratified sandstones record the formation and migration of sub-aqueous dune forms, suggesting deposition within a fluvial channel setting. However, the presence of ant burrows (Attaichnus) and rootlets suggest prolonged periods of sub-aerial exposure between periods of dune form migration, with the upwards increase in pedogenic modification recording the gradual abandonment of the depositional landform. The broadly coarsening upwards profile might be consistent with deposition in a crevasse splay complex but could equally represent a bar-tail setting in a through-going channel.

Figure 4-32: Core description of an oil filled fluvial channel sequence in Well Ngamia-2



Ngamia-2 Core 3

White Light

Ultraviolet Light

Oil Filled Fluvial Channel

Mudstone sections providing a seal.

Figure 4-33: Core photograph of an oil filled fluvial channel sequence in Well Ngamia-2

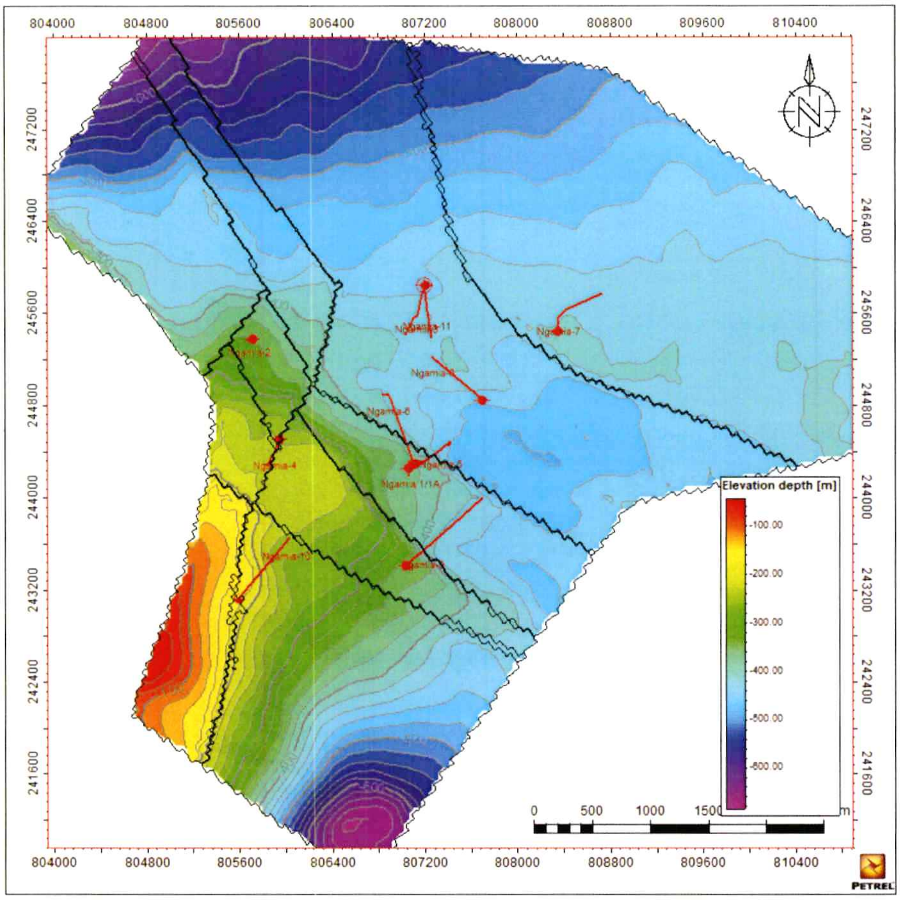


Figure 4-34: Ngamia Depth Structure Map (LKT80) and segmentation in the field

4.6.1.3 Geophysics

The RAP PreSTM 3D data volume was used to map the four key markers for the Lower Auwerwer Formation over the Ngamia field. The four markers mapped are the LKT80, LKT78, LKT76, and LKT70 as illustrated in the stratigraphic column in Figure 4-7. All four markers are good quality picks over the Ngamia Field on the RAP PreSTM 3D data volume (see Figure 4-35).

The LKT80, LKT78, LKT76 and LKT70 two-way time structure maps are shown in Figure 4-36 to Figure 4-39. The Ngamia structure at these levels is generally a three-way fault closure in the hanging wall of the northwest-southeast trending Lokichar Fault, which is further compartmentalized by several north-south and northwest-southeast faults. A north-south seismic line (Figure 4-35) shows that these faults create crestal collapse for the most part, with less displacement at the LKT70.

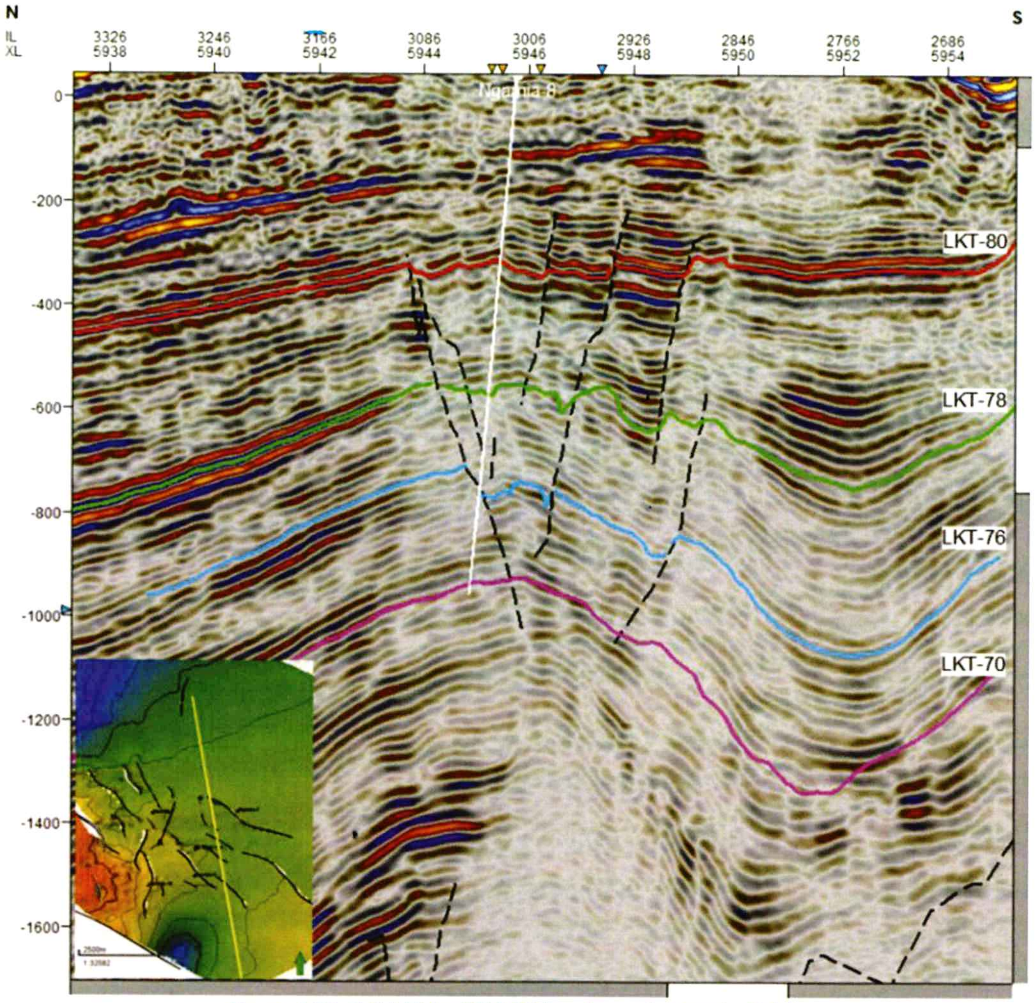


Figure 4-35: N-S RAP PreSTM 3D line through Ngamia Field

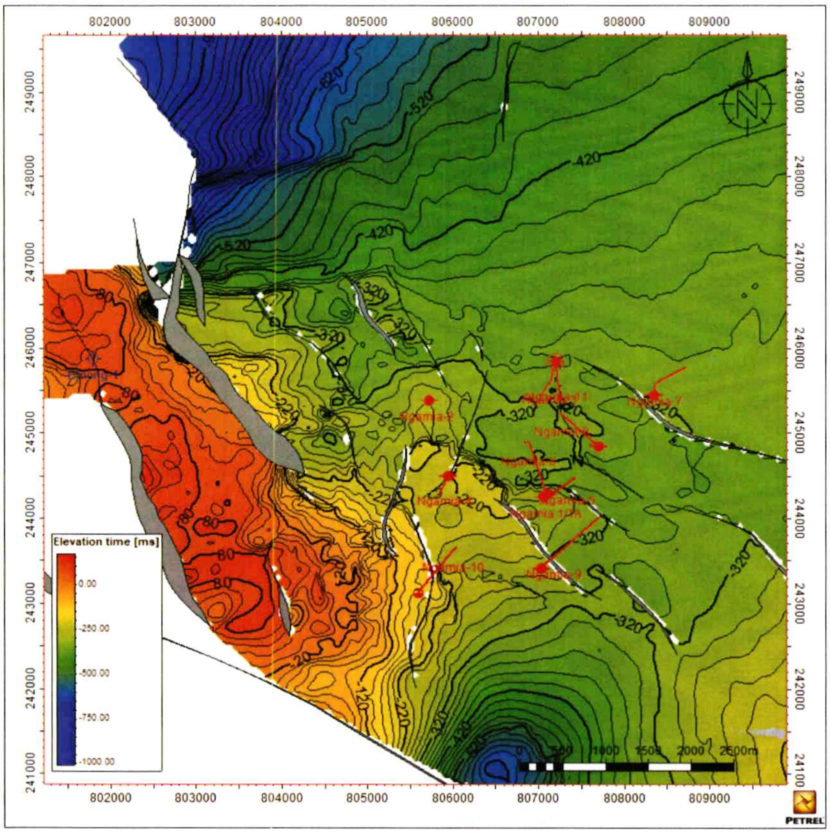


Figure 4-36: Ngamia Field RAP PreSTM LKT80 two-way time structure map (milliseconds)

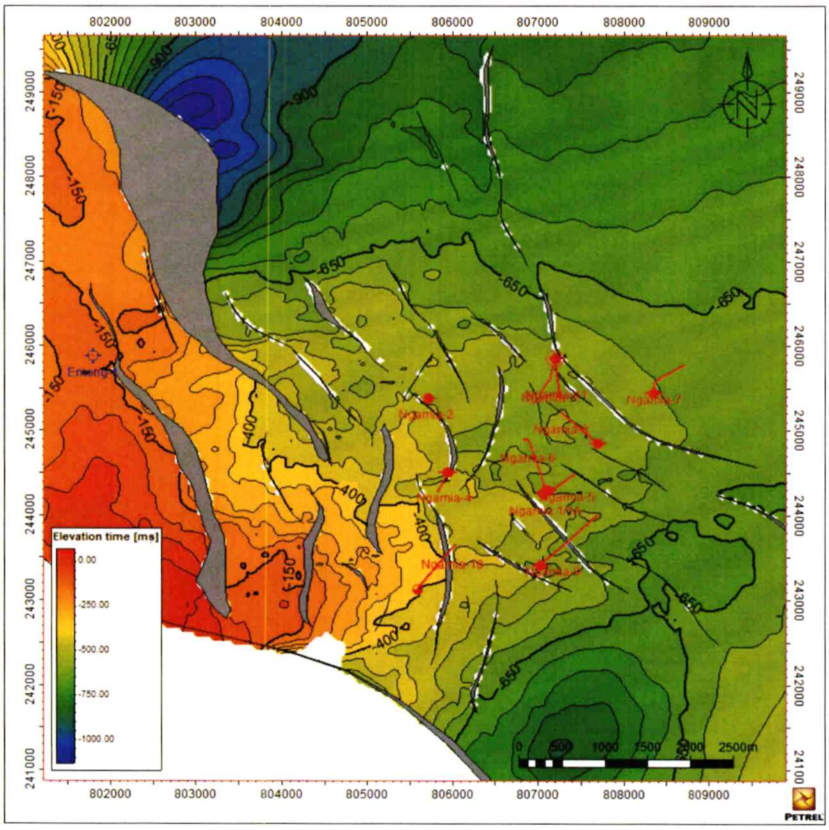


Figure 4-37: Ngamia Field RAP PreSTM LKT78 two-way time structure map (milliseconds)

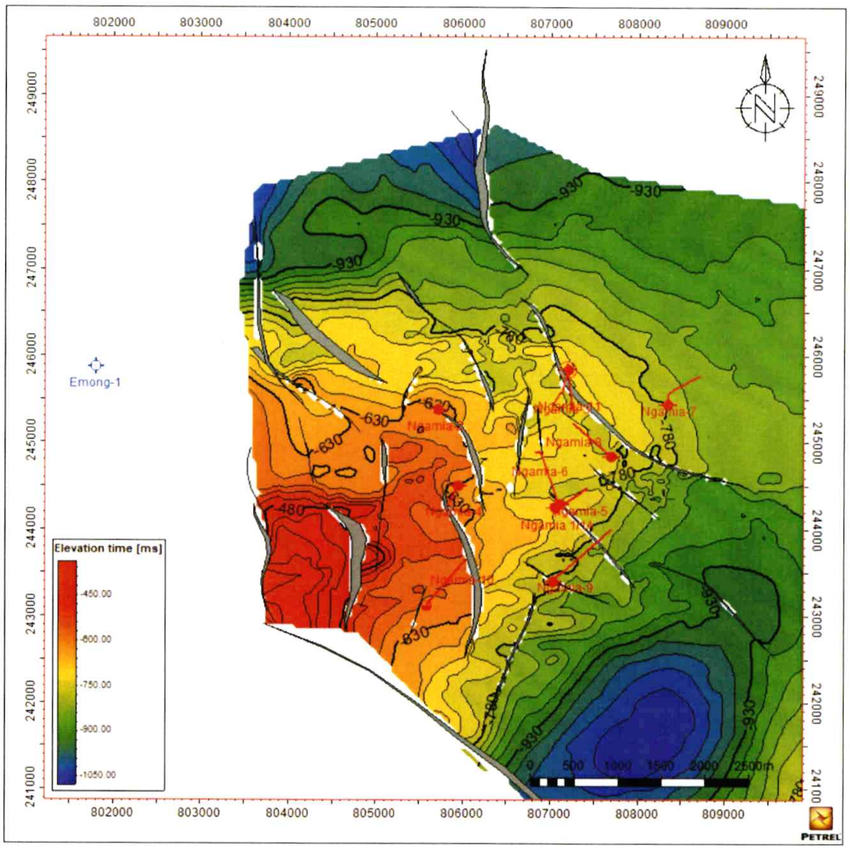


Figure 4-38: Ngamia Field RAP PreSTM LKT76 two-way time structure map (milliseconds)

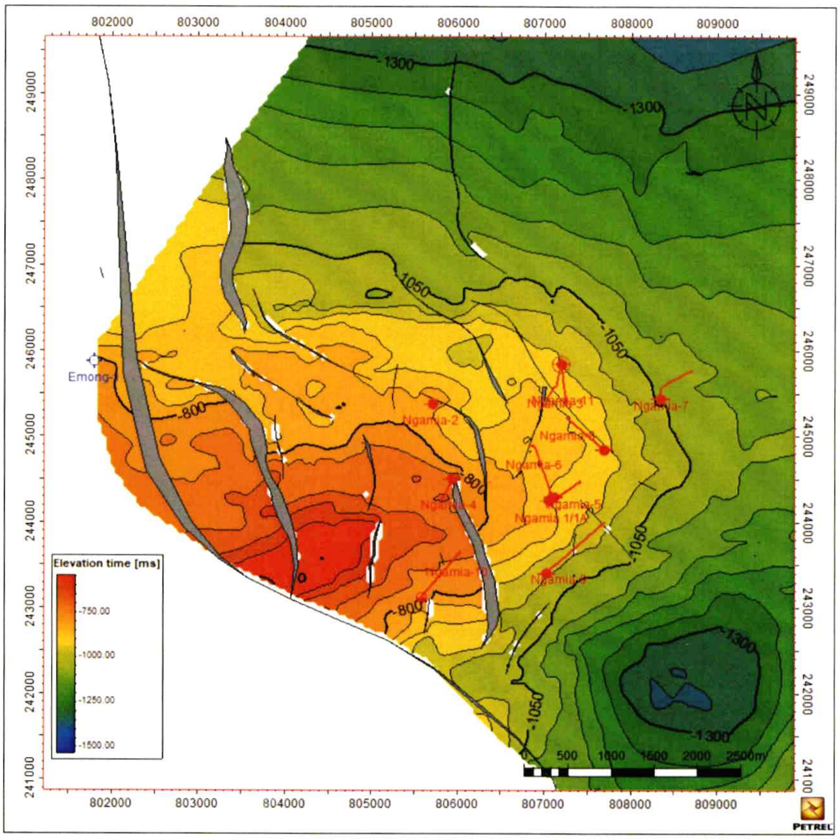


Figure 4-39: Ngamia Field RAP PreSTM LKT70 two-way time structure map (milliseconds)

Depth Conversion

Depth conversion of the RAP PreSTM 3D seismic two-way time horizon interpretation was performed using an interval-based modelling technique (Figure 4-40). The model incorporated five key intervals defined from the RAP PreSTM 3D two-way time horizon interpretation and the corresponding pseudo-interval velocities calculated at each well tie with the RAP PreSDM 3D seismic data.

The seismically defined intervals are:

- Ground Level to LKT80 (refraction static replacement velocity model was used)
- LKT80 to LKT78
- LKT78 to LKT76
- LKT76 to LKT70
- LKT70 to LKT60

Aside from the first layer where refraction static velocity surface has been used, pseudo-interval velocities are calculated at each well tie using the corresponding layer isopach from well log data and the two-way time isochron value from the RAP PreSTM seismic data interpretation. The pseudo interval velocities at each well tie are gridded over the entire field area using a convergent gridding algorithm resulting in a two-dimensional grid of pseudo-interval velocity for each of the four key seismic intervals

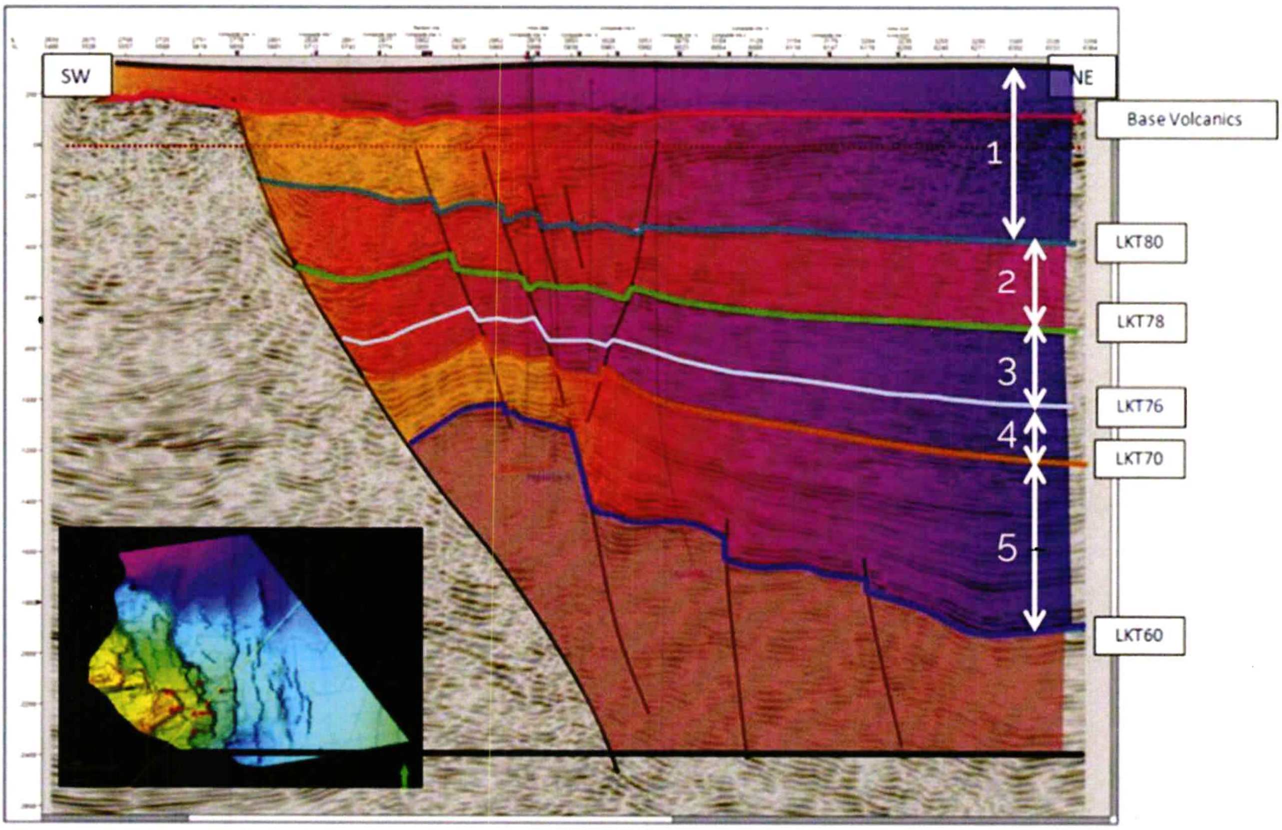


Figure 4-40: RAP PreSTM seismic line through Ngamia Field showing key seismic horizons and intervals used in interval velocity model]

The resulting depth maps from the depth conversion is shown below in Figure 4-41 to Figure 4-44

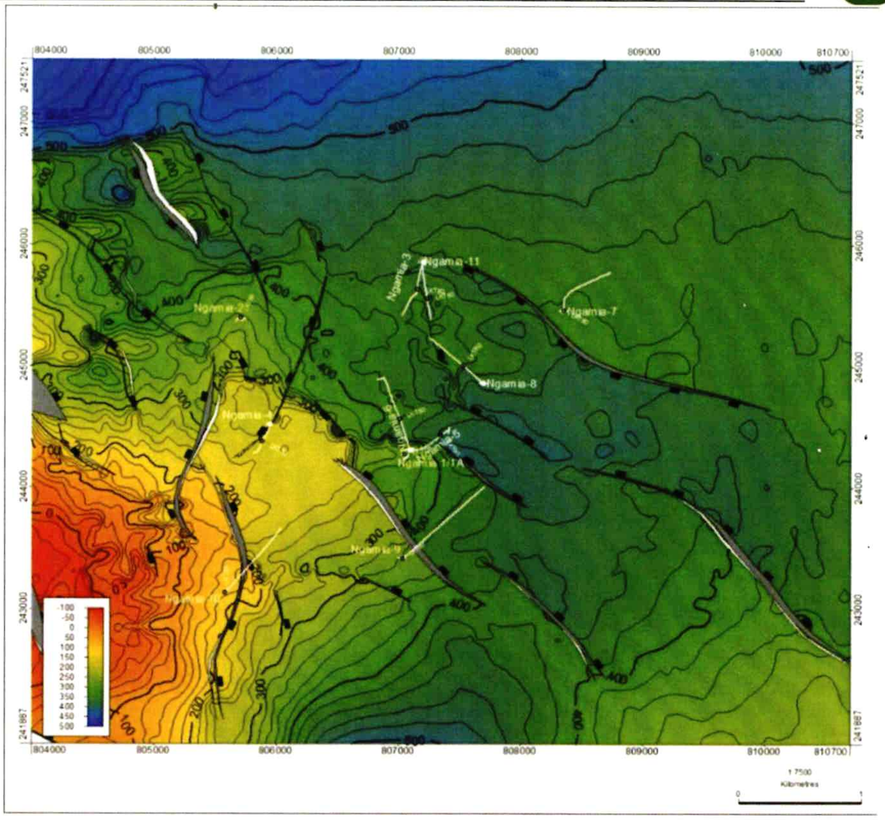


Figure 4-41: Ngamia LKT80 Depth Map

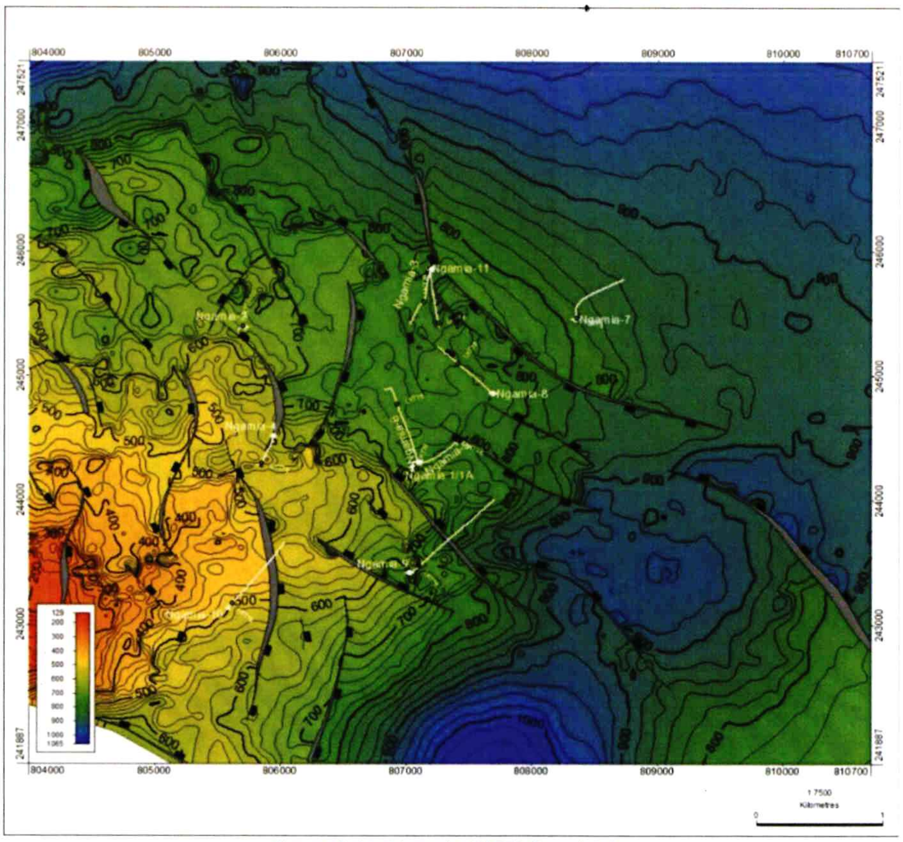


Figure 4-42: Ngamia LKT78 Depth Map

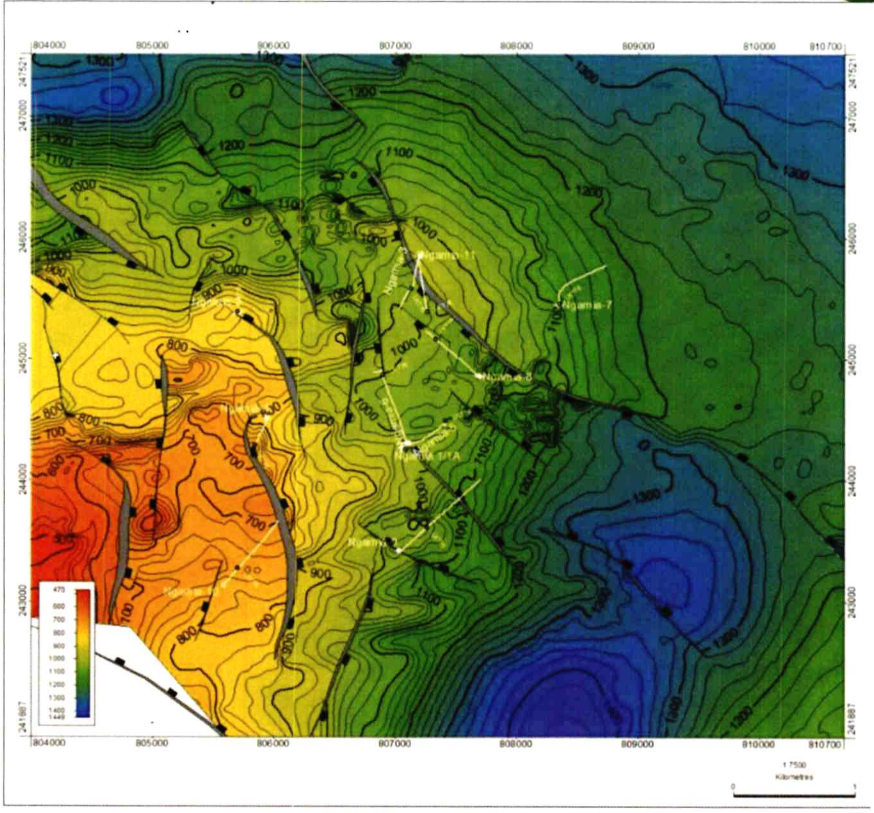


Figure 4-43: Ngamia LKT76 Depth Map

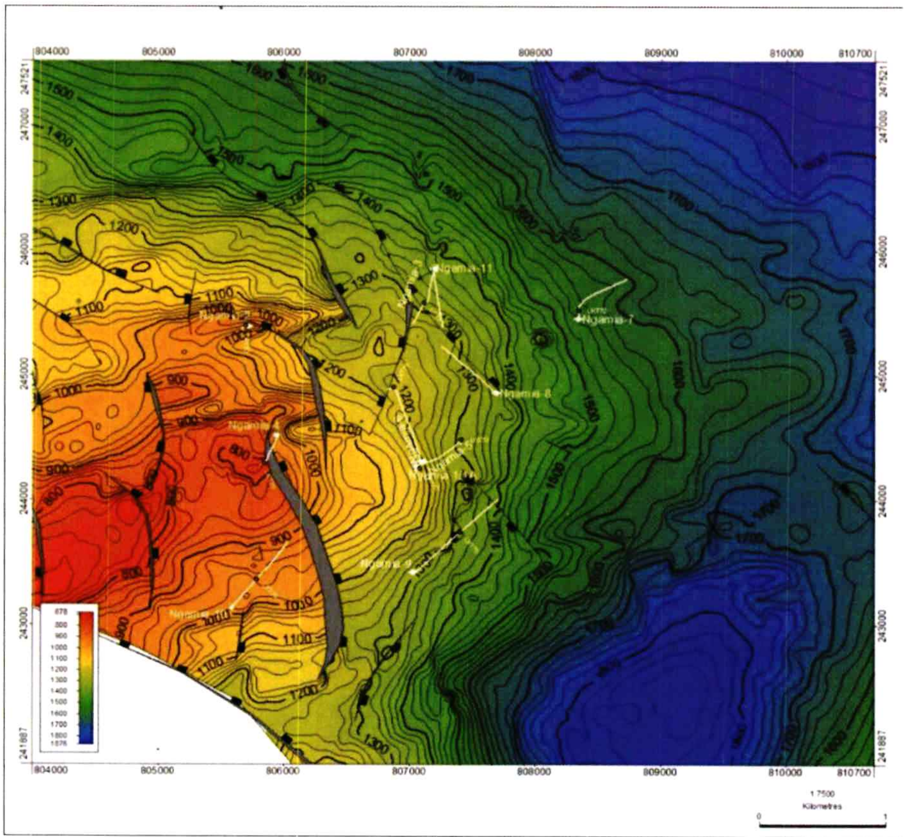


Figure 4-44: Ngamia LKT60 Depth Map

4.6.1.4 Petrophysics

The general petrophysical workflow was described in Section 4.4. This section will discuss available data and processes specific to the Ngamia Lower Auwerwer analysis. The Ngamia Field has the most robust set of petrophysical data of any of the fields in the South Lokichar Basin. Numerous conventional full diameter cores, and robust logging suites in most of the wells provides a very complete petrophysical database.

Conventional full diameter cores from the Lower Auwerwer section were acquired in the Ngamia-2, 3, 4, and 5 wells, totaling 422 m of core recovered (Table 4-4). RCA analysis was performed in the core to provide measurements of porosity, permeability, grain density, etc. to guide the petrophysical analysis of the log data acquired. Core plugs from the Ngamia cores were a large part of the extensive x-ray diffraction study that was completed to narrow down the range of volume of shale calculated in the reservoir. Table 4-4 is a cross plot of porosity versus permeability from core data in the Lower Auwerwer Formation acquired in Ngamia wells. Figure 4-46 displays petrophysical curves from the Lower Auwerwer section in the Ngamia-3 well comparing core data to calculated curves for porosity and water saturation.

Table 4-4: Conventional core acquired from the Lower Auwerwer Formation in the Ngamia Field

Well	Core #	Top (m)	Base (m)	Total (m)	Mud	Formation	Facies
Ngamia - 2	2	828	854	26	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 2	3	857	911	54	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 2	4	1010	1047	37	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 2	5	1184	1238	54	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 3	1	1106	1159	53	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 3	2	1257	1311	54	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 3	3	1442	1488	46	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 4	1	988	1037	48	SBM	Auwerwer	Fluvial Lacustrine
Ngamia - 5	1	1234	1284	50	SBM	Auwerwer	Fluvial Lacustrine
Total	**9**			**422**			

The data acquired in the core analysis and the subsequent petrophysical analysis of the log data was used to define the different facies in the static geological model as well as the primary reservoir components leading to the estimation of resource volumes in the Lower Auwerwer formation in the Ngamia Field.

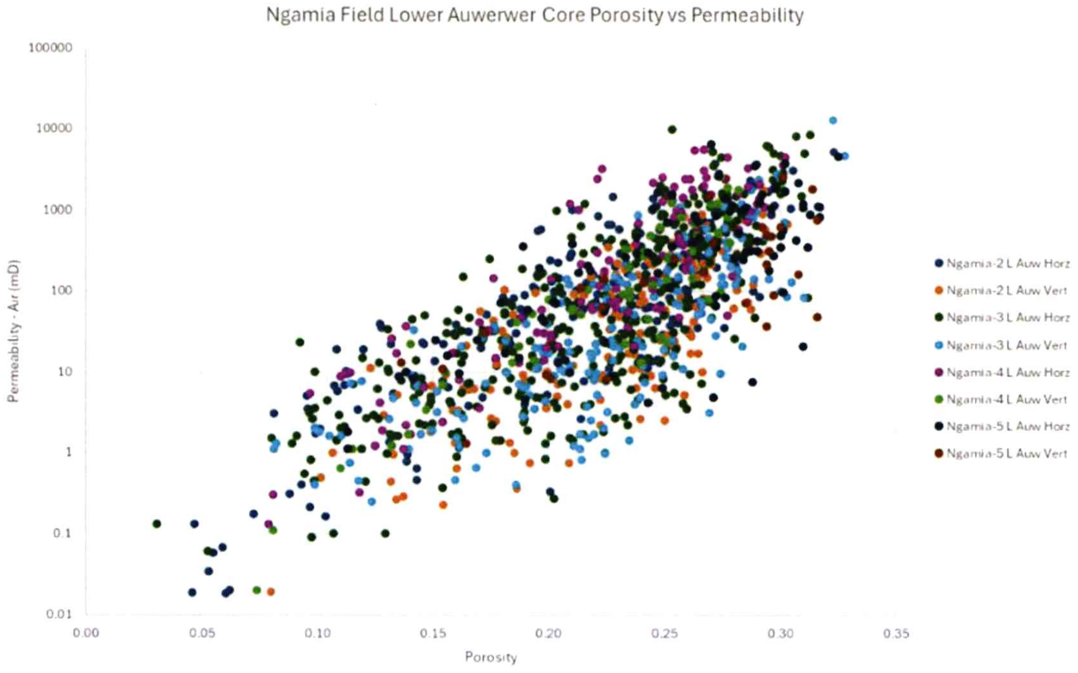
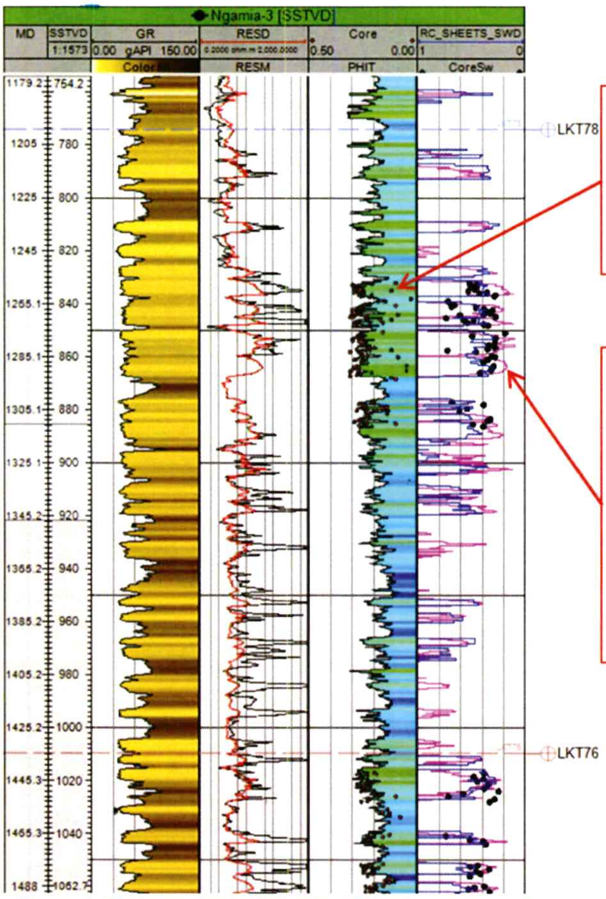


Figure 4-45: Porosity-Permeability cross plot of core data in the Lower Auwerwer Formation from Ngamia cores



Porosity

Dots are core values

Curve is calculated total porosity

Water Saturation

Dots are Dean Stark Sw values

Pink curve is calculated water saturation

Blue curve is Sw from saturation height function

Figure 4-46: Petrophysical display of the Lower Auwerwer section from Well Ngamia-3

4.6.1.5 Static Modelling

<u>Grid</u>

A structural grid for the Auwerwer-only model has been constructed using 21 faults and four depth surfaces from the seismic interpretation. The depth surfaces were LKT80 (Top Mid-Auwerwer Shale), LKT78 (Top Lower Auwerwer), LKT76 (Intra Auwerwer), and LKT70 (Lower Auwerwer Sandstone). Subzones within the reservoir are generated by isopachs consistent with well tops and the overall reservoir envelope. The faults were used to create 10 segments in the grid (Figure 4-47). The X and Y grid increment was set at 50 m.

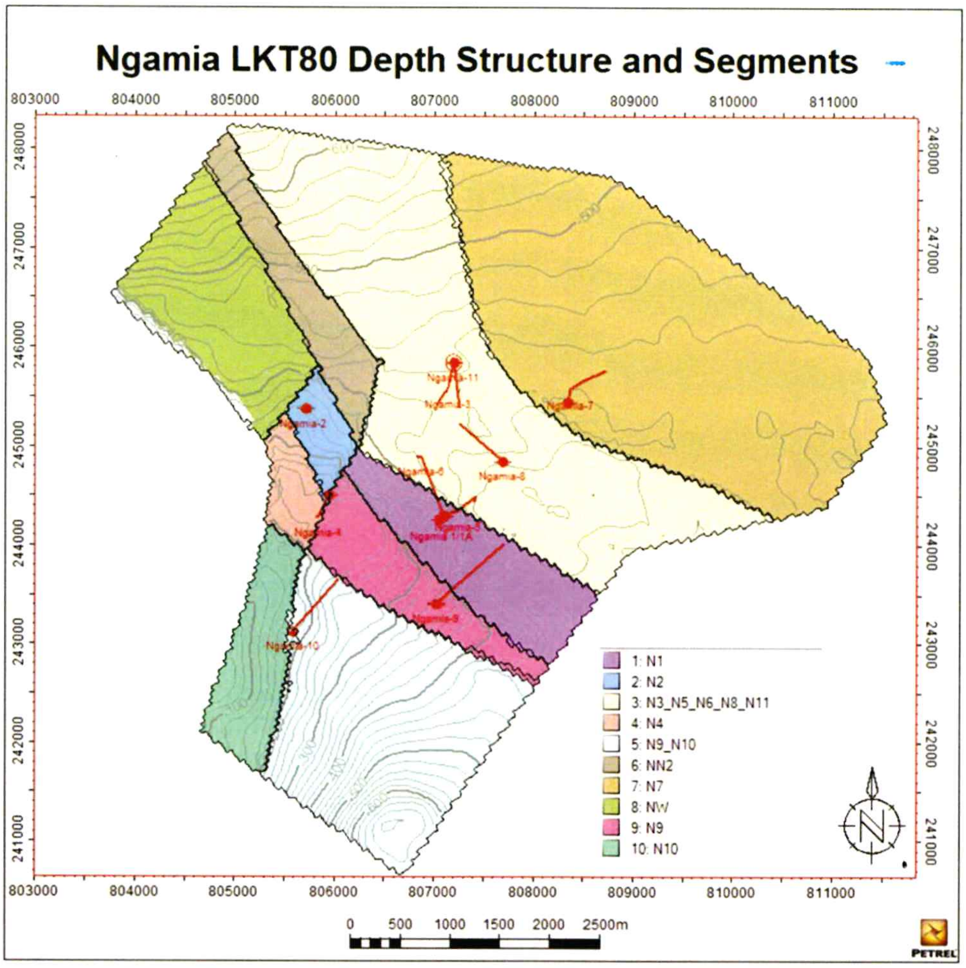


Figure 4-47: Ngamia 3D model segment map

Zones and Layers

A zonal correlation has been made between all wells drilled in Ngamia, which integrates the seismic, log, pressure and sample data. Isochores of the fifteen Auwerwer zones identified have been used to insert the zones into the 3D structural model (Figure 4-48, Figure 4-49).

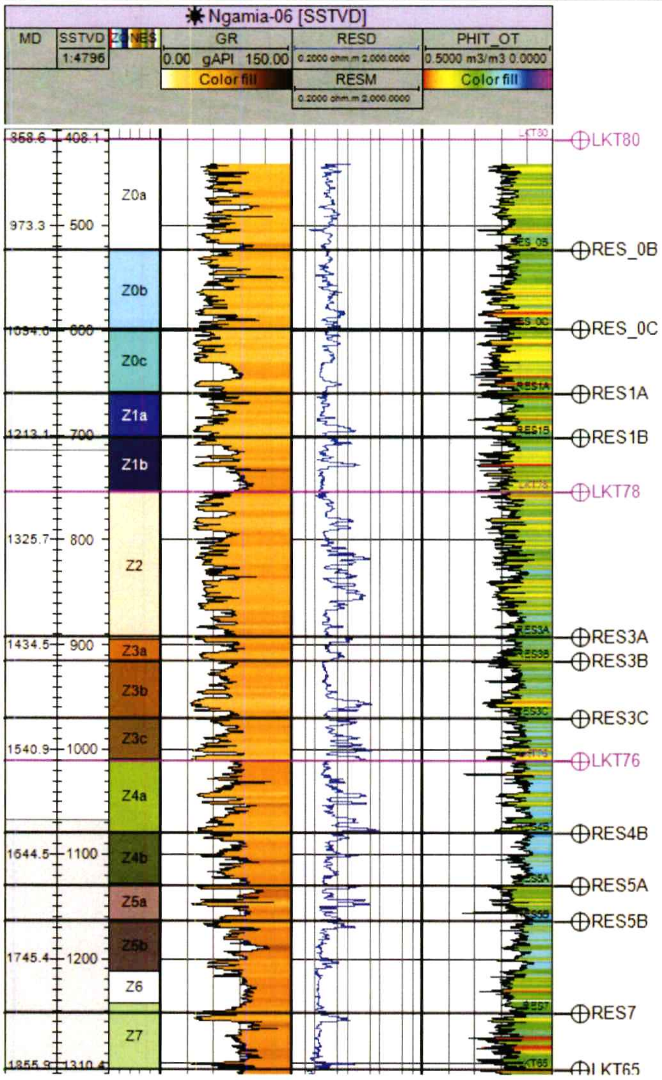


Figure 4-48: Ngamia 6 well correlation showing correlation and reservoir zonation. NOTE: Pink picks represent seismic picks

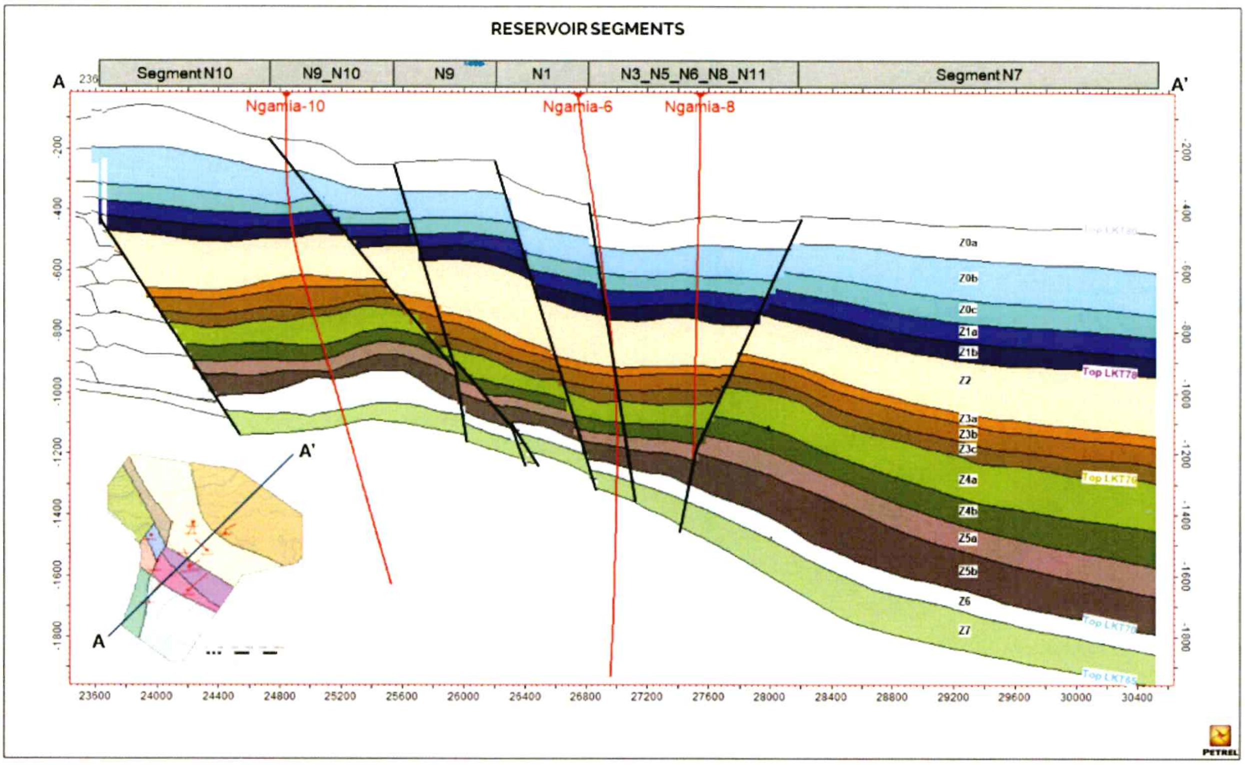


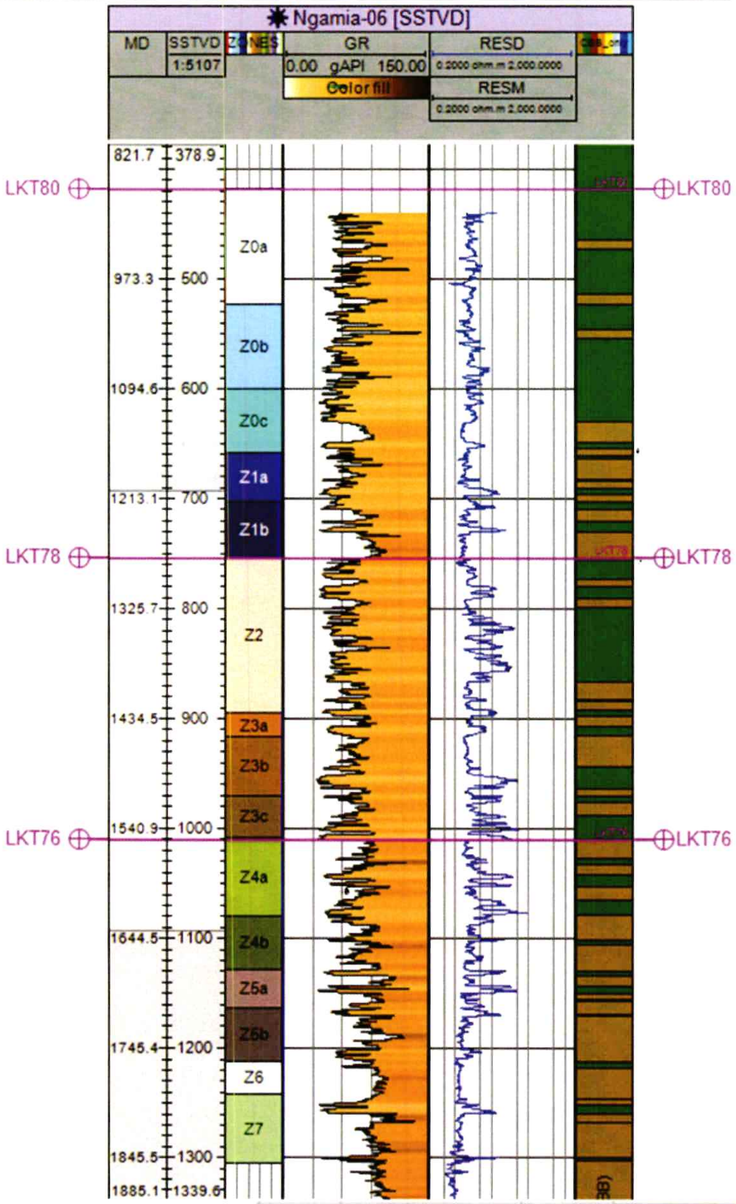
Figure 4-49: Cross section through 3D model showing reservoir zonation

Facies Modelling

As described in Section 4.5.2 facies modeling in Ngamia utilizes a multi-step approach to best model the interpreted and conceptualized depositional patterns. The initial step involves identifying the alluvial-fluvial boundary using polygon sets. Well data drives the mapping of the fluvial succession.

Firstly, thick shales interpreted based on well data are populated within the fluvial succession. Starting with thick shales promotes laterally extensive shales between channel belts. Next, channel belt bodies (CBBs) are populated within the broadly sandy interval (Figure 4-50). CBBs are used to partition sand prone regions from shale prone regions. Intra CBBs are populated within sand prone regions, modelled as a composite of many individual events. Reservoir sands are populated within the CBBs. Net-to-gross (NTG) values are ensured to match zonal averages from the wells.

Resulting Ngamia Auwerwer facies model is shown in Figure 4-51.



0	AP (non CBB)	🟫
1	CB (non NET)	🟩

Figure 4-50: Well Ngamia-6 log showing CBB interpretation

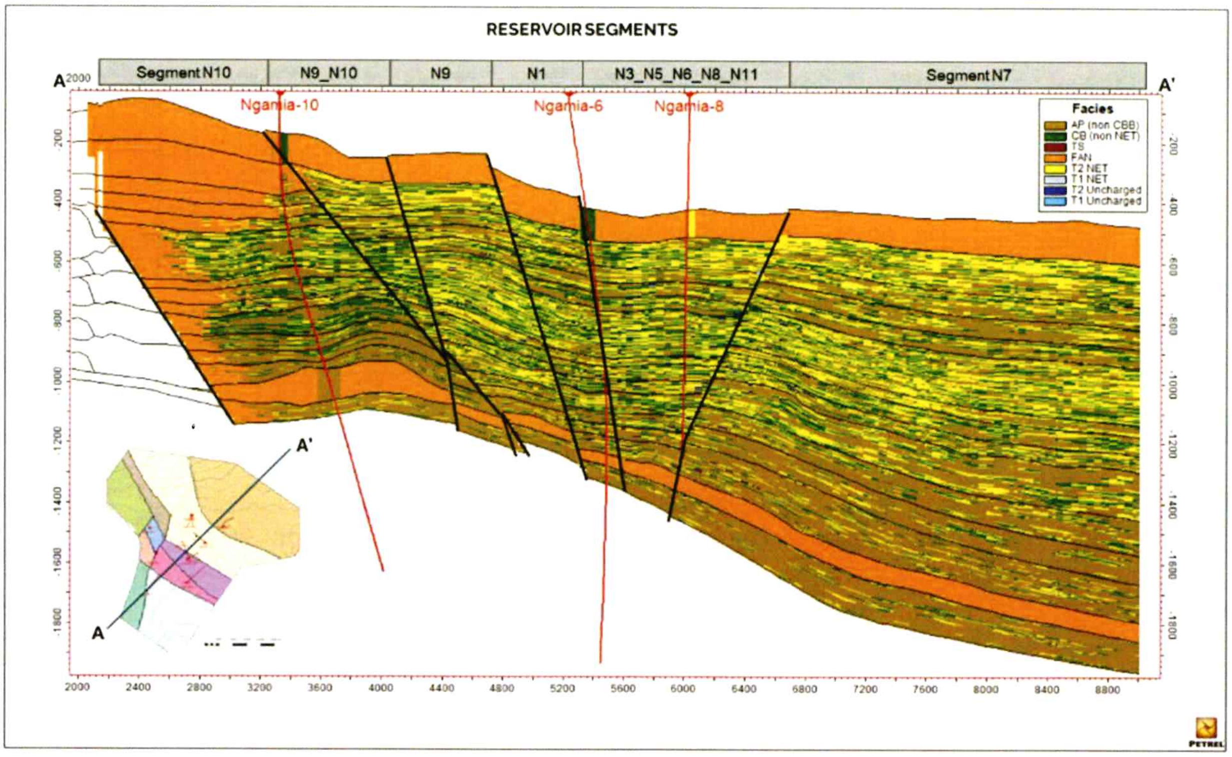


Figure 4-51: Ngamia SW-NE cross section showing Auwerwer Facies model

Property Modelling

Total porosity is upscaled from well data and modeled within the net channel facies. Each stratigraphic unit is modeled separately with its own porosity distribution and transform derived from well and core data. This distribution, along with channel body azimuth trends and variograms are input to the sequential gaussian simulation to generate the porosity model Figure 4-49.

Permeability has been modelled using available routine core analysis from Ngamia wells filtered to Auwerwer interval. A porosity-permeability model has been developed which captures the shape of the core porosity-permeability cloud.

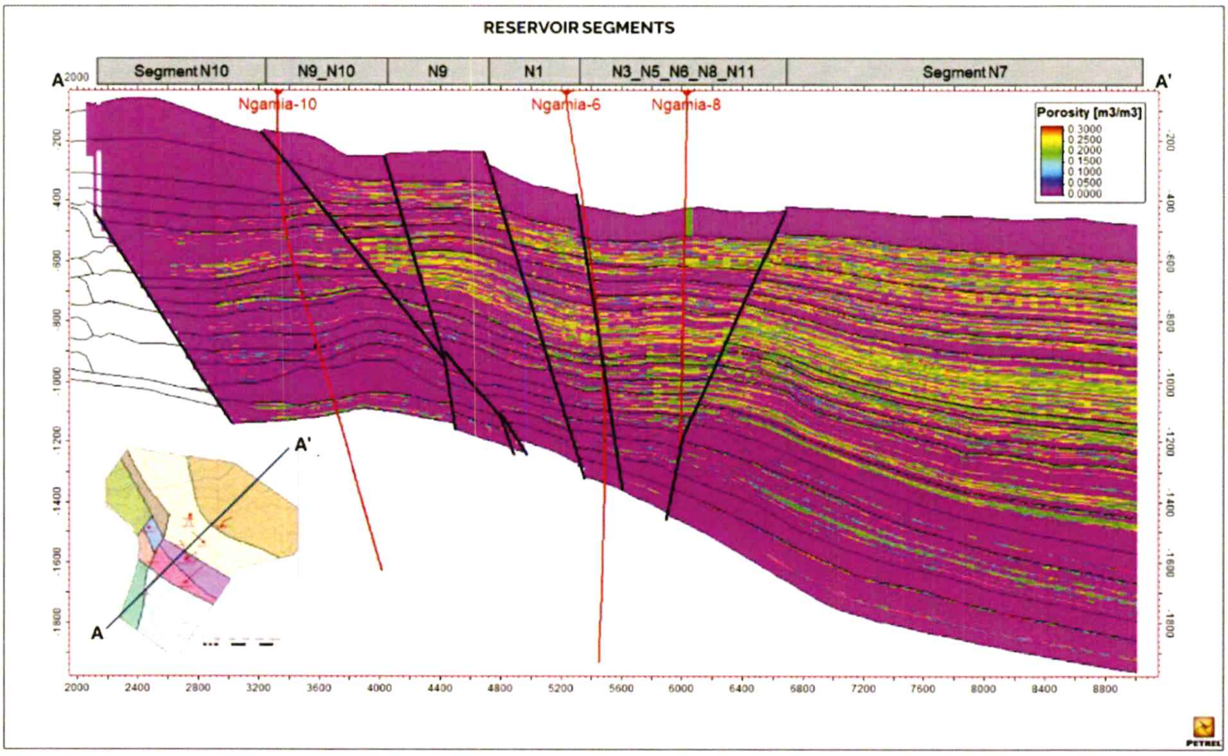


Figure 4-52: Ngamia SW-NE cross section showing Auwerwer porosity distribution

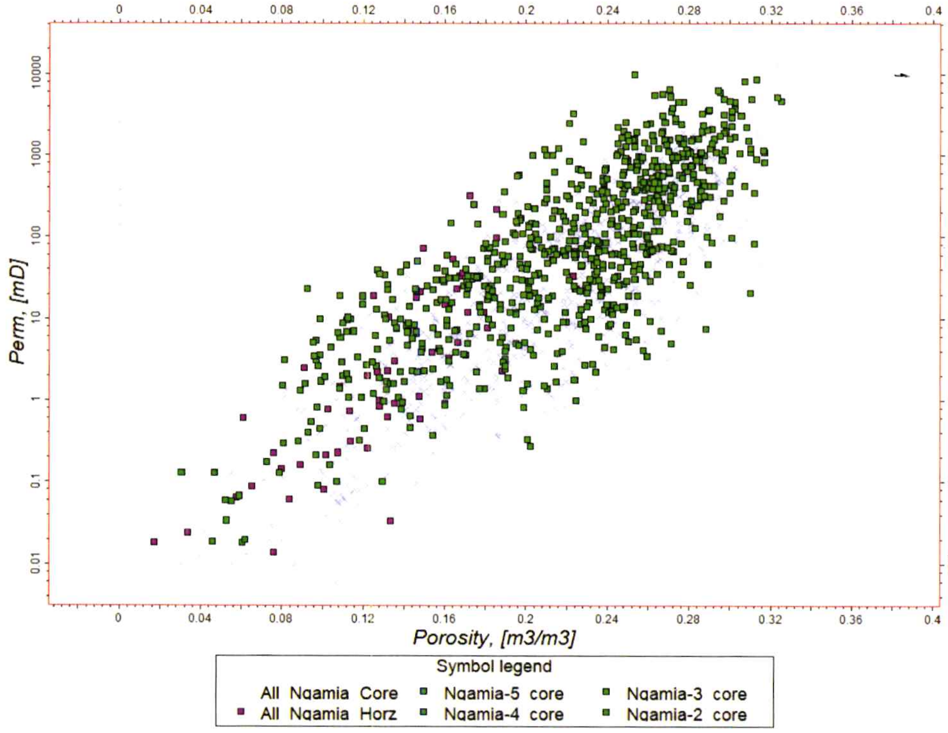


Figure 4-53: Ngamia core data – porosity / permeability cross plot

4.6.1.6 Hydrocarbon Contacts

The Lower Auwerwer reservoir is separated into a number of separate intervals (oil pools). The pools appear to be pressure isolated within the individual mapped fault segments.

Formation pressures have been acquired in each well in the Ngamia field using either the Modular formation Dynamics Tester ("MDT") or Reservoir Characterization Instrument ("RCI") tools. Oil-water and gas-oil contacts are picked, where possible, from the intersection of the gas, oil and water gradients. Due to the relatively freshwater salinity the density contrast between oil and water is small and so using traditional plots of formation pressure vs depth does not give clear indications of fluid contacts. Instead plots of differential / excess pressure vs depth have been used where the difference in pressure between the acquired data and the pressure of a reference fluid at that depth is plotted (typically the aquifer pressure). This allows more subtle pressure differences and density differences to be observed. The assessment was carried out on a segment-by-segment basis, considering only the data from penetrating wells. The interpretation was corroborated by the fluid samples collected. Figure 4-54 shows the Ngamia formation pressures and best estimate contacts for each zone.

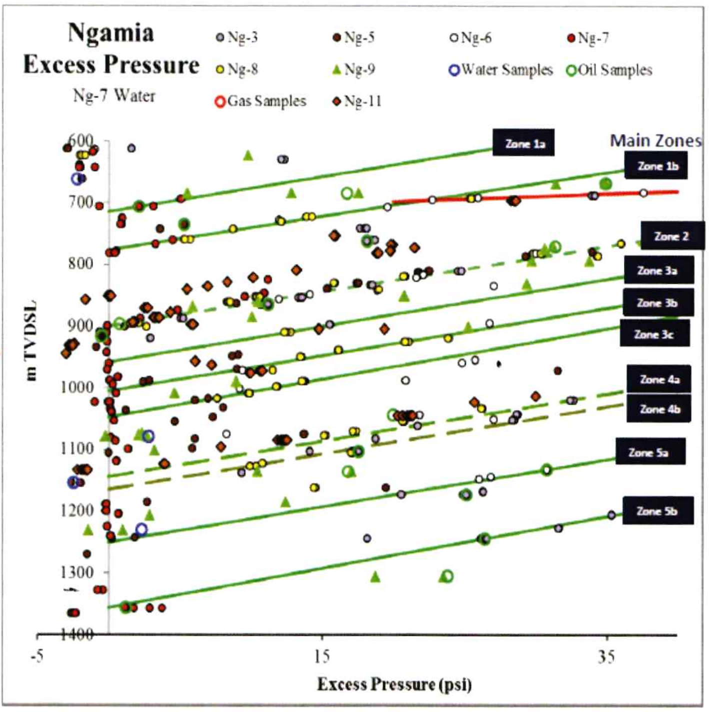


Figure 4-54: Ngamia Formation Differential Pressure plot (relative to NG-07 water gradient)

The best estimate hydrocarbon contacts have been modelled in the static model, as shown in Figure 4-55 and Figure 4-56.

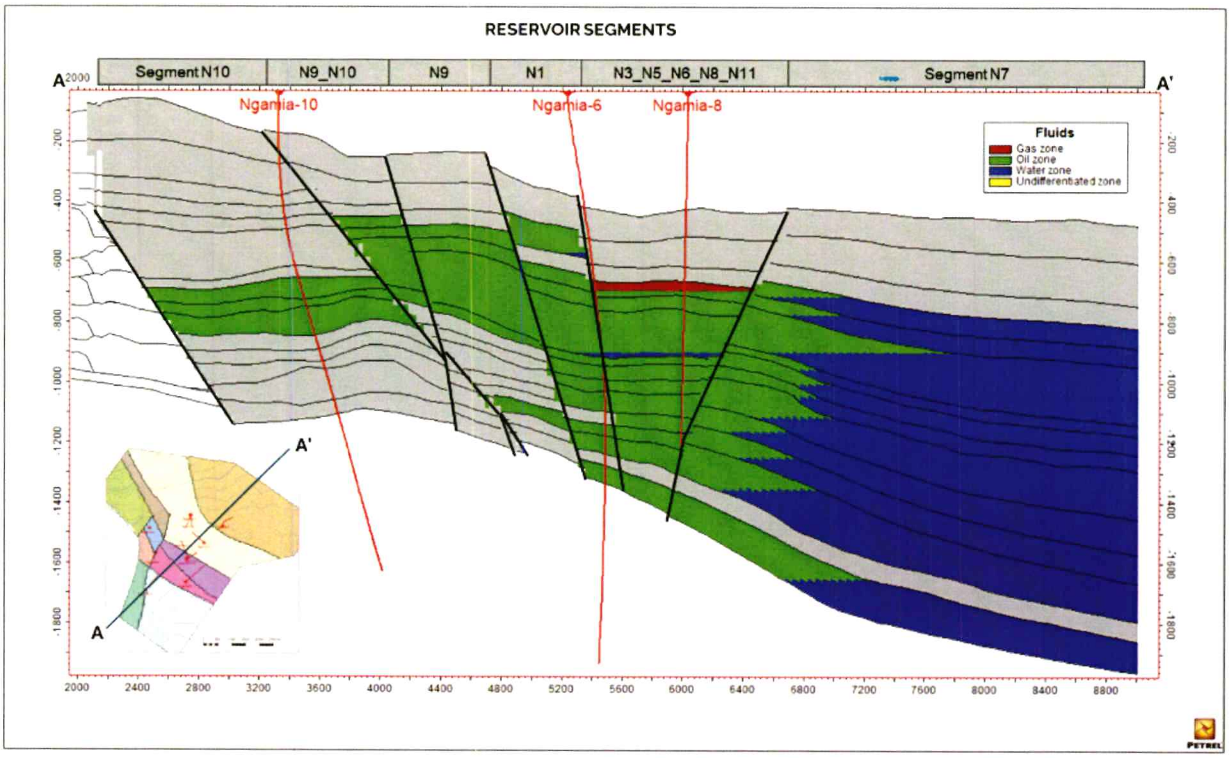


Figure 4-55: Ngamia SW-NE Cross Section Showing Mid Case Hydrocarbon Contacts within the Auwerwer Model

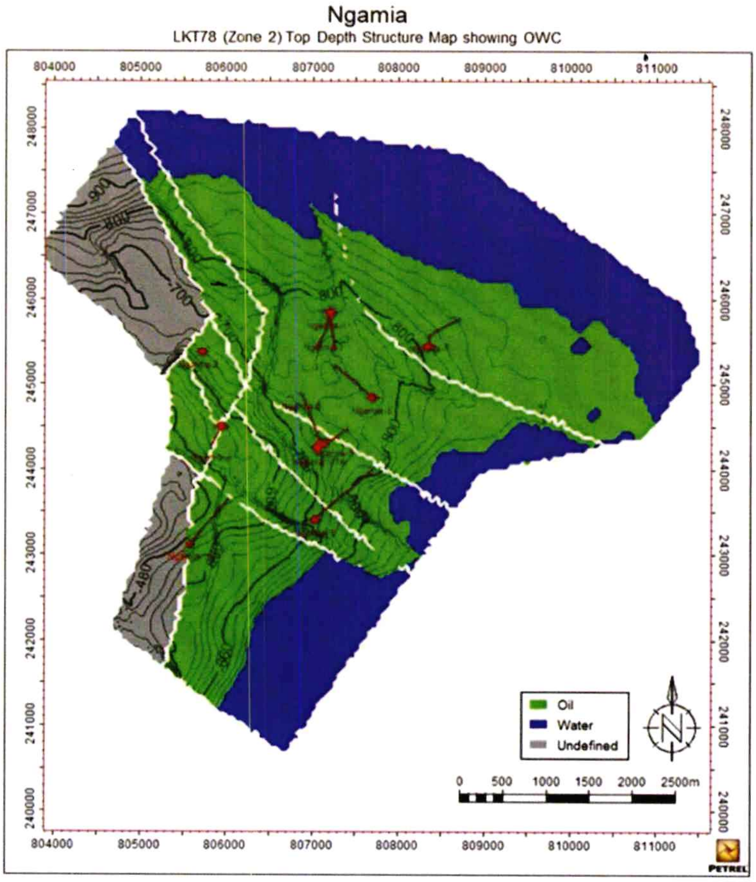


Figure 4-56: Top LKY78 (Zone 2) Depth Structure Map showing Mid Case OWC across the Ngamia Field

4.6.1.7 Volumetrics

The Mid case STOIIP value has been calculated using a static model. Low and high case STOIIP values have been estimated using a separate methodology using a statistical approach.

The same sets of TWT grids and depth-converted grids used in the mid case/static model have also been used for the low and high case estimates. GRV variations are dominated by contact uncertainty and segment inclusion or exclusion. The reservoir parameter ranges were based on sums and averages, and the fluid parameters were based on PVT data from fluid samples.

The following table summarizes the field-wide volumetrics for the Ngamia Auwerwer accumulation:

Table 4-5: Ngamia Auwerwer STOIIP

CASE	STOIIP (MMstb)
LOW (1C)	459
MID (2C)	680
HIGH (3C)	984

4.6.1.8 Production and Injection Testing

The Ngamia Auwerwer field has undergone several testing and production periods during its appraisal history. These include production testing of Ngamia-1A, the 2015 Extended Well Test ("EWT") and 2019 Early Oil Pilot Scheme ("EOPS").

The original basin discovery well, Ngamia-1A, was tested across six separate intervals with one Lokone test and five in the Auwerwer section. Table 4-3 shows a summary of the Ngamia-1A Auwerwer DSTs.

Table 4-6: Ngamia DST Summary

	Depth Top (MMDBRT)	Depth Base (MMDBRT)	Peak Oil Rate (BBL/D)	Well Test Kh (MD.FT)	Net Pay (M)	Dst Net Pay Perm (MD)	Test Pi (BBL/D/PSI)	BS&W (%)
DST#2	1,529	1,550	72	1,260	8.0	48	0.1	2%
DST#3/3A	1,254	1,406	819	6,030	62.5	29	1.0	0%
DST#4	1,142	1,213	415	4,220	41.5	31	0.7	0%
DST#5/5A	1,028	1,074	1,175	27,500	25.5	329	1.7	0%
DST#6	856	930	410	21,000	30.0	214	1.6	0%

The DSTs in the well were conducted separately, beginning with the deepest interval, and moving upwards to shallower test zones after plugging back. Downhole surface readout ("SRO") gauges and downhole shut-in tools were deployed in the well with surface test separator equipment set up to maximise the quality of information acquired during the tests.

The well completions were set up with circulating valves to allow oil to be flushed from the tubing during the shut-in periods as there was considered to be a high risk of wax dissolution during wellbore cooling. The wells were completed with either progressing cavity pumps ("PCPs") or electrical submersible pumps ("ESPs") depending on the zonal productivity. Downhole and surface fluid samples were gathered during the flow tests and production logs were acquired on DST#3A and DST#5A using a Y-tool logging bypass on the ESP.

The Ngamia EWT was carried out in 2015, examining production in individual zones across three wells and observing offset pressure responses. Starting in late May 2015, individual zones in Ngamia-3, Ngamia-6, and Ngamia-8 were flowed during a six-week well clean-up period, while bottom hole pressure recorders captured the flowing and shut-in pressures for each zone. In September of that year, individual zones at the key production well, Ngamia-8, were sequentially opened to flow over approximately two and a half months to monitor interference at the neighbouring Ngamia-3 and Ngamia-6 wells.

The next testing activity on the field was in February 2017 when a brief water injection test was conducted at Ngamia-5 (during a program of Lokone testing). Two zones were individually tested over a short period, injecting a total of 1,583 m3 (9,957 bbl) of water.

In December 2017, the Ngamia-11 water injection began with injection into Zones 2, 3 and 4. Injection during this period was commingled although individual zones were alternately opened and closed in various combinations. Ngamia-11 injected approximately 149 Mstb of water over a period of ten months. While this injection was ongoing Ngamia-3 Zone 4 and Ngamia-8 Zone 2 were opened to flow for a short period of time. At the completion of this interference testing period in October 2018 the field was once again shut in. By that time, a total of approximately 75.5 Mstb of oil with a very small volume of water had been produced from the three producing wells.

Beginning in late May 2019, Ngamia-3, Ngamia-6, and Ngamia-8 were opened to flow using the installed facilities of the EOPS (Figure 4-57). Except for Zone 1 at Ngamia-8, production was commingled from all five zones in each well during this period.

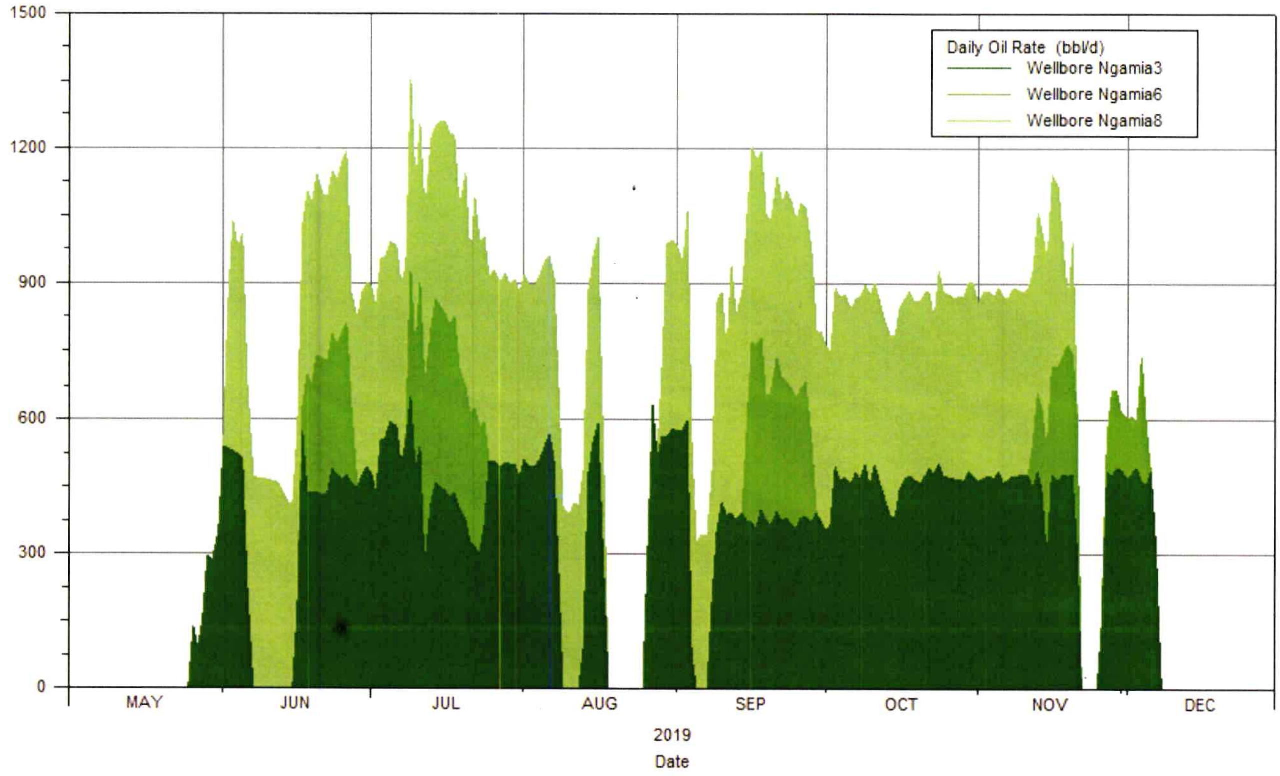


Figure 4-57: Ngamia EOPS Oil Production Rates

The EOPS period ended in December 2019 after producing an additional 152.6 Mstb of oil from Ngamia for a total cumulative oil production of 225.9 Mstb, including the EWT phase. The field has since been shut-in.

The EWT, EOPS and water injection pilot have helped to demonstrate large oil volumes connected to the EWT wells and pressure communication between them.

4.6.1.9 Fluid Properties

An extensive reservoir fluid sampling campaign was carried out during the exploration and appraisal of the Ngamia Auwerwer reservoir. Samples have been acquired at various stratigraphic levels within the oil-bearing sections (APPENDIX D) and the pressurized samples were taken using downhole wireline samplers during logging operations and during flow testing operations (both DST and EWT/EOPS) for PVT laboratory experiments. Fluid samples have been extensively analysed in the laboratory. Pressure-Volume-Temperature (PVT) experiments have characterized the oils as medium gravity, low viscosity, undersaturated black oils with low gas-oil-ratios (GOR) (Table 4-7). Dead oil crude property analysis shows the Ngamia Auwerwer oils to be low in sulphur, asphaltene and aromatics but moderately high in wax content with high wax appearance (WAT) and pour point temperatures above ambient conditions. The associated gas is rich and sweet with some localised high carbon dioxide content.

Table 4-7: Summary of Ngamia Auwerwer Fluid Properties

Reservoir Pressure (psia)	Reservoir Temperature (deg C)	Saturation Pressure (psia)	Gas-oil Ratio (scf/stb)	Oil Gravity (deg API)	In-situ Viscosity (cp)	Formation Volume Factor (rb/stb)	Wax Appearance Temperature (deg C)	Wax Content (mol %)	Pour Point (deg C)
1300 – 2100	75 – 92	700 – 1160	100 – 240	30 – 33	2 – 13	1.1 – 1.3	63 – 68	23 - 37	42 - 51

4.6.1.10 Relative Permeability

Relative permeability measurements have been completed on core from Twiga South-1, Amosing-2A and Ngamia-3. These data have been reviewed by an external consultant[1] and concern was raised regarding the cleaning processes and the wettability restoration used to prepare the core for flooding. Work has since been ongoing to optimise the appropriate cleaning process and to determine the duration required to restore the rock wettability to its original state.

Although generally an uncommon condition for oil reservoirs, it is believed that the assumption of water-wet rock is most likely to represent actual in-situ conditions. Water-wet rock is usually associated with the following characteristics of the South Lokichar Basin reservoirs:

- Alkaline (high pH) formation water
- High connate water saturation
- Very low/near-zero asphaltene content of the oil

Water-wet relative permeability functions were used to describe a single set of normalized functions for both water/oil and gas/oil phases. Endpoint scaling was applied to denormalize these functions on a grid block basis in the simulation models.

Results from a single well chemical tracer test (SWCT) on Amosing-2A Zone 2 show an average residual oil saturation (Sorw) of 17.8% (± 2%) following a period of water injection. A range for Sorw between three individual oil-bearing sands in the well, derived from numerical modelling of the test, was calculated to be between 12% to 26% (Values of 12%, 20% and 26% were reported). Lower values of Sorw may ultimately be obtained following an extended period of water injection. There is insufficient data from this investigation to assign values specifically to various rock types and the range of uncertainty was therefore narrowed to reflect a need for upscaling to simulation dimensions.

The normalized relative permeability curves used in the simulation are shown in Figure 4-58. These curves are scaled in the simulation model to reflect the connate water and residual oil saturation for each cell in the oil zone. These curves are also used in the Amosing and Twiga simulation models.

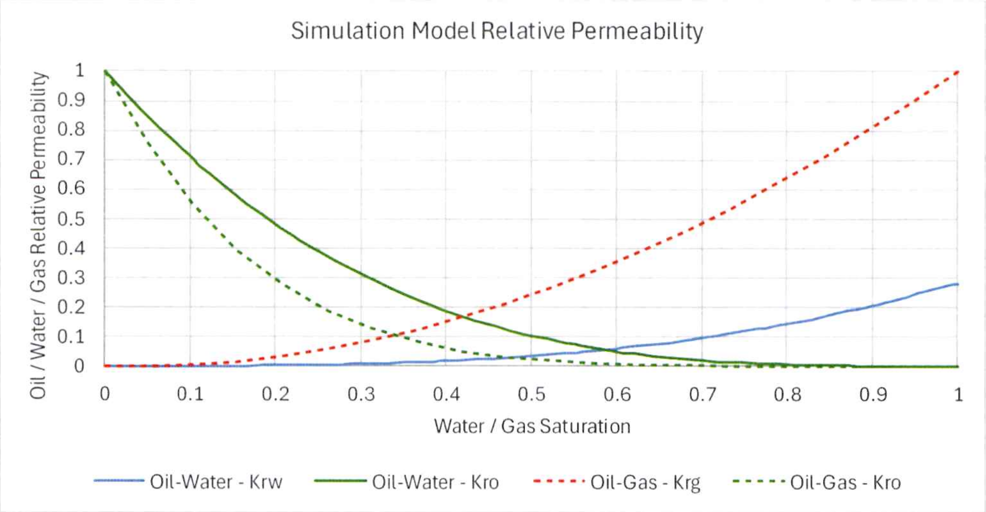


Figure 4-58: Relative Permeability Curves

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[1] "Review of 2015-2017 Special Core Analysis Measurements for South Lokichar Basin, Kenya." Ted Braun. 18th October, 2017

4.6.1.11 Reservoir Model Initialisation

Fluid contacts, datum depths and initial pressures were provided for a total of 34 individual and isolated pools that were defined by a combination of fault block and zone. The Auwerwer aquifer pressures fall on a regional gradient for Ngamia and are assumed to be in hydrostatic equilibrium. Two pools within the Auwerwer, N2_Z1b and N3_Z1a have initial free gas present, the latter of which has been identified as one of two potential gas storage reservoirs to help in gas management for the development.

4.6.1.12 Ngamia Auwerwer Simulation Modelling

The history matching was performed on the wells that produced during the dynamic reservoir testing: Ngamia-1A DSTs; Ngamia-5 DST and water injection test; Ngamia-3, -6 and -8 Extended Well Test; Ngamia-11 water injection trial and EOPS. The wells produced during the EOPS period were the main focus for the history match, given the longer production and build-up periods. Although there is a large quantity of high-quality data available to match, it is concentrated in a single area of the field. Rather than applying local edits to reservoir properties to achieve a match, where justifiable, edits have been applied across the field.

The model comprises distinct zones, and a history match is performed across all zones as they contribute to the overall pressure response. Core data from Ngamia wells were reviewed, and a poroperm relationship was derived that corrected from air permeability to liquid permeability and accounted for the effect of the overburden. This poroperm relationship was then used to populate permeability throughout the entire model.

Figure 4-59 shows the pressure matches for Well Ngamia-3. The final buildup pressure for four of the five zones perforated in Ngamia-3 is good. Injection at Ngamia-11 was into Zones 2, 3 and 4. For Zone 4, the model response to injection was relatively well-matched other than over the latter period (October 2018 to May 2019), where the injection data used as input to the model suggests injection continued, whereas the observed data would suggest injection had ceased. The final build-up pressure for the Ngamia-3 Zone 4 was lower than the observed pressures.

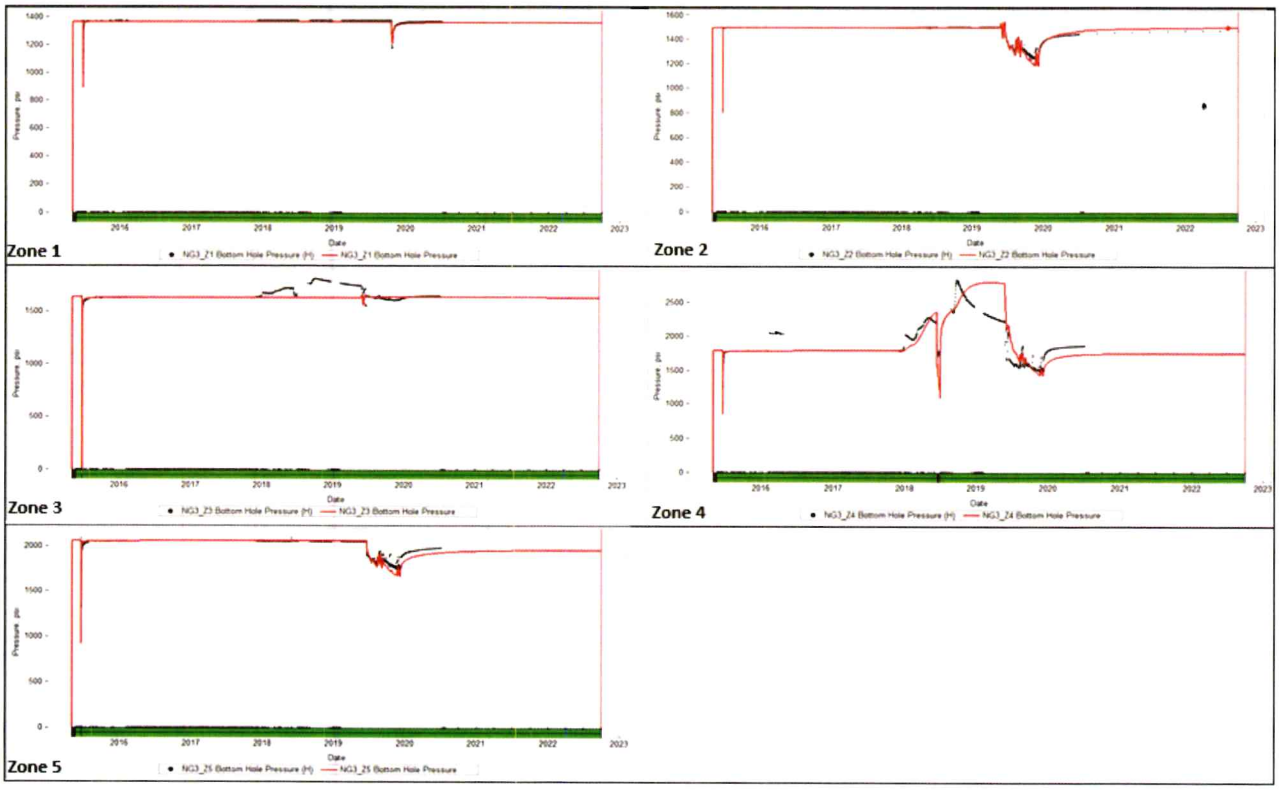


Figure 4-59: Ngamia-3 History match across zones

Figure 4-60 shows the pressure responses at Ngamia-6 to the EOPS production. The drawdowns in most zones in the model are not as large as observed in history, suggesting an overprediction of permeability, but a balance was struck between matching the drawdowns and the build-ups.

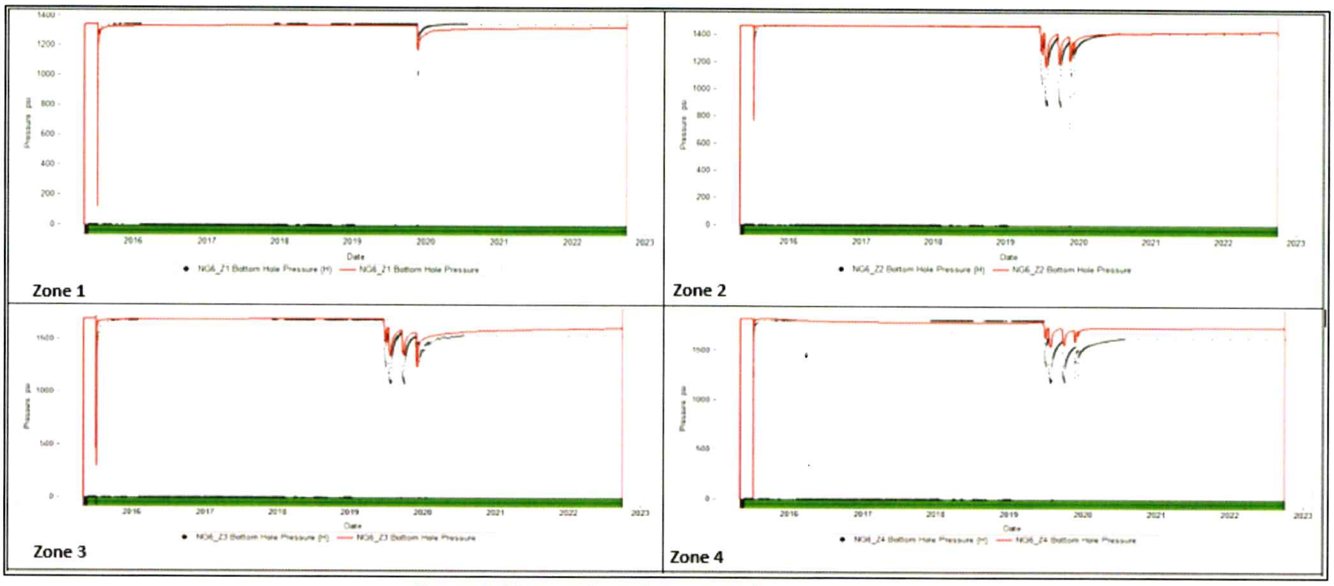


Figure 4-60: Ngamia-6 History match across zones

The simulated pressures at Ngamia-8 for Zones 1, 2 and 4, are shown in Figure 4-61. A reasonable match is achieved.

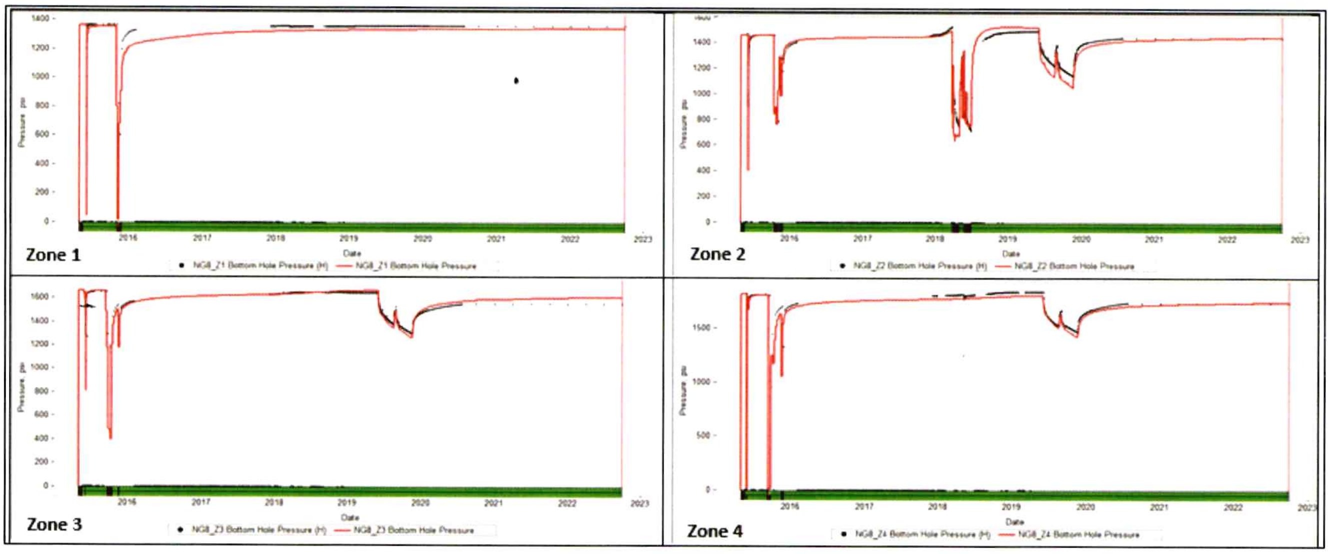


Figure 4-61: Ngamia-8 History match across zones

4.6.1.13 Ngamia Material Balance Assessment

The extended period of production and injection during EWT and EOPS, and the measurement of pressure data in multiple intervals of the EWT wells has provided sufficient information to complete material balance calculations on multiple intervals of the Lower Auwerwer reservoir. Pressure data were acquired separately for each zone with pressures reported through to 2020. Connectivity between the zones is demonstrated through the EOPS pressures recorded and so defining the connected oil volume precisely is challenging. However, assuming each zone is independent of the others and the final build up pressures are representative of the connected oil volume in communication with the completion suggests a connected volume (Ngamia-3/-6/-8) of around 334 MMstb. In the Ngamia EWT fault block, the base case static model contains 172 MMstb of oil indicating that communication across faults into other areas appears likely. These results also give confidence that connectivity across the pattern well spacing is likely to be good.

4.6.1.14 Ngamia Development Scenario

The development scheme is planned to be an inverted 5 spot pattern on a 200m spacing which has been shown to give an optimal recovery. The initial patterns from the Phase 1 development have been planned around existing wells Ngamia-3 and Ngamia-11 - 11 which broadly fit a 200m spacing within an area of high hydrocarbon saturations (Figure 4-62). These initial wells have been planned to be drilled from the existing Ngamia-3 well pad and a new pad to the south. A total of 24 wells have been planned for Phase 1.

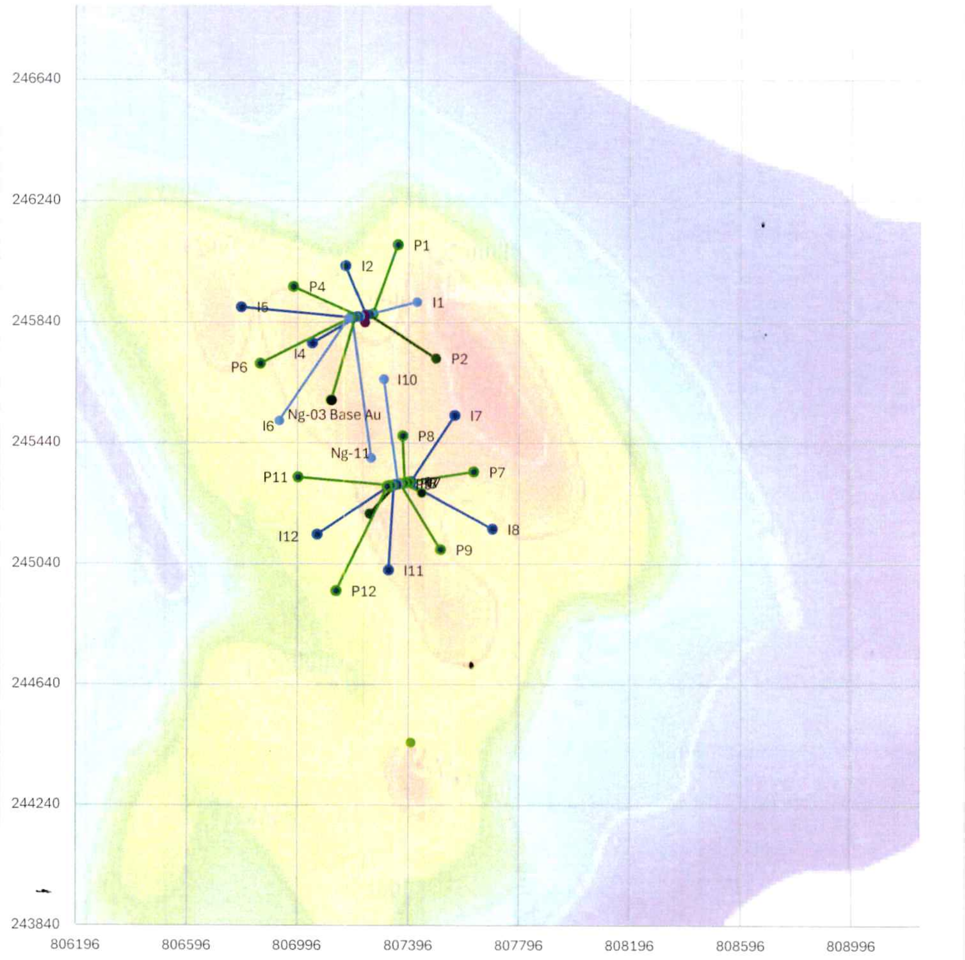


Figure 4-62: Phase 1 Ngamia well subsurface locations (background map of volume weighted oil saturation)

Phase 1 drilling is planned to commence in July 2026 with the Ngamia wells drilled between October 2026 and May 2027.

Wells associated with Phase 2 have been placed in the subsurface model to maintain the 200m well spacing grouped as far as possible to be drillable from a 12-slot pad. (Figure 4-63).

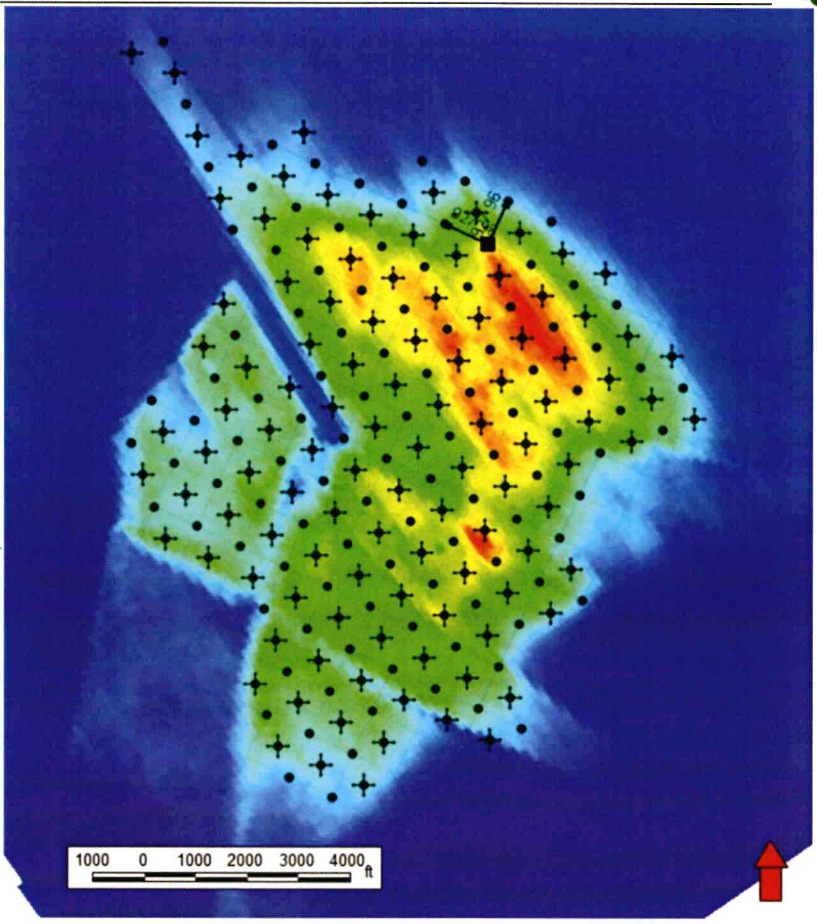


Figure 4-63: Ngamia Phase 2 well pattern (map of HCPV)

Phase 2 producers within the simulation grid are perforated in net sand where the water relative permeability is less than 0.001. Water injectors are perforated in the model where they have penetrated net sand.

A maximum liquid production rate of 3,000 bbl/d and a minimum bottomhole pressure of 44.8 bara (650 psia) were assigned to each producing well, consistent with rates and pressures that can be achieved using the selected artificial lift methods of ESP, PCP and jet pumps. Injection wells were limited to matrix injection with a peak rate of 3,000 b/d with a maximum bottomhole pressure of 2900 psia. Water injection is available at first production and a voidage replacement ratio of 1.0 was maintained within each identified fault block throughout the life of the field.

A limiting surface water cut of 97 percent was used to shut in wells and reduce excess water production during production forecasts. The base forecasts have been created without any downhole interventions to manage water breakthrough. Opportunities to use zonal isolation of producing or injecting intervals are described in Section 6.3. For the Phase 1 part of the forecast the simulation facility limits have been set to match the proposed Early Production Facility capacities. As the model transitions into the Phase 2 facility, no maximum field liquid or oil production constraints have been specified nor a minimum oil rate to terminate the forecast in the simulation model. Facility constraints and uptimes have been applied as the forecasts are combined with the other fields' forecasts.

4.6.1.15 Ngamia Recoverable Resources

GEBV's estimates of total recovery from Ngamia have been presented in Table 6-2, Section 6.1.3. These estimates are from a probabilistic calculation based on a recovery factor range of 17% - 25% - 34% based on a maximum EUR from the simulation model as well as analytical Buckley Leverett / Dykstra Parsons calculations.

The Best Estimate recoverable resources associated with the planned Phase 1 and Phase 2 wells in Ngamia are 151 MMstb representing a recovery factor of 23% for the well count presented and the areas of the field developed. Within the license period of 25 years a total of 134 MMstb are produced from Ngamia, with the remainder being deferred past the end of the license due to combining production with the other basin fields and constraining production through the Phase 2 CPF limits.

4.6.2 Amosing

4.6.2.1 Introduction

The Amosing field was the sixth hydrocarbon discovery in the South Lokichar Basin. Unlike the Ngamia Field, where the two main reservoirs are separated by thick lacustrine shales of the Lokone Shale, the Lokone Shale equivalent here comprises stacked fluvial and alluvial sandstones. As there is no field wide Lokone shale separating the two main formations, they are captured in one geological model.

Amosing-1 spudded in November 2013 and drilled vertically to a total depth of 2,351 metres in the Lokone Sandstone Formation (Figure 4-64).

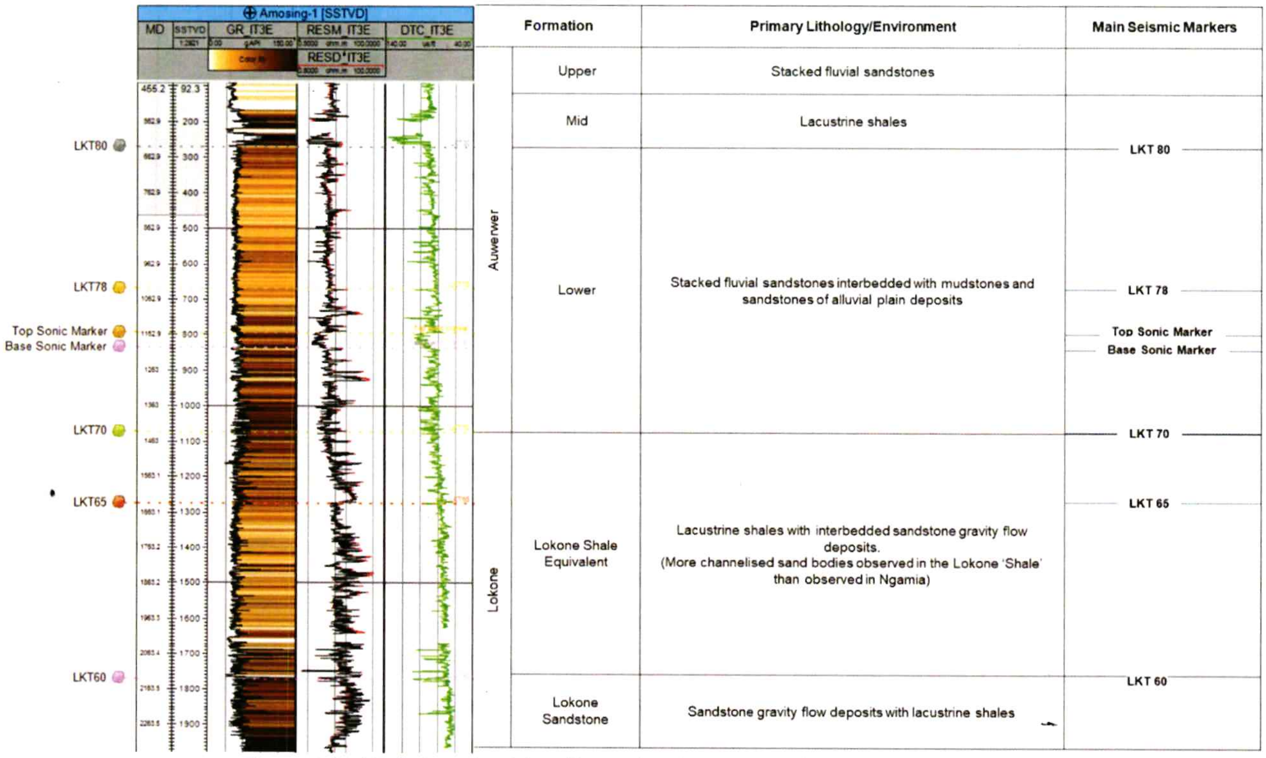


Figure 4-64: Well, Amosing-1 Log Illustrating the Stratigraphy in the Amosing Field

The well discovered over 750 metres of gross reservoir in the Lower Auwerwer Formation and sandstones equivalent in age to the Lokone Shale formation. The Amosing-1 well location was selected on 2D seismic data. During the drilling of the well, logging while drilling measurements including gamma ray and resistivities were acquired. A complete set of conventional wireline logs were acquired at the end of the main hole sections. Sidewall cores were acquired through the acquisition of both percussion and rotary sidewall cores and formation pressures and fluid samples were taken with a wireline formation testing tool.

The Amosing Field appraisal, to date, has consisted of eight additional wellbores, Amosing-2, 2A, 3, 4, 5, 5A, 6 and 7 (Figure 4-65). All appraisal wells have encountered hydrocarbons at varying levels in the wells. The facies and net-to-gross varies significantly between the wells, primarily due to the presence of the alluvial facies which become more dominant on the western side of the field proximal to the western bounding fault of the South Lokichar Basin. These appraisal wells also acquired significant data both during and following the drilling of the well. Full diameter conventional core has been acquired in four wells, Amosing-2, -2A, -6 and -7. Four of the appraisal wells, Amosing-2, -2A, -3 and -4 encountered similar reservoir quality sections and hydrocarbon pools as Amosing-1. Amosing-6 and 7, while also discovering hydrocarbons were too far to the west and encountered predominantly non-reservoir rift edge (alluvial) facies. The Amosing-5 well and its sidetrack, Amosing-5A, were drilled in the fault block north of Amosing-3 block. The wells encountered hydrocarbons; however, they drilled more non-reservoir rift facies than the main Amosing wells and net hydrocarbon thicknesses are less. Figure 4-65 shows the modelled hydrocarbon pore volume (HCPV) for the Amosing field from the reface case model.

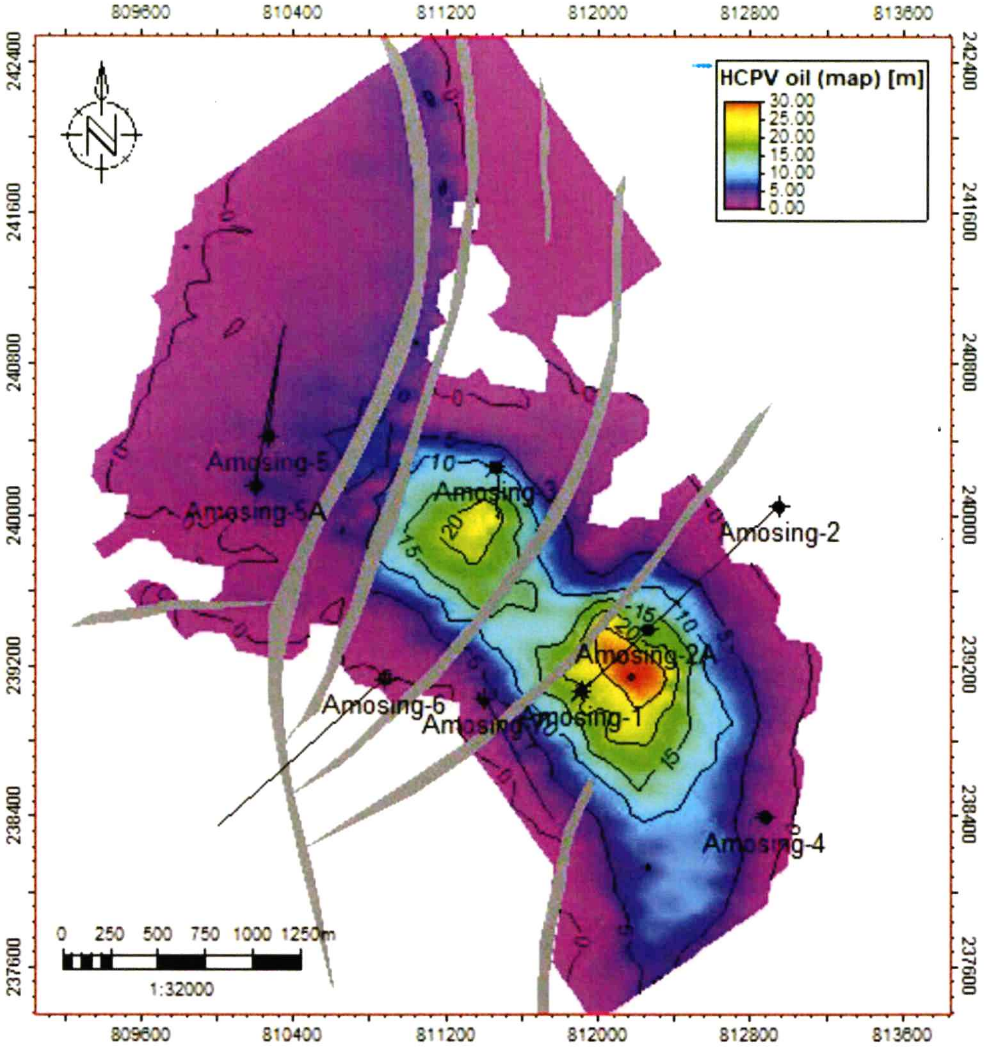


Figure 4-65:Amosing Field HCPV (all zones) with well locations and LKT78 level fault polygons

While some uncertainties still exist on the edges of the Amosing field, particularly in the west where the extent of alluvial facies deposition is unclear, there is sufficient confidence in the main portion of the field for development planning.

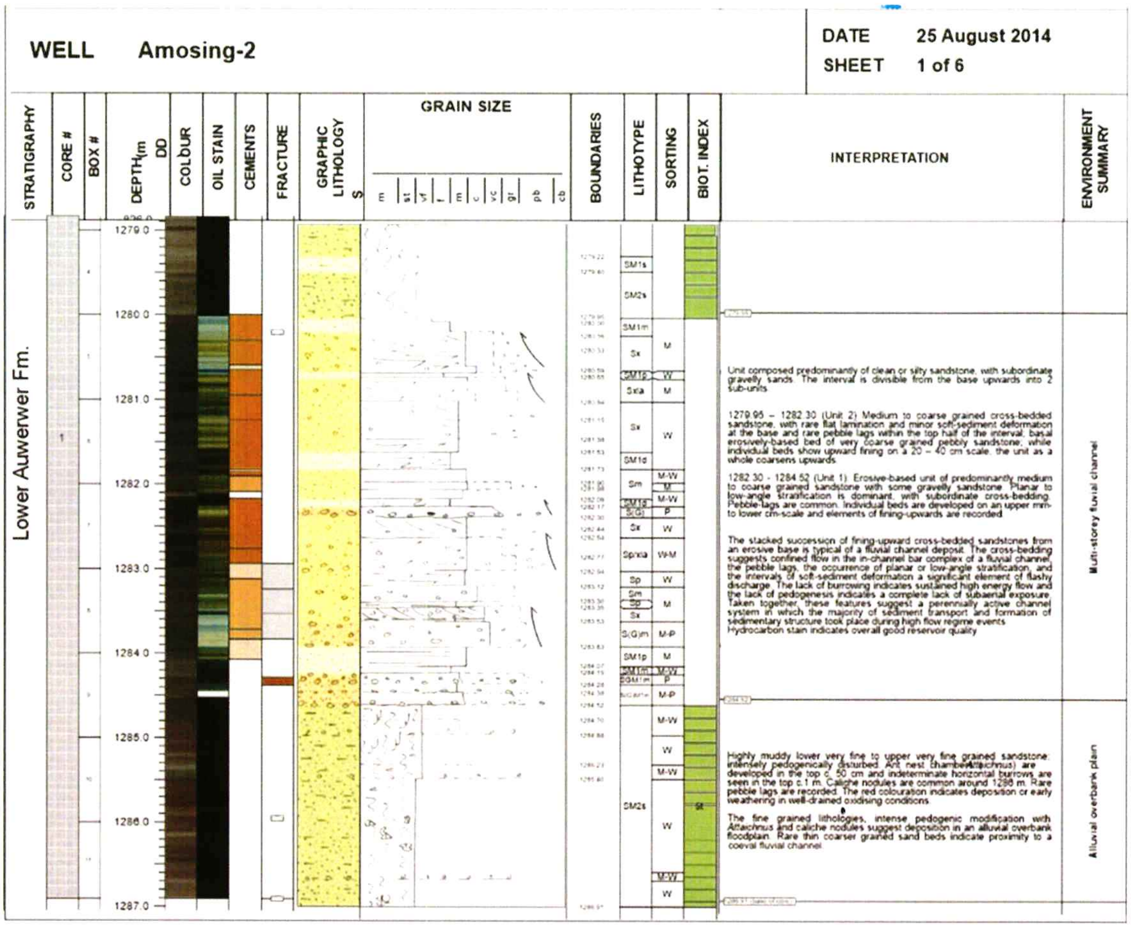
4.6.2.1 Geology

The Amosing Field is a moderately faulted, three-way dip closed anticlinal structure along the western margin of the South Lokichar Basin. The field is ultimately bounded to the west by the large north-south trending basin bounding fault.

The sandstones of the Lower Auwerwer and Lokone Formations are the main reservoirs in the Amosing Field. These reservoir sandstones are primarily fluvial in origin (Figure 4-66 and Figure 4-67). The main difference in the stratigraphy in the Amosing Field compared to the Ngamia Field is that the Lokone Shale has transitioned from lacustrine to stacked fluvial and alluvial plain deposits, very similar to the Lower Auwerwer Formation. There is significant evidence of some poorer quality reservoir sandstones thought to be more alluvial in origin close to the main fault systems. The influence of this poorer quality non- reservoir alluvial facies has a large impact on the Amosing Field.

There is some level of structural complexity in the Amosing field with seismically visible faults separating the field into separate segments (Figure 4-68 and Figure 4-88). Most of these faults have enough throw to provide some sealing capacity as seen in the formation pressure data where hydrocarbon pools are not common across all fault blocks.

Hydrocarbon bearing sandstones within the Lower Auwerwer and Lokone Sandstones are individually sealed by laterally extensive mudstones within the sequence. The ultimate top seal to all the hydrocarbon discoveries is provided by the Mid- Auwerwer Shale at the base of the Upper Auwerwer Sandstone.



Unit composed predominantly of clean or silty sandstone, with subordinate gravelly sands. The interval is divisible from the base upwards into 2 sub-units.

1279.95 – 1282.30 (Unit 2) Medium to coarse grained cross-bedded sandstone, with rare flat lamination and minor soft-sediment deformation at the base and rare pebble lags within the top half of the interval; basal erosively-based bed of very coarse grained pebbly sandstone; while individual beds show upward fining on a 20 – 40 cm scale, the unit as a whole coarsens upwards.

1282.30 - 1284.52 (Unit 1). Erosive-based unit of predominantly medium to coarse grained sandstone with some gravelly sandstone. Planar to low-angle stratification is dominant, with subordinate cross-bedding. Pebble-lags are common. Individual beds are developed on an upper mm- to lower cm-scale and elements of fining-upwards are recorded.

The stacked succession of fining-upward cross-bedded sandstones from an erosive base is typical of a fluvial channel deposit. The cross-bedding suggests confined flow in the in-channel bar complex of a fluvial channel, the pebble lags, the occurrence of planar or low-angle stratification, and the intervals of soft-sediment deformation a significant element of flashy discharge. The lack of burrowing indicates sustained high energy flow and the lack of pedogenesis indicates a complete lack of subaerial exposure. Taken together, these features suggest a perennially active channel system in which the majority of sediment transport and formation of sedimentary structure took place during high flow regime events. Hydrocarbon stain indicates overall good reservoir quality.

Highly muddy lower very fine to upper very fine grained sandstone; intensely pedogenically disturbed. Ant nest chambers (Attaichnus) are developed in the top c. 50 cm and indeterminate horizontal burrows are seen in the top c.1 m. Caliche nodules are common around 1286 m. Rare pebble lags are recorded. The red colouration indicates deposition or early weathering in well-drained oxidising conditions.

The fine grained lithologies, intense pedogenic modification with Attaichnus and caliche nodules suggest deposition in an alluvial overbank floodplain. Rare thin coarser grained sand beds indicate proximity to a coeval fluvial channel.

Figure 4-66: Core description of an oil filled fluvial deposit in the Lower Auwerwer Formation in the Amosing 2 well.

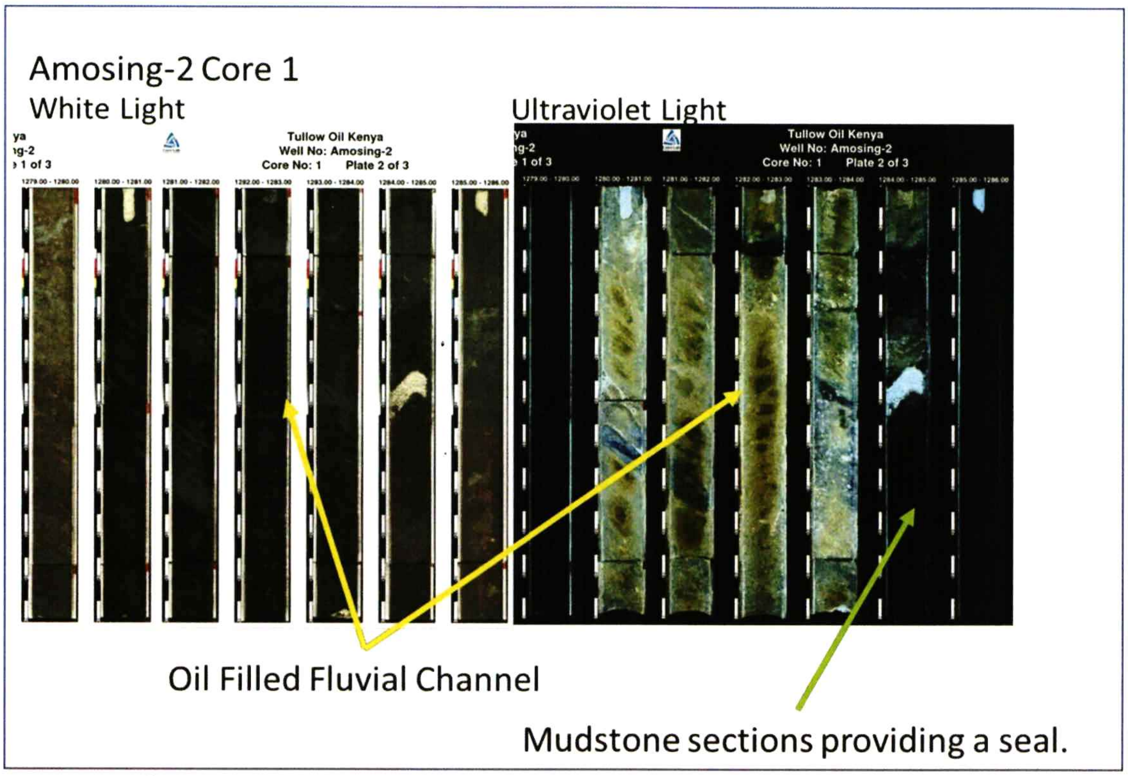


Figure 4-67: Core photographs of an oil filled channel deposit in the Lower Auwerwer Formation in the Amosing-2 well.

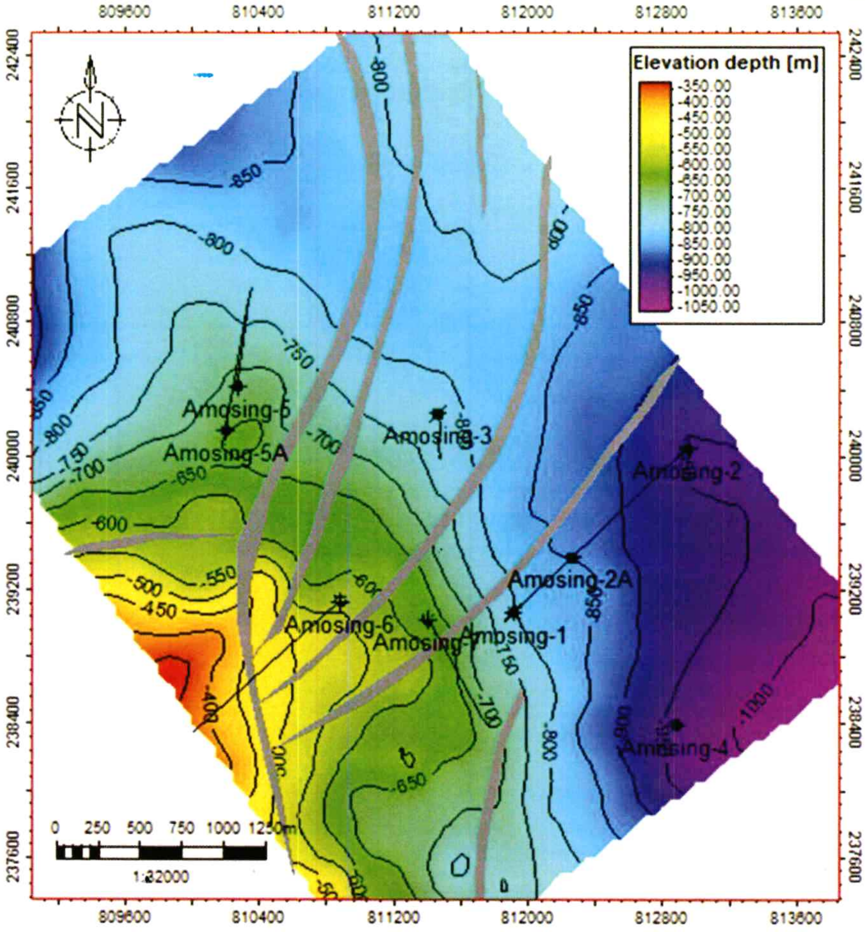


Figure 4-68: LKT78 depth structure map, Amosing Field, static model

4.6.2.2 Geophysics

The RAP Pre STM 3D data volume was used to map the five key seismic markers over the Amosing Field: the LKT80, LKT78, LKT70, LKT65 and LKT60 as illustrated in Figure 4-7. All five markers are good quality picks over the Amosing Field (see Figure 4-95 and Figure 4-96) and have synthetic ties to well data. The quality of the well-tie was good for Amosing-1, Amosing-2, Amosing-3 and Amosing-4. It was poor at Amosing-2A and average at Amosing-5. The two-way time structure maps for the five markers are shown in Figure 4-69, Figure 4-70, Figure 4-71, Figure 4-72 and Figure 4-73.

The Amosing structure is a three-way fault closure in the hanging wall of the northwest- southeast trending Lokichar Fault. The LKT80, LKT78 and LKT70 structure maps are dominated by a north-south trending graben on the northern limb of the Amosing anticline. The graben is bounded to the west by a north-south trending synthetic normal fault showing displacement at the LKT80, LKT78, LKT70, LKT65 and LKT60 markers (see Figure 4-74). The deepest LKT60 marker is relatively undisturbed except for some minor faulting as it dips basinwards.

Adjacent to the Lokichar Fault in the hanging wall of the fault, the reflectivity of the LKT80, LKT78, LKT70 and LKT60 markers becomes very poor due to the presence of alluvial rift edge facies as illustrated in Figure 4-74. The zone of poor reflectivity caused by the alluvial rift edge facies extends along strike with the Lokichar Fault and for up to two kilometers basinwards from the Lokichar Fault. The extent of the alluvial rift edge facies is a key uncertainty in Amosing, and this has been accounted for in volumetric estimation of STOIIP.

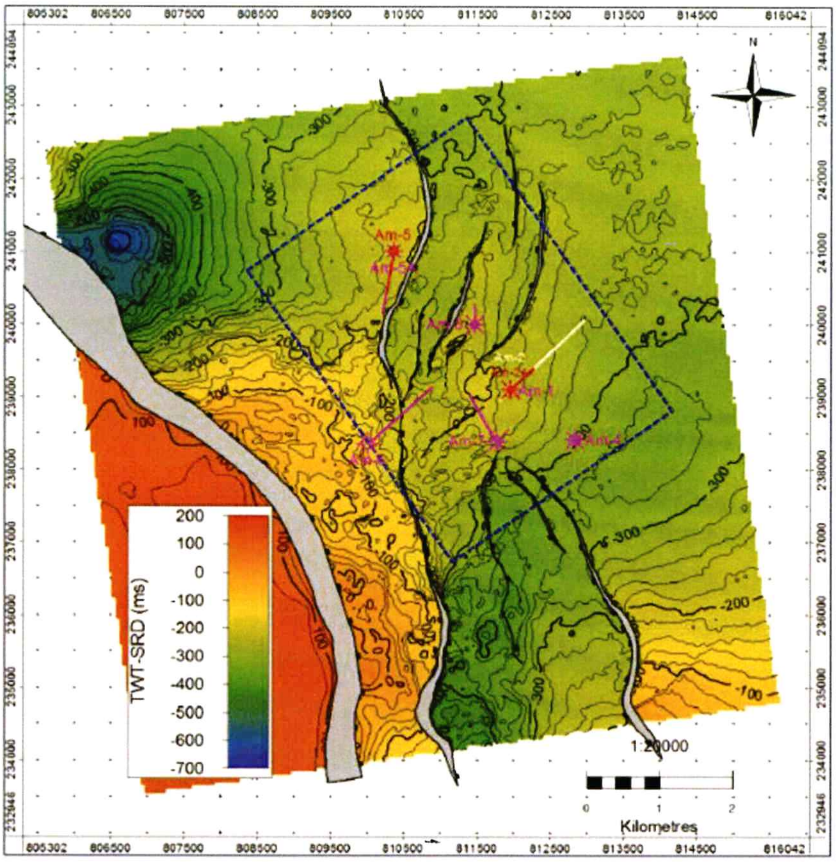


Figure 4-69: Amosing Field LKT80 two-way time structure map (seconds)

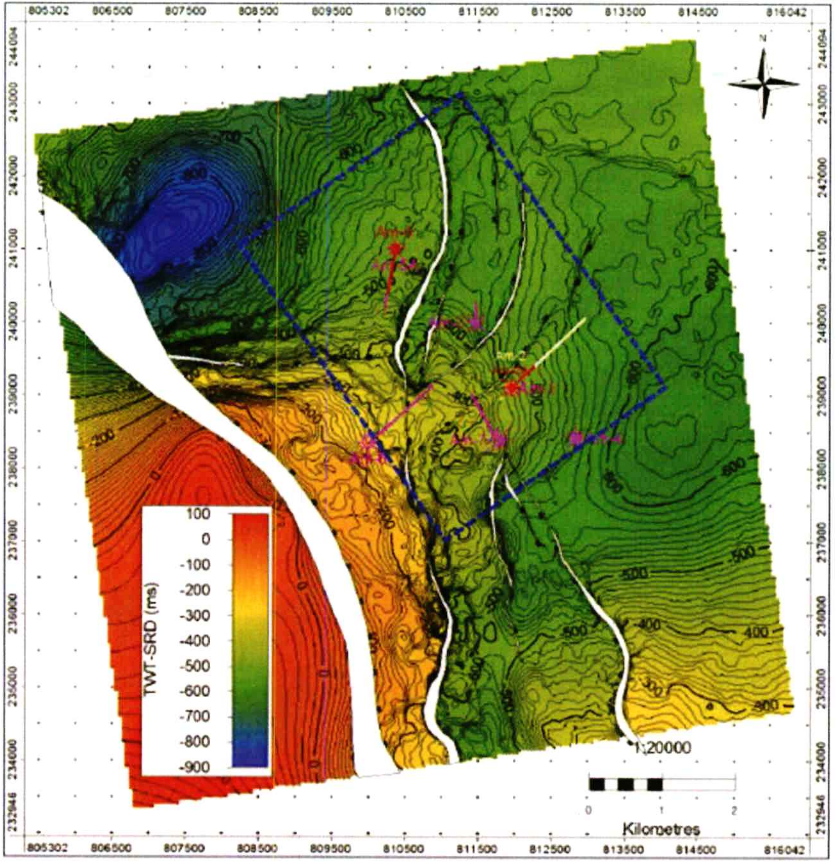


Figure 4-70: Amosing Field LKT78 two-way time structure map (seconds)

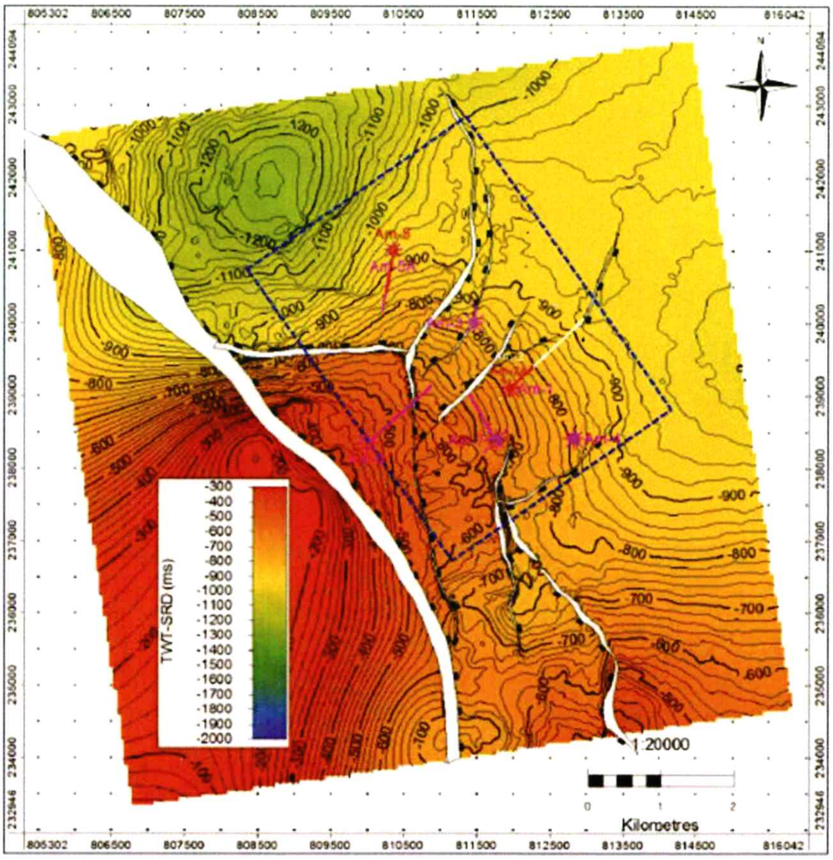


Figure 4-71: Amosing Field LKT70 two-way time structure map (seconds)

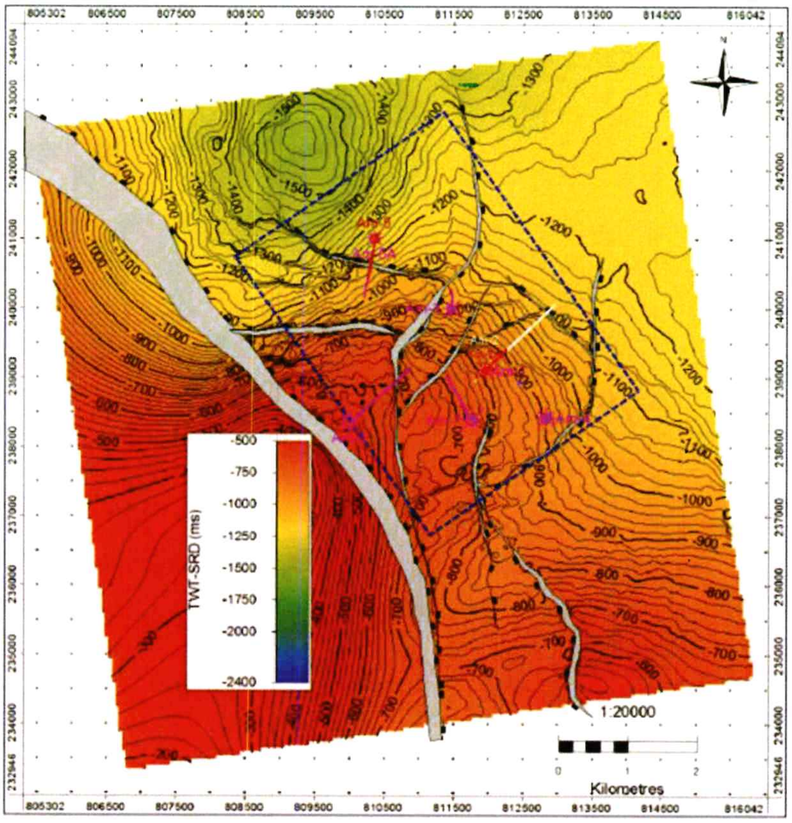


Figure 4-72: Amosing Field LKT65 two-way time structure map (seconds)

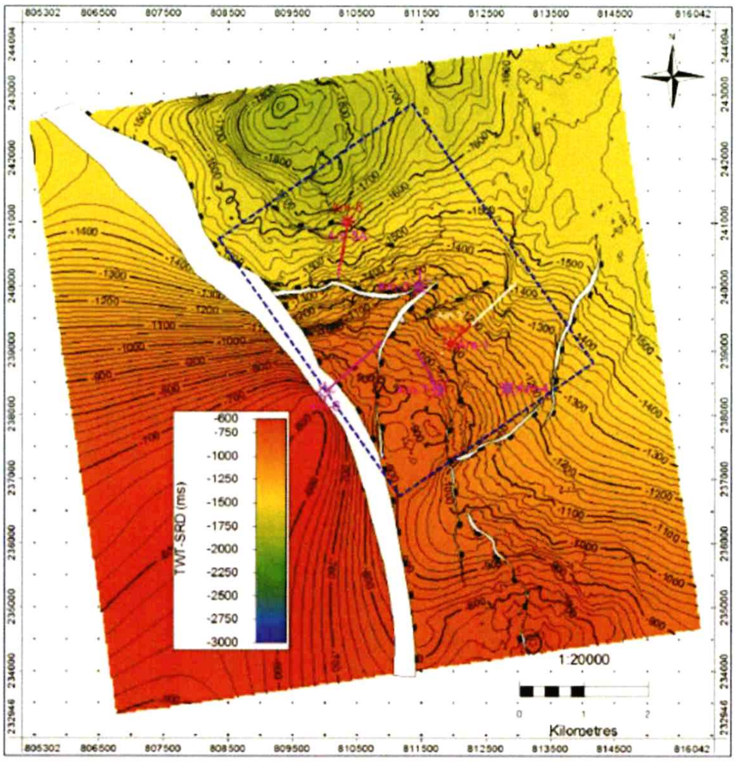


Figure 4-73: Amosing Field RAP PreSTM LKT60 two-way time structure map (seconds)

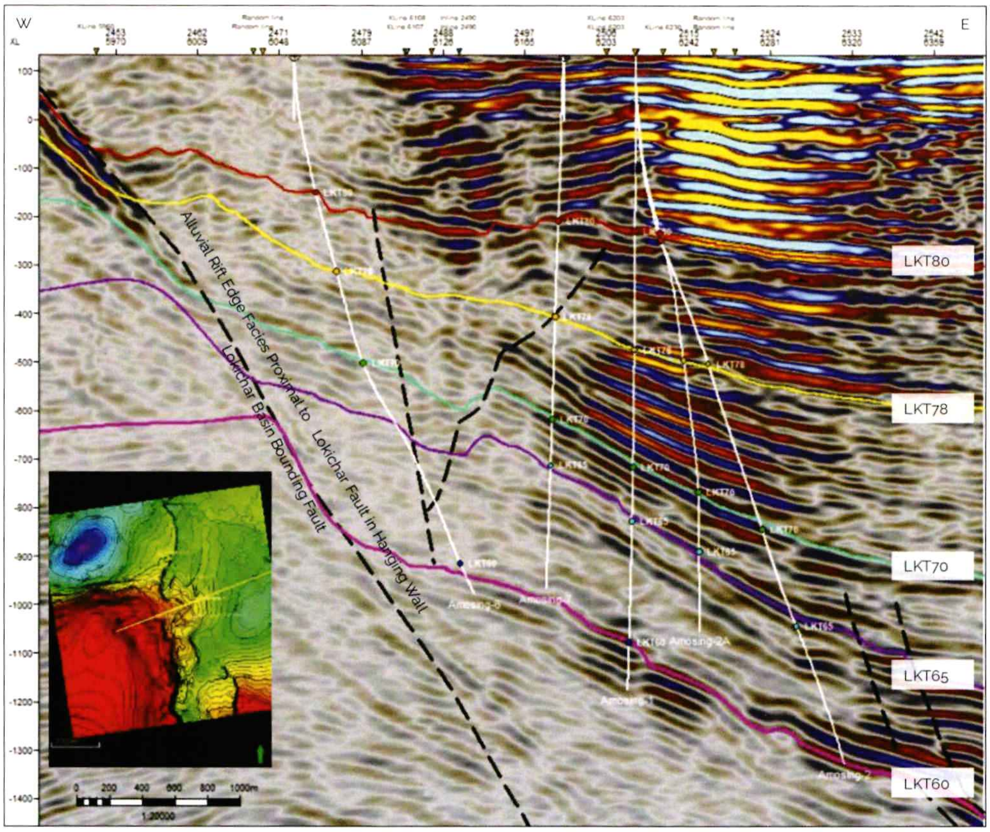


Figure 4-74: Amosing Field W-E RAP PreSTM 3D seismic line through Am-6, Am-7, Am-1, Am-2 & Am-2A wells

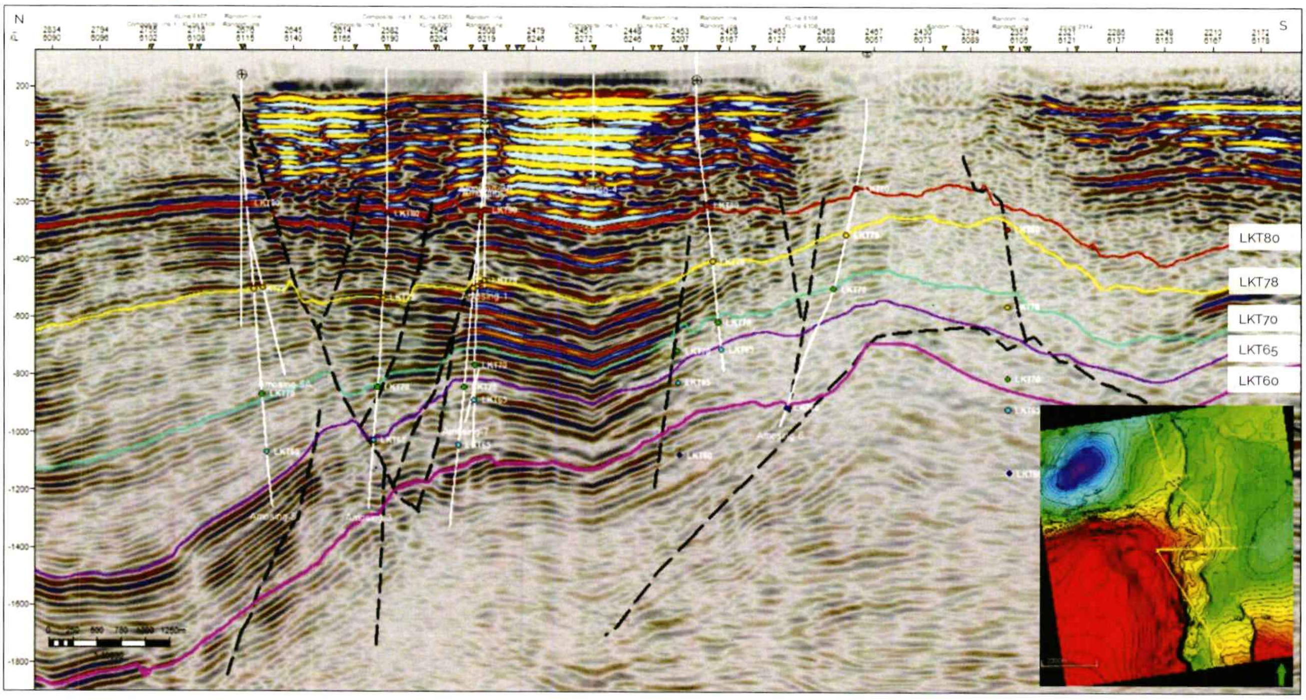


Figure 4-75: Amosing Field north-south RAP PreSTM 3D seismic line through all Amosing Wells

Depth Conversion

Initially the depth conversion over Amosing used velocities from best fit compaction trends but the trends varied spatially (Figure 4-76). The spatial variation was therefore accounted for in a second iteration by using the processing seismic velocities that have been calibrated to well data (Figure 4-77). The up-dip wells, Amosing-6 and 7 have a fast compaction gradient, mid-dip wells Amosing-1 and 4 having an intermediary compaction and the down dip wells Amosing-2, 2A and 3 shows almost no compaction trend. In general, there is a good match between RAP PreSTM migration velocities and calibrated well velocities (Figure 4-78).

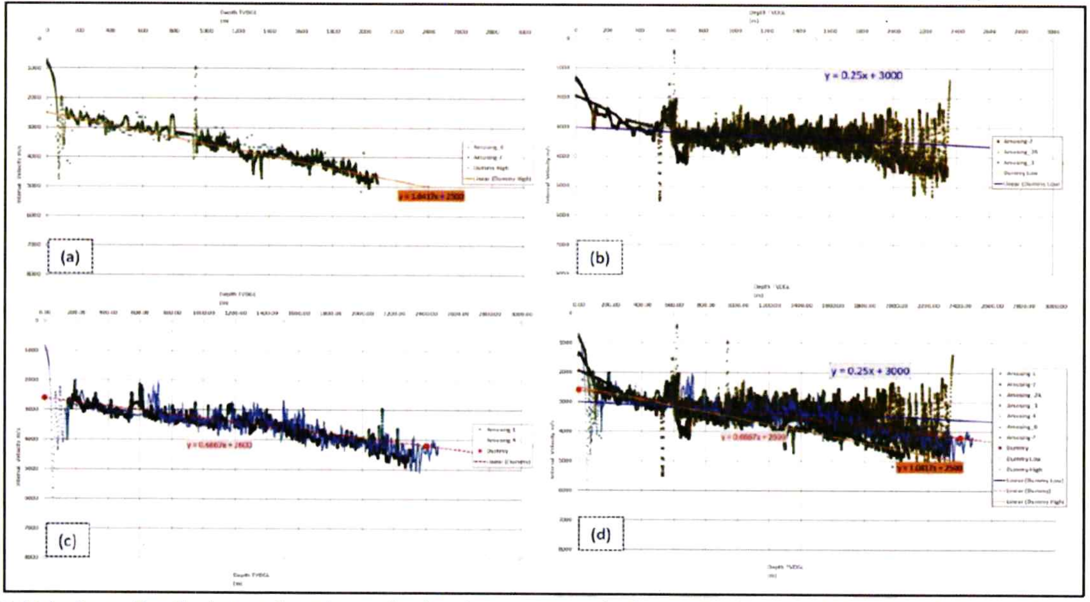


Figure 4-76: Velocity vs. Depth plots at Amosing wells showing variation of velocity at different well locations. (a) updip Amosing 7 and 6 wells on high compaction trend (c) Amosing 1 & 4 wells on intermediate compaction trend (b) downdip wells, 2, 2A & 3 on almost no compaction trend (d) Velocity depth trends in Amosing wells

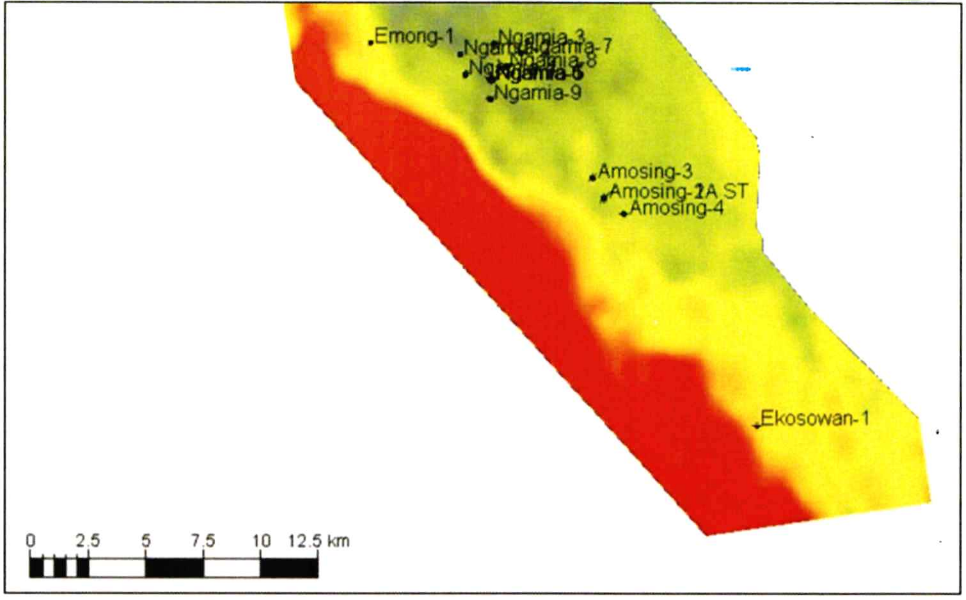


Figure 4-77: Amosing-Ngamia Seismic Interval Velocity Field

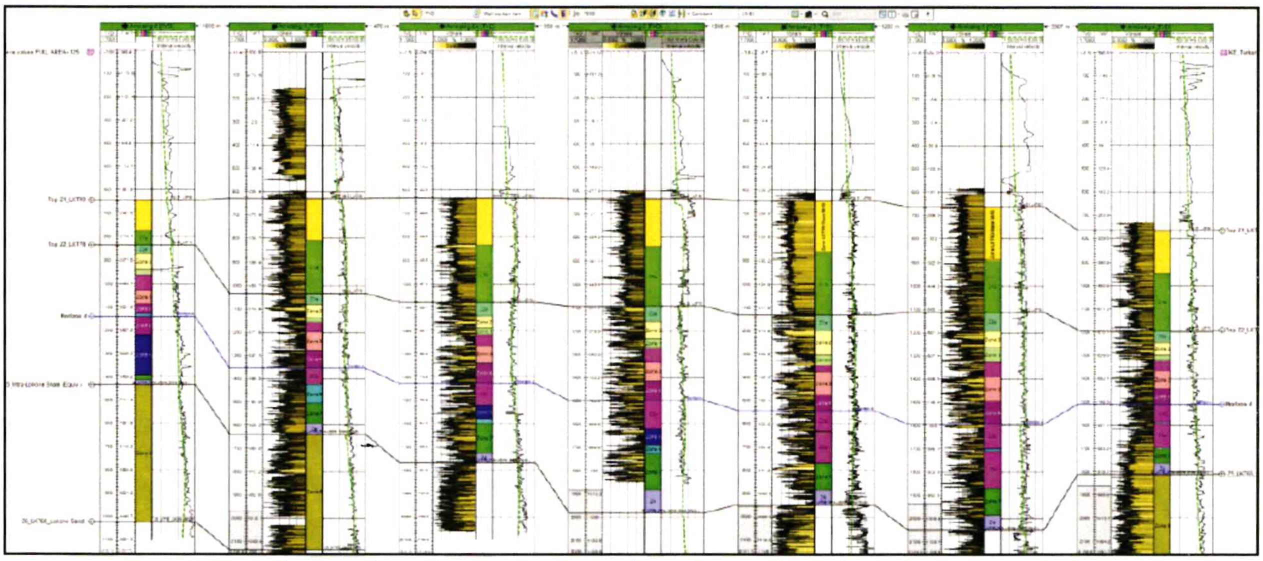


Figure 4-78: Well section shows the seismic velocities (green) now calibrated with the well-interval velocities

Final depth maps for LKT80, LKT78, LKT70, LKT65 and LKT60 markers can be seen in Figure 4-79, Figure 4-80, Figure 4-81, Figure 4-82 and Figure 4-83 respectively below.

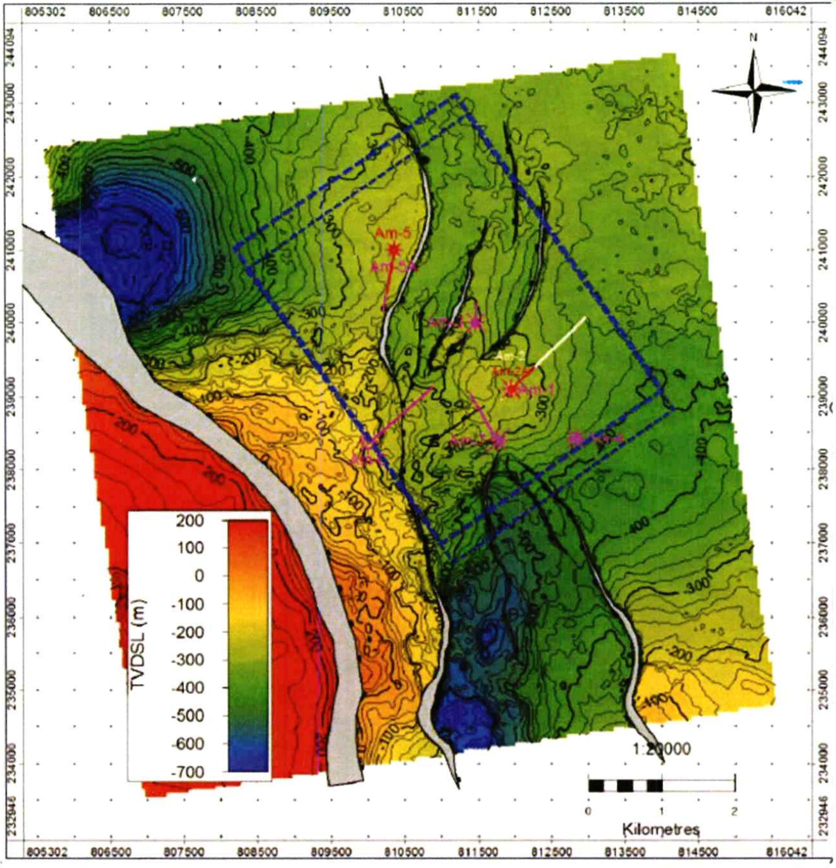


Figure 4-79: Amosing Field LKT80 depth structure map (mTVDSS)

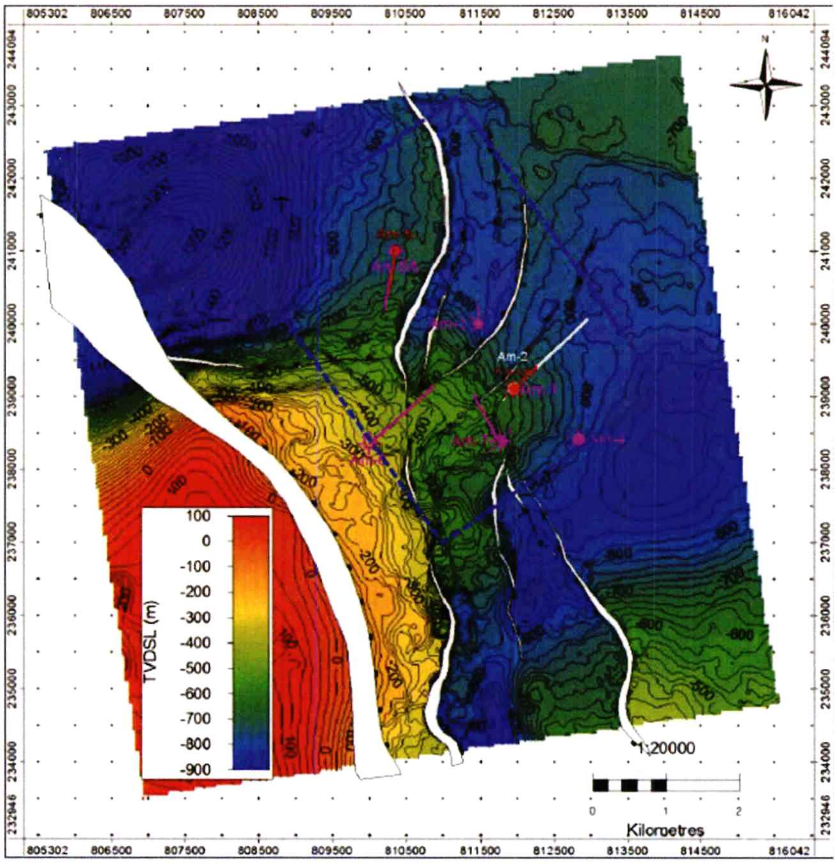


Figure 4-80: Amosing Field LKT78 depth structure map (mTVDSS)

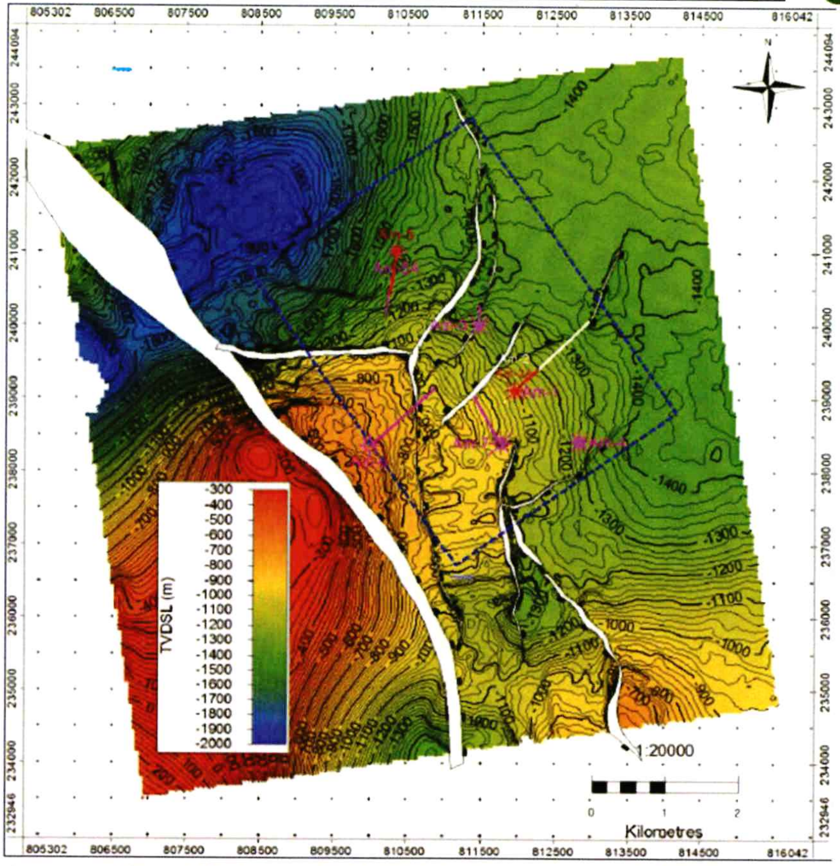


Figure 4-81: Amosing Field LKT70 depth structure map (mTVDSS)

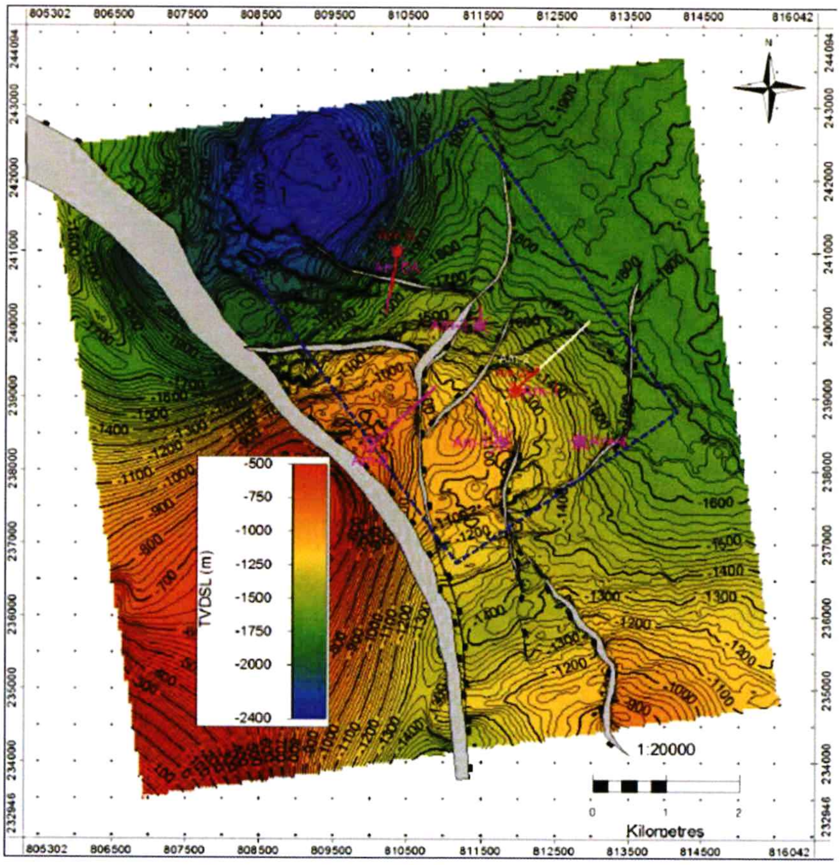


Figure 4-82: Amosing Field LKT65 depth structure map (mTVDSS)

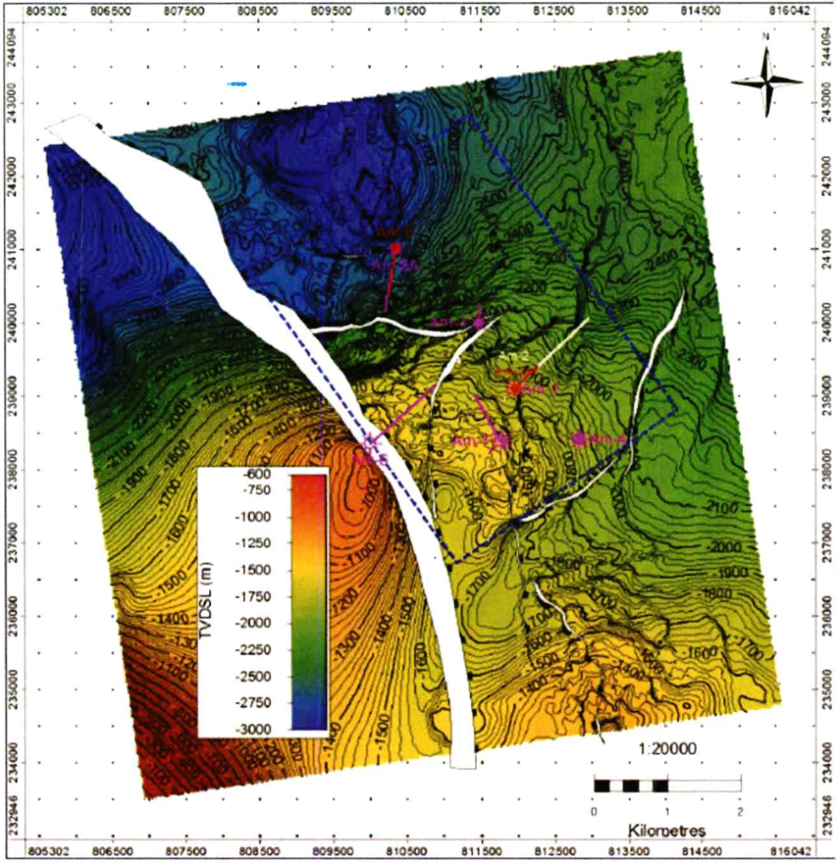


Figure 4-83:Amosing Field LKT60 depth structure map (mTVDSS)

4.6.2.3 Petrophysics

The general petrophysical workflow was described in Section 4.4. This section will discuss available data and processes specific to the Amosing Lower Auwerwer and Lokone analysis.

The Amosing Field has a robust set of petrophysical data available for analysis. Numerous conventional full diameter cores, and full log suites in most of the wells provides a comprehensive petrophysical database. As discussed above, there is no clear distinction between the Lower Auwerwer and the Lokone Shale at Amosing and the boundary between the two formations is not apparent on log data but is based on a seismic marker. From a petrophysical perspective the two formations are processed in the same way in the Amosing Field.

Conventional full diameter cores were acquired in Amosing-2, 2A, 6, and 7. This core was analysed to provide measurements of porosity, permeability, grain density, etc. to guide the petrophysical analysis of the log data acquired. Core plugs from the Amosing cores were a large part of the extensive x-ray diffraction study (XRD) that was completed to narrow down the range of volume of shale calculated in the reservoir. Figure 4-84 is a cross plot of porosity versus permeability from core data acquired in Amosing-2 and Amosing-2A (Amosing-6 & Amosing-7 largely encountered non-reservoir). Figure 4-85 is an example of the petrophysical data illustrating the calculated curves and core data for porosity and water saturation. As discussed elsewhere, the water saturation values for geomodelling purposes are derived from a saturation height function. The data acquired in the core analysis and the subsequent petrophysical analysis of the log data was used to define the different facies in the static geological model as well as the primary reservoir components leading to the estimation of resource volumes in the Amosing Field.

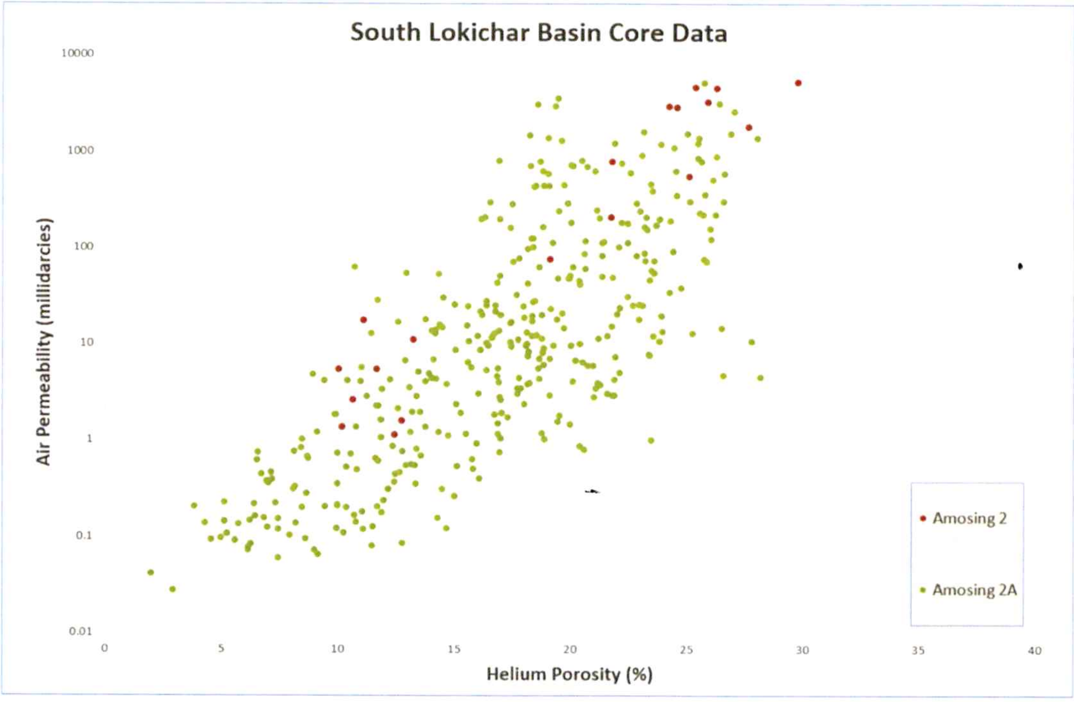


Figure 4-84: Porosity Permeability cross plot for core data from Amosing wells (Am-2 & Am-2A).

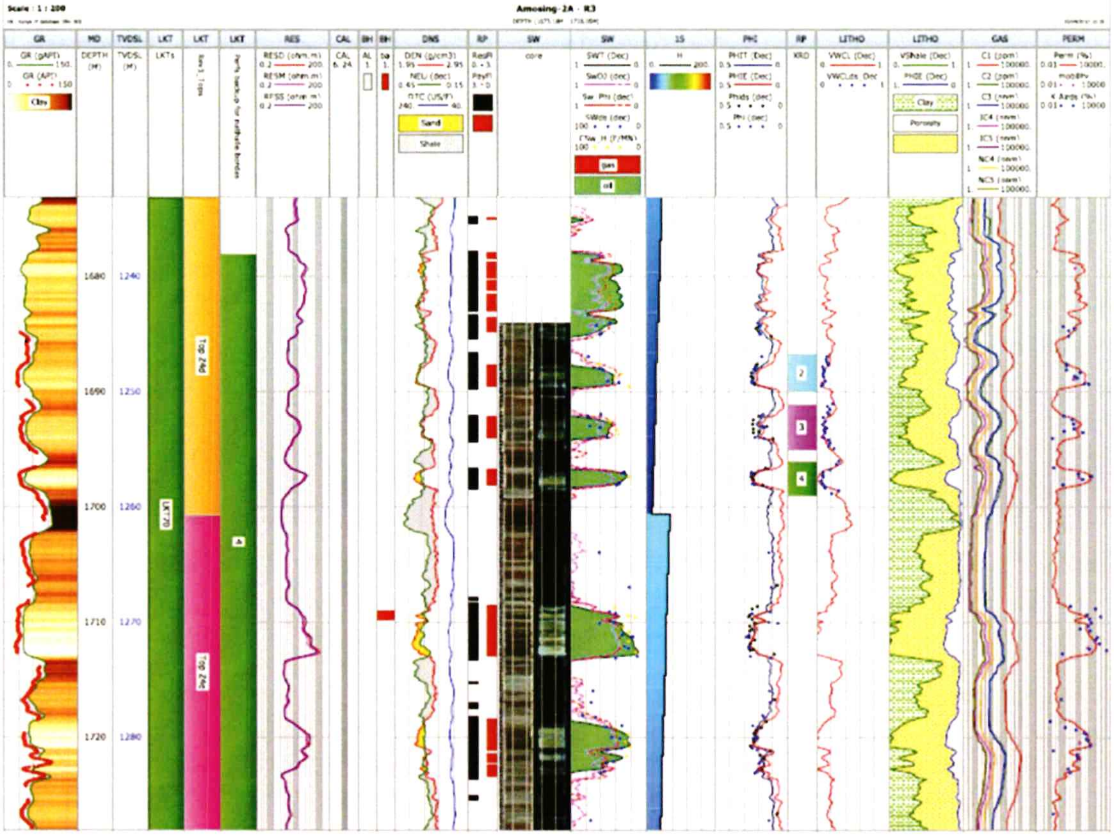


Figure 4-85: Petrophysical display from Amosing-2A with XRD.

It is observed that the Amosing field has a bimodal porosity distribution. In order to model this distribution in a representative manner, a rock typing exercise has been undertaken to reduce any 'dilution' effect of poorer quality rock on better quality rock. A Vsh filter alone didn't remove the low Phi peak due the presence of finer grained sands and although increasing the porosity cut off could remove it, there would be a significant impact on hydrocarbon storage capacity and subsequently STOIIP.

Figure 4-86 shows the porosity distribution with no cut offs applied, capturing all sands, shales and silts. The 12% Phi cut off has been superimposed to show where net from non-net would sit with a bimodal porosity distribution clearly observed.

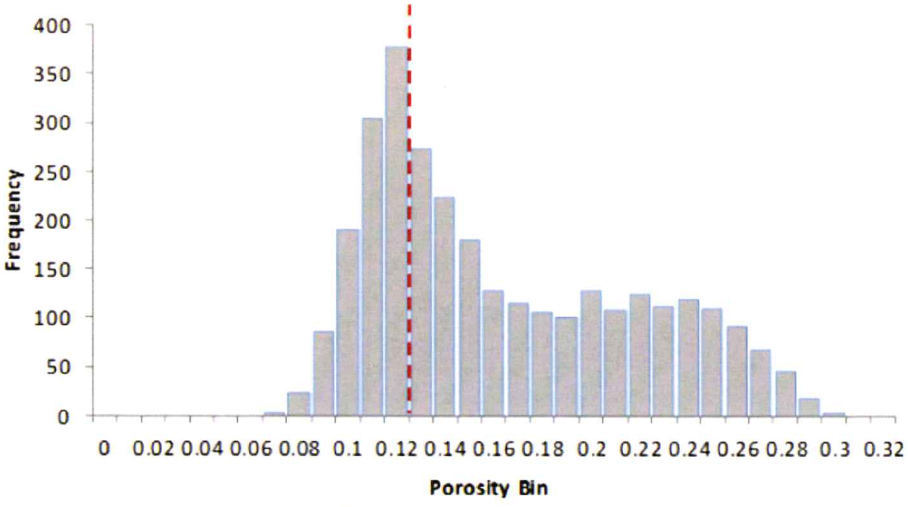


Figure 4-86: Example from Zones 2 & 3 of Amosing PHIT Distribution

By applying a PHIT/VSh ratio to the data it was observed that the two distributions could be separated. A trial-and-error approach found that a PHIT/Vsh ratio filter of less than 0.5 isolated the two porosity distributions. The resulting distributions can be seen in Figure 4-87. Type 1 facies (grey bars) ranges from 12-19% Phi, whilst Type 2 (green bars) can vary from 12-29% Phi.

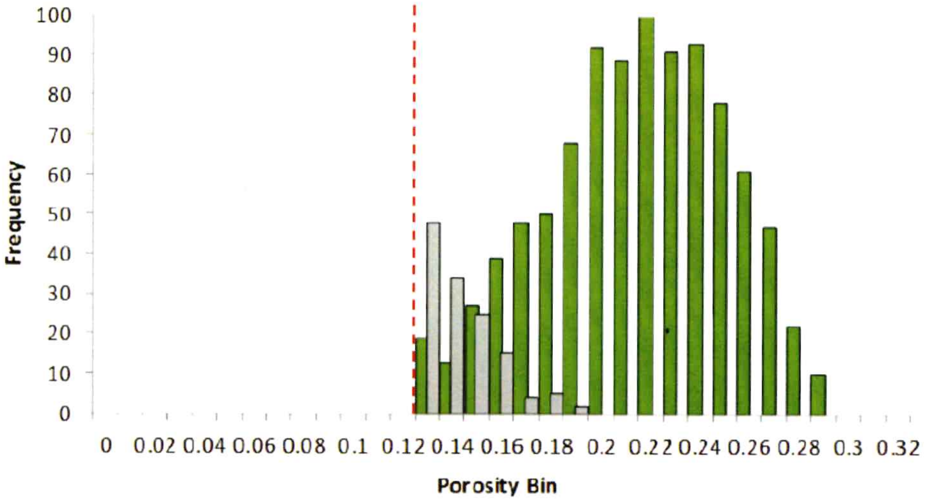


Figure 4-87: Example from Zone 2 & 3 of Amosing PHIT Distribution Rock Typing Results

As all Amosing wells have a continuous PHIT/Vsh ratio curve, identifying the Type 1 and Type 2 facies is a simple exercise. The bimodal effect was only present on Amosing. Ngamia, in contrast, has a normal distribution.

4.6.2.4 Static Modelling

Grid

The Amosing structural grid has been constructed using 14 key faults and 5 depth surfaces from the seismic interpretation and depth conversion. The depth surfaces were LKT80 (Top Upper Auwerwer), LKT78 (Top Mid-Auwerwer shale) and LKT70 (Top Lokone Shale), LKT65 and LKT60. Subzones within the reservoir are generated by isopachs consistent with well tops and the overall reservoir envelope. The faults were used to create 5 segments in the grid see Figure 4-88. Panel 1 in the south, Panels 2,3, and 4 progressively stepping down into the central graben, and Panel 5 in the north.

The X and Y grid increment is set at 50 m. The grid is oriented north-south parallel to the strike of the Lokichar Fault and also to the long axis of the main axial fluvial system.

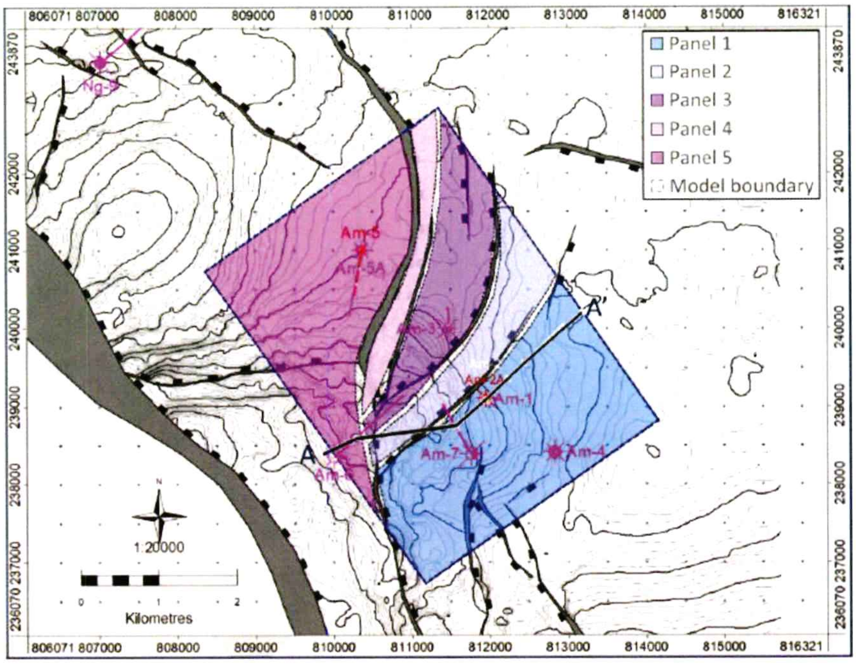


Figure 4-88: Amosing depth structure map at Top Lower Auwerwer illustrating model segmentation

Zones and Layers

A zonal correlation has been made between all wells drilled in Amosing, which integrates the seismic, log, pressure and sample data. Isochores of the 25 Auwerwer zones identified have been used to insert the zones into the 3D structural model (Figure 4-89, Figure 4-90). The zones have proportional layering with a mean layer thickness of 1 m targeted within the hydrocarbon column. Higher vertical resolution would allow thinner sands to be captured more accurately but would greatly increase dynamic simulation runtimes and reduce the time available for detailed analysis of the results.

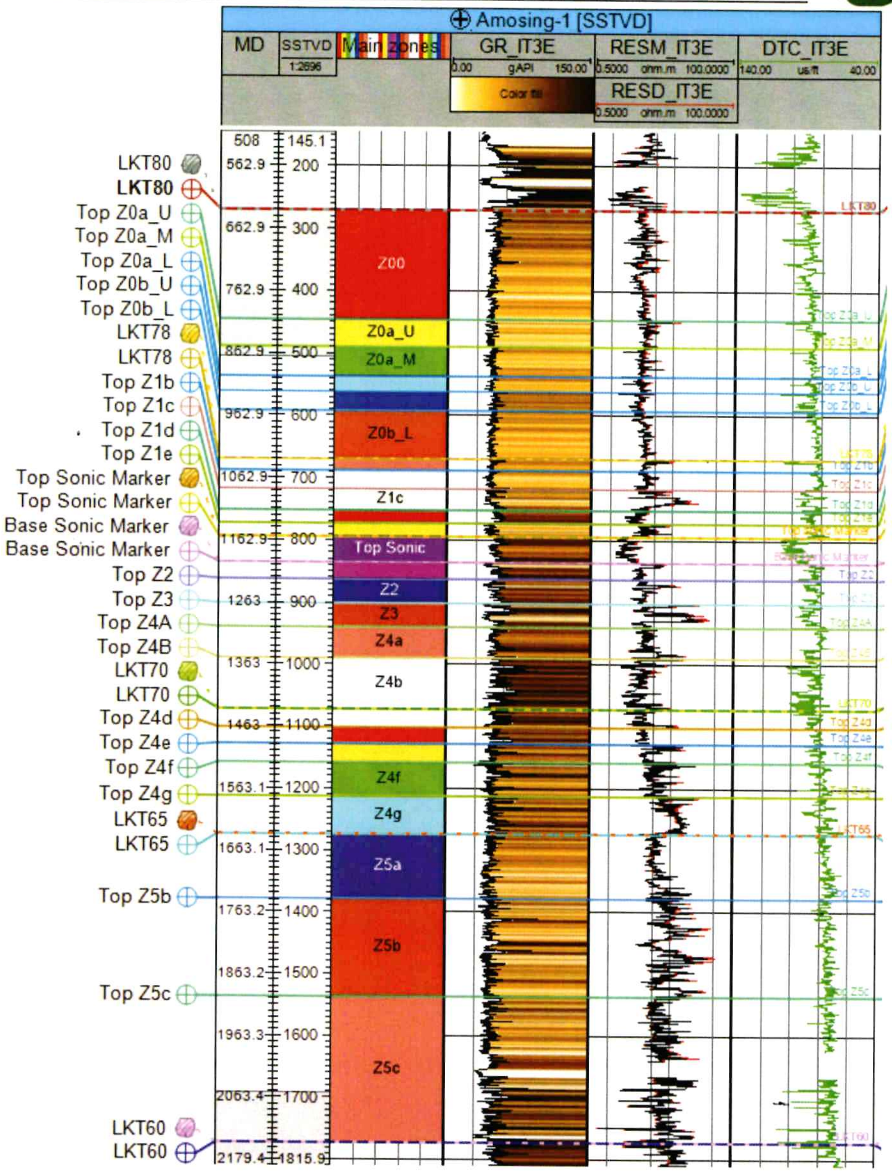


Figure 4-89: Well Amosing-1 showing reservoir zonation. Dotted lines represent seismic picks

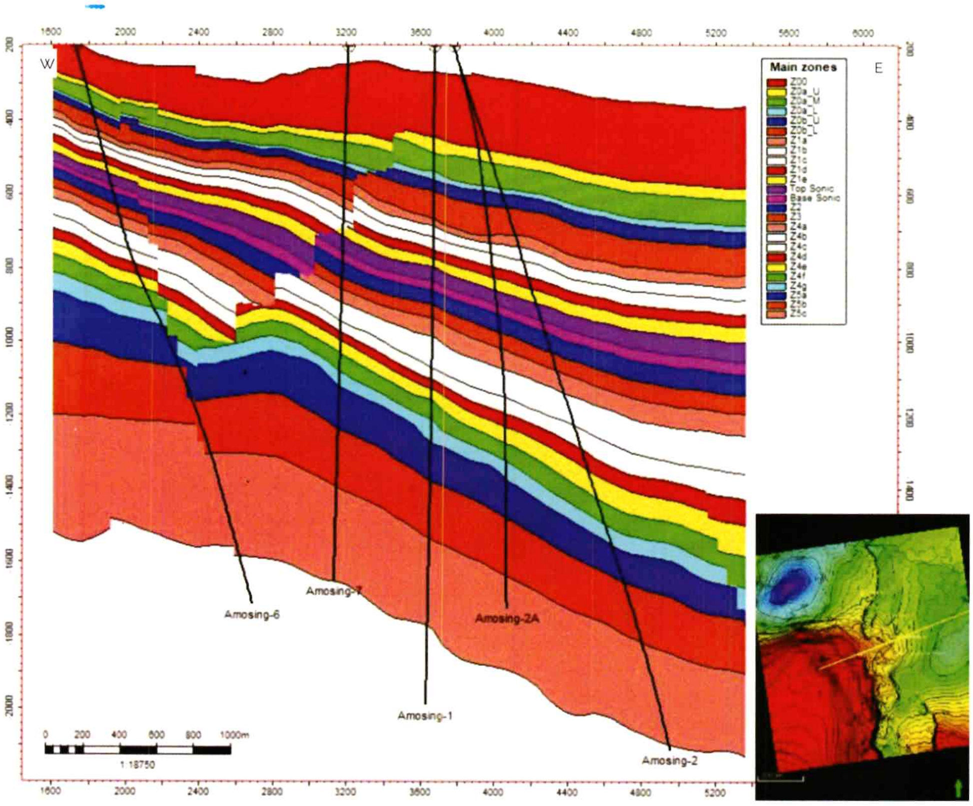


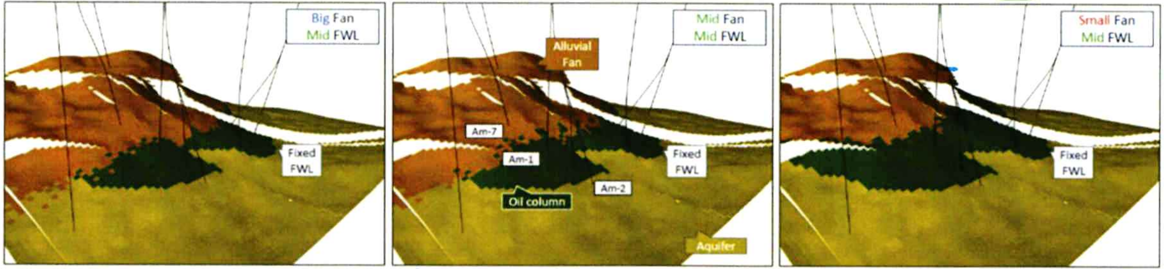
Figure 4-90: Cross section through Amosing model showing reservoir zonation and seismic markers picked (in red text)

Facies Modelling

Miocene fluvial systems deposited successions of stacked sands and lacustrine shales across the South Lokichar Basin. In Ngamia, thick lacustrine shales in the Lokone Shale interval are interpreted between the LKT60-LKT65 seismic surfaces. Several kilometres to the south in Amosing, there is a facies transition to mainly fluvial-deltaic sands, allowing the interpretation of paleo lake shoreline between the fields at this time. In both fields, Lower to Middle Miocene reservoirs are interpreted as being deposited by predominantly northerly flowing axial distributive fluvial systems with local basin floor subsidence and topography creating some sedimentological differences. The shallowest reservoirs on both fields sit between the interpreted LKT78 and LKT80 surfaces, here interpreted alluvial fan facies extend further east into the basin in Amosing than Ngamia. These differences are likely due to either differential subsidence of the paleo basin floor, or due to a dominant laterally fed alluvial fan from the Lokichar Fault.

Facies is modelled in a multi-step process.

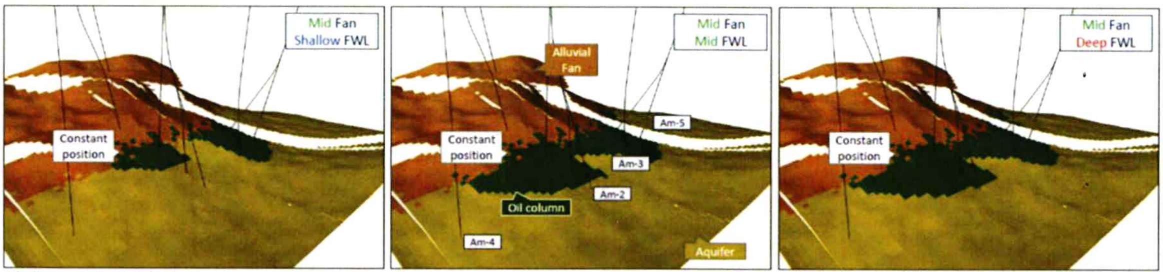
The alluvial fan extent, evidenced from a poor seismic response, has an impact on the up-dip GRV in Amosing. The alluvial fan deposits are considered non-reservoir and so the distance they are mapped from the bounding fault has an impact on GRV and therefore ultimate STOIIP. The alluvial fan extent is modelled using a series of polygons to define the extent of the deposition. The reference case model uses the mid case mapped fan extents and contact assumptions (Figure 4-91 & Figure 4-92).



Alluvial fan extends closer to fluvial penetrations- shrinking the up-dip uncalibrated volume

Reference case assumptions

Up-dip uncalibrated region has expanded significantly as alluvial fan shrinks



Shallower FWLs shrinks the up-dip uncalibrated region

Reference case assumptions

Oil column extends deeper into the down-dip uncalibrated region

Figure 4-91: Illustration of uncertainty modelling of alluvial fan facies extents

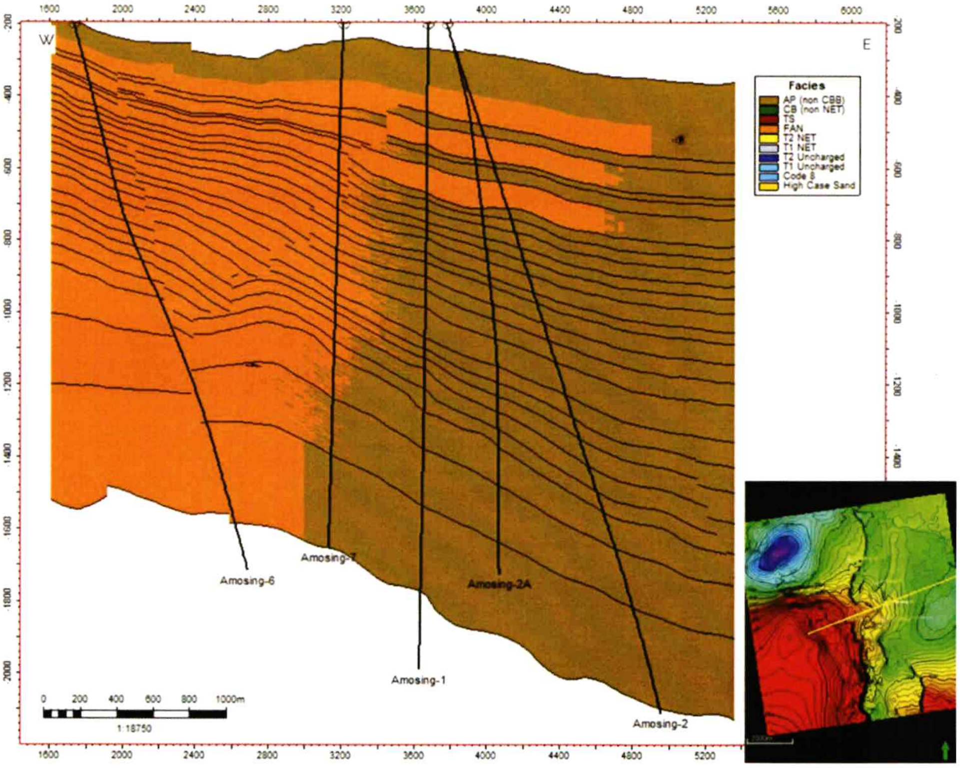


Figure 4-92: Reference case static model alluvial fan facies extent cross-section

Channel belt bodies are the next depositional feature to be incorporated into the static model.

Well data drives the mapping of channel belt bodies. Channel orientation is derived by a conceptual model with deposition at Amosing generally being axial. These bodies are populated in the model using statistics from the petrophysical workflow, variograms and trend mapping to control the areal distribution. The exact methodology varies by zone dependent on the conceptual depositional models that hypothesise the channel system to either be low NTG ribbon-like channel fill or higher NTG sheet like, multistorey channel fill. Ribbon-like channel fills are the product of avulsion and limited lateral migration of meanders. In a higher NTG scenario vertical and limited lateral communication would be expected. Sheet-like channel fills have little preserved overbank sediment within them, largely because of greater mobility of the active channels and the competency of bank material. This is illustrated by the work of Fisher and Nichols (2013) and Guy (2018) - Figure 4-93.

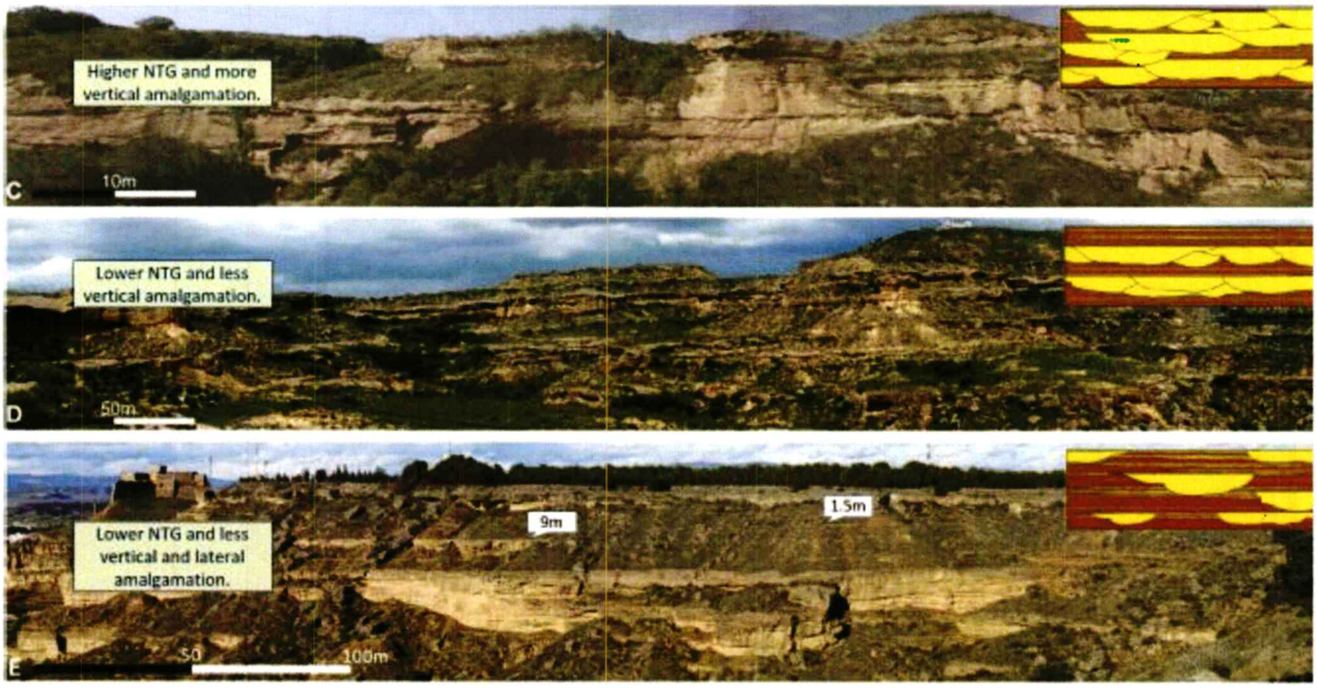


Figure 4-93:Distributive Fluvial Channel Architectures, Ebro Basin. Modified after Modified after J. A. Fisher and G.J. Nichols (2013) and D.Guy (2018).

Following on from this, non-net inter-channel facies are populated using sequential indicator simulation.

Finally, the alluvial fan model and the channel depositional model are merged to create a facies model as a suitable foundation for porosity, permeability and water saturation modelling (Figure 4-94).

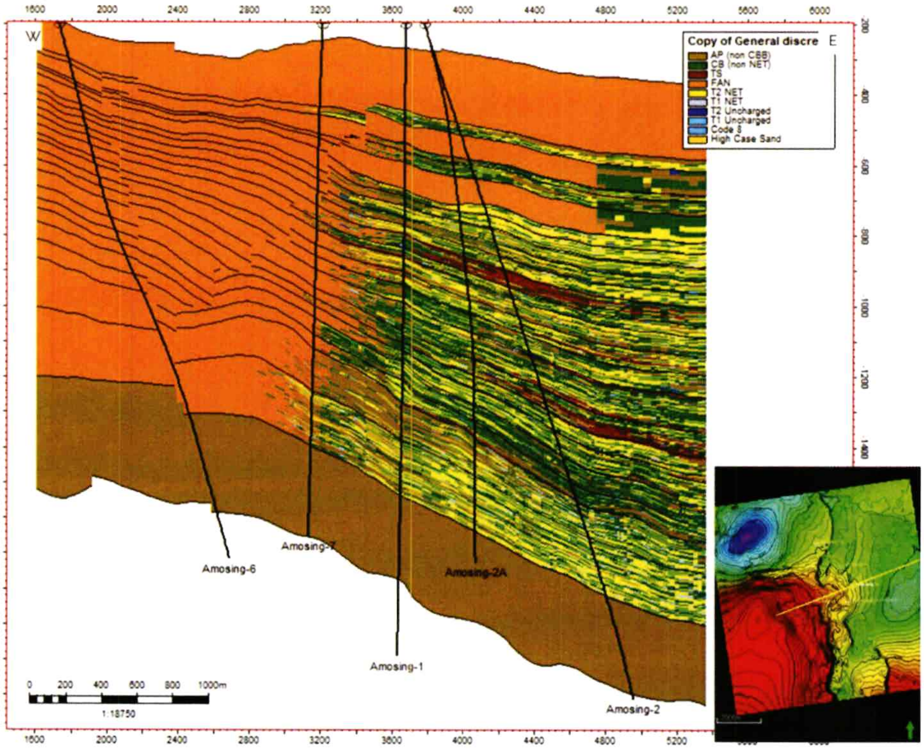


Figure 4-94: Cross-section of reference case combined facies model

Property Modelling

Net-to-Gross (NTG)

A NTG of 1 has been assigned to channel belt body facies. All other facies have been assigned a NTG of 0 as they are assumed to be non-net (Figure 4-95).

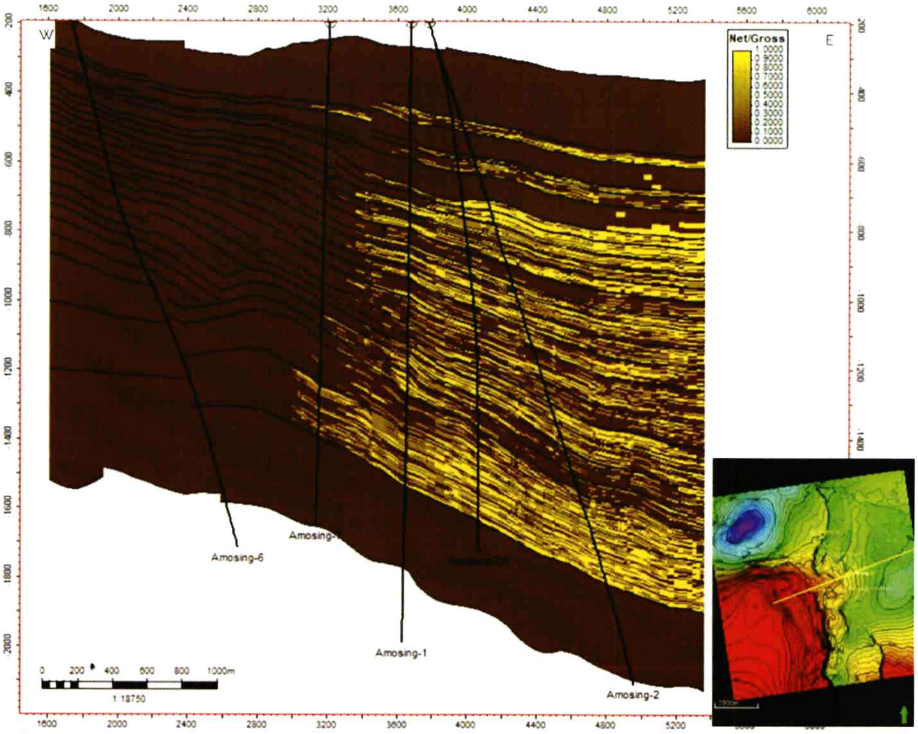


Figure 4-95: Cross-section illustrating Amosing model NTG

Porosity (PHIT)

PHIT is stochastically distributed by rock type (based on the PHIT/Vsh ratio discussed in Section 4.4.4.5) using Gaussian Random Function Simulation with a variogram anisotropy of 400*200*3 in the direction of the Channel Belt Bodies (Figure 4-96 & Figure 4-97). This promotes lateral continuity within the model and therefore models the prevalence of low and high permeability bands adequately.

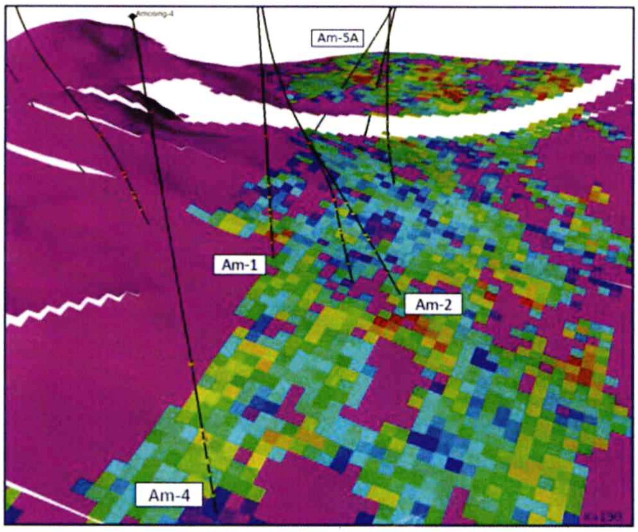


Figure 4-96: Example of PHIT distribution at K-layer 190 in the Amosing model

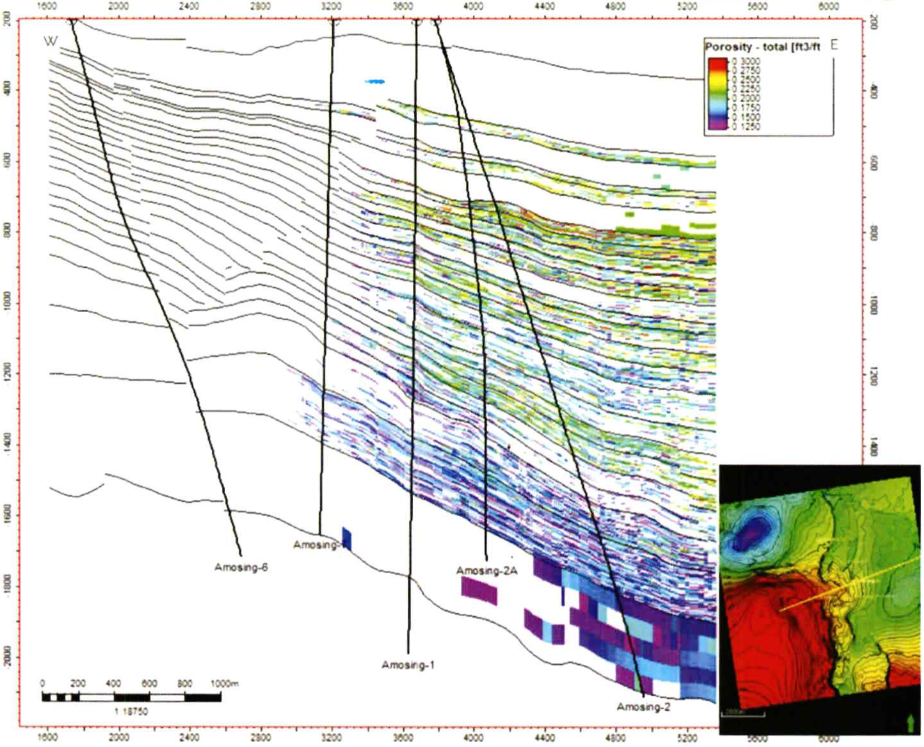


Figure 4-97: Cross-section illustrating PHIT modelling in CBB facies that have a NTG of 1

Volume of Shale (Vsh)

Vsh is required for permeability modelling. In this instance it has been modelled as a function of PHIT where log scale observations have shown a relationship between PHIT and Vsh (Figure 4-98 to Figure 4-100).

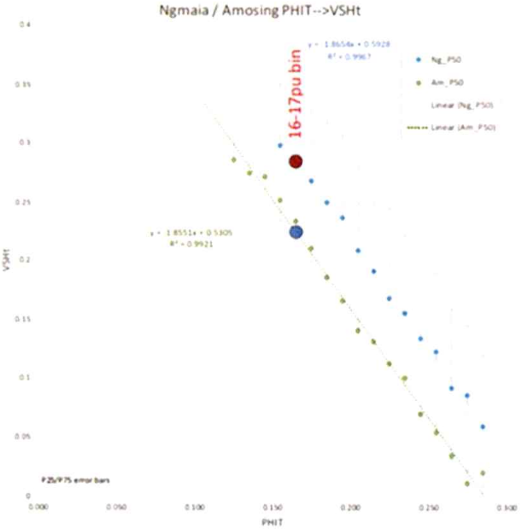


Figure 4-98: PHIT-Vsh relationship from log data

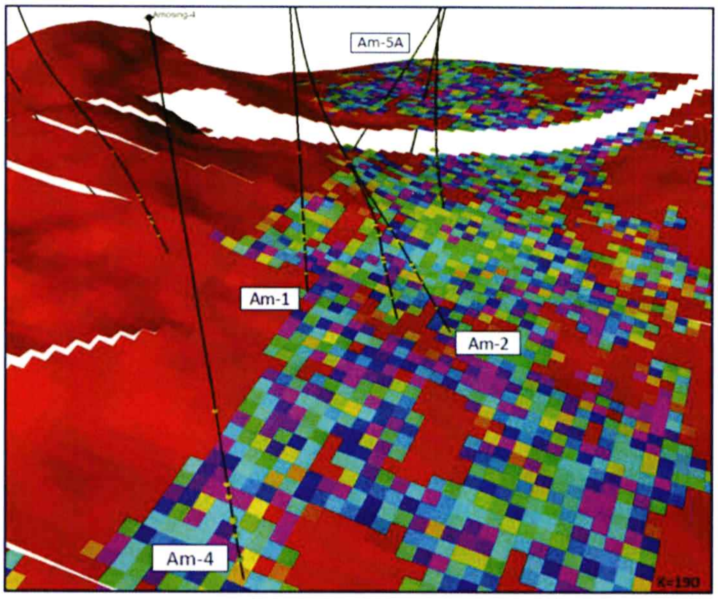


Figure 4-99: Example of Vsh distribution at K-layer 190 in the Amosing model

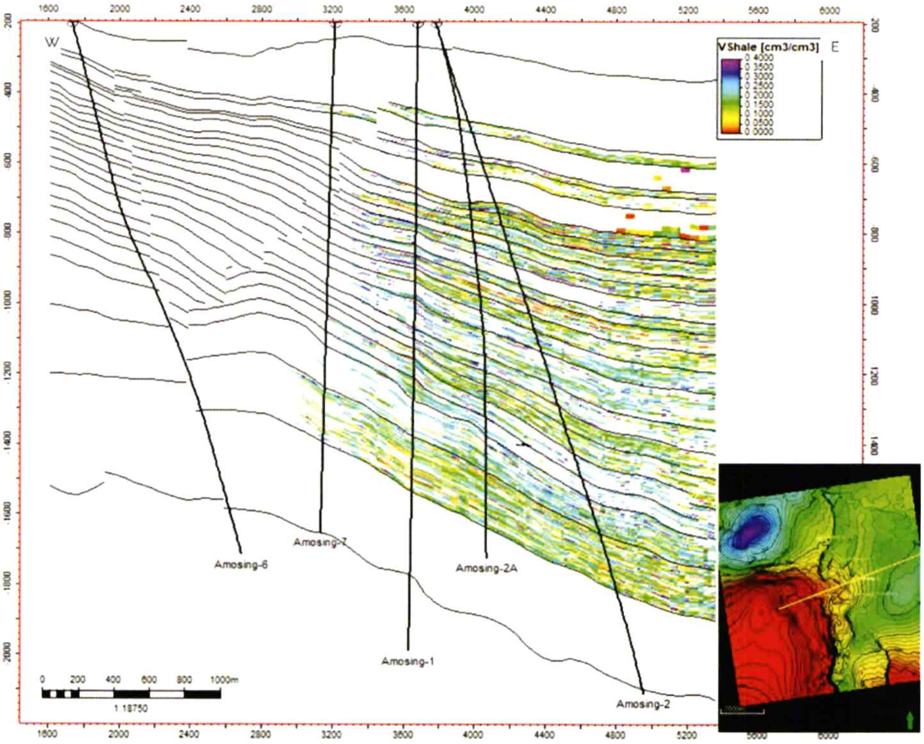


Figure 4-100: Cross-section illustrating Vsh modelling in CBB facies that have a NTG of 1

Permeability

Permeability has been modelled geologically using a poro-perm transform (Figure *4-84*) derived from available routine core analysis from the Amosing wells. Air permeability is modelled (Figure 4-101 & Figure 4-102) and liquid corrections are made in the simulation model.

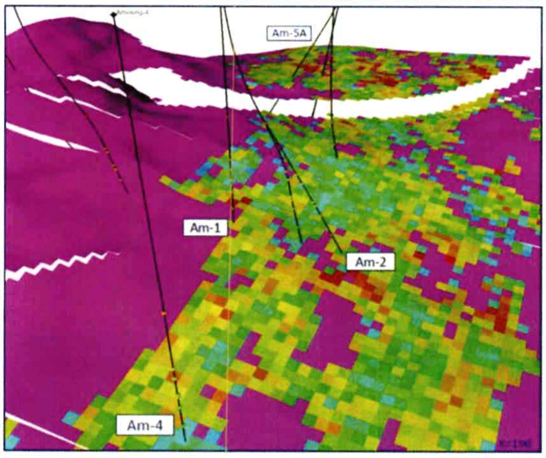


Figure 4-101: Example of permeability distribution at K-layer 190 in the Amosing model

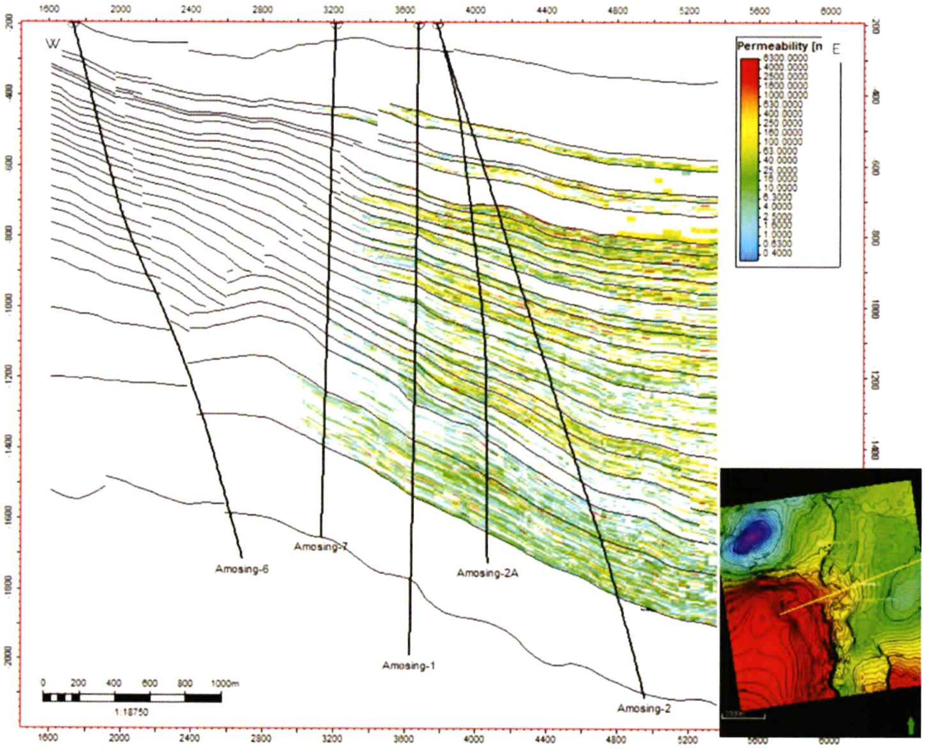


Figure 4-102: Cross-section illustrating permeability modelling in CBB facies that have a NTG of 1

Water Saturation

As detailed in the main petrophysical section (Figure 4-103) saturation has been modelled using a saturation height function that has been optimised for Amosing.

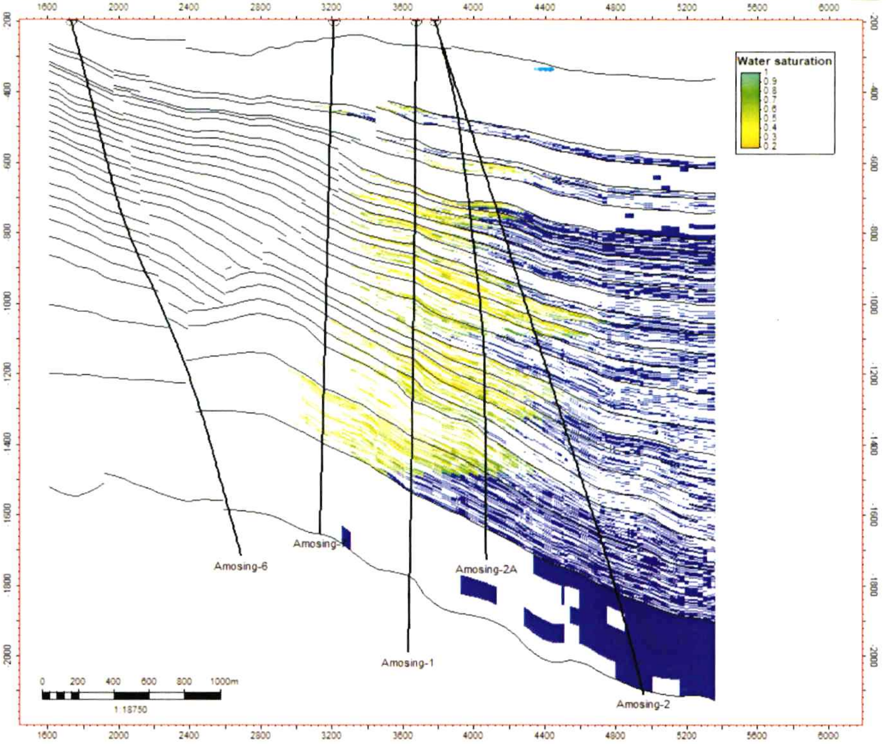


Figure 4-103: Cross-section illustrating saturation modelling in CBB facies that have a NTG of 1

Well data shows that not all sands are connected or charged. As the saturation height function populates hydrocarbons above a given water level, failure to capture these sands will lead to an overestimation in STOIIP. This would also be problematic for perforations due to the presence of water in the production phase. In wells, non-charged sands have been identified from core fluorescence, samples and pressure, resistivity derived SWT and gas chromatography. In each well a flag has been manually generated where a water bearing interval overlies an oil-bearing interval and identified as uncertain pay (Figure 4-104). These uncertain pay zones have been designated as water bearing in the model so as not to bias the model towards an overestimation of hydrocarbons.

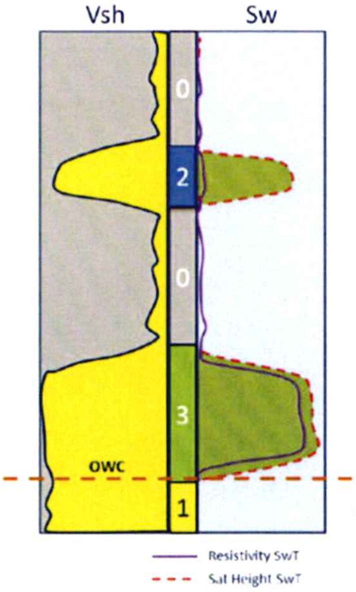


Figure 4-104: Illustration of a zone being assigned as uncertain pay (2) where water has been identified to overlies oil (3) in a well.

4.6.2.5 Hydrocarbon Contacts

Formation pressures have been acquired in each well in the Amosing field using either MDT or RCI tools. Oil-water and gas-oil contacts are picked, where possible, from the intersection of the gas, oil and water gradients. Due to the relatively freshwater salinity the density contrast between oil and water is small and so using traditional plots of formation pressure vs depth does not give clear indications of fluid contacts. Instead plots of differential / excess pressure vs depth have been used where the difference in pressure between the acquired data and the pressure of a reference fluid at that depth is plotted (typically the aquifer pressure). This allows more subtle pressure differences and density differences to be observed. The assessment was carried out on a segment-by-segment basis, considering only the data from penetrating wells. The interpretation was corroborated by the fluid samples collected. Figure 4-105 shows the Amosing formation pressures and best estimate contacts for each zone.

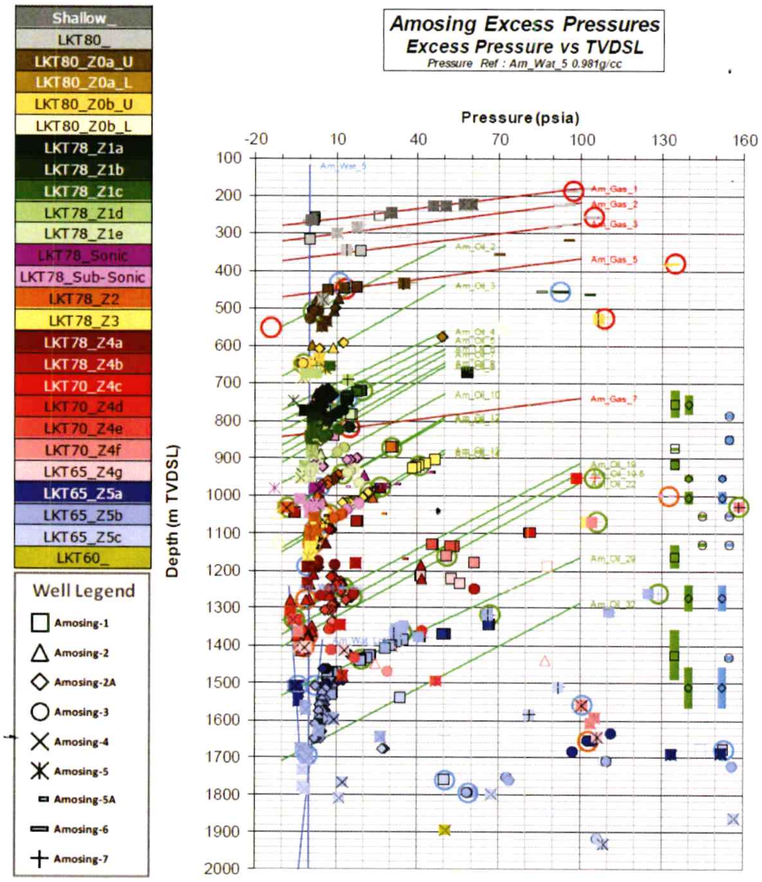


Figure 4-105: Amosing Formation Differential Pressure plot (relative to AM-05 water gradient)

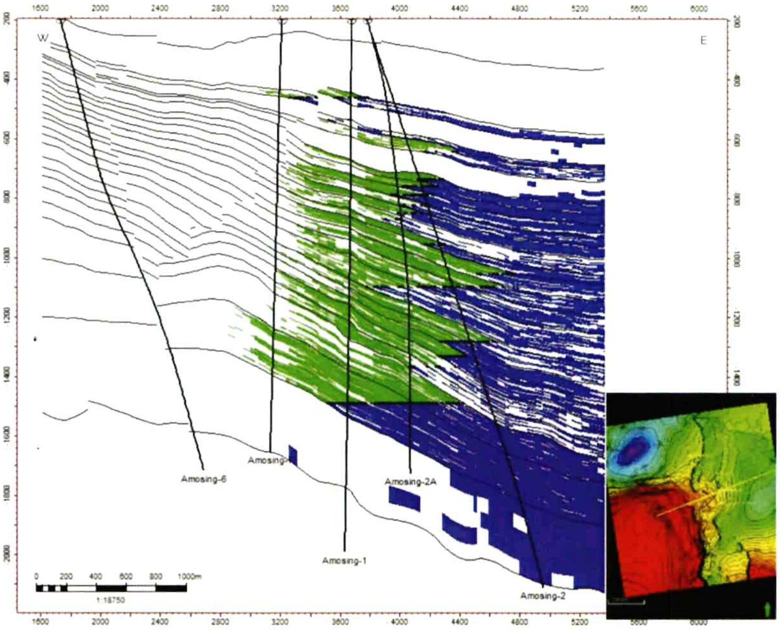


Figure 4-106: Cross section through Amosing showing OWC

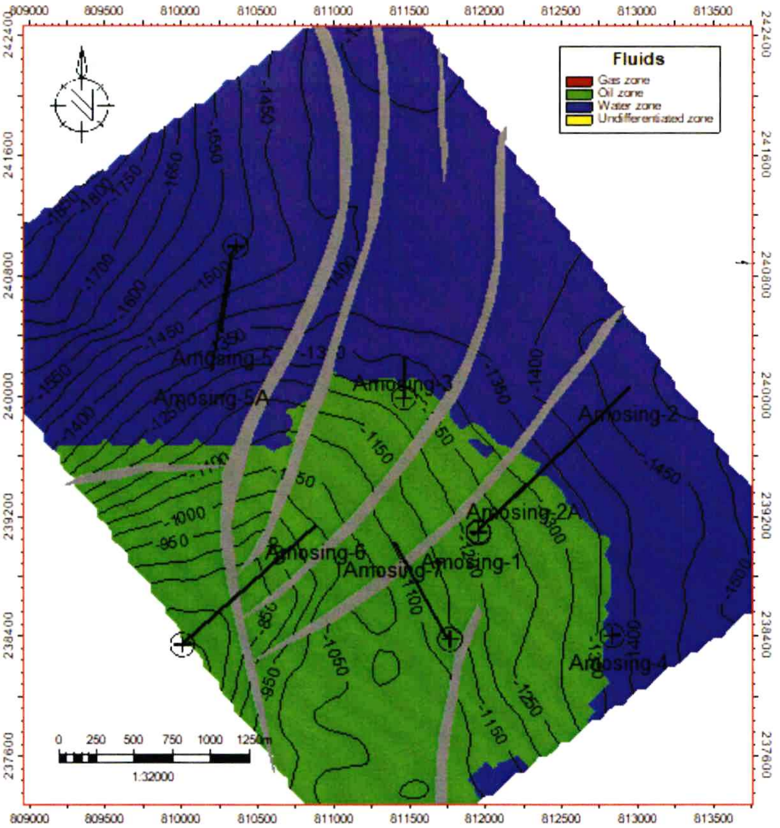


Figure 4-107: Map showing OWC at LKT78

4.6.2.6 Volumetrics

The following table (*Table 4-8*) summarizes the field wide volumetrics for the Amosing accumulation:

Table 4-8: Amosing Auwerwer & Lokone STOOIP

Field	Reservoir	STOIIP (MMstb)		
		Low	Mid	High
Amosing	Auwerwer	186	252	394

The mid case is from the reference case static model and the low and high cases are derived from probabilistic analysis of the field.

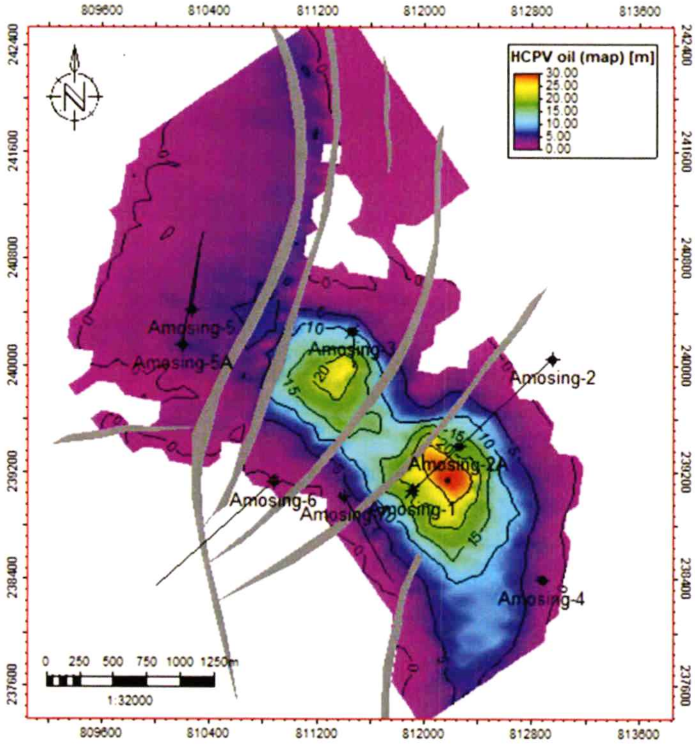


Figure 4-108: Distribution of hydrocarbon pore volume (HCPV) across the Amosing Auwerwer reservoir

Figure 4-108 shows the mapped distribution of hydrocarbon pore volume (HCPV) across the Amosing Auwerwer accumulation.

4.6.2.7 Production and Injection Testing

Amosing-1 and Amosing-2A have been extensively tested during the EWT and EOPS operations. The Amosing Extended Well Test (EWT) was conducted in 2015, production testing individual zones in the two wells and observing the offset pressure response. The reservoir correlations are presented in Figure 4-109. The initial clean-up phase of testing began in February 2015 and the main test phase was conducted in May 2015. Data quality was good throughout the Amosing EWT production testing phase, in terms of flow metering, well stability and pressure data. The offset gauges demonstrated high levels of communication between the two Amosing wells in all completed reservoir zones. Table 4-9 and Table 4-10 show a summary of flow rate data and interpreted reservoir properties.

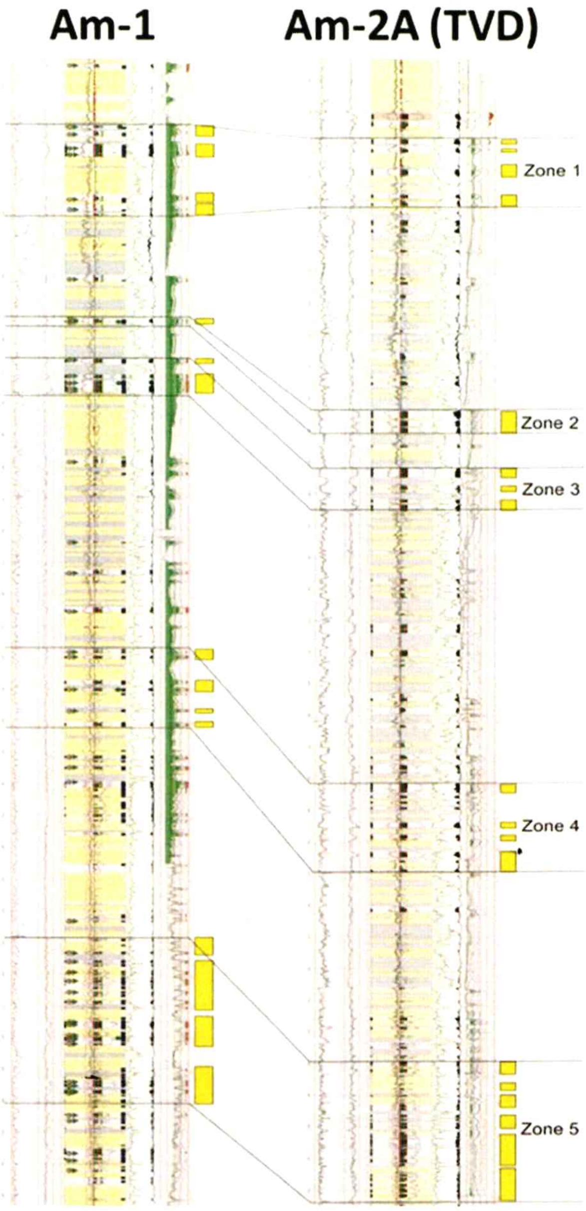


Figure 4-109: Amosing-1 and -2A EWT perforations and reservoir correlation

Table 4-9: Amosing-1 EWT Clean-up Production Data

Interval	Flow Duration (Hours)	P.I. (stb/d/psi)	Oil Gravity (API)	Three Hour Flow Period (After Clean-Up)			PBU Interpretation		
				Oil Rate (stb/d)	Water Rate (stb/d)	Liquid Rate (stb/d)	Permeability (mD)	Kh (md/ft)	Skin Factor
ZONE 5	11.3	2.2	33	1550	0	1550	190	16700	-0.8
ZONE 4 **	21	0.3	n/a	155	104	259	270	4400	-1.5
ZONE 3	9.3	1.4	31	1052	0	1052	85	4200	1.6
ZONE 2	10.5	1.9	36	1110	0	1110	5	200	0.6
ZONE 1	10	7.8	37	1709	0	1709	62	7220	2
ZONE 4 REPEAT	16.3	0.3	n/a	240	0	240	270	4400	-1.5
TOTAL	78.3			5662	0	5662			

** Note: In Zone 4 first flow period production was slugging badly and flow rate values are uncertain. Zone 4 test was repeated successfully.

Table 4-10: Amosing-2A EWT Clean-up Production Data

Interval	Flow Duration (Hours)	P.I. (stb/d/psi)	Oil Gravity (API)	Three Hour Flow Period (After Clean-Up)			PBU Interpretation		
				Oil Rate (stb/d)	Water Rate (stb/d)	Liquid Rate (stb/d)	Permeability (mD)	Kh (md/ft)	Skin Factor
COMBINED	10		n/a	1580	484	2063	120	2400	-0.5
ZONE 5	16.5	2.7	n/a	8	409	417	85	6200	-0.2
ZONE 4	17.5	2.9	38	1667	0	1667	125	6200	0.5
ZONE 3	13.8	2	33	1123	0	1123	190	9500	0.4
ZONE 2	13.5	3.3	32	1124	0	1124	380	23900	4
ZONE 1	15.8	5.8	32	2086	0	2086	120	2400	-0.5
TOTAL	87		n/a	6008	409	6417	85	6200	-0.2

Following the production phase of the EWT, water injection tests were performed on Amosing-2A Zones 3, 4 and 5. Due to a high bacterial population and poor injection water quality, the tests failed to demonstrate matrix injection at adequate rates. Following a root cause investigation and extensive core testing, the well was re-entered and following stimulation operations successful matrix water injection was established. A chemical tracer test (SWCT) was also conducted on Amosing-2A Zone 2 after an extended period of water injection.

As described above, in Section 4.6.1.8, the Early Oil Production System (EOPS) was installed in 2019 to provide additional oil storage and an export facility to truck produced crude to Mombasa for export. Amosing-1 was the key producer during EOPS, producing 158.6 mstb of oil. Amosing-2A produced 27.9 mstb before operations were suspended (Figure 4-110). The relative volumes produced do not reflect well potential or recoverable resources for each well as the producing time for each well was driven by operational availability.

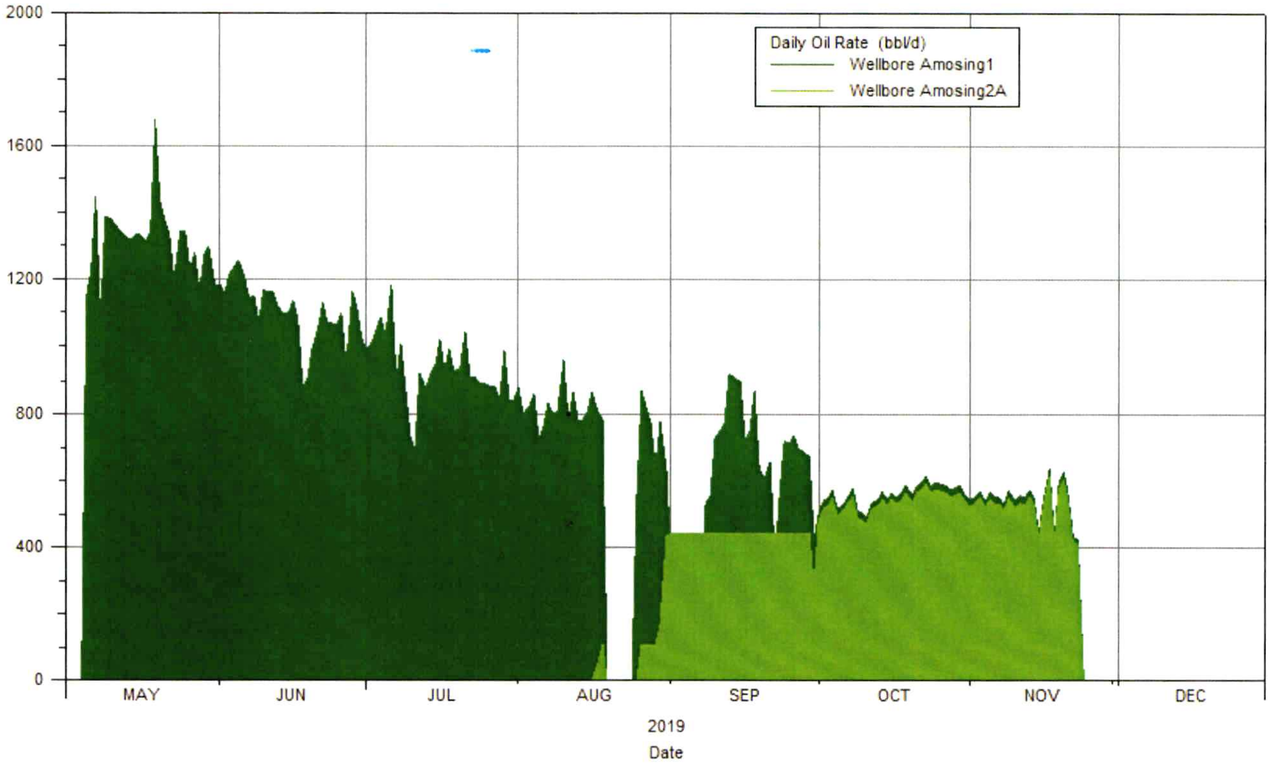


Figure 4-110: Amosing EOPS Oil Production Rates

4.6.2.8 Fluid Properties

Downhole fluid samples have been taken in the Amosing reservoir from most stratigraphic levels using wireline formation testers during open hole logging operations and using downhole sampling tools during the EWT. Fluid samples have been analysed and the oil, typically for a South Lokichar crude, is characterized as medium gravity, low viscosity, undersaturated black oil with low gas-oil-ratio. (Table 4-11).

Dead oil crude property analysis shows the oil to be low in sulphur, asphaltene and aromatics but moderately high in wax content with high wax appearance (WAT) and pour point temperatures above ambient conditions. Analysis of laboratory results of South Lokichar PVT demonstrates a correlation between depth/reservoir temperature and viscosity. Generally speaking, deeper zones have lower oil viscosities and based on depth, viscosity in Amosing would likely vary between a low of 2 cp to a high of 10 cp.

Table 4-11: Summary of Amosing Fluid Properties

Reservoir Pressure (psia)	Reservoir Temperature (deg C)	Saturation Pressure (psia)	Gas-oil Ratio (scf/stb)	Oil Gravity (deg API)	In-situ Viscosity (cp)	Formation Volume Factor (rb/stb)	Wax Appearance Temperature (deg C)	Wax Content (mol %)	Pour Point (deg C)
1370-3500	75-116	835-1140	190-265	28-40	2-10	1.1 – 1.2	60 – 67	22-27	39-45

4.6.2.9 Amosing Simulation Modelling

The history matching was performed on the wells that produced during the dynamic reservoir testing: Amosing-1 and -2A Extended Well Test and EOPS.

During the EOPS, Zones 2, 3, 4 and 5 were flowed in Well Amosing-1 first and then shut in. This was followed by a period of production from Zone 1 in Well Amosing-1 and Zones 2, 3 and 4 in Well Amosing-2A. Interference effects are observed between zones in a given well and also between the two wells, resulting in a challenging history match.

Observed data and simulated pressures across all five zones in Wells Amosing-1 and Amosing-2A are shown in Figure 4-111. Sensitivity studies were performed to investigate whether the match could be improved by applying field-wide modifications to permeability. The drawdown pressures in the simulator in Well Amosing-1, Zones 2 and 5, and in Well Amosing-2A, Zone 3, remain high relative to the observed data suggesting the permeability in the model is higher than in the reservoir. However, when reductive multipliers were applied, the reasonable match in all other zones was compromised. The final version of the permeability grid adopted was the static model property, unedited, which corresponds the simulated pressured in Figure 4-111.

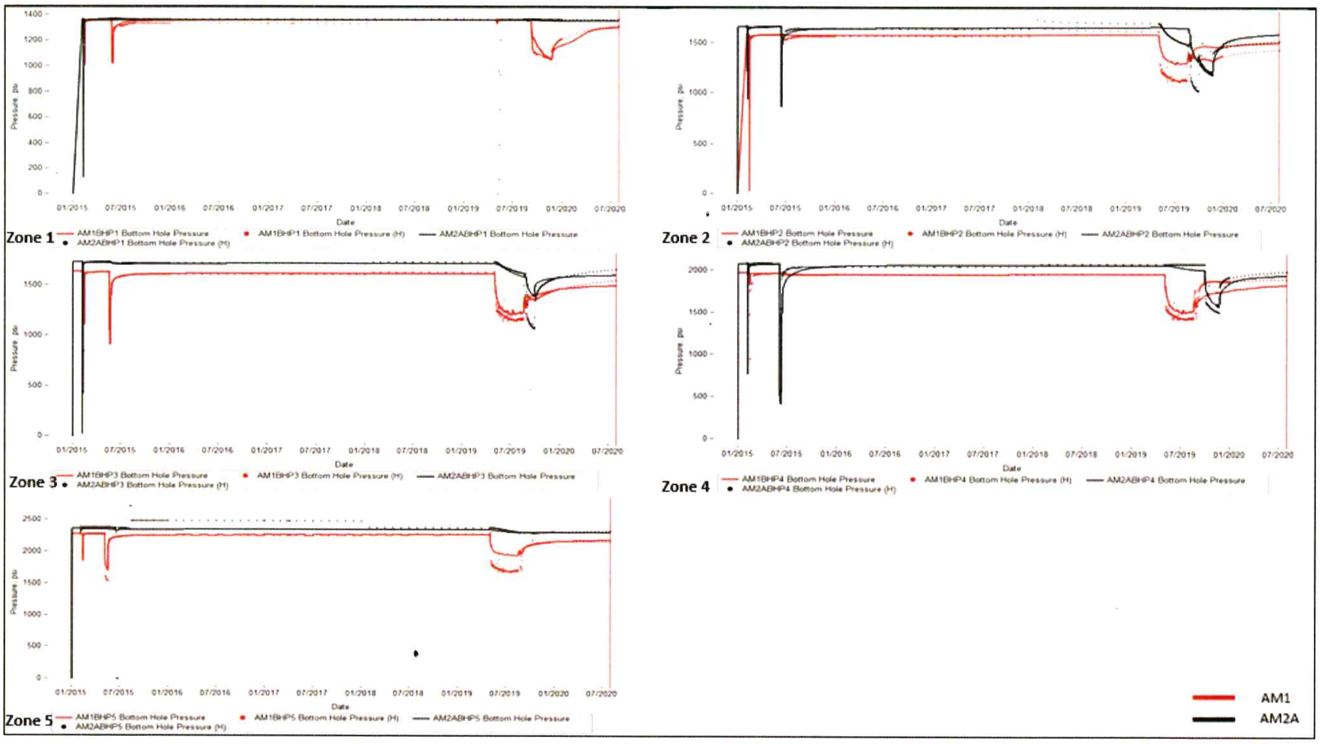


Figure 4-111: Amosing 1 and 2A History match across zones.

4.6.2.10 Amosing Material Balance Assessment

As with Ngamia, the extended period of production from Amosing during EWT and EOPS, and the measurement of pressure data in multiple intervals of the EWT wells has enabled material balance calculations on the Amosing field. Amosing is divided into three separate fault blocks, designated Amosing Main, Amosing-3 Graben and Amosing-5 block. The two EWT / EOPS wells, Amosing-1 and -2A are both in the Main area.

In Amosing Main fault block, the base case static model contains 139 MMstb of oil. Material balance calculations of the EWT/EOPS pressures demonstrates a volume connected to the EWT wells of 300 MMstb. The material balance calculation estimates 50% more volume than is captured in the model. The difference may be due to an underestimate of the oil-in-place or the impact of the aquifer that is not captured in the estimate. The Lower Auwerwer aquifer is seen to have common pressures throughout the basin and is quite extensive, but its strength under production conditions is unknown.

The Amosing Main fault block appears to be structurally quite simple with little seismic evidence for faulting within the block and that is supported by the large, connected volume from the material balance calculation. The EWT/EOPS data analysis supports this prognosis, and the risk associated with reservoir compartmentalisation is significantly reduced.

4.6.2.11 Amosing Development Scenario

The development scheme is planned to be an inverted 5 spot pattern on a 200m spacing which has been shown to give an optimal recovery. The initial patterns from the Phase 1 development have been planned around existing wells Amosing -1, Amosing 2A and Amosing-3 which broadly fit a 200m spacing within an area of high hydrocarbon saturations (Figure 4-112). These initial wells have been planned to be drilled from the existing Amosong-1 and Amosing-3 well pads. A total of 24 wells have been planned for Phase 1.

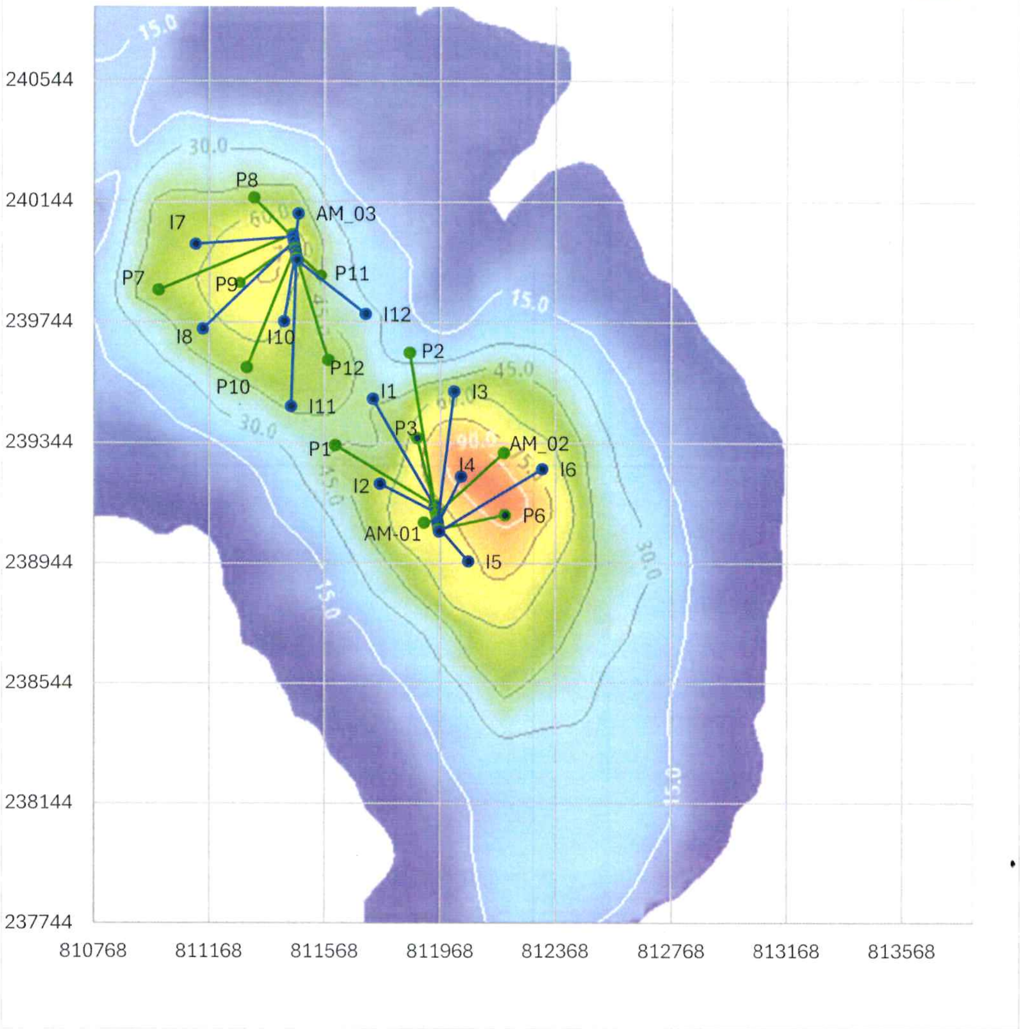


Figure 4-112: Phase 1 Amosing well subsurface locations (background map of volume weighted oil saturation)

Phase 1 drilling is planned to commence in December 2026 with seven new wells from the Amosing -1 pad before moving to Ngamia and then returning to drill up the Amosing -3 pad. Finally, the remaining three wells from the Amosing-1 pad will be drilled and completed.

Wells associated with Phase 2 have been placed in the subsurface model to maintain the 200m well spacing grouped as far as possible to be drillable from a 12-slot pad. (Figure 4-113).

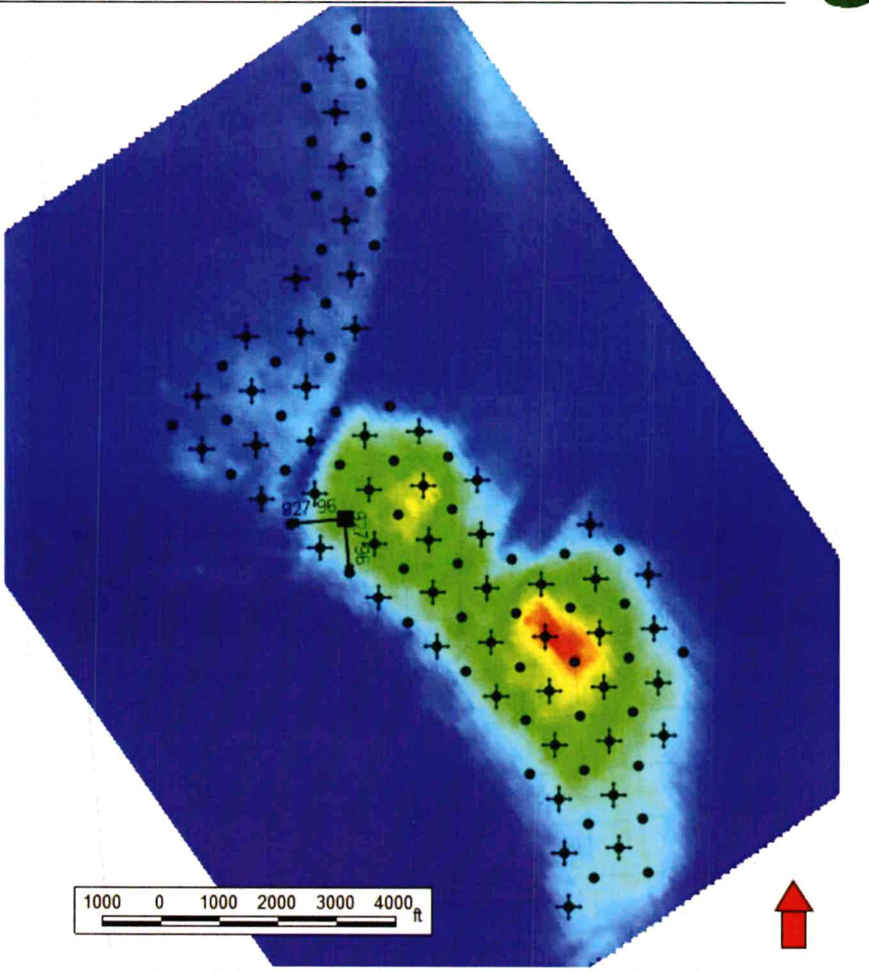


Figure 4-113: Amosing Phase 2 well pattern (map of HCPV)

Phase 2 producers within the simulation grid are perforated in net sand where the water relative permeability is less than 0.001. Water injectors are perforated in the model where they have penetrated net sand.

A maximum liquid production rate of 3,000 b/d and a minimum bottomhole pressure of 44.8 bara (650 psia) were assigned to each producing well, consistent with rates and pressures that can be achieved using the selected artificial lift methods of ESP, PCP and jet pumps. Injection wells were limited to matrix injection with a peak rate of 3,000 b/d with a maximum bottomhole pressure of 2900 psia. Water injection is available at first production and a voidage replacement ratio of 1.0 was maintained within each identified fault block throughout the life of the field.

A limiting surface water cut of 97 percent was used to shut in wells and reduce excess water production during production forecasts. The base forecasts have been created without any downhole interventions to manage water breakthrough. Opportunities to use zonal isolation of producing or injecting intervals are described in Section 6.3. For the Phase 1 part of the forecast the simulation facility limits have been set to match the proposed Early Production Facility capacities. As the model transitions into the phase 2 facility no maximum field liquid or oil production constraints have been specified nor a minimum oil rate to terminate the forecast in the simulation model. Facility constraints and uptimes have been applied as the forecasts are combined with the other field's forecasts.

A reservoir voidage replacement ratio of 1.0 was specified for each segment within the reservoir. Given the relatively low GOR of the oil and uncertainty regarding the level of aquifer support that may be expected under production conditions, water injection is specified at the start of production in the South Lokichar reservoirs.

4.6.2.12 Recoverable Resources

GEBV's estimates of total recovery from Amosing have been presented in Table 6-2, Section 6.1.3. These estimates are from a probabilistic calculation based on a recovery factor range of 19% - 27% - 37% based on a maximum EUR from the simulation model as well as analytical Buckley Leverett / Dykstra Parsons calculations.

The Best Estimate recoverable resources associated with the planned Phase 1 and Phase 2 wells in Amosing are 58.1 MMstb representing a recovery factor of 23% for the well count presented and the areas of the field developed. Within the license period of 25 years a total of 54.3 MMstb are produced from Ngamia, with the remainder being deferred past the end of the license due to combining production with the other basin fields and constraining production through the Phase 2 CPF limits.

4.6.3 Twiga Auwerwer

4.6.3.1 Introduction

The Twiga field (Figure 4-114) was the second major discovery of hydrocarbons in the South Lokichar Basin. The main reservoir in the field is the Lower Auwerwer Formation (Figure *4-114*). There is additional potential in the Lokone Formation as encountered in Well Twiga-3, however these resources were not fully evaluated and will require further appraisal before being considered for development. This section focuses on the Lower Auwerwer Formation.

Well Twiga-1 (initially named Twiga South-1) was spudded on August 21, 2012 with the Weatherford 804 drilling rig. The well drilled to a total depth of 3,250 mMD in the Lokone Sandstone Formation. The well discovered hydrocarbons in the Lower Auwerwer Formation, sandstones within the Lokone Shales Formation as well as the Lokone Sandstone Formation. Well Twiga-1 location was selected on 2D seismic data. The well rig was released from the drilling and testing program on February 22, 2013.

During the drilling of the well, six conventional cores were acquired in the Lower Auwerwer and the Lokone Sand formations. Logging while drilling measurements including gamma ray and resistivities were acquired. A comprehensive suite of conventional wireline logs was recorded in each hole section and both percussion and rotary sidewall cores were acquired. Using a wireline formation testing tool, formation pressures were acquired throughout the well in addition to fluid samples.

Well Twiga-1 was drill stem tested immediately after drilling and a total of five drill stem tests were performed in the well. Two open hole tests were conducted in the tight reservoirs of the Lokone Sandstone formation and three cased hole tests were run in the Lower Auwerwer Formation. The two DSTs in the Lokone Sandstone Formation confirmed early log analysis that the reservoir had poor porosity and flow capacity as the facies in this location was heavily indurated, immature alluvial material. The three DSTs in the Lower Auwerwer formation demonstrated very good quality fluvial sandstones with good porosity and flow capability. One test flowed naturally at around 2,000 barrels per day.

Three appraisal wells have been drilled in the Twiga field, Twiga-2, Twiga-2A and Twiga-3. Twiga-2 was spudded with the Sakson PR5 drilling rig on February 11, 2014 and drilled vertically to a total depth of 2,101 mMD. While the well encountered thin beds of reservoir sandstones where both oil and gas samples were acquired, the well contained predominantly tight non-reservoir quality rock. The decision was made to sidetrack the well to the east to move away from the rift bounding fault and associated tight alluvial facies. Twiga-2A sidetracked from the original wellbore and reached a total depth of 2,886 mMD within the Lokone Shale Formation. The goal of the sidetrack was realized and the section that was essentially non-reservoir in Twiga-2 was mostly stacked fluvial reservoir and alluvial plain material in the Twiga-2A well. The Twiga-2A well encountered several oil-bearing pools within the Lower Auwerwer formation. Unfortunately, wellbore conditions in Twiga-2A were very poor and open hole wireline logs could not be acquired. Twiga-2A had casing run and cemented, and cased hole logs were acquired. Twiga-2A well was re-entered later to perform a drill stem test. Three perforated through-casing flow tests were performed in addition to a combined test. The results of the drill stem testing are discussed in the reservoir engineering section.

The Twiga-3 appraisal well was drilled vertically to a total depth of 2,575 mMD in the Lokone Sandstone Formation. Twiga-3 found only a thin oil pool in the Lower Auwerwer Sandstones that appears to correlate to an oil pool in the Twiga South-1 well. Mud gas readings while drilling and cutting analysis of the Lokone Formation also indicate a two-hundred-meter section that appears oil-bearing. Only the first wireline run was able to log this unit, and no formation pressures, fluid, or sidewall core samples were acquired.

The Lower Auwerwer oil resources in the Twiga Field are planned to be developed in the second development phase of the South Lokichar Basin. Current estimates of STOIIP range from 59 MMstb to 170 MMstb, with a best technical estimate of 87 MMstb. The mid case estimate is based on a rigorous process of incorporating the geophysical, geological, petrophysical and reservoir engineering data and interpretations into a three-dimensional static model. The process of building this model will be described in the following sections. The low and high case estimates are based on statistical volumetrics methodology which incorporates a suitable range of uncertainty in the volumetric parameters and reservoir extent. This methodology is also discussed in the following sections.

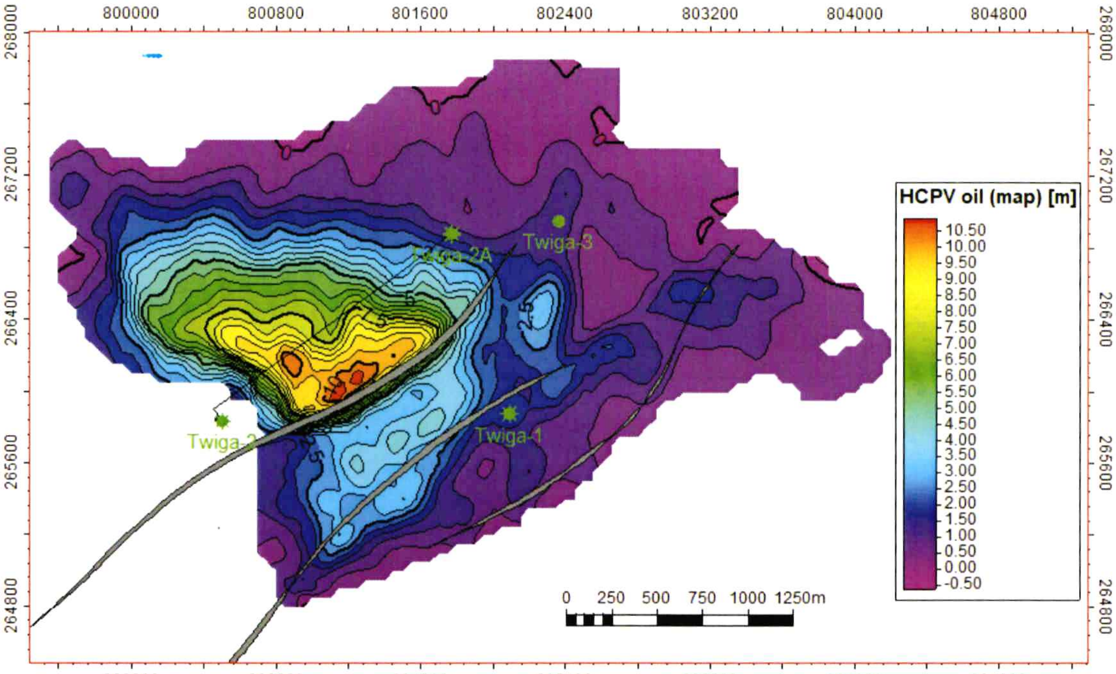
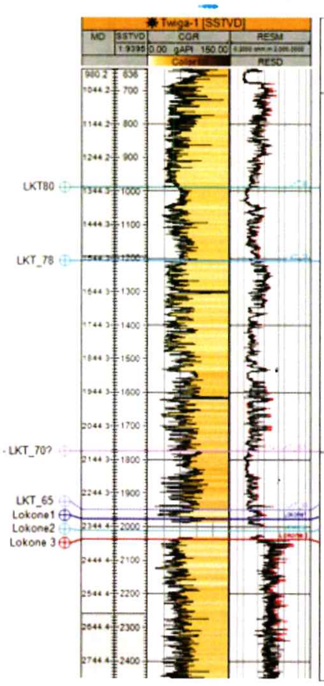


Figure 4-114: Twiga Best Case Oil Field HCPV and well locations



Formation		Primary Lithology/Environment	Main Seismic Markers
Auwerwer	Upper	Stacked fluvial sandstones	
	Mid	Lacustrine shales	LKT 80
	Lower	Stacked fluvial sandstones interbedded with mudstones and sandstones of alluvial plain deposits	LKT 78 LKT 70
Lokone	Lokone Shale	Lacustrine shales with interbedded sandstone gravity flow deposits	LKT 65 LKT 60
	Lokone Sandstone	Sandstone gravity flow deposits with lacustrine shales	

Figure 4-115: Well Twiga-1 log illustrating the stratigraphy of Twiga

4.6.3.2 Geology

The Twiga Field is a moderately faulted, three-way dip closed anticlinal structure along the western margin of the South Lokichar Basin (Figure 4-116). The field is ultimately bounded to the west by the large, basin bounding fault.

The sandstones of the Lower Auwerwer formation are the main reservoirs in the Twiga Field (Figure 4-117 and Figure 4-118). These reservoir sandstones are primarily fluvial in origin. There is significant evidence of poorer quality sandstones thought to be more alluvial in origin close to the main fault systems. The influence of this poorer quality non-reservoir alluvial facies has a large impact on the Twiga Field. The impact of the tight alluvial facies is clearly illustrated in the Twiga-2 and Twiga-2A wells. In Twiga-2 there is little in the way of good quality reservoir sandstones, being mainly tight alluvial facies. Twiga-2A, which is only a few hundred metres basinwards, has no tight alluvial fan facies and consists of stacked good quality fluvial and alluvial plain deposits.

There is some level of structural complexity in the Twiga field with seismically visible faults separating the field into segments (Figure 4-116). Faults, both synthetic and antithetic, to the basin bounding fault cut through the Lower Auwerwer section. Most of these faults have enough throw on them to provide at least some sealing capacity during production.

Hydrocarbon bearing sandstones within the Lower Auwerwer Sandstone are individually sealed by laterally extensive mudstones within the sequence. The ultimate top seal to all the hydrocarbon discoveries is provided by the Mid Auwerwer Shale at the base of the Upper Auwerwer Sandstone. Hydrocarbons were also discovered in the Lokone formation sandstones, however the sandstones were characterised by very poorly sorted and low porosity alluvial deposits making the resources not viable to produce at this time.

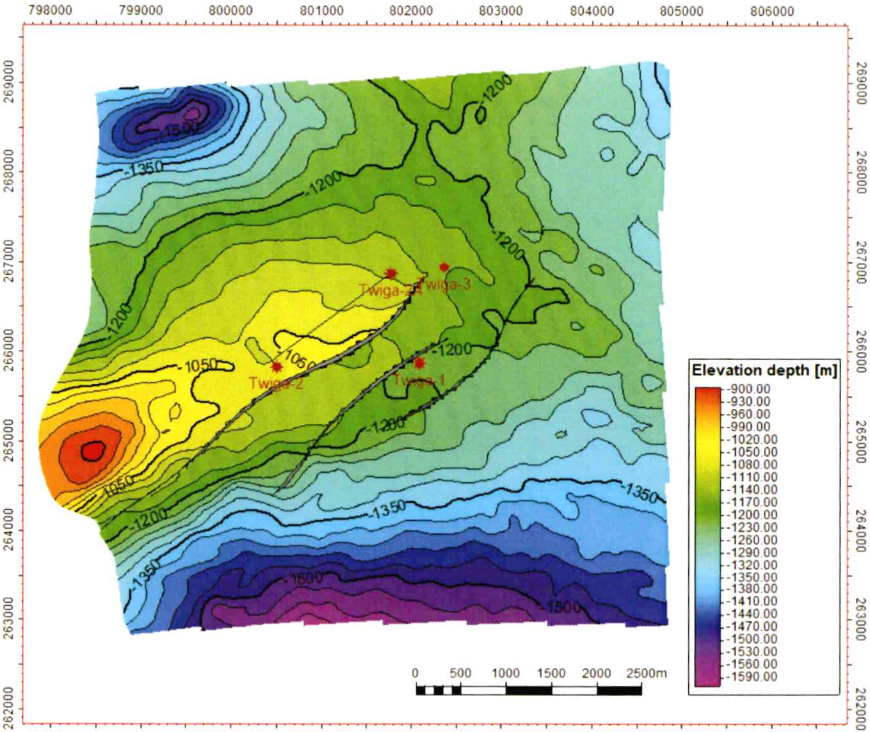
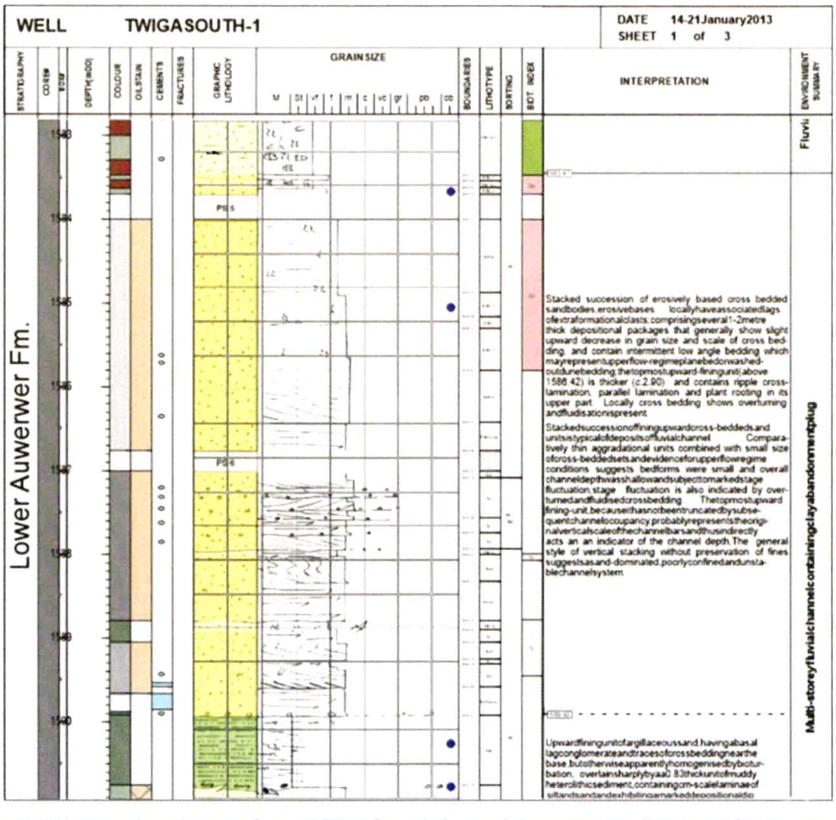


Figure 4-116: Intra Auwerwer (LKT 78) depth structure map, Twiga Field



Stacked succession of erosively based cross bedded sandbodies. erosive bases locally have associated lags of extraformational clasts. comprising several 1-2metre thick depositional packages that generally show slight upward decrease in grain size and scale of cross bedding, and contain intermittent low angle bedding which may represent upper flow-regime plane bed or washed-out dune bedding. the topmost upward-fining unit (above 1588.42) is thicker (c.2.90) and contains ripple cross-lamination, parallel lamination and plant rooting in its upper part. Locally cross bedding shows overturning and fluidisation is present.

Stacked succession of fining upward cross-bedded sand units is typical of deposits of fluvial channel. Comparatively thin aggradational units combined with small size of cross-bedded sets and evidence for upper flow regime conditions suggests bedforms were small and overall channel depth was shallow and subject to marked stage fluctuation. stage fluctuation is also indicated by overturned and fluidised cross bedding. The topmost upward fining-unit, because it has not been truncated by subsequent channel occupancy, probably represents the original vertical scale of the channel bars and thus indirectly acts an an indicator of the channel depth. The general style of vertical stacking without preservation of fines suggests a sand-dominated, poorly confined and unstable channel system.

Upward fining unit of argillaceous sand, having a basal lag conglomerate and traces of cross bedding near the base, but otherwise apparently homogenised by bioturbation, overlain sharply by a a 0.83 thick unit of muddy heterolithic sediment, containing cm-scale laminae of silt and sand and exhibiting a marked depositional dip

Figure 4-117: Core description of an oil filled fluvial channel deposit in Well Twiga-1(Twiga South-1).

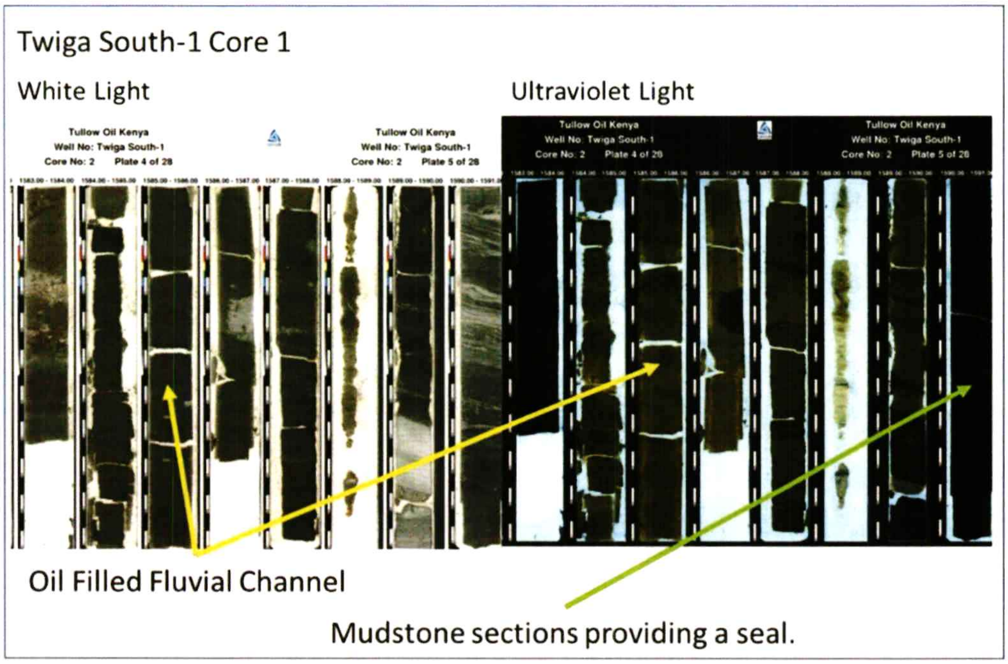


Figure 4-118: Core photographs of an oil filled fluvial channel deposit in the Lower Auwerwer Formation in the Twiga South-1 well.

4.6.3.3 Geophysics

The RAP PreSTM 3D data volume was used to map the key seismic markers over the Twiga Field. The four key seismic markers mapped are Base Volcanics, LKT78, LKT70 and LKT65 as illustrated. All four seismic markers are good quality picks over the Twiga Field (see Figure 4-119 and Figure 4-120) and provide good synthetic ties at the wells.

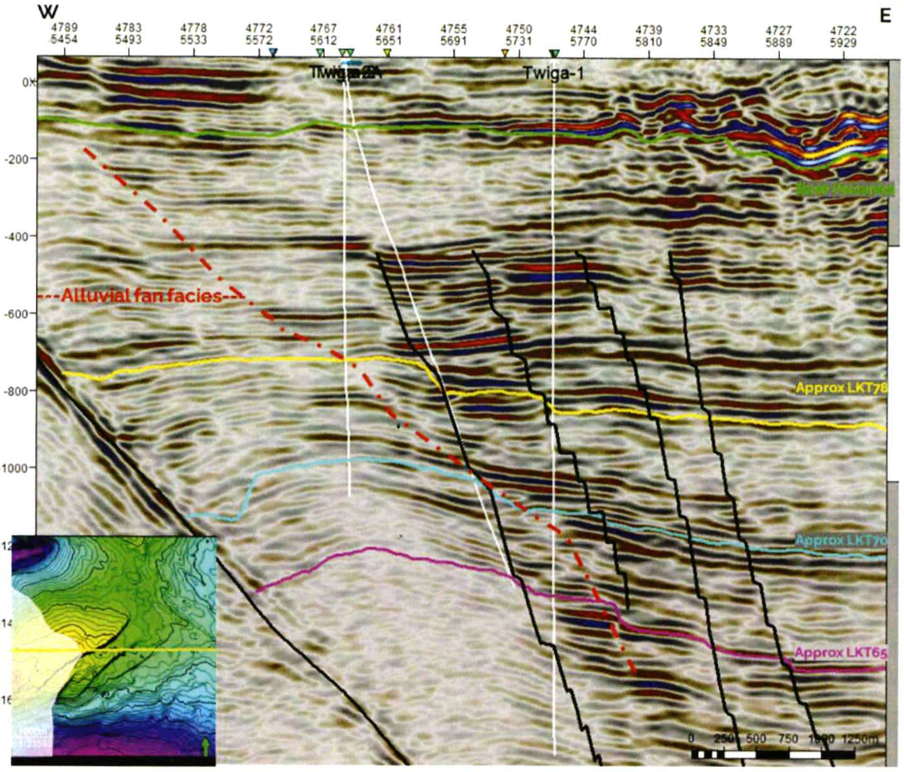


Figure 4-119: West-East RAP PreSTM 3D seismic line through Twiga-2 and Twiga-1 wells

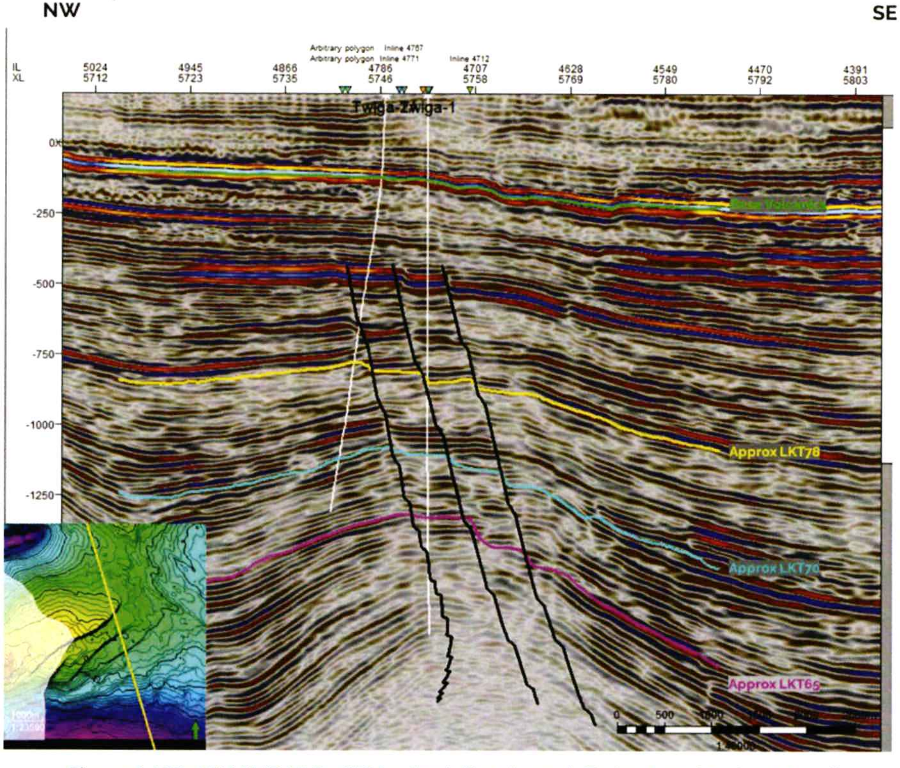


Figure 4-120: NW-SE RAP PreSTM seismic line through Twiga-1 and Twiga-2A wells

These markers have also been used for velocity modelling. Some two-way time structure maps over the Twiga Field are shown in Figure 4-121, Figure 4-122, and Figure 4-123. The Twiga structure is a three-way fault closure in the hanging wall of the north-south trending Lokichar Fault.

The LKT78, LKT70, and LKT65 two-way time structure maps are dominated by the three northeast-southwest trending normal synthetic faults (see Figure 4-119 and Figure 4-120). Displacement along all three faults is evident at the LKT78, LKT70, and LKT65 seismic markers.

Adjacent to the Lokichar Fault, in the hanging wall, the reflectivity of the seismic markers becomes very poor due to the presence of alluvial rift edge facies as illustrated in Figure 4-119. The zone of poor reflectivity caused by the alluvial rift edge facies extends up to two kilometres basinwards from the Lokichar Fault (see Figure 4-121, Figure 4-122, and Figure 4-123).

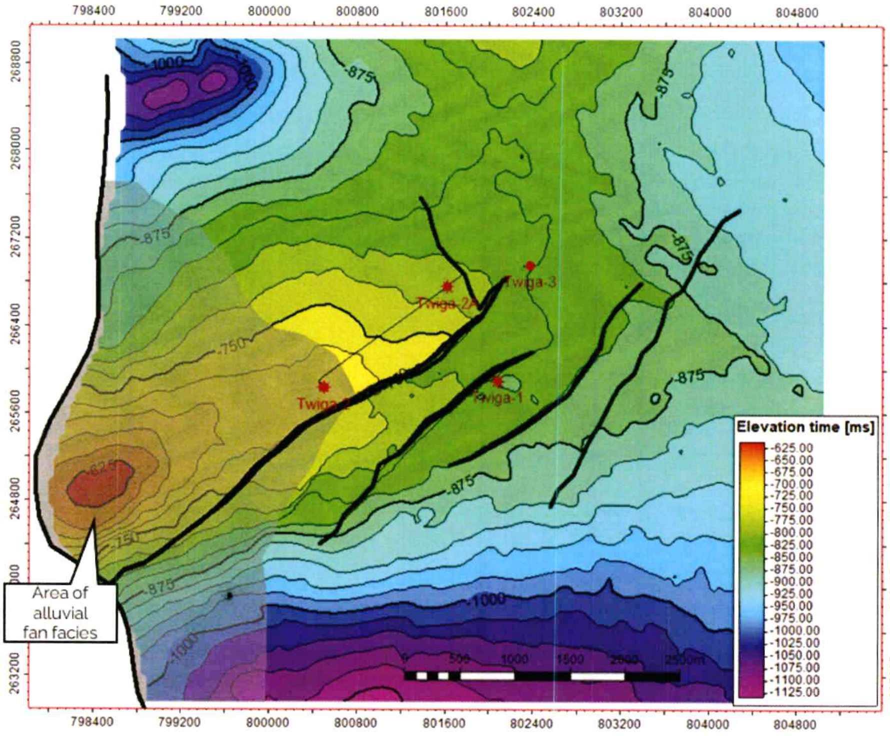


Figure 4-121: Twiga Field RAP PreSTM LKT78 two-way time structure map (milliseconds)

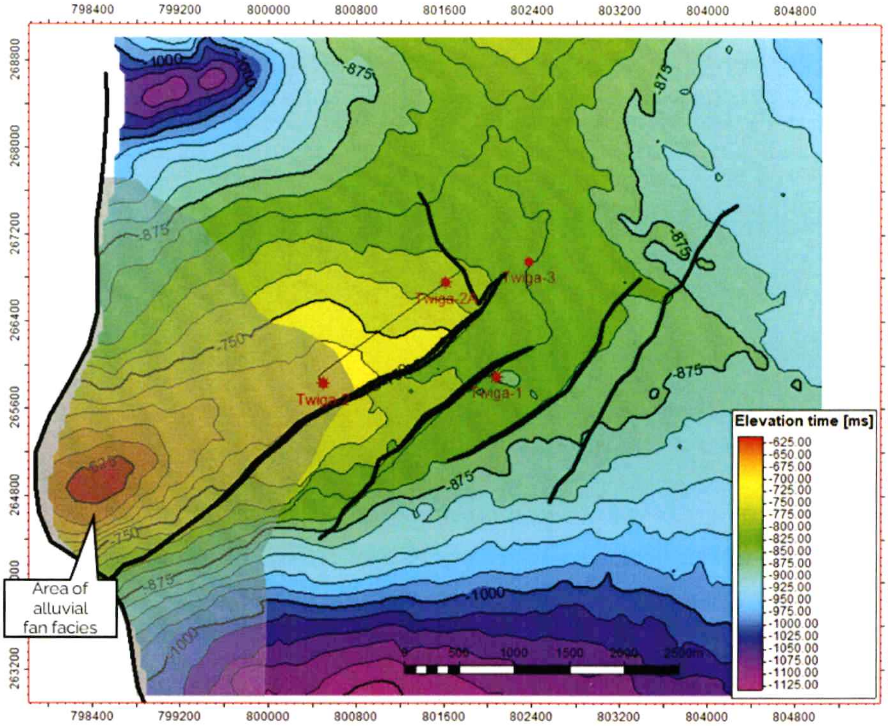


Figure 4-122: Twiga Field RAP PreSTM LKT70 two-way time structure map (milliseconds)

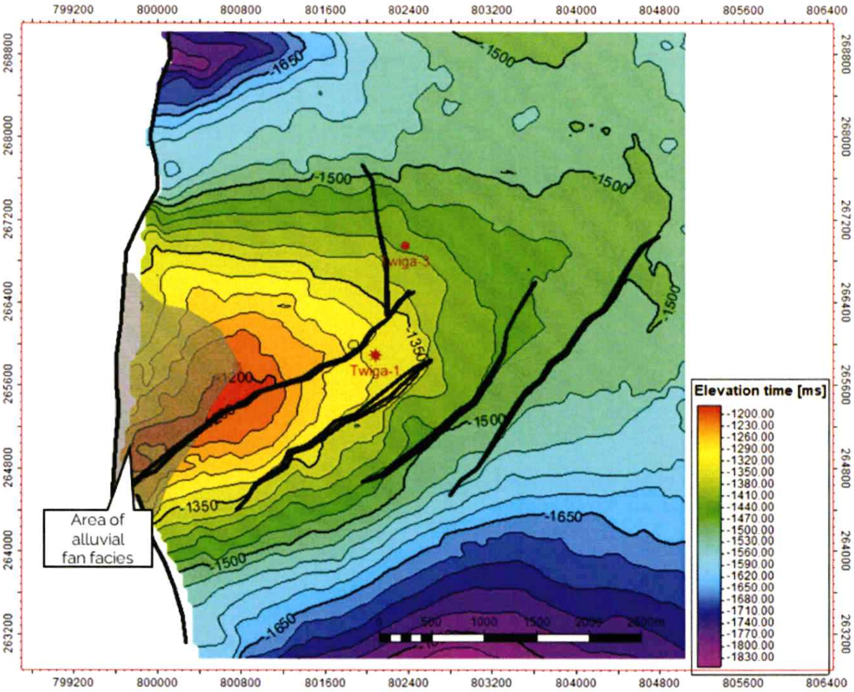


Figure 4-123: Twiga Field RAP PreSTM LKT65 two-way time structure map (milliseconds)

Depth Conversion

Depth conversion in Twiga was performed using an interval-based velocity modelling. The model incorporated four key intervals from the 3D two-way time horizon interpretation, namely Base Volcanics, LKT78, LKT70, and LKT65. Pseudo-interval velocities are calculated at each well tie using the corresponding layer isopach from well log data and the two-way time isochron value from the RAP PreSTM seismic data interpretation.

The resulting depth maps are shown in Figure 4-124 to Figure 4-126.

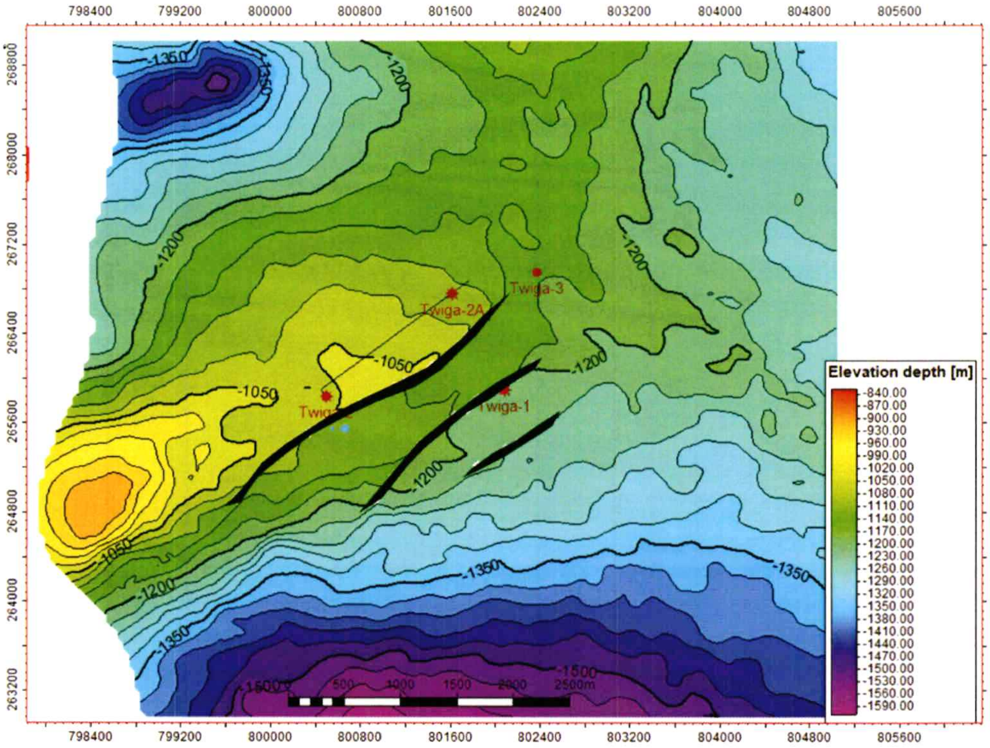


Figure 4-124: Twiga LKT78 Depth Map

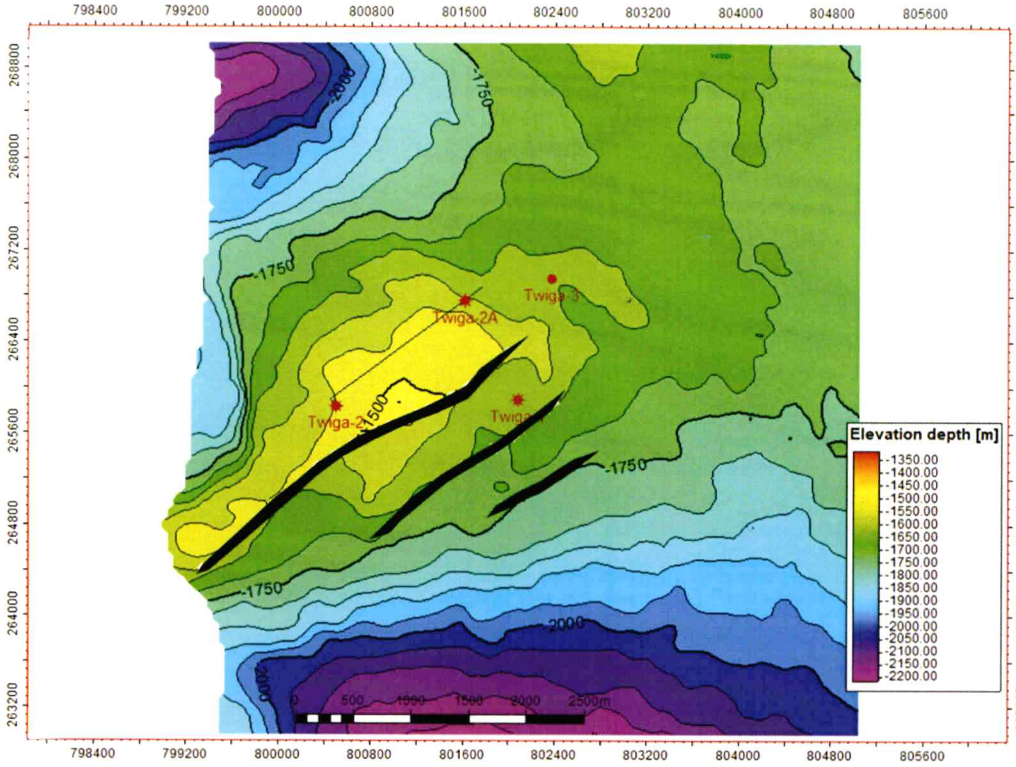


Figure 4-125: Twiga LKT70 Depth Map

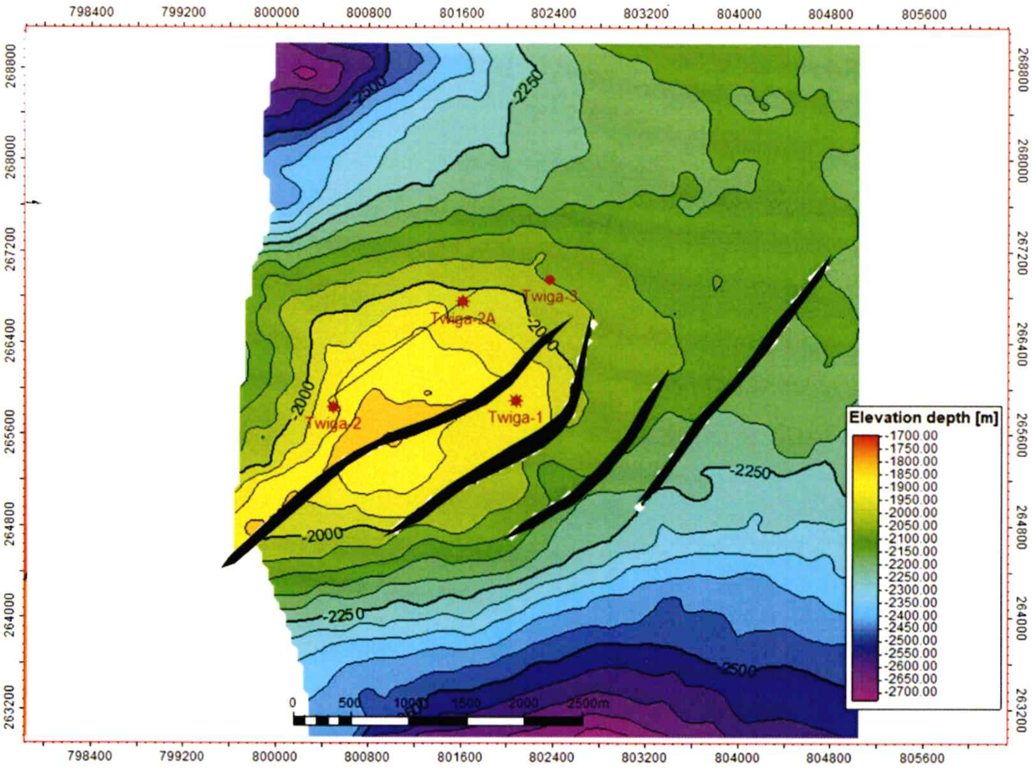


Figure 4-126: Twiga LKT65 Depth Map

4.6.3.4 Petrophysics

This section will discuss available data and processes specific to the Twiga Lower Auwerwer analysis. The Twiga Field has a relatively poor and incomplete set of petrophysical data. Well Twiga-1 (also known as Twiga South-1) was the second well drilled on the east side of the South Lokichar Basin and was drilled with water-based mud which led to poor hole conditions in the well. While several full diameter cores and an extensive logging program were acquired, the overall data quality was relatively poor. Well Twiga-2 had good data acquisition but encountered mainly non-reservoir facies. The sidetrack, Well Twiga-2A, encountered better reservoir and hydrocarbon bearing zones, but due to wellbore conditions, open hole logs were not acquired. Only LWD and cased hole logs were acquired in the well. Well Twiga-3 encountered only a thin pay zone in the Lower Auwerwer Formation, and a thicker section of hydrocarbon bearing sandstones in the upper part of the Lokone Sandstones. Again, poor wellbore conditions did not allow for pressures or fluid samples to be acquired in the Lokone section.

Conventional full diameter cores from the Lower Auwerwer section were acquired in Well Twiga-1, totaling 42 m of core recovered (Table 4-12). An additional 78 m were recovered from the Lokone formation, but this is mainly non-reservoir. This core was analysed extensively through RCA to provide measurements of porosity, permeability, grain density, etc. to guide the petrophysical analysis of the log data acquired. Figure 4-127 is a cross plot of porosity versus permeability data from core taken in the Lower Auwerwer Formation in Well Twiga-1. Figure 4-128 displays petrophysical curves from Well Twiga-1 comparing core and wireline porosity. As Well Twiga-1 was drilled with water-based mud, any Dean-Stark water saturation values would be of little use.

Table 4-12: Conventional core acquired from the Lower Auwerwer and Lokone Formations in the Twiga Field

Well	Core #	Top (m)	Base (m)	Total (m)	Mud	Formation	Facies
Twiga-1	1	1567.3	1580.9	13.7	WBM	Auwerwer	Fluvial Lacustrine
Twiga-1	2	1582.1	1609.9	27.8	WBM	Auwerwer	Fluvial Lacustrine
Twiga-1	4	2513.0	2540.3	27.2	WBM	Lokone SS	Alluvial
Twiga-1	5	2540.6	2565.4	24.9	WBM	Lokone SS	Alluvial
Twiga-1	6	2567.4	2593.8	26.3	WBM	Lokone SS	Alluvial
Total	**5**			**120.0**			

The data acquired in the core analysis and the subsequent petrophysical analysis of the log data was used to define the different facies in the static geological model as well as the primary reservoir components leading to the estimation of resource volumes in the Lower Auwerwer formation in the Twiga Field.

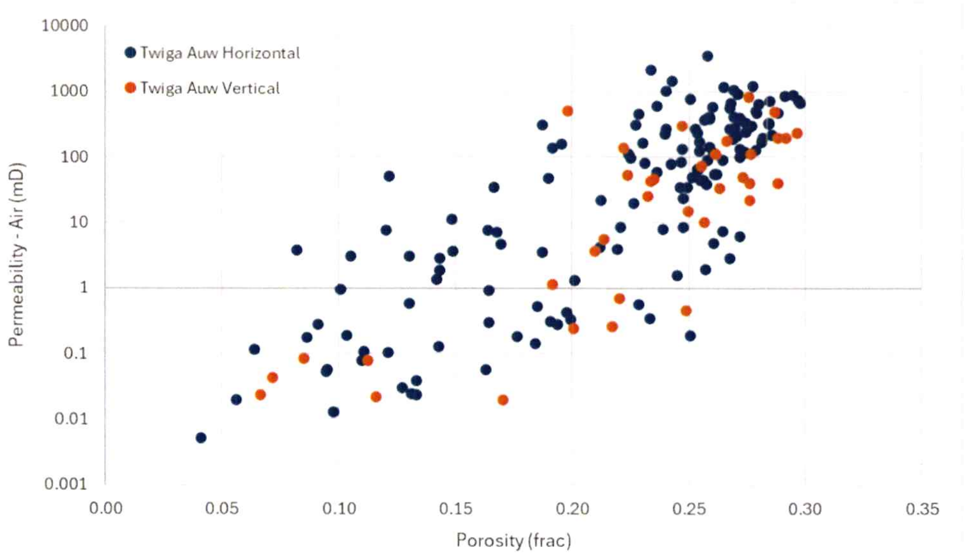
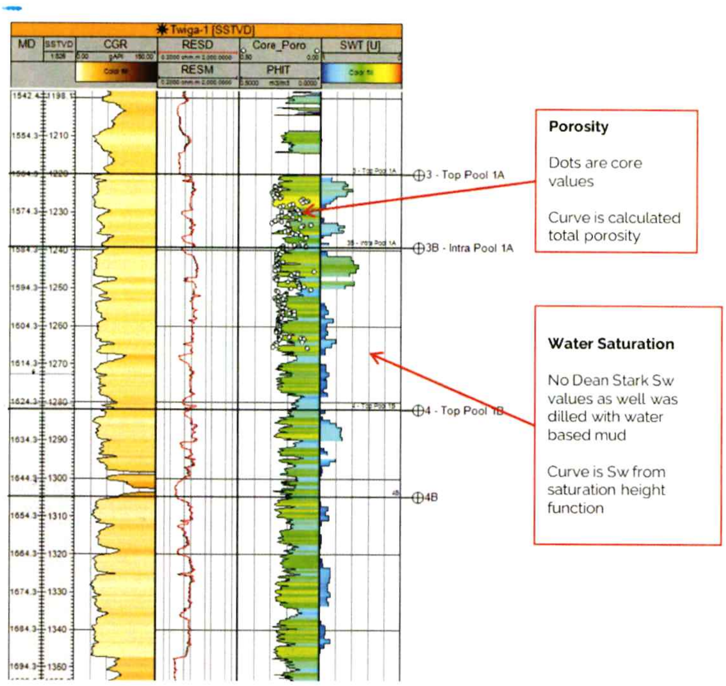


Figure 4-127: Porosity Permeability cross plot of core data from the Well Twiga-1



Porosity

Dots are core values

Curve is calculated total porosity

Water Saturation

No Dean Stark Sw values as well was dilled with water based mud

Curve is Sw from saturation height function

Figure 4-128: Petrophysical display of Well Twiga-1

4.6.3.5 Static Modelling

Grid

A structural grid for the Twiga model combines both Lower Auwerwer and Lokone Formations. The grid has been constructed using six faults and five depth surfaces from the seismic interpretation. The depth surfaces were LKT78 (Top Mid-Auwerwer Shale), Seismic Top Shale 2, Top Pool 3A, LKT 65 (Top Lokone Shale), and LKT60 (Top Lokone Sand). Subzones within the reservoir are generated by isopachs consistent with well tops and the overall reservoir envelope. The faults were used to create three segments in the grid (Figure 4-129). The X and Y grid increment was set at 50 m. The grid is oriented north-south which is parallel to the strike of the Lokichar Fault and thus also to the long axis of the main axial fluvial system.

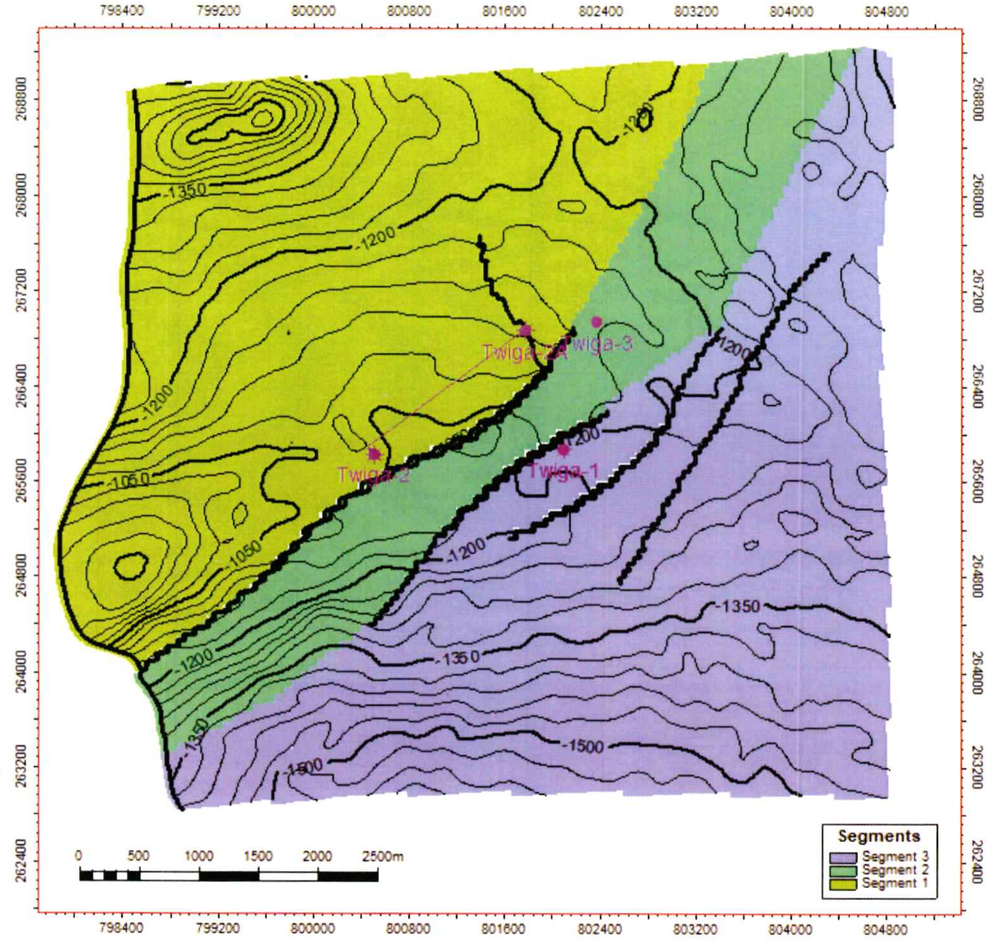


Figure 4-129: Depth structure map at LKT78 showing model segmentation

Zones and Layers

A zonal correlation has been made between all wells drilled in Twiga (Twiga-1, Twiga-2, Twiga-2 (ST) and Twiga-3), which integrates the seismic, log, pressure and sample data. Isochores of the 17 Auwerwer zones identified (8 of which are hydrocarbon bearing) have been used to insert the zones into the 3D structural model (Figure 4-130 and Figure 4-131). The zones have ~1 m proportional layers which are required to effectively capture the vertical heterogeneity observed in the well (and core) logs.

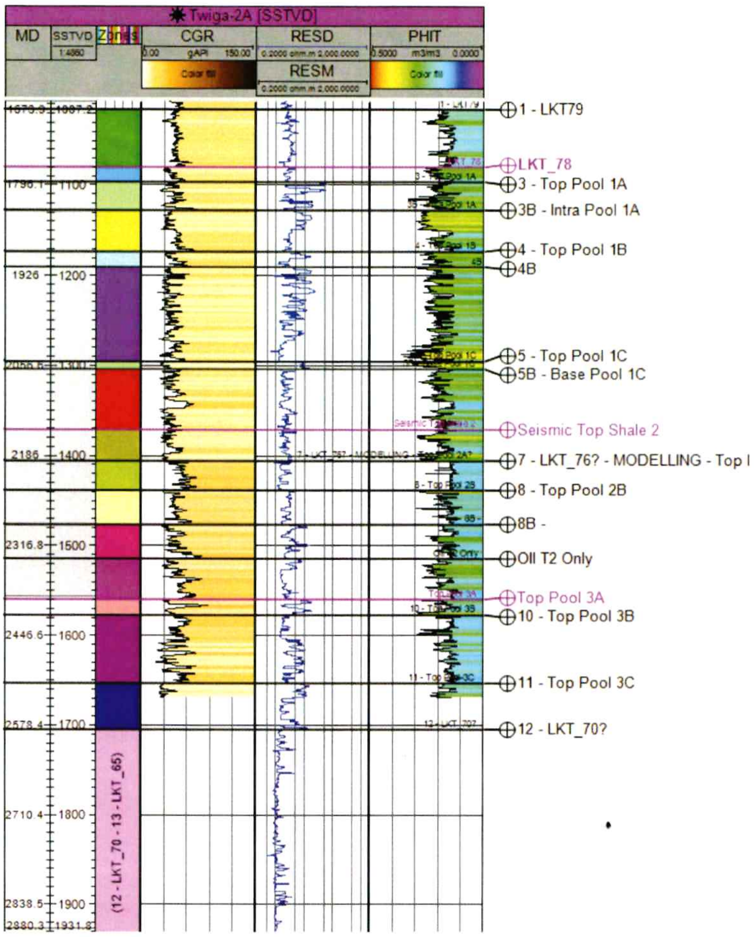


Figure 4-130: Twiga-2A well correlation showing reservoir zonation. NOTE: Pink picks represent seismic picks

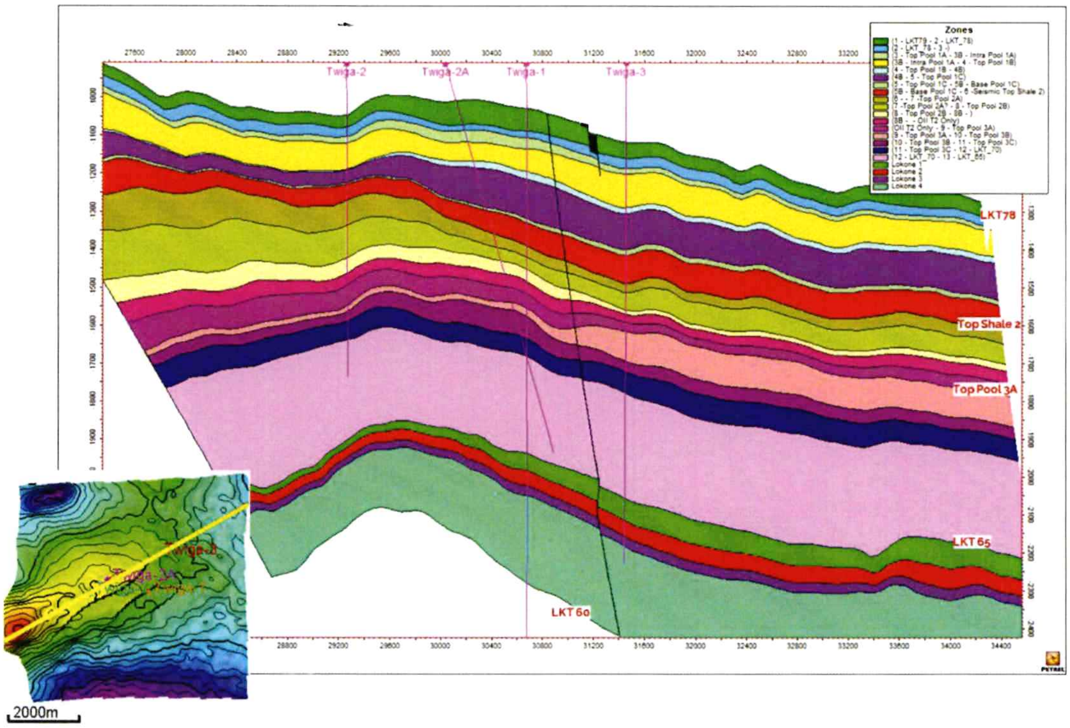


Figure 4-131: Cross section through Twiga model showing reservoir zonation and seismic markers picked (in red text)

Facies

Facies modeling at Twiga utilizes a multi-step approach attempting to best model the interpreted and conceptualized depositional patterns.

The first step is to define the alluvial fan and alluvial plain facies using a fan probability or trend map (Figure 4-132). The alluvial fan facies was penetrated by Well Twiga-2. Next, channel belt bodies (CBB) are distinguished from non-CBB (shale). In the third step, net and non-net sands are distributed within the CBB facies. This is followed by rock type modelling within the CBB net sands. Five net rock types have been defined based on permeability trend. Figure 4-133 illustrates the facies (rock type) property in the model. The Lokone area has also been populated.

The facies model is used a suitable foundation for porosity, permeability, and water saturation modelling

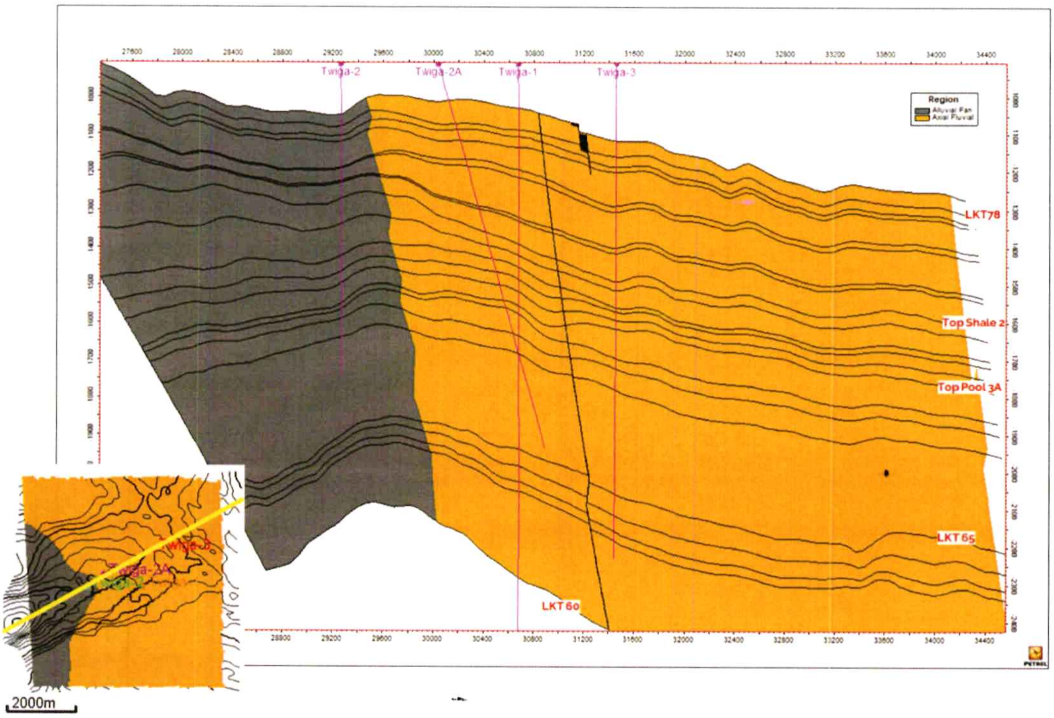


Figure 4-132: Cross section through Twiga model showing alluvial fan and alluvial plain region

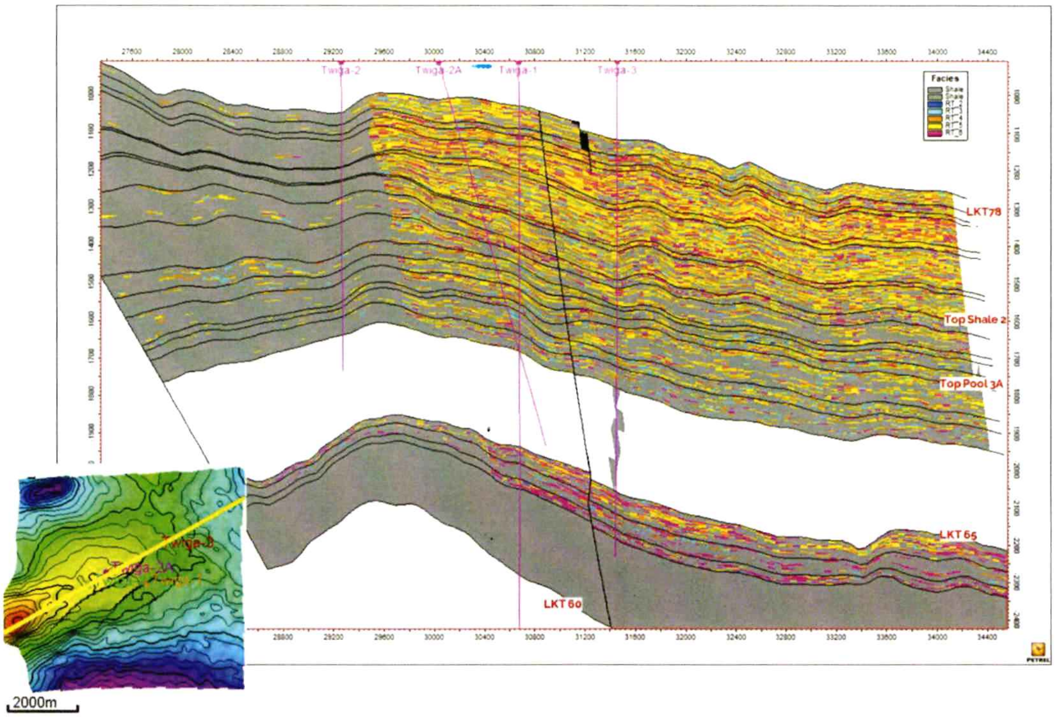


Figure 4-133: Cross section through Twiga model showing rock type

Property Modelling

Total porosity is upscaled from well data and modeled within the rock type property. Gaussian random function simulation is used to generate the porosity model (Figure 4-134).

Permeability has been modelled using available routine core analysis from Twiga wells filtered to Auwerwer interval. Different porosity-permeability function has been used for different rock type, as seen in Figure 4-135.

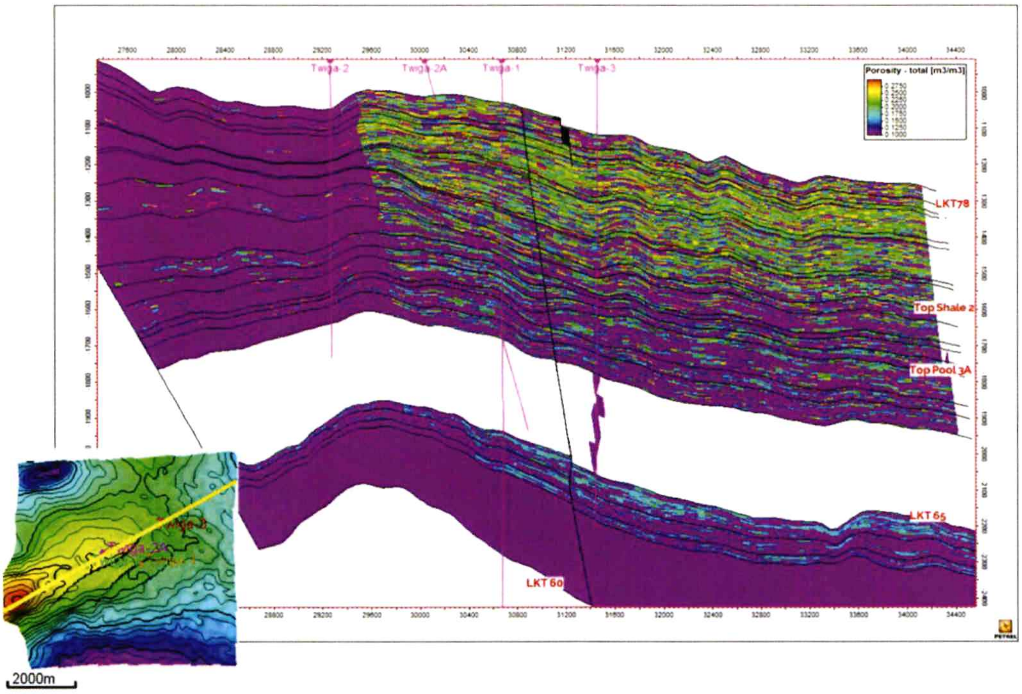


Figure 4-134: Cross section through Twiga model showing porosity distribution

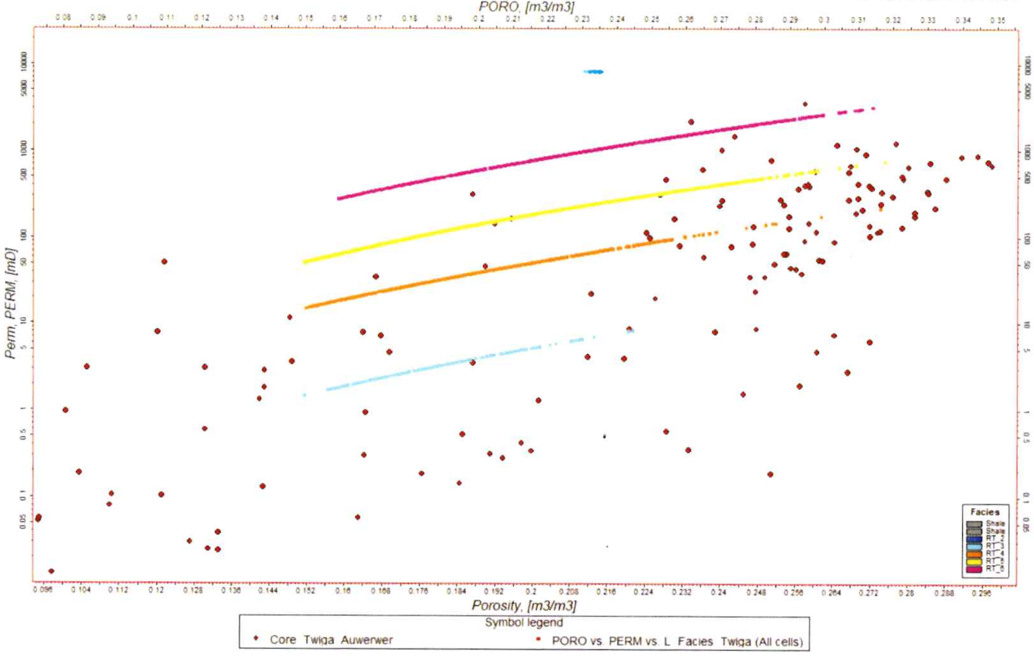


Figure 4-135: Twiga Porosity-Permeability Cross Plot

4.6.3.6 Hydrocarbon Contacts

The Twiga excess pressure plot is shown in Figure 4-136. The Twiga-1 pressures are noisy due to hole conditions and Twiga-2 was predominantly alluvial fan rift edge facies. The acquisition of pressure data across the reservoir section of Twiga-2A was not possible due to hole conditions; Twiga-3 was predominantly wet. There are insufficient data to establish OWCs through the pressure and so contacts were defined by ODTs and WUTs (interpreted from resistivity logs, gas logs, available DSTs, water-cut and sample information) and spill in all cases.

There are seven oil pools (Pools 1A, 1B, 1C, 2A, 2B, 3 and 4). There is ambiguity over the OWC in each oil pool due to significant scatter of the data and the difficulty in identifying a unique water gradient. Oil samples have been recovered from Pools 1, 2 and 3 in Well Twiga-1. There were apparently valid (mobility >5 mD/cp) MDT points obtained in Pools 2 and 3. However, insufficient data are available to corroborate the contacts (oil and water points are in different sand bodies) and so any pressure derived contacts are deemed very uncertain.

Figure 4-133 and Figure 4-134 show the interpreted best estimate hydrocarbon water contacts in the Twiga reservoir on a structural section.

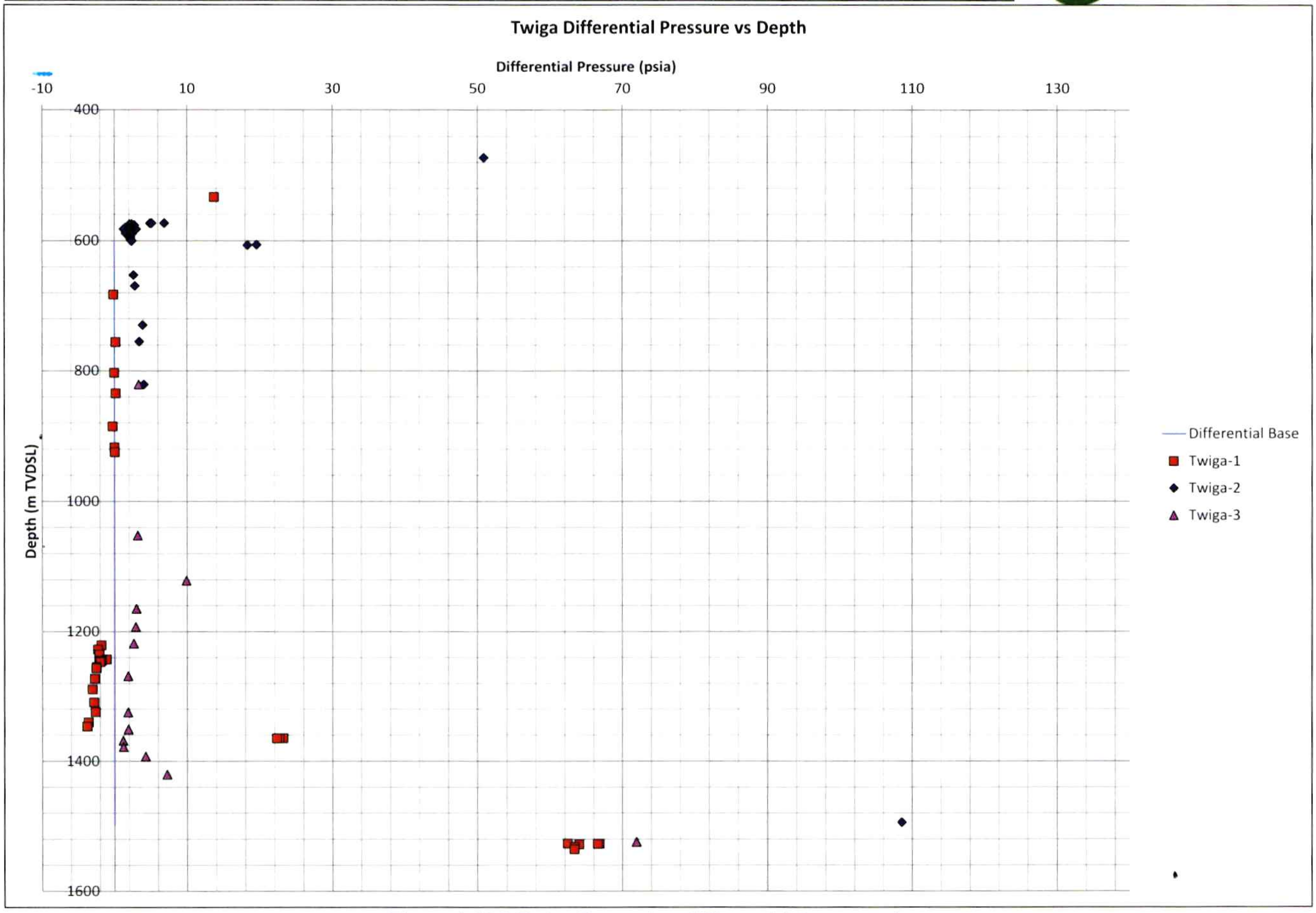


Figure 4-136: Twiga Formation Differential Pressure plot

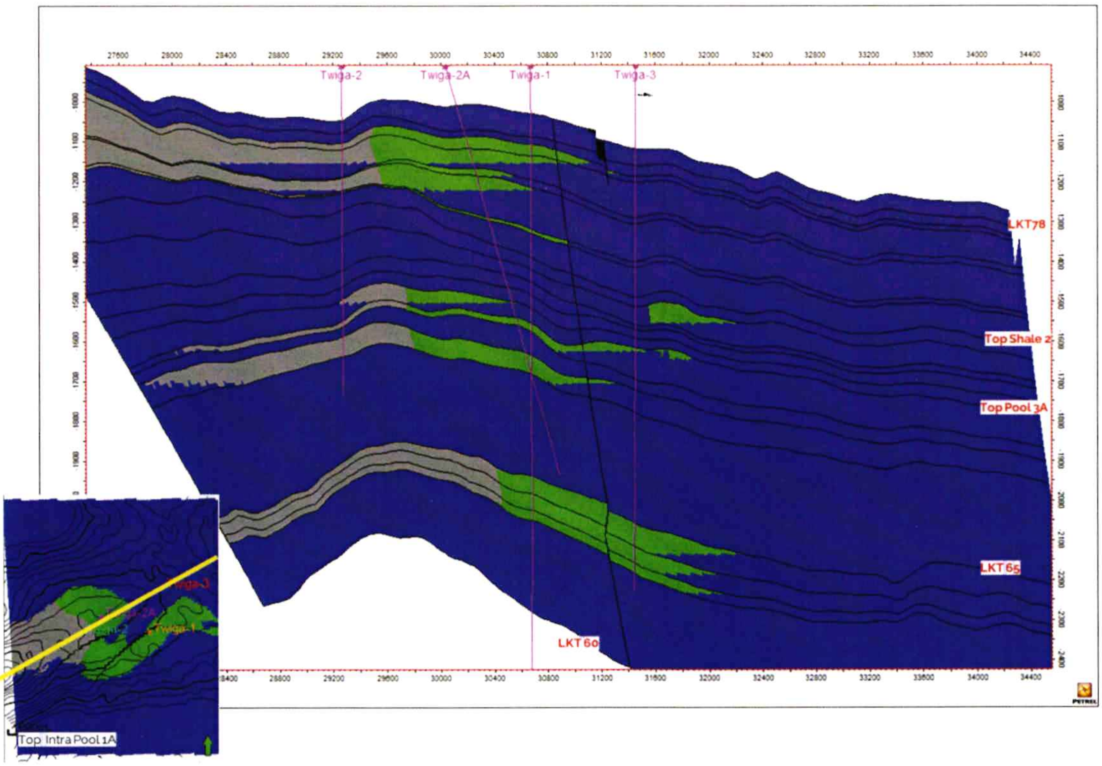


Figure 4-137: Hydrocarbon contacts in North segment of the Twiga Field

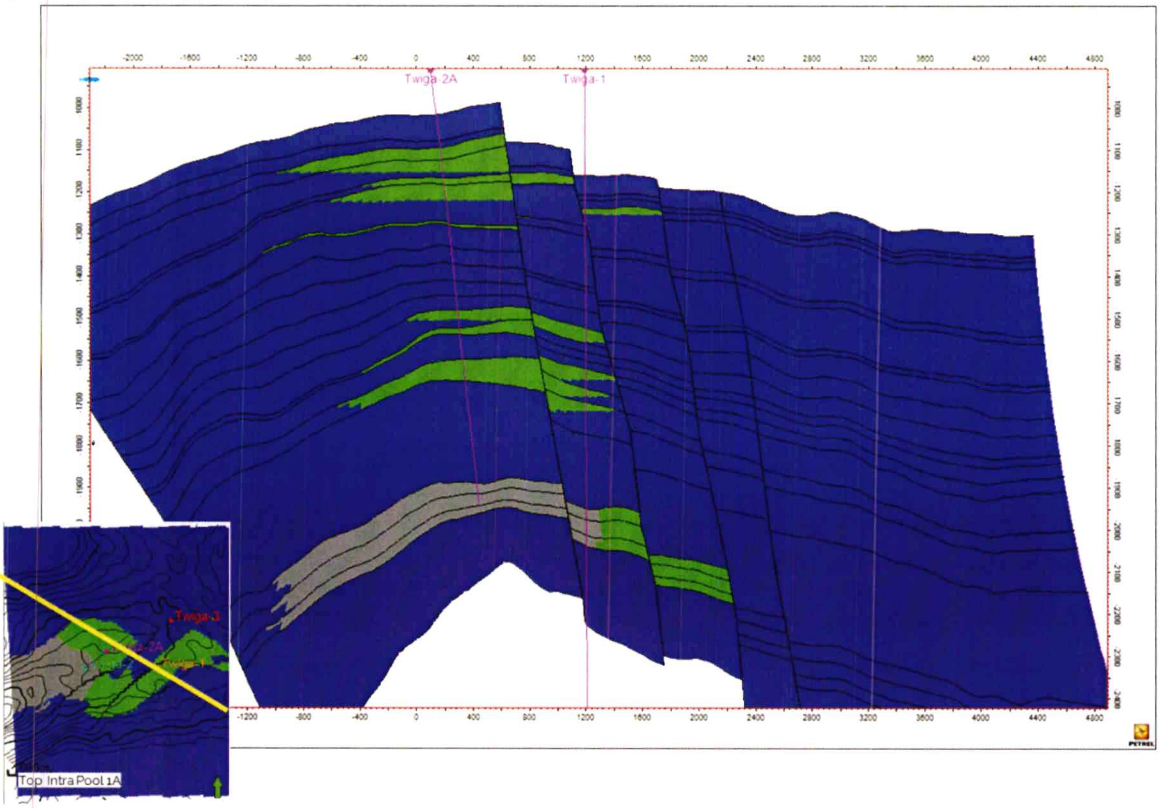


Figure 4-138: Hydrocarbon contacts in North, central and southern segments of the Twiga Field

4.6.3.7 Volumetrics

The Mid case STOIIP value has been calculated using a static model. Low and high case STOIIP values have been estimated using a separate methodology using a statistical approach.

The following table summarizes the field wide volumetrics for the Twiga Auwerwer accumulation.

Table 4-13: Twiga Auwerwer STOIIP

Case	STOIIP (MMSTB)
LOW (1C)	59
MID (2C)	87
HIGH (3C)	170

4.6.3.8 Production Testing

Both Wells Twiga-1 and Twiga-2A have been production tested. Five intervals were produced in Well Twiga-1, with flow to surface achieved in three Auwerwer intervals (Table 4-14). Three Auwerwer intervals were successfully tested in Twiga-2A (Table 4-15); DST#4 was a commingled of the DST#2 and DST#3 intervals. In both wells, good rates were achieved, both in free-flowing condition and lifted by ESP. During all DST operations, there were only slight traces of sand production and no H2S or CO2 were recorded.

Table 4-14: Well Twiga-1 DST Summary

Interval	P.I. (stb/d/psi)	Oil API	Production Rate			PBU Interpretation		
			Oil Rate (bbl/d)	Water Rate (bbl/d)	Liquid Rate (bbl/d)	Permeability (mD)	Kh md.ft	Skin factor, S
DST #1	No flow to surface, no measurable hydrocarbon inflow (Rift Edge Facies)							
DST #2	No flow to surface, hydrocarbons identified on tubing gradient survey (Rift Edge Facies)							
DST #3	10	40	1,860	0	1,860	202	5,960	1
DST #4A	8	37	530	15	545	398	8,360	3
DST #5	12	37	375	0	375	230	5,290	1

Table 4-15: Twiga-2A DST Summary

Interval	P.I. (stb/d/psi)	Oil API	Production Rate			PBU Interpretation		
			Oil Rate (bbl/d)	Water Rate (bbl/d)	Liquid Rate (bbl/d)	Permeability (mD)	Kh md.ft	Skin factor, S
DST #1	0.02	39	12	0	12	3	200	0
DST #2	3.3	39	200	500	700	80	8,550	0
DST #3	8	40	2,500	0	2,500	680	24,200	-1
DST #4	9	37	2,800	700	3,500	398	26,000	0

Water production was seen during Twiga-2A DST #2 and #4, however it is thought that this water is the product of water channeling behind casing. Cement evaluation logs show poor to moderate cement quality and low bond strength across the reservoir. Figure 4-139 shows a reservoir summary log across the DST#2 interval with a qualitative isolation flag in the third track. Cement coverage is incomplete across the tested interval and the potential for water channeling exists.

A production log run during DST#4 indicates the presence of water flowing below the lowest perforations (Figure 4-140). The temperature anomaly, highlighted in the red outline, at the base of the lowest perforation shows the temperature in the wellbore *increasing* at the base of the perforations. This is the result of inflow from below and it is possible to see, in the expanded section of the temperature log, that the wellbore temperature begins to differ to the geothermal gradient because of flow behind the casing.

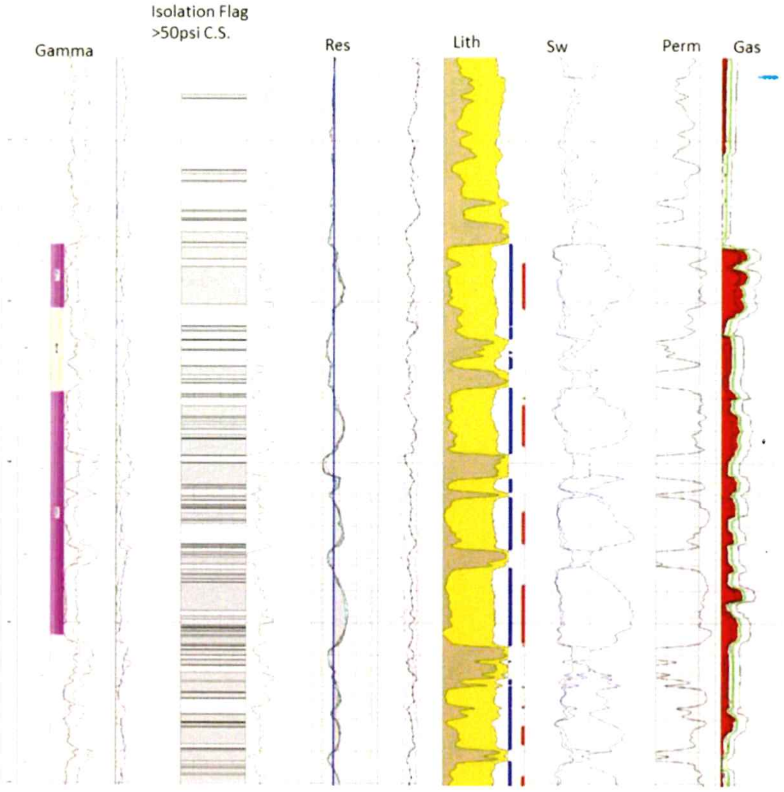


Figure 4-139:Twiga-2A DST#2 Interval Showing Cement Compressive Strength Flag

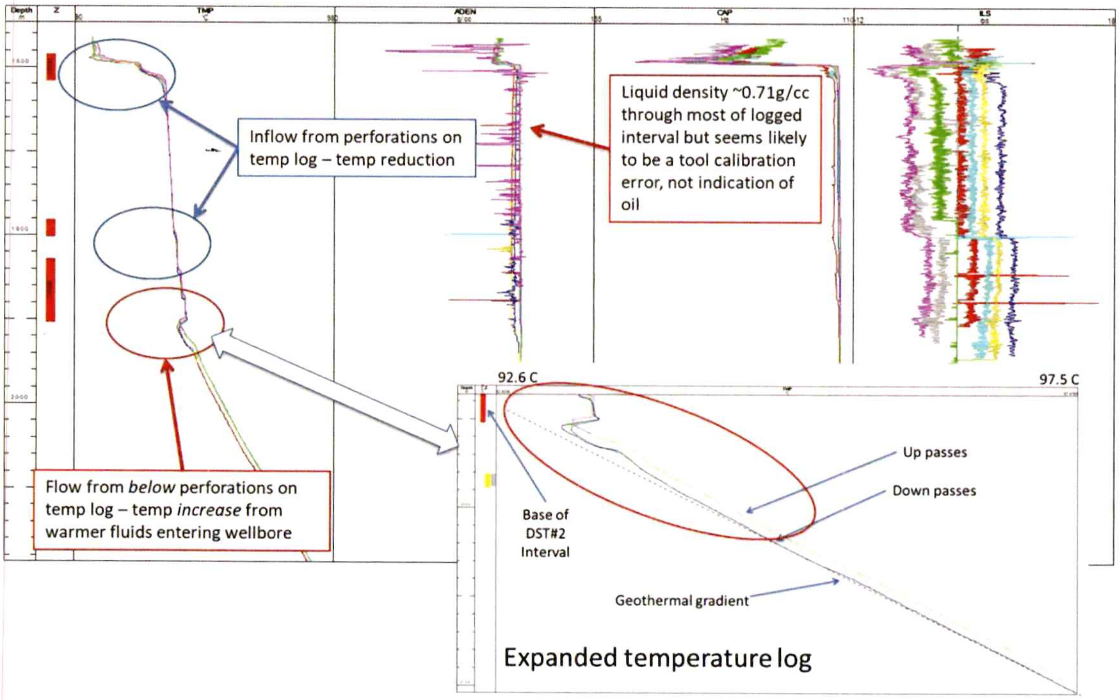


Figure 4-140: Twiga-2A DST#4 PLT Log

4.6.3.9 Fluid Properties

Eleven bottomhole fluid samples were collected from Twiga South-1 prior to completing the well. Of these, six were subsequently combined to create three separate fluid samples for laboratory analysis and a seventh sample was analysed on its own. The samples were subjected to a single stage flash test and reservoir fluid composition analysis only. Three of the resulting fluids represented the primary hydrocarbon bearing Auwerwer zones. The fourth sample was obtained from the Lokone Shale formation.

Table 4-16: Summary of Twiga Fluid Properties

Reservoir Pressure (psia)	Reservoir Temperature (deg C)	Saturation Pressure (psia)	Gas-oil Ratio (scf/stb)	Oil Gravity (deg API)	In-situ Viscosity (cp)	Formation Volume Factor (rb/stb)	Wax Appearance Temperature (deg C)	Wax Content (mol %)	Pour Point (deg C)
2,000-2,700	85 - 115	485 - 2,200	80 - 420	31 - 42	0.5 - 4	1.1 – 1.2	67 – 68	29 - 30	42 - 45

4.6.3.10 Twiga Simulation Modelling

The DSTs from Wells Twiga-1 and Twiga-2A have been used to calibrate the Twiga simulation model prior to production forecasts being run.

As was done for the Ngamia field, core data from Twiga wells were reviewed and a poroperm relationship was derived that corrected from air permeability to liquid permeability and accounted for the effect of the overburden. This poroperm relationship was then used to populate permeability throughout the entire model.

The history matches for Wells Twiga-1 and Twiga-2A are shown in Figure 4-141 and Figure 4-142, respectively.

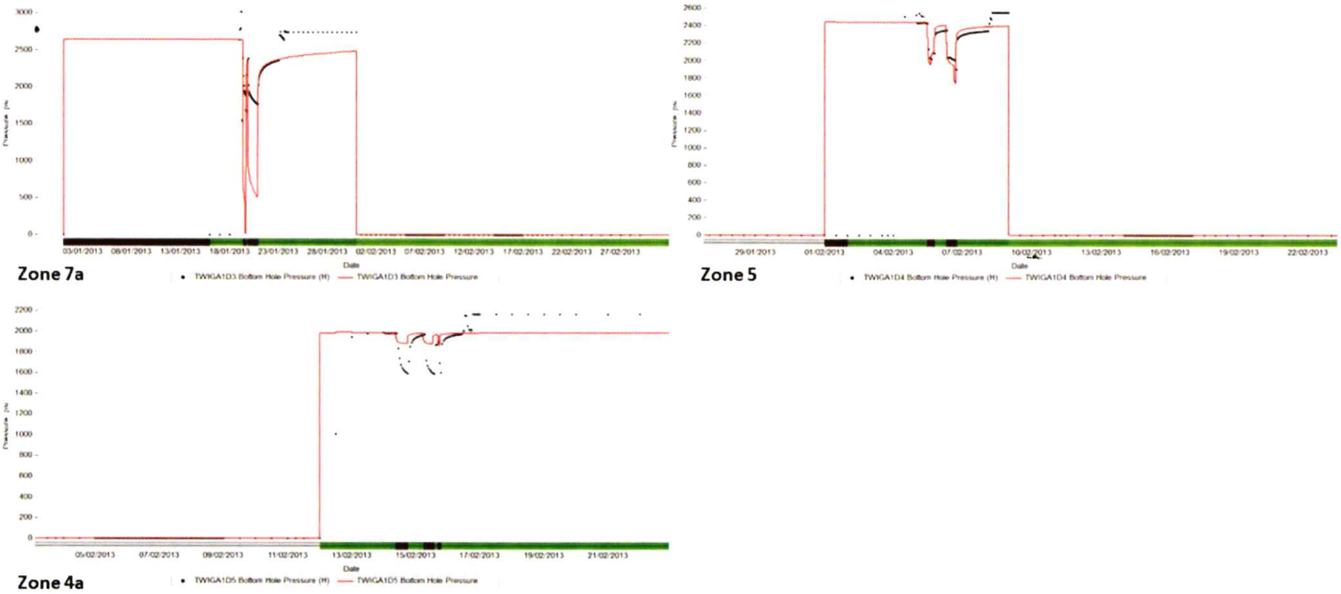


Figure 4-141: DST Observed Pressures and History Match for Well Twiga-1, Zones 4a, 5 and 7

For each of Zones 4a and 7a, contrasting edits would be required to improve the match. The drawdown in Zone 4a is too little, suggesting a lower permeability is required, whereas the drawdown in Zone 7a is too much, suggesting a higher permeability is required. Without making local adjustments it would not be possible to improve the match in both zones, and so no further edits were made. The match to Zone 5 is reasonable.

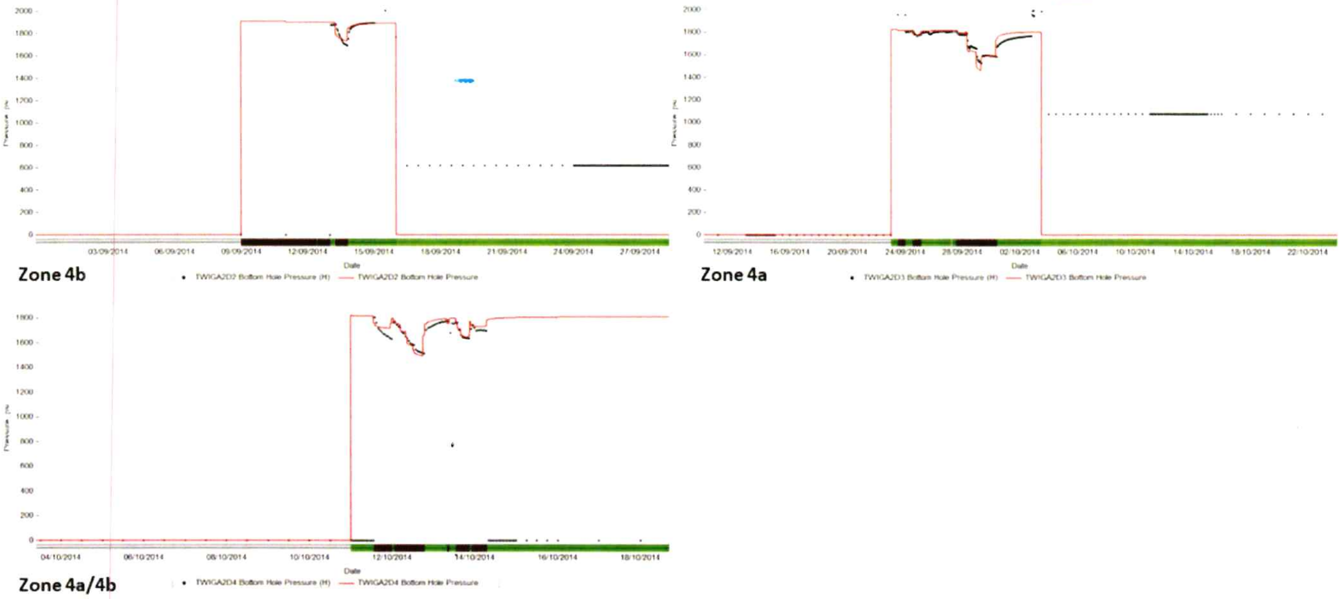


Figure 4-142: DST Observed Pressures and History Match for Well Twiga-2A, Zones 4a, 4b and Commingled from both

The match to all three zones in Well Twiga-2A is reasonable.

All Twiga development wells are associated with Phase 2 and have been placed in the subsurface model to maintain the 200m well spacing and grouped, as far as possible, to be drillable from a 12-slot pad. (Figure 4-143Figure 4-63).

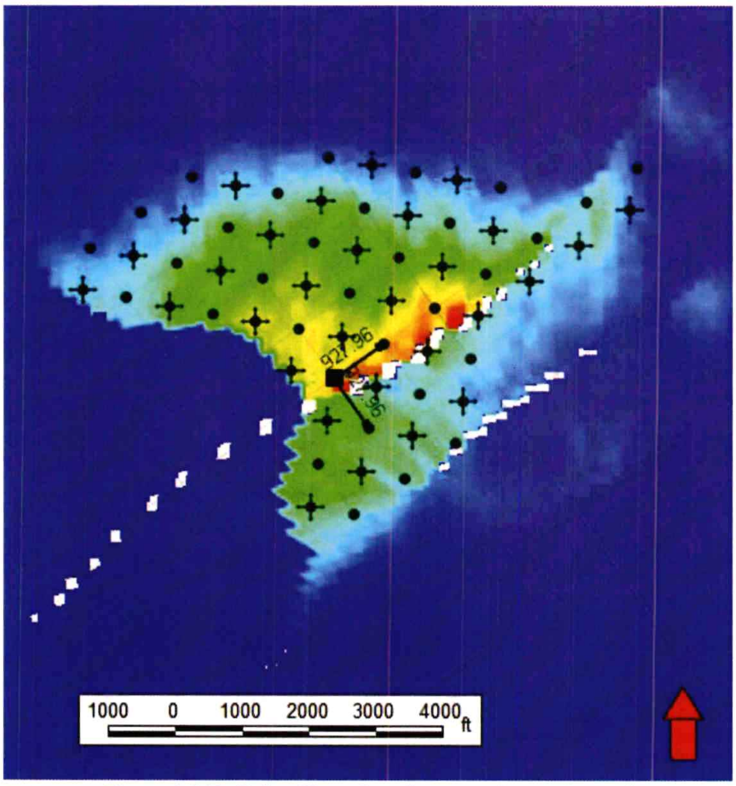


Figure 4-143: Twiga Phase 2 well pattern (map of HCPV)

Phase 2 producers within the simulation grid are perforated in net sand where the water relative permeability is less than 0.001. Water injectors are perforated in the model where they have penetrated net sand.

A maximum liquid production rate of 3,000 b/d and a minimum bottomhole pressure of 44.8 bara (650 psia) were assigned to each producing well, consistent with rates and pressures that can be achieved using the selected artificial lift methods of ESP, PCP and jet pumps. Injection wells were limited to matrix injection with a peak rate of 3,000 b/d with a maximum bottomhole pressure of 2900 psia. Water injection is available at first production and a voidage replacement ratio of 1.0 was maintained within each identified fault block throughout the life of the field.

A limiting surface water cut of 97 percent was used to shut in wells and reduce excess water production during production forecasts. The base forecasts have been created without any downhole interventions to manage water breakthrough. Opportunities to use zonal isolation of producing or injecting intervals are described in Section 6.3. For the Phase 1 part of the forecast the simulation facility limits have been set to match the proposed Early Production Facility capacities. As the model transitions into the phase 2 facility no maximum field liquid or oil production constraints have been specified nor a minimum oil rate to terminate the forecast in the simulation model. Facility constraints and uptimes have been applied as the forecasts are combined with the other fields' forecasts.

All Twiga production wells are expected be completed with ESPs. These are required because of the higher line back pressures prevalent at the Twiga wellpads due to the distance of the field from CPF.

4.6.3.11 Recoverable Resources

GEBV's estimates of total recovery from Twiga have been presented in Table 6-2, Section 6.1.3. These estimates are from a probabilistic calculation based on a recovery factor range of 10% - 17% - 30% with the range established through analogy with the other basin fields reviewing net thickness, fluid properties and reservoir quality.

The Best Estimate recoverable resources associated with the planned Phase 2 wells in Twiga are 12.6 MMstb representing a recovery factor of 14% for the well count presented and the areas of the field developed. Within the license period of 25 years a total of 12.56 MMstb are produced from Twiga, with the remainder being deferred past the end of the license due to combining production with the other basin fields and constraining production through the Phase 2 CPF limits.

4.6.4 Ekales

4.6.4.1 Introduction

The Ekales field was the fourth major discovery of hydrocarbons in the South Lokichar Basin. The main reservoir in the field is the Lower Auwerwer Formation. There is additional potential in the Lokone Formation as encountered in Well Ekales-2, however these resources were not fully evaluated and will require further appraisal before being considered for development.

Well Ekales-1 location was selected on 2D seismic data. The exploration well was drilled to a total depth of 2,554 m MD. The well discovered several hydrocarbon pools in the Lower Auwerwer Formation and was the fourth straight hydrocarbon discovery in the basin. The rig was released from the drilling part of the program on October 14, 2013.

During the drilling of the well, three conventional cores were acquired representing the Lower Auwerwer Formation. Logging while drilling measurements including gamma ray and resistivities were acquired. Conventional wireline logs were acquired at the end of the main hole sections and included a very robust selection of modern log measurements (ref). Further rock samples were acquired through the acquisition of both percussion and rotary sidewall cores. Using a wireline formation testing tool, formation pressures were acquired throughout the well in addition to fluid samples.

Well Ekales-1 was re-entered on January 29, 2014, with the SMP 5 drilling rig to complete a drill stem test program. Two perforated through casing drill stem tests were performed in the well. Both tested zones produced dry oil, with the lower test, DST#1 containing mainly tight alluvial facies and flowed low rates, and the upper test DST#2 containing some higher qualify fluvial sandstones which flowed at much higher rates. These tests will be discussed in more detail in the reservoir engineering section.

To date two appraisal wells have been drilled into the Ekales Field, namely Wells Ekales-2 and Ekales-3. Well Ekales-2 encountered several oil pools in the Lower Auwerwer Formation as well as probable oil deposits in the Lokone Formation based on data acquired during drilling. Well Ekales-2 was fully evaluated through the Lower Auwerwer section with a full wireline suite of logs, rotary sidewall cores as well as reservoir pressure measurements and fluid samples. The well encountered at least 4 oil pools.

Well Ekales-3 was one of the later appraisal wells and was drilled in 2017 to a total depth of 2,721 m MD. While the well penetrated good quality fluvial sandstone units, very little hydrocarbons were encountered with the exception of a thin 3 m oil bearing sandstone at 1923 m MD. The well was plugged and abandoned with the rig released on August 25, 2017.

The Lower Auwerwer oil resources in the Ekales Field are planned to be developed in the second development phase of the South Lokichar Basin. The current range of STOIIP estimates are from a low of 15 MMstb a mid case of 49 MMstb and a high of 164 MMstb. Mid case (P50) STOIIP estimate was based on a statistical distribution between the low (P90) and high (P10) case inputs.

4.6.4.2 Geology

The Ekales-1 discovery lies midway between Twiga South and Ngamia which lie ~10 km along the Lokichar Basin bounding fault to the north and south respectively. The discovery has a very similar structural form to both Twiga South and Ngamia, consisting of a three-way dip closure with updip trap against the prominent basin bounding fault immediately to the west (Figure 4-144).

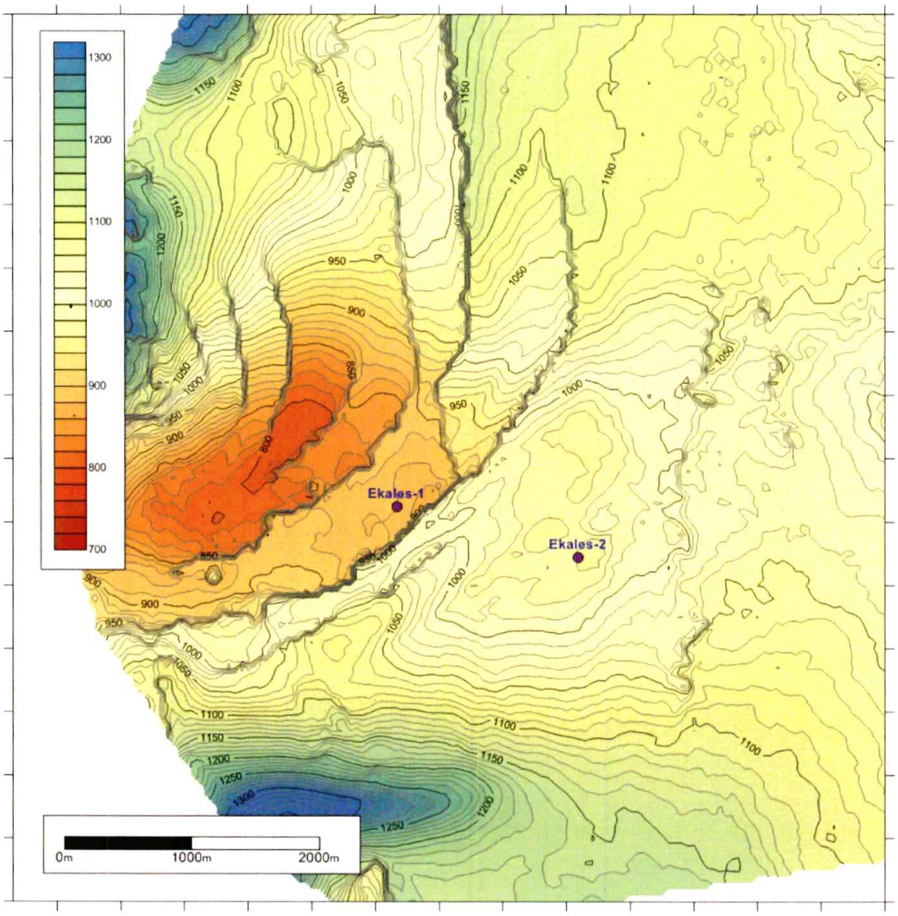
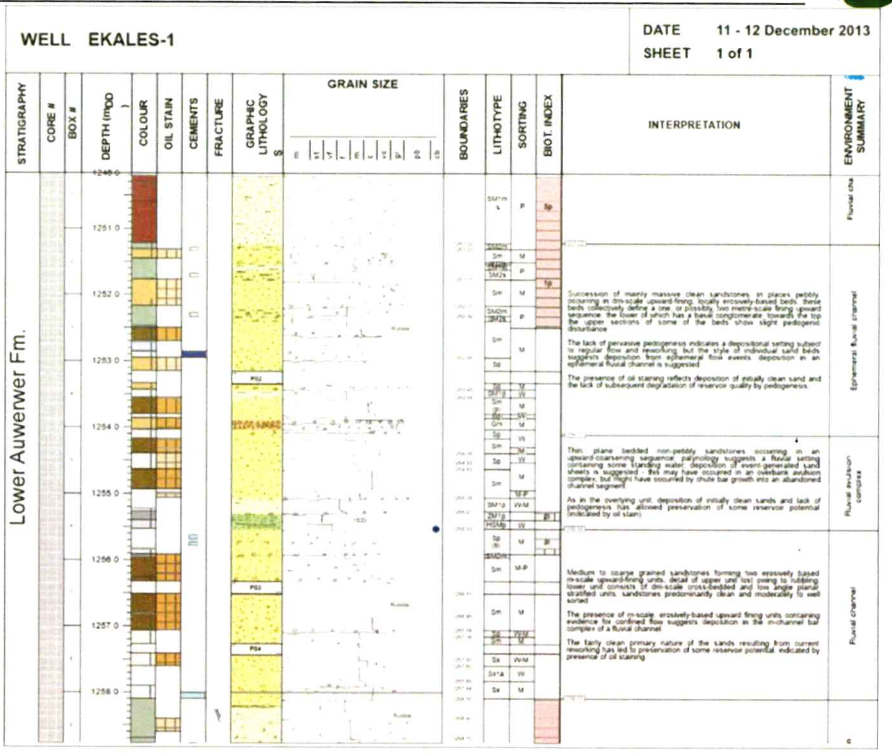


Figure 4-144: Depth Structure map on the Top Lower Auwerwer Formation

The sandstones of the Lower Auwerwer Formation are the main reservoirs in the Ekales Field. These reservoir sandstones are primarily fluvial in origin (Figure 4-145). There is significant evidence of some poorer quality reservoir sandstones thought to be more alluvial in origin close to the main fault systems. The tight alluvial facies is clearly illustrated in the Ekales-1 well where core was acquired in the Lower Auwerwer Formation illustrating interbedded fluvial channel sandstone with good reservoir properties and tight alluvial deposits which are tight and non reservoir (Figure 4-145 and Figure 4-146).

There is some level of structural complexity in the Ekales field with seismically visible faults. Faults both synthetic and antithetic to the basin bounding fault cut through the Lower Auwerwer section. Most of these faults have enough throw on them to provide at least some sealing capacity during production. Over a long period of time, most do not seal, as a large area of the field has similar hydrocarbon contacts and are in communication with the regional aquifer.

Hydrocarbon bearing sandstones within the Lower Auwerwer Sandstone are individually sealed by laterally extensive mudstones or tight alluvial deposits within the sequence. The ultimate top seal to all the hydrocarbon discoveries is provided by the Mid Auwerwer Shale at the base of the Upper Auwerwer Sandstone. Hydrocarbons were also discovered in the Lokone Formation sandstones, however, due to deteriorating hole conditions, no wireline data was acquired.



Succession of mainly massive clean sandstones, in places pebbly, occurring in dm-scale upward-fining, locally erosively-based beds; these beds collectively define a one, or possibly two metre-scale fining upward sequence, the lower of which has a basal conglomerate; towards the top the upper sections of some of the beds show slight pedogenic disturbance

The lack of pervasive pedogenesis indicates a depositional setting subject to regular flow and reworking, but the style of individual sand beds suggests deposition from ephemeral flow events: deposition in an ephemeral fluvial channel is suggested

The presence of oil staining reflects deposition of initially clean sand and the lack of subsequent degradation of reservoir quality by pedogenesis

Thin, plane bedded non-pebbly sandstones occurring in an upward-coarsening sequence; palynology suggests a fluvial setting containing some standing water; deposition of event-generated sand sheets is suggested - this may have occurred in an overbank avulsion complex, but might have occurred by chute bar growth into an abandoned channel segment

As in the overlying unit, deposition of initially clean sands and lack of pedogenesis has allowed preservation of some reservoir potential (indicated by oil stain)

Medium to coarse grained sandstones forming two erosively based m-scale upward-fining units; detail of upper unit lost owing to rubbling; lower unit consists of dm-scale cross-bedded and low angle planar stratified units; sandstones predominantly clean and moderately to well sorted

The presence of m-scale, erosively-based upward fining units containing evidence for confined flow suggests deposition in the in-channel bar complex of a fluvial channel

The fairly clean primary nature of the sands resulting from current reworking has led to preservation of some reservoir potential, indicated by presence of oil staining

Figure 4-145: Core description of oil filled fluvial channel deposits interbedded with tight alluvial deposits in core from Ekales-1

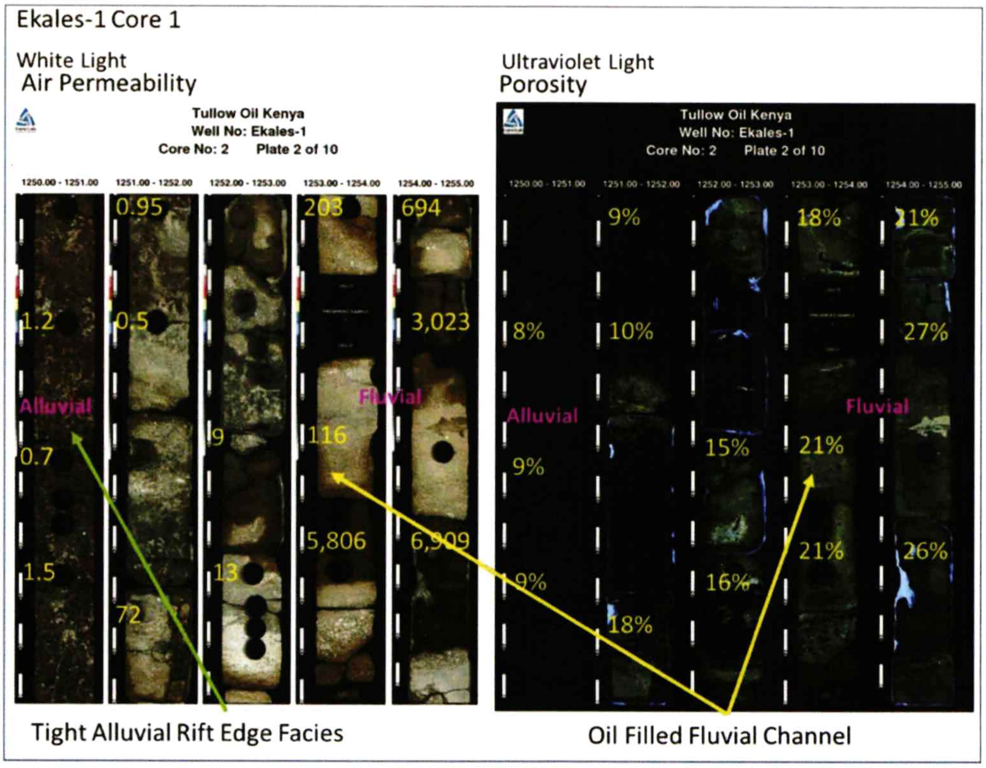


Figure 4-146: Core photographs of oil filled fluvial channel deposits capped by non reservoir rift edge facies in the Ekales-1 well

4.6.4.3 Geophysics

The RAP PreSTM 3D data volume was used to map the three key markers for the Lower Auwerwer Formation over Ekales. The three markers mapped are LKT80, LKT70 and LKT65. All three markers are good quality picks over the Ekales field on the RAP PreSTM 3D data volume.

Seismic line through Wells Ekales-1 and -2 indicates that the Ekales discovery is a 3-way dip closure with an updip trap against the prominent basin bounding fault immediately to the west (Figure 4-147).

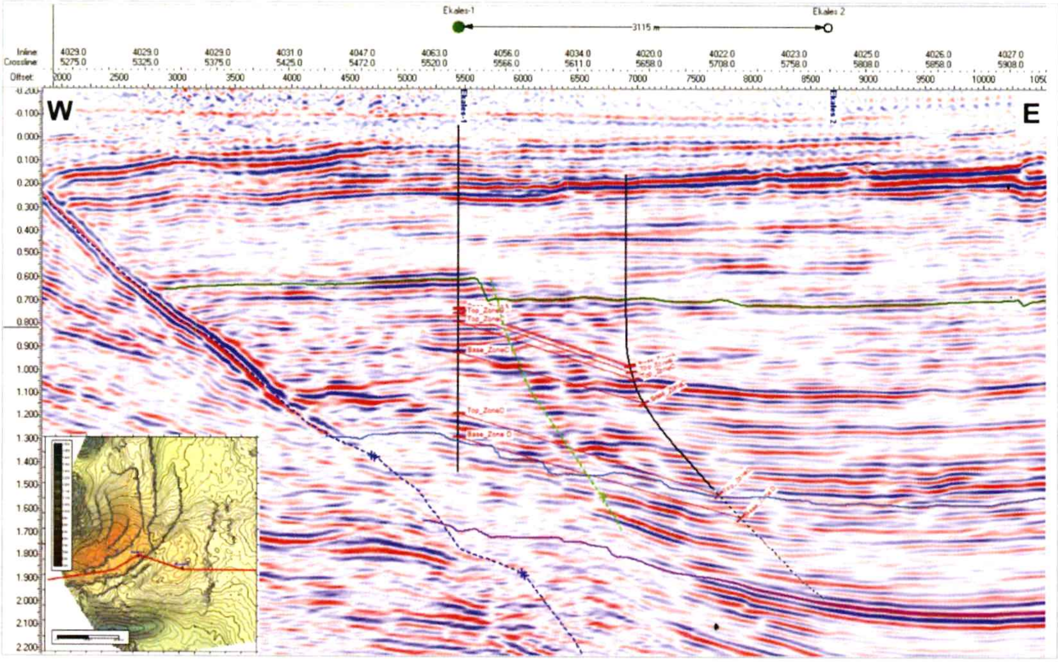


Figure 4-147: Arbitrary dip line through Wells Ekales-1 and -2 (3D PreSTM TWT)

The three TWT grids were depth converted with a low and high degree of compaction and both resulting sets of maps were tied to formation top picks.

4.6.4.4 Petrophysics

Shale volume (Vsh) is calculated from neutron/density, or gamma ray (GR) if there is a bad hole. It is calibrated to XRD total clay measurements using a Vcl to Vsh ratio of 55%. Total porosity is calculated from density, and is calibrated to core porosity. Water saturation (Sw) is calculated using both Waxman Smits and Indonesian equations to put a wider range on volumetric estimates to better account for uncertainty in saturation. A CPI of Ekales-2 can be seen in Figure 4-148.

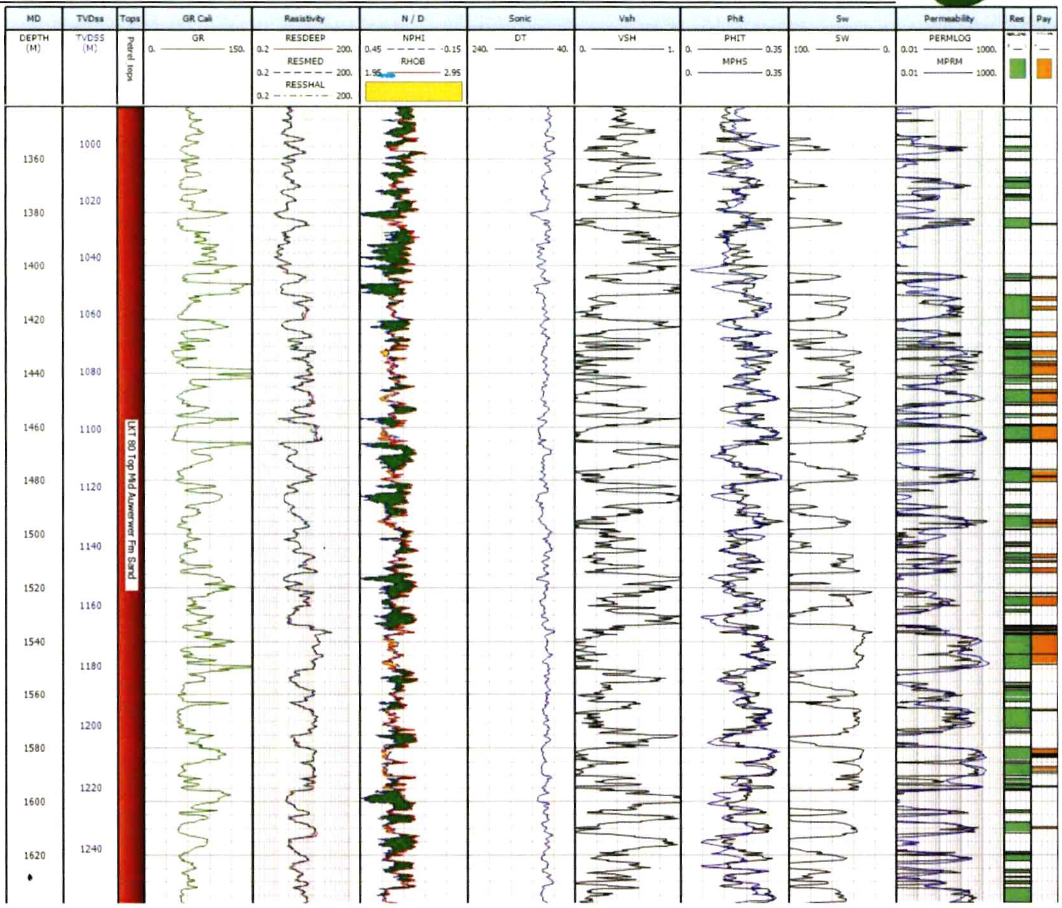


Figure 4-148: Ekales-2 CPI

Conventional full diameter cores from the Lower Auwerwer section were acquired in the Ekales-1 well, totaling 37 m of core recovered (Table 4-17). This core was analysed extensively through RCA to provide measurements of porosity, permeability, grain density, etc. to guide the petrophysical analysis of the log data acquired. Figure 4-149 is a porosity versus permeability cross plot of data from the analysed Ekales-1 core data.

Table 4-17: Conventional core acquired from the Lower Auwerwer and Lokone Formations in the Ekales Field

Well	Core #	Top (m)	Base (m)	Total (m)	Mud	Formation	Facies
Ekales - 1	1	1,248	1,249.0	1	WBM	Auwerwer	Fluvial Lacustrine
Ekales - 1	2	1,250	1,276.5	26	WBM	Auwerwer	Fluvial Lacustrine
Ekales - 1	3	2,114	2,123.5	9	WBM	Lokone Shale	Alluvial
Total	3			37			

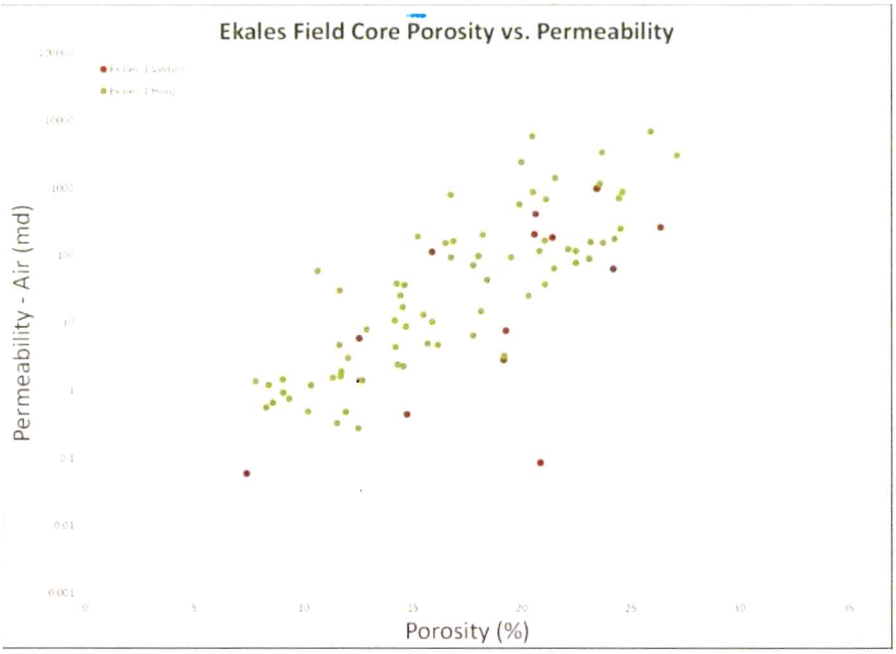


Figure 4-149: Porosity Permeability cross plot for Core data from the Ekales Field

4.6.4.5 Hydrocarbon Contacts

Zonation based on log data has been developed and rationalized against sample and pressure data.

Pay zones have been grouped into four separate oil-bearing intervals: Zone A, B, C, and D (Figure 4-150). Petrophysical analysis, pressure analysis and fluid samples imply that Zones B, C & D comprise several individual stacked units and not a single continuous oil column.

Figure 4-151 shows the MDT pressures taken in Well Ekales-1 in Zone B. The oil and water samples and the results of the PLT-log run in Well Ekales-1 during DST2 are also shown in this figure. All pressures (oil and water) are elevated above the water pressure line seen in other zones, which might be indicative of a perched zone. Given the good mobilities of the pressure samples, the pressures do not deviate away from the water gradient as would be expected if Zone B consisted of a single continuous oil column. Instead, the small deviations in pressure are consistent with a thin bedded, stacked pay model. Furthermore, the results of the Ekales-1 DST2 PLT run which show high initial water-cut in each measured interval, are also consistent with a series of discrete pressure isolated sands. The DST tests results (average rates) from Well Ekales-1 are summarised in Table 4-18.

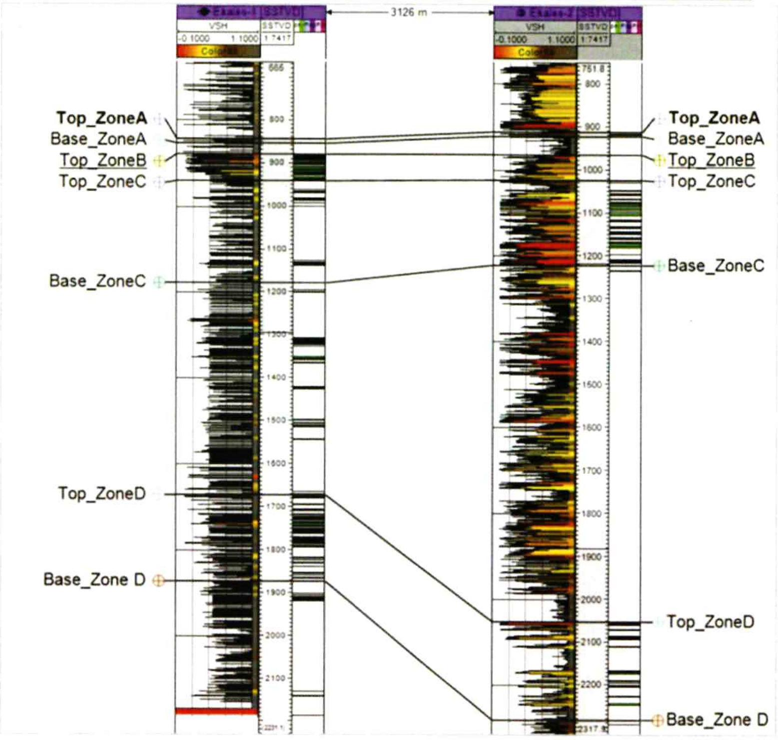
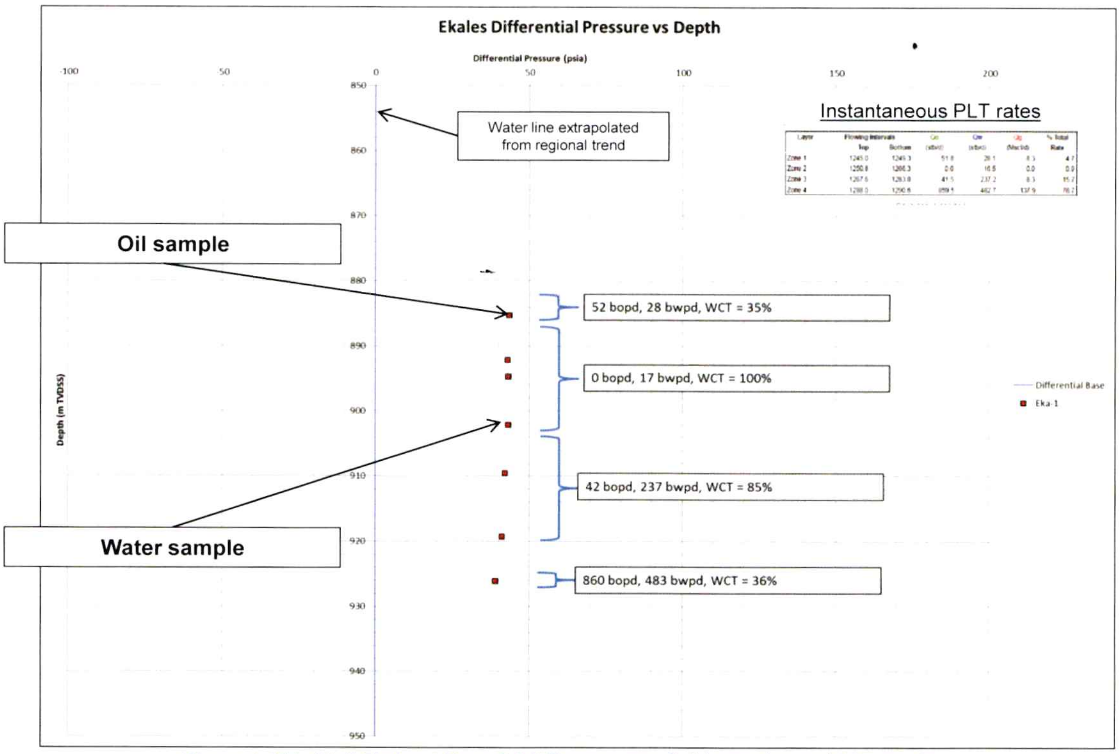


Figure 4-150: Pay Zonation in shown in Wells Ekales-1 and -2 Correlation



Layer	Flowing Intervals Top	Flowing Intervals Bottom	Qo (stb/d)	Qw (stb/d)	Qg (Mscf/d)	% Total Rate
Zone 1	1245.0	1249.3	51.8	28.1	8.3	4.7
Zone 2	1250.8	1266.3	0.0	16.5	0.0	0.9
Zone 3	1267.6	1283.8	41.5	237.2	8.3	15.7
Zone 4	1288.0	1290.6	859.5	482.7	137.9	78.7

Figure 4-151: Well Ekales-1 Zone B MDT pressures, fluid samples and DST results

Table 4-18: Well Ekales-1 DST results

Well	DST	Testing Interval (m)	Avg Oil Rate (STB/D)	Water Rate (BOWD)	GOR	PI (bbl/d/psi)	Drawdown (psi)	Artificial Lift
Ekales-1	DST #1A	2035 - 2155	50	No flow	235.5	0.03	1650	HRP pump
Ekales-1	DST #2	1243 - 1300	500	7.4	6.2	6.2	80.6	ESP

DST#2, which flowed oil at a water cut of ~50 %, has shown high productivity sands, although the PLT log indicated a major contribution from three meters at the base of the perforated interval and also water influx from shallower levels. These observations support the interpretation that the interval comprises thin, stacked sands.

DST#1A has shown a very poor influx, considerably lower than the pre-DST estimate. The results are consistent with MDT sampling in that the tested section has no valid MDT data (tight or no seal between 2038 and 2140 m MDrkb).

Figure 4-152 shows the MDT pressures taken in Wells Ekales-1 and Ekales-2 in Zone C. The water line is reasonably well constrained by water samples from Wells Ekales-1 and 2. Again, the pressures do not deviate away from the water gradient as would be expected if Zone C consisted of a single continuous oil column. However, oil samples have been taken which implies multiple stacked pay. Assuming a degree of uncertainty in the water line, maximum and minimum column thicknesses have been calculated for the stacked units and used for net rock volume (NRV) calculations described in Section 4.6.4.6.

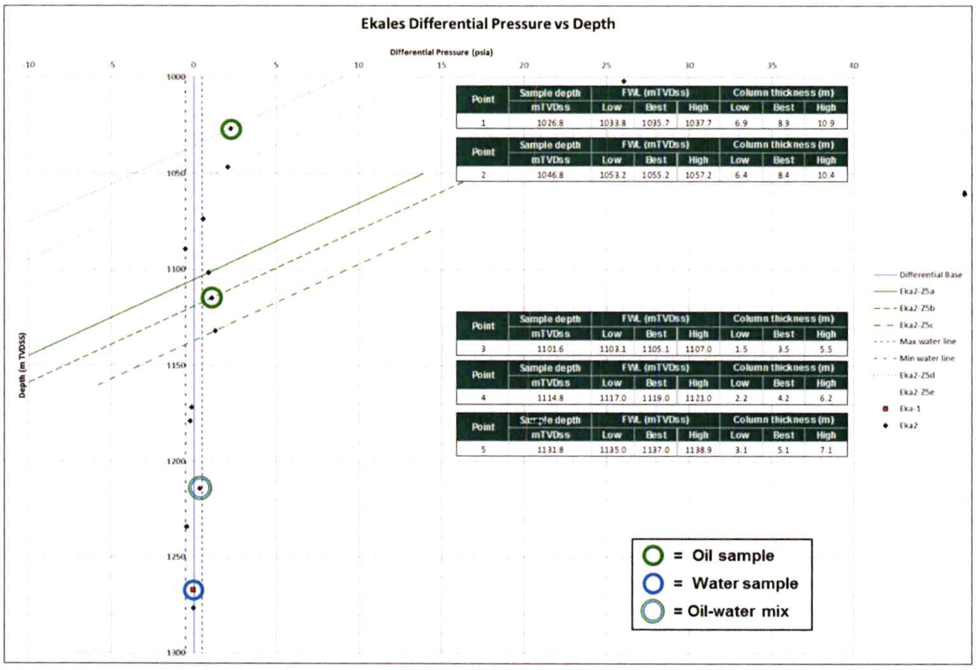


Figure 4-152: Ekales-1 & -2 Zone C MDT pressures, fluid samples and column thicknesses*

** 10 mD/cP mobility cut-off applied*

4.6.4.6 Volumetrics

Remaining consistent with the assumption of a thin bedded stacked pay model (described in Section 4.6.4.6), the general approach applied in each zone was the use of a combination of pressure and petrophysical data to estimate the range of possible column heights within the stacked units.

This range of penetrated column heights was then used to compute low and high case areal extents for the thin bedded stacked pay intervals. These areas were multiplied deterministically by petrophysically derived low and high case net values in order to compute a lognormally distributed NRV range.

An example set of low and high case height above maps used for deriving areas are shown in Figure 4-153.

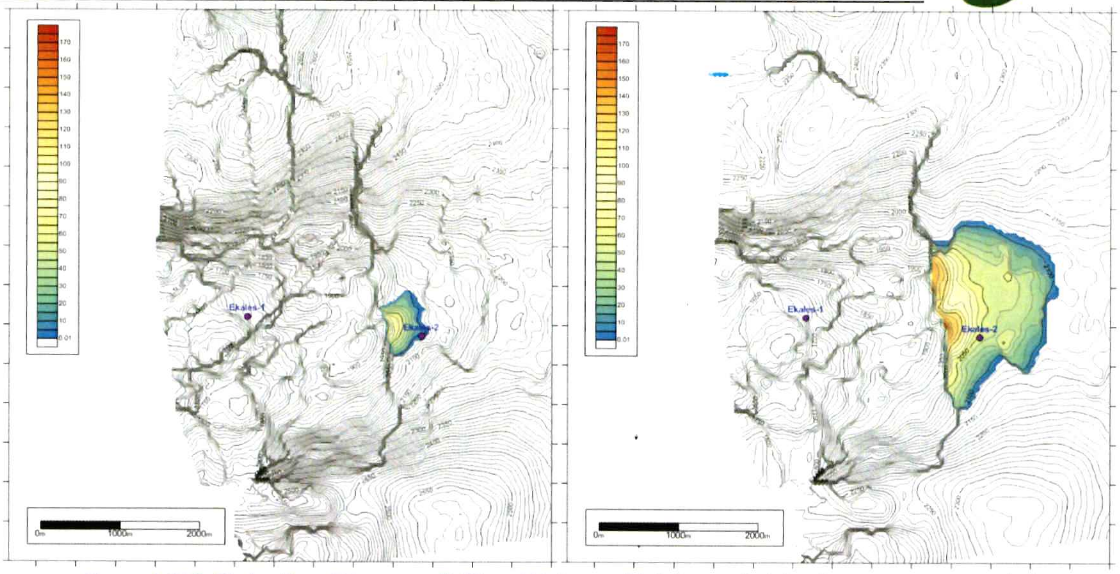


Figure 4-153: Ekales Zone D low case (left) and high case (right) gross height above contact maps (m)

The volumetric input parameters are presented in Table 4-19. STOIIP resulted from probabilistic simulation is shown in Table 4-20.

Table 4-19: Ekales STOIIP Input Parameters

Reservoir	NRV (MMm3)			Porosity (frac.)			Sh (frac.)			Bo (frac.)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Zone_A	0.5	1.6	5.2	0.23	0.24	0.24	0.40	0.51	0.65	1.10	1.13	1.17
Zone_B	7.6	17.7	41.3	0.18	0.20	0.21	0.40	0.51	0.65	1.10	1.13	1.17
Zone_C	13.0	40.0	123.0	0.23	0.24	0.24	0.40	0.51	0.65	1.10	1.13	1.17
Zone_D	5.0	22.6	102.0	0.16	0.18	0.20	0.40	0.51	0.65	1.10	1.13	1.17

Table 4-20: Ekales STOIIP

Reservoir	STOIIP (MMstb)			
	1C	2C	3C	Mean
Zone A	0.3	1.1	3.5	1.7
Zone B	4.0	9.8	23.6	12.4
Zone C	8.4	26.6	83.9	39.7
Zone D	2.5	11.5	53.0	23.4
Total	15.2	48.8	164.0	77.2

4.6.4.7 Production Testing

Two Lower Auwerwer production tests were conducted on Ekales-1. The first DST tested 15m of net pay in a 120m gross section of thin interbedded Lower Auwerwer sandstones and flowed around 25 bbl/d oil. The well cleaned up to zero water production but flow was intermittent, and rates were estimated based on tank levels as the separator meter rates were erratic.

The second DST tested a 26m of net pay in a 57m gross interval of high-quality channel sands. DST#2 tested at oil rates up to 1,090 bbl/d with an ESP but with variable water cut, ranging from 0.5% to 80% during the initial well clean-up period. A PLT run during the DST suffered from poor data quality with the density tool malfunctioning during the test that gave no indication of water in the well bore. Cement evaluation suggests channeling behind casing is not the source of any water. The final water cut stabilised around 50% but the production log run during the test was not definitive in identifying either oil or water inflow intervals.

Table 4-21: Ekales DST Summary

Interval	P.I. (stb/d/psi)	Oil Gravity (API)	Production Rate Oil Rate (stb/d)	Water Rate (stb/d)	Liquid Rate (stb/d)	PBU Interpretation Permeability (mD)	Kh (md/ft)	Skin Factor
DST #1A	0.05	n/a	25	0	25	2	80	-1
DST #2	6.5	23-29	1090	1090	2180	340	29,000	0

4.6.4.8 Fluid Properties

Six pressurized bottomhole oil samples were collected from Ekales-1, four using a wireline formation tester during open hole logging and two during the Ekales-2 DST #2. One of the downhole DST samples was subject to extensive PVT analysis. Additional separator, dead oil and water samples were taken, and these were used to perform detailed wax property measurements.

Table 4-22: Summary of Ekales Fluid Properties

Reservoir Pressure (psia)	Reservoir Temperature (deg C)	Saturation Pressure (psia)	Gas-oil Ratio (scf/stb)	Oil Gravity (deg API)	In-situ Viscosity (cp)	Formation Volume Factor (rb/stb)	Wax Appearance Temperature (deg C)	Wax Content (mol %)	Pour Point (deg C)
600 – 2,100	56 - 89	1,160	80 - 420	23-29	5	1.2 – 1.3	60 - 61	28	33 - 39

4.6.4.9 Recoverable Volumes and Production Forecasting

A dynamic simulation model has not been constructed at this stage for Ekales. Recoverable resource volumes have been estimated probabilistically including recovery factors in the Monte Carlo STOIIP calculations (Section 4.6.4.6). The recovery factor range used for Ekales is 10 – 17 – 30% across the low, mid and high range of confidence.

Table 4-23:Ekales STOIIP and Recoverable Resources

Discovery	Reservoir	STOIIP (MMstb)			Gross Recoverable Resources (MMstb)		
		Low	Best	High	1C	2C	3C
Ekales	Auwerwer	15	49	164	2.3	8.5	32

Ekales production forecasts have been generated based on estimates of recovery per well and type curves with initial production rates and decline parameters.

The well count has been developed by dividing the area covering the HCPV of the field by the pattern area of a 200m well spacing (0.08 km2) and assuming a 1:1 producer:injector ratio from an inverted 5-spot pattern. The recoverable volume per producer is then estimated by dividing the recoverable resource volume by the number of production wells. For Ekales, a recoverable volume of 0.33 MMstb per production well is assumed and 26 producer and 26 injection wells are planned.

Initial production rates for the production wells have been guided by trends of rate vs hydrocarbon pore thickness from the available simulation models and also trends of initial rate vs 2C resource per well. Decline curve parameters (for both oil and water) have then been derived from trends based on wells of similar net thickness and recoverable volume from the available simulation model results. A full field forecast is built based on the drilling schedule planned. These are combined with the other field forecasts (with simulation and type well forecasts). On a monthly basis the sum of the unconstrained production rates is calculated and the current system constraint (oil, water or gas) established. Production is then cut to honour the limit which is being exceeded by the largest amount. This calculation method is consistent with commercial software such as Petro VR.

It is noted that this methodology allows for the total probabilistically estimated resources to be recovered, however, the well count is potentially conservative. A similar calculation for Ngamia, for example, suggests that 442 wells total would be required, however the simulation model is using 216. Similarly, the Amosing areal methodology would suggest 160 wells compared to 104 planned in the simulator. Gulf is planning to refine the well count through further simulation ahead of executing Phase 2 guided by the results of the Phase 1 drilling and early production.

4.6.5 Etom

4.6.5.1 Introduction

The Etom discovery lies in Block 13T of Kenya, south of Lake Turkana (Figure 4-154). Well Etom-1 was drilled in mid-2014, the eighteenth well drilled in the Lokichar basin onshore Kenya. The well found 10m of net pay in the Lokone sands of Tertiary age. Well Etom-2 was completed in December 2015. The well was drilled to a final depth of 1,655 m MDRKB and encountered approximately 100 m of net oil pay in two sand packages in the Auwerwer and Lokone formations.

Wells Emekuya-1 and Etom-3 were drilled during the 2016-2017 Exploration and Appraisal Campaign. Emekuya-1 encountered a good quality oil-bearing Lokone section (greater than 108m) with a N/G of approximately 50%. Etom-3 encountered poor reservoir throughout the Lokone oil Zone, with a N/G of less than 5%.

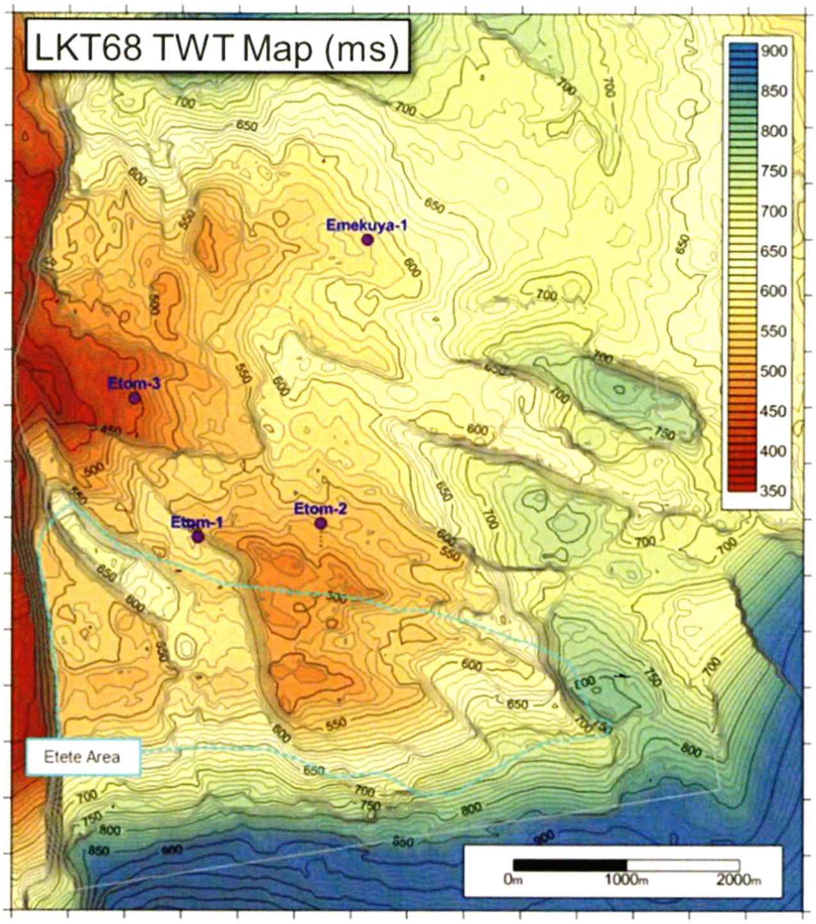


Figure 4-154: Etom LKT68 TWT Map (ms)

4.6.5.2 Geology

Etom is the northern most discovery to have been found in the South Lokichar Basin, it is located 8km of a major bend of the Lokichar Fault and approximately 6km NE of the major NW-SE Agete Fault (Figure *4-155*). Movement on this fault throughout the Miocene has led to the creation of a four-way-roll-over-feature at the Etom location, at both the Lokone and Auwerwer levels.

The Etom structure is interpreted as a three-way dip closure against the main bounding fault at the northern end of the Lokichar basin. Although a clear structural high could be mapped at the time of drilling Etom-1, the detail and fault configuration to the west was somewhat uncertain on the 2D data available.

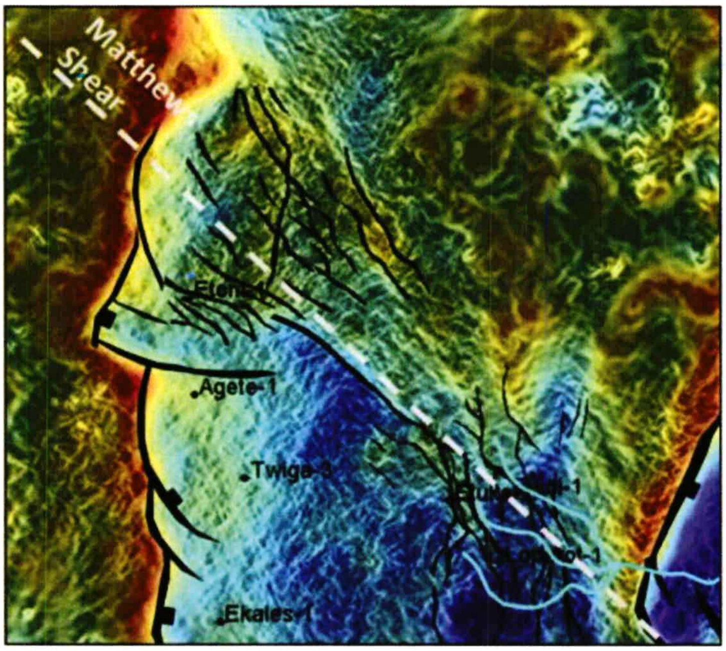


Figure 4-155: Location of Etom in northern part of the South Lokichar Basin

Three wells have been drilled which have targeted this roll over structure. Etom 1 drilled into the graben in the centre of the structure. The Etom-1 well encountered approximately 10 metres of net oil pay, extending the proven oil basin significantly northwards. The well discovered oil from MDT sampling in a sandstone interval near the top of the Lokone Formation (Pool 2) between depths 710 m and 740 m TVDsl. Well Etom 2 was planned on a new 3D seismic dataset and was drilled approximately 1 km east of Well Etom-1. The target was the footwall of a tilted fault block that exhibited gas peaks in Well Etom-1.

Well Etom-2 encountered a continuous hydrocarbon column at the crest of this fault block, with a contact encountered and ~45 m net pay in the Auwerwer. A deeper fault block with a similar trapping mechanism was also encountered in the Lokone interval, which contained ~55 m net pay within slightly lower quality interbedded sands and shales. MDT pressure and sample data were obtained from the upper and lower reservoirs. Both reservoirs are dip closed to the north and appear to rely on faults for updip trap and side seal. Well Etom-2 penetrates a section of blocky sandstone reservoirs of good reservoir quality.

Well Emekuya-1 proves the oil-bearing Lokone interval to be laterally extensive to the north. Sand porosities are interpreted to be around 21%. 54m of core was taken and multiple oil / water samples and MDT pressures. A deeper contact was encountered than that interpreted in Wells Etom-1 and -2 to the south.

A Lokone waste zone is interpreted between the Lokone Shale and Lokone Reservoir in Etom-1, Etom-2 And Emekuya-1.

The poor quality Lokone interval encountered by Well Etom-3 has been interpreted to be alluvial fan in origin, having been deposited off the basin bounding fault lying approximately 1 km west.

4.6.5.3 Geophysics

The Etom area is covered by good quality 3D PreSTM RAP seismic data (Figure 4-156). Reflector continuity and fault plane imaging is clearer across the Etom area than over the majority of discoveries further south. As there is uncertainty in the seismic, several interpretations of the depth surfaces are possible. For the purposes of this FDP, one set of seismic interpretation in time has been adopted, the difficulties of mapping key horizons south of Amosing and Ngamia has been built into the uncertainty in the volumetric approach where hydrocarbons in place are estimated.

Historical depth conversion studies have explored depth uncertainty of these interpreted horizons using several approaches including altering V0 grids, scaling seismic velocities and using TDR-based surfaces. GRV uncertainty from these methods varies by < +/-15% reflecting the good degree of depth control provided by the four well penetrations.

There are difficulties in closing the structure to the NE when using the deeper contact encountered in Well Emekuya-1. As such, the final depth maps used in volumetric estimation for the Etom structure have been created using an isochron vs isopach down to Auwerwer and a mapped V0 from Auwerwer to Lokone layer 2 methodology. A correction for potential faster material to the east of Etom was also applied, allowing closure to the NE.

It should be noted it is likely some throw exists along the interpreted fault south of Well Etom-2, given the throw in the overburden and change in seismic character. Given the differences in contact observed in the discovery wells, it is possible that the Etete area is not in charge communication with Well Etom-2.

A Lokone waste zone (non-net reservoir between the top seal and top reservoir pick) is interpreted between the Lokone Shale and Lokone Reservoir in Etom-1, Etom-2 And Emekuya-1. This is modelled in the depth conversion using an isochore that has been added to the top reservoir in all volumetric cases.

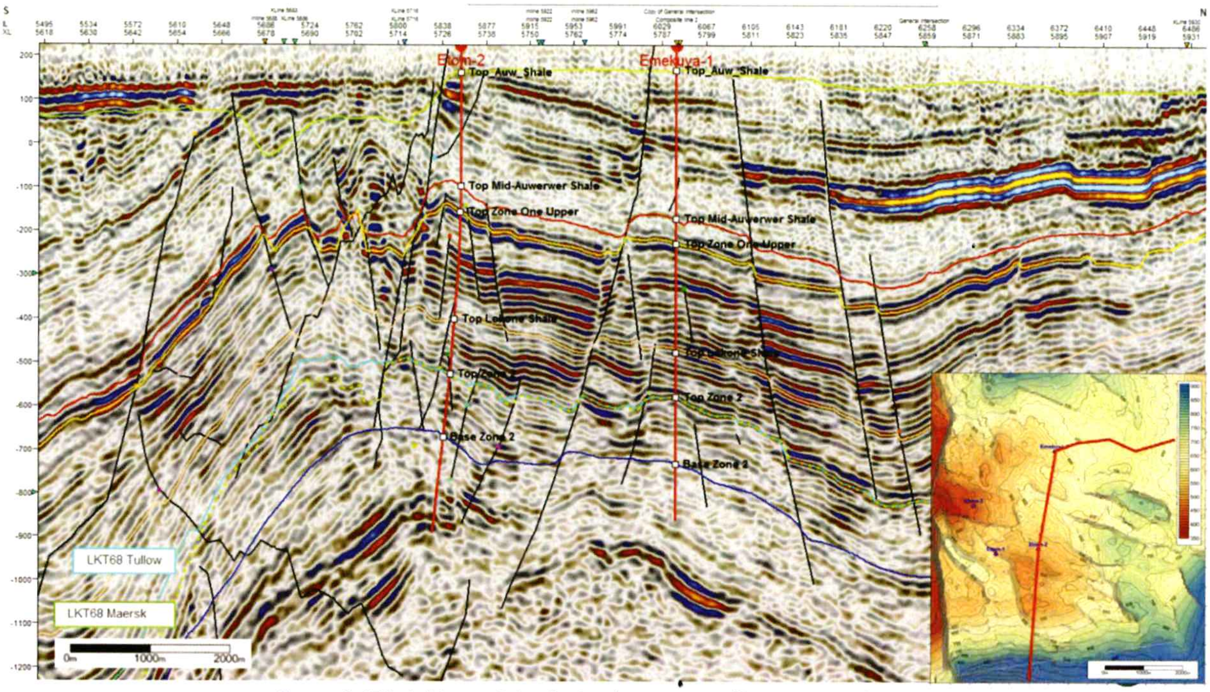


Figure 4-156: Arbitrary Seismic Line between Wells Etom-1 and Etom-2

4.6.5.4 Petrophysics

See Section 4.4 for a detailed overview of the petrophysical analysis workflow.

There is no conventional core from well Etom-1 although sidewall cores were collected.

There is conventional core on Emekuya-1, and side wall cores on all wells. Unfortunately, there is very limited SCAL data. Petrophysical cut-offs of 15% porosity and 35% Vsh and 65% Sw were used for Etom-Emekuya. As previously mentioned, the reservoirs in Kenya are fresh water, with high shale conductivity, so have low contrast pay and are non-Archie. For this reason, there is a high uncertainty associated with log-based Sw. Future modelling would likely use a saturation height function to model Sw, as seen in Amosing, Ngamia and Twiga.

CPI's of Etom-1 and Emekuya-1 can be seen in Figure 4-157 and Figure 4-158.

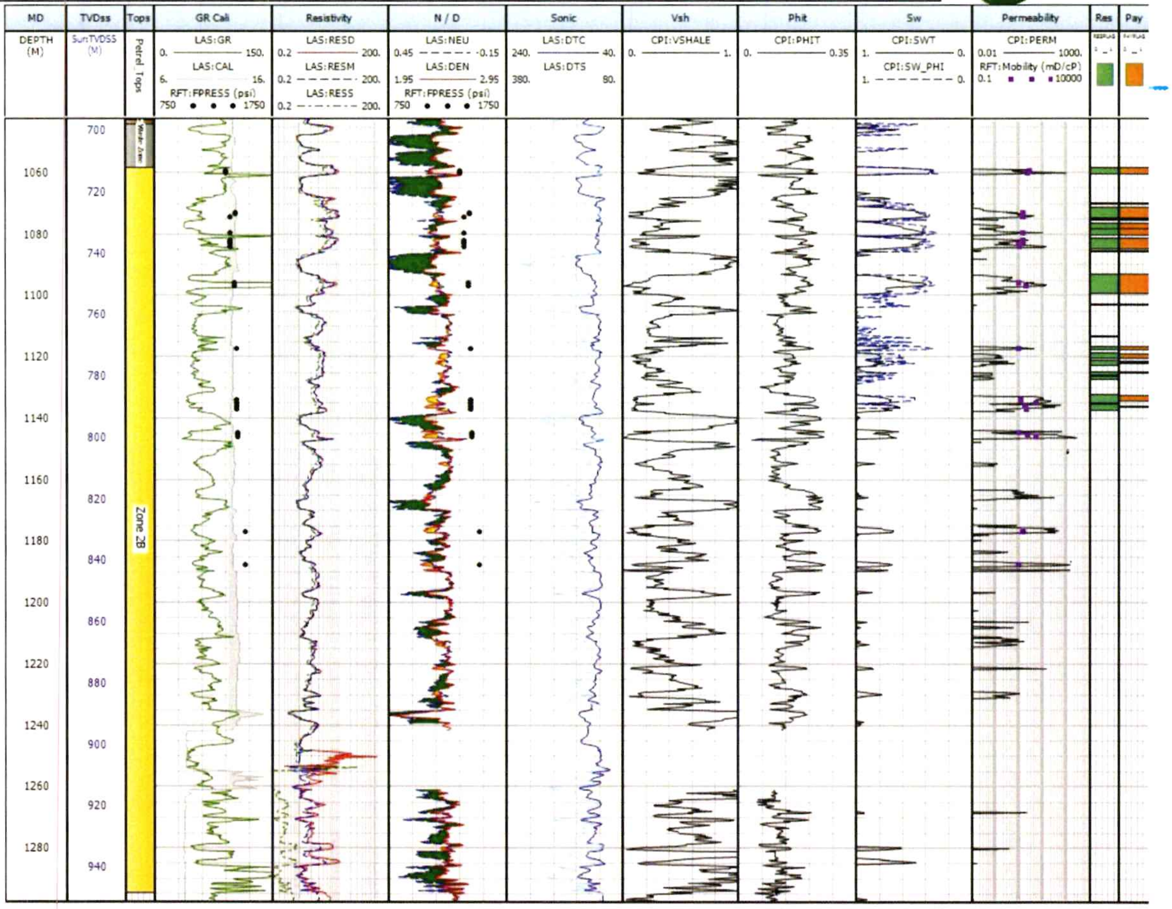


Figure 4-157: Etom-1 CPI

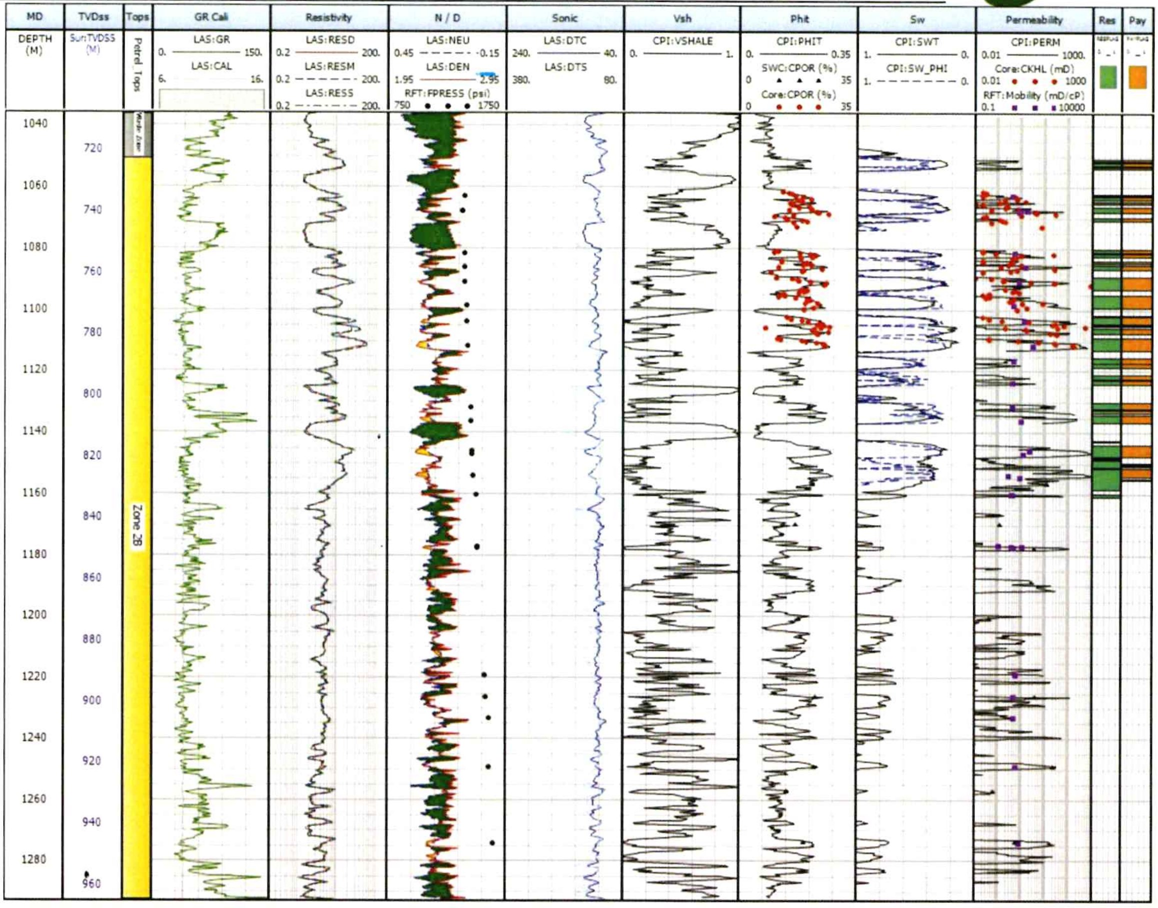


Figure 4-158: Emekuya-1 CPI

4.6.5.5 Hydrocarbon contacts

Figure 4-159 and Figure 4-160 show the excess pressure plots of formation pressure data acquired in Etom and Emekuya, Lokone interval.

The MDT logging runs in Well Etom-1 (approximately half of the total 44 pre-tests were valid) measured pressures which had a high degree of scatter and no clear identification of oil gradients was possible based on this well only.

MDT tests taken in Well Etom-2 provided additional points for gradient interpretations. However, for this well, only pressures taken on the downward pass have been included and only pressure points considered to be of good quality (as opposed to 'tight' or 'lost seal') in the raw data have been included.

Points taken in Emekuya show a clear pressure differential when compared to Etom-2 points, this is in line with the deeper logged contact and sample data obtained in Etom-2.

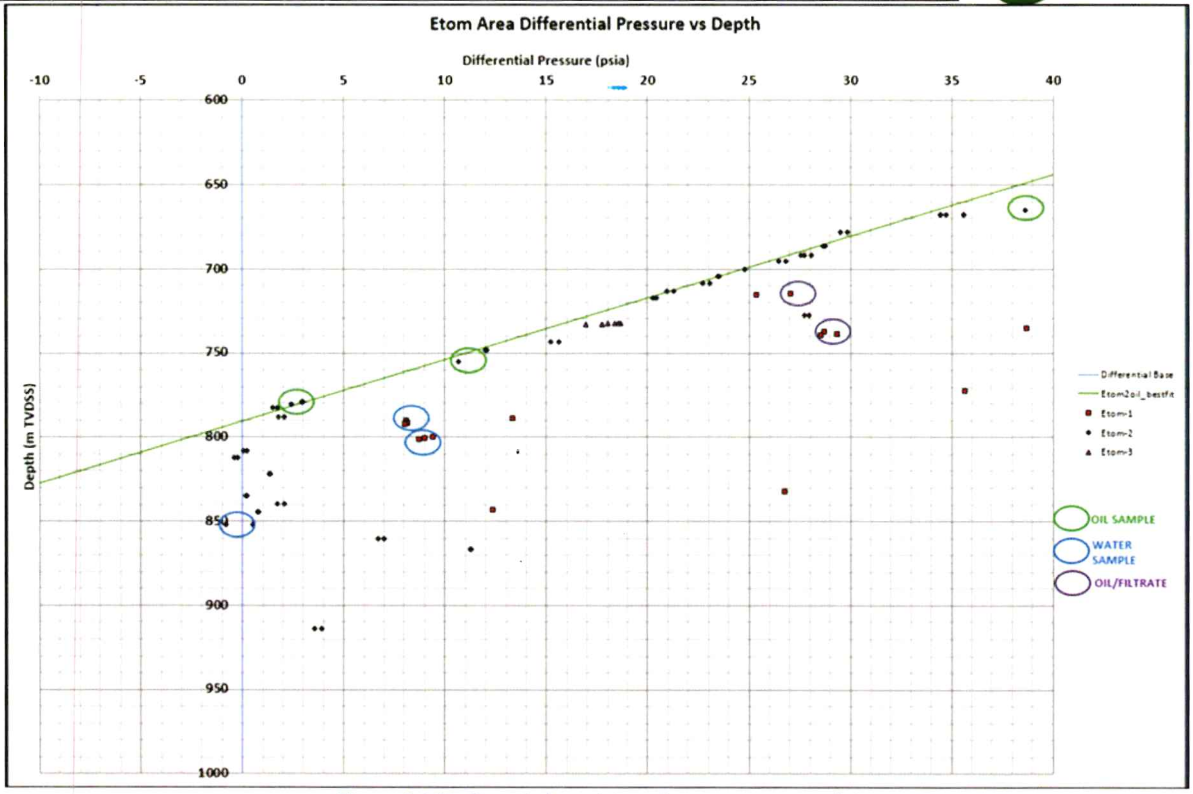


Figure 4-159: Etom Lokone interval excess pressure plot

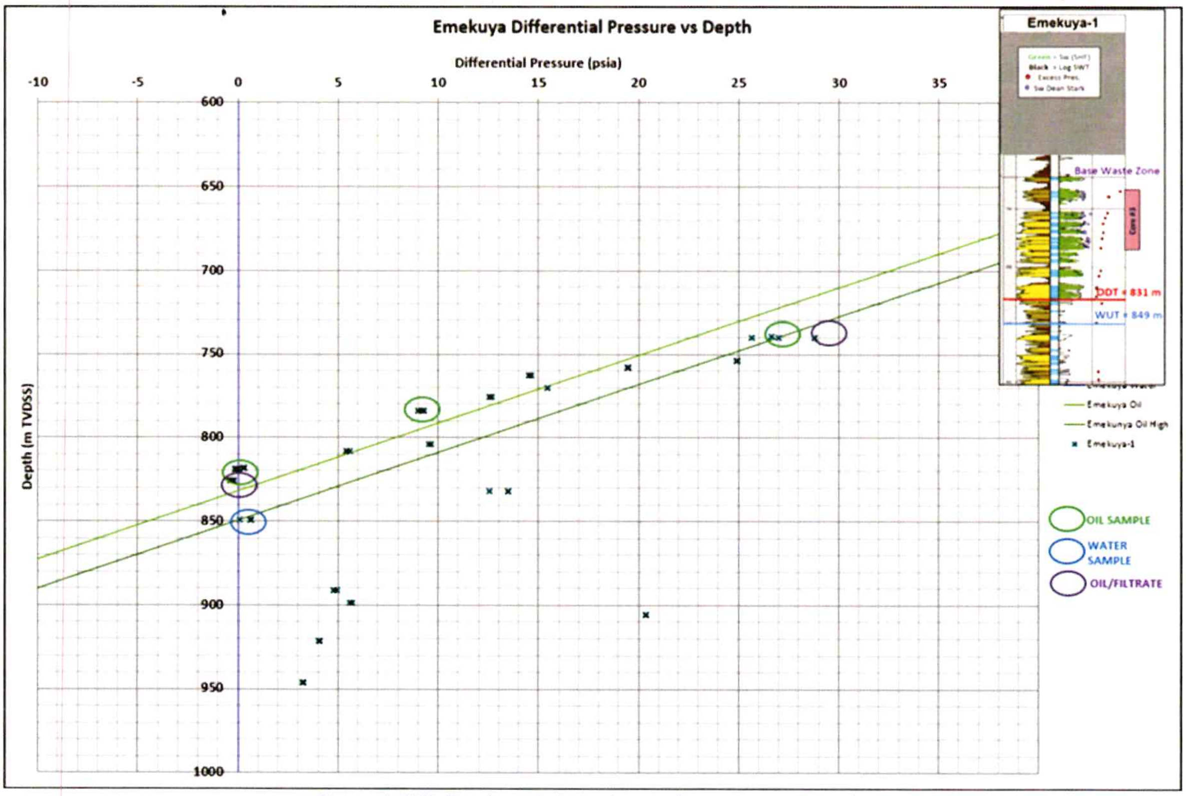


Figure 4-160: Emekuya Lokone interval excess pressure plot

A water gradient of 1.398 psi/m has been used and pinned from the water sample collected at 852 m TVDsl (1215 m MDRT). We have considered an estimated +/- 5 m uncertainty around the depth of our best estimate for Zone 2 FWL, with the low case incorporating the Etom-1 water sample at 788.7 mTVDsl. Interpretation of data provides a FWL depth of 790 m TVDsl. The high case assumes the Etom-1 water sample is within the transition zone.

The low case is calculated using a gradient pinned from ODT (from Log, bottom of sands) at 831 m TVDsl. A high case was calculated using an oil gradient pinned from WUT (water sample) at 849 m TVDsl.

A summary of the low and high case contacts derived from pressure data, fluid sampling and the petrophysical interpretation is shown in Table 4-24.

Table 4-24: Etom & Emekuya low and high case contacts (mTVDsl)

Area	Contact (mTVDsl)	
	Low Case	High Case
Etom	785	795
Emekuya	831	849

Hydrocarbon saturation response appears more reliable in Etom wells than elsewhere in the basin, with a good correlation to oil samples and identifiable ODTs and WUTs on logs which can be corroborated by available MDT pressure data. A schematic depicting the ODT and WUT depths for each of the wells as based on logs and samples is shown in Figure 4-161. Values are consistent the with contact ranges described in Table 4-24.

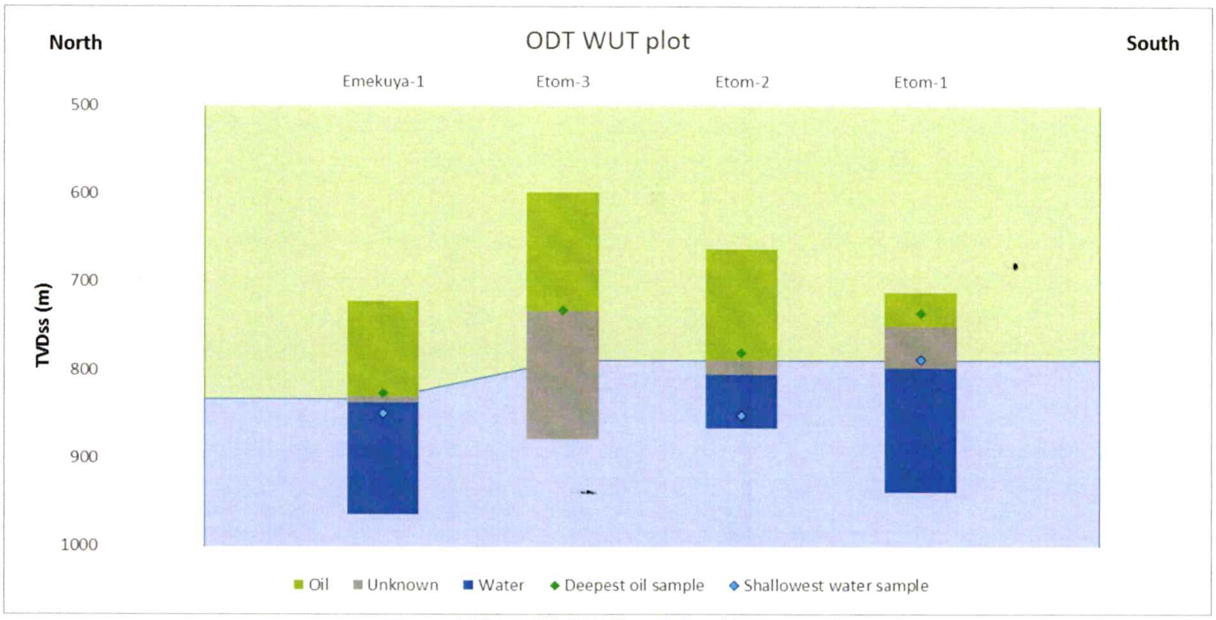


Figure 4-161: ODT / WUT as defined by logs and samples

4.6.5.6 Volumetrics

For the purposes of this FDP and forecasting, there is not currently a reliable, audited model that can be used for volumetric estimates and Resource forecasting. As such a pragmatic, probabilistic approach has been used to determine a range of volumes that embrace the subsurface uncertainty.

The high and low depth surfaces as described in Section 4.6.5.3 have been used in the Lokone GRV estimation along with the hydrocarbon contact ranges described in Section 4.6.5.5. In Figure 4-162 the Red area indicates areas removed, based on the potential areal extent of Well Etom-3 facies and removal of Etete area from the P90 GRV. The high case Etom area contacts have been used within the Etete area when calculating the P10 GRV. Due to uncertainty in boundary between Etom and Emekuya areas, the eastern area (purple polygon) switches contact region between low and high cases.

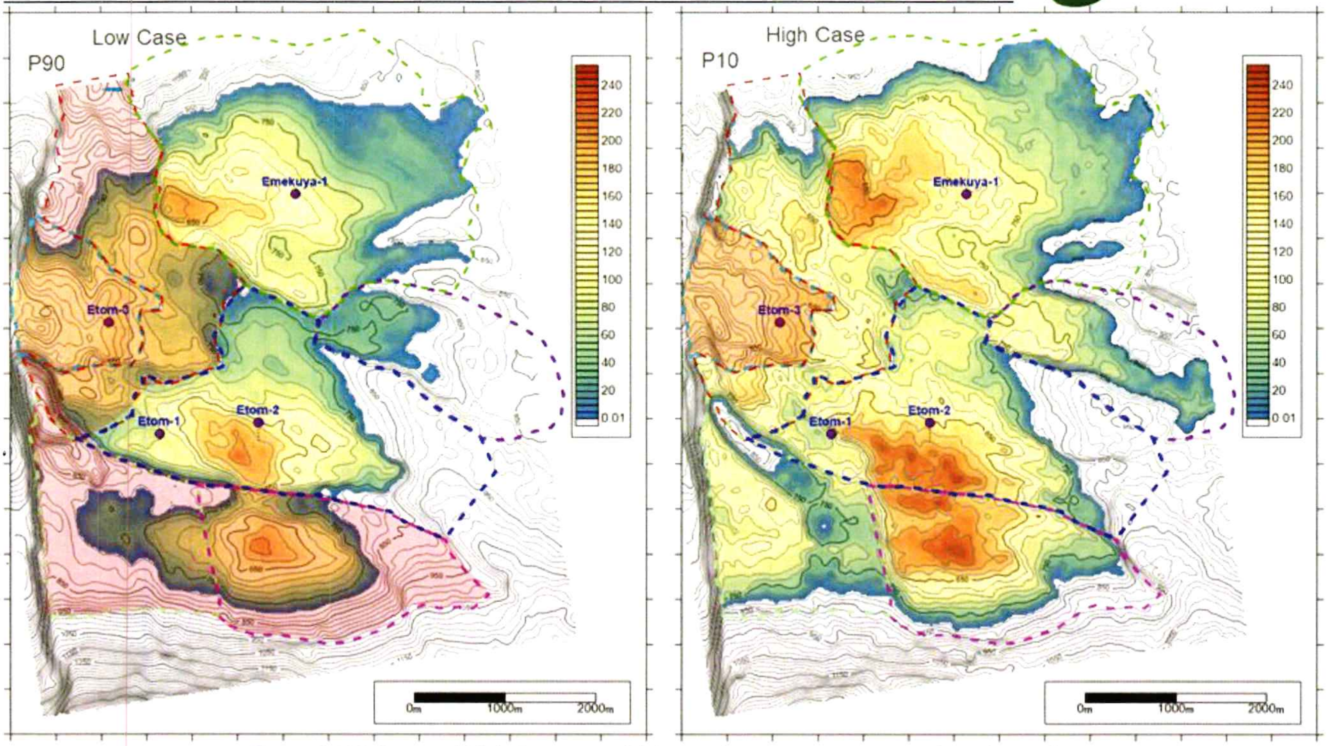


Figure 4-162: Low and High Case gross thickness above contact maps, Lokone interval

Low and high case parameters for NTG, porosity and water saturation were derived from petrophysical analysis of the wells and ranges for formation volume factors were derived from PVT samples. Recovery factors, assuming waterflood recovery, of 15 to 40 % with a lognormal distribution have been applied.

Gross Etom and Emekuya STOIIP and Resource estimates can be found in Table 4-25

Table 4-25: Etom & Emekuya STOIIP & Gross Contingent Resources. Auwerwer & Lokone

Field	Reservoir	STOIIP (MMstb)			Gross Contingent Resources (MMstb)		
		P90	P50	P10	1C	2C	3C
Etom + Emekuya	Lokone	173	327	598	36	80	173
Etom	Auwerwer	51	75	112	10	19	35
Total Etom & Emekuya	Auwerwer + Lokone	224	402	710	46	99	208

4.6.5.7 Production Testing

Production testing of both the Auwerwer and Lokone reservoirs was undertaken in Well Etom-2 in May 2017 including injectivity testing and fracture stimulation of the Lokone (Table 4-26). Lokone permeabilities were estimated to be in the range of 7 – 32 mD and so comparable to the Auwerwer permeabilities in the basin.

Table 4-26: Etom DST Flow Data

Sand	Auwerwer	Pre Stimulation Lokone	Post Stimulation Lokone	Post Stimulation Lokone with additional perforations
Liquid Rate (stb/d)	727	208	200	294
PI (stb/d/psi)	1.3	0.37	0.3	0.58

4.6.5.8 Fluid Properties

Twelve formation fluid samples have been acquired in Wells Etom-1 and Etom from RCI tools. The oil samples from Etom-1 were not valid for PVT analysis and the samples from Etom-2 were all atmospheric dead oil samples. However, dead oil analysis was carried out on the Etom-2 samples. From this analysis, elevated molar content of heavy components indicates that the fluids in Etom are heavier than those sampled in Twiga, Amosing and Ngamia. Properties have been estimated from correlations matching the available data.

Reservoir Pressure (psia)	Reservoir Temperature (deg C)	Saturation Pressure (psia)	Gas-oil Ratio (scf/stb)	Oil Gravity (deg API)	In-situ Viscosity (cp)	Formation Volume Factor (rb/stb)
710 - 1385	65 - 85	300 - 750	50 - 160	29-32	5 - 14	1.06 - 1.11

4.6.5.9 Production Forecasting

Etom production forecasts for the Auwerwer and Lokone have been generated based on estimates of recovery per well and type curves with initial production rates and decline parameters.

The well count has been developed by dividing the area surrounding the HCPV of the field by the pattern area of a 200m well spacing (0.08 km2) for the Auwerwer and a wider spacing of 250m (0.125 km2) for the Lokone to accommodate fractured completions and a 1:1 producer:injector ratio expected from an inverted 5 spot pattern. The recoverable volumes per producer are then estimated by dividing the recoverable resource volume by the number of production wells. For Etom Lokone a recoverable volume of 0.64 MMstb per production well is assumed (based on the lower viscosity / reservoir quality combination) and 125 producers and 125 injectors are planned. For the Etom Auwerwer a recoverable volume of 0.44 MMstb per production well is assumed and 42 producers and 42 injectors are planned.

Initial production rates for the production wells have been guided by trends of rate vs hydrocarbon pore thickness from the available simulation models and also trends of initial rate vs 2C resource per well. Decline curve parameters (for both oil and water) have then been derived from trends based on wells of similar net thickness and recoverable volume from the available simulation model results. A full field forecast is built based on the drilling schedule planned. These are combined with the other field forecasts (with simulation and type well forecasts). On a monthly basis the sum of the unconstrained production rates is calculated and the current system constraint (oil, water or gas) established. Production is then cut to honour the limit which is being exceeded by the largest amount. This calculation method is consistent with commercial software such as Petro VR.

It is noted that this methodology allows for the total probabilistically estimated resources to be recovered, however, the well count is potentially conservative. A similar calculation for Ngamia, for example, suggests that 442 wells total would be required, however the simulation model is using 216. Similarly, the Amosing areal methodology would suggest 160 wells compared to 104 planned in the simulator. Gulf is planning to refine the well count through further simulation ahead of executing Phase 2 guided by the results of the Phase 1 drilling and early production.

4.6.6 Agete

4.6.6.1 Introduction

The Agete field was discovered in 2013 by Well Agete-1, which penetrated the Auwerwer reservoir (Figure 4-163) and an underlying alluvial fan/rift edge facies. The Lokone formation is absent from the well. Well Agete-2 was drilled in 2014 to appraise the structure down dip and was found to be water bearing throughout the entire Auwerwer section.

During the drilling of Well Agete-1, one conventional core totaling 52.3 m in length was acquired representing the Lower Auwerwer formation. Logging while drilling measurements including gamma ray and resistivities were acquired.

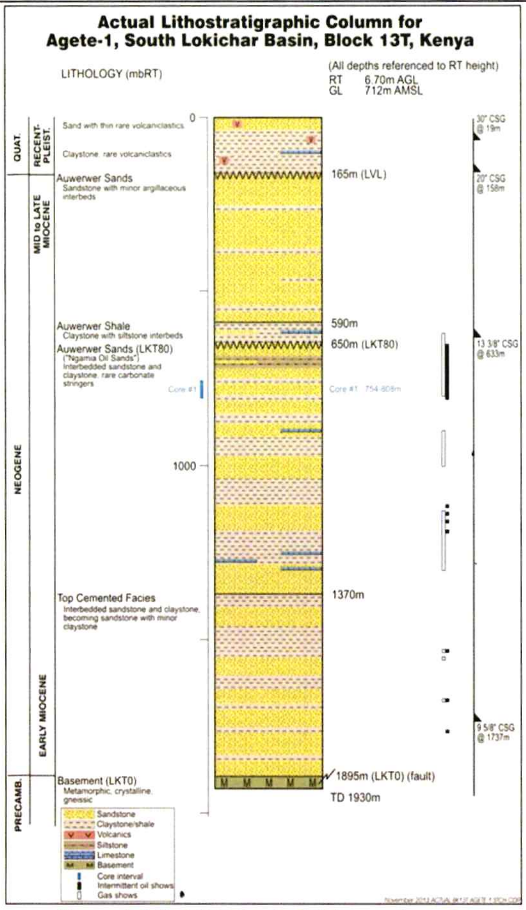


Figure 4-163: Well Agete-1 lithostratigraphy

In the period May-June 2014 the appraisal Well Agete-2 was drilled as a deviated down-dip appraisal well, but was found to be water-bearing. The well had borehole stability issues and no open-hole wireline logs were obtained. The well was plugged and abandoned.

4.6.6.2 Geology

Agete has a similar structural form to Twiga South, consisting of a dip closure with updip trap against the prominent basin bounding fault immediately to the west. Unlike Twiga, the trapping mechanism to the NE is thought to be due to a splay off the basin bounding fault (Figure 4-164). The structure is mapped with reasonable confidence on the PreSTM seismic data (Figure 4-165), although interpretation is increasingly uncertain towards the updip fault.

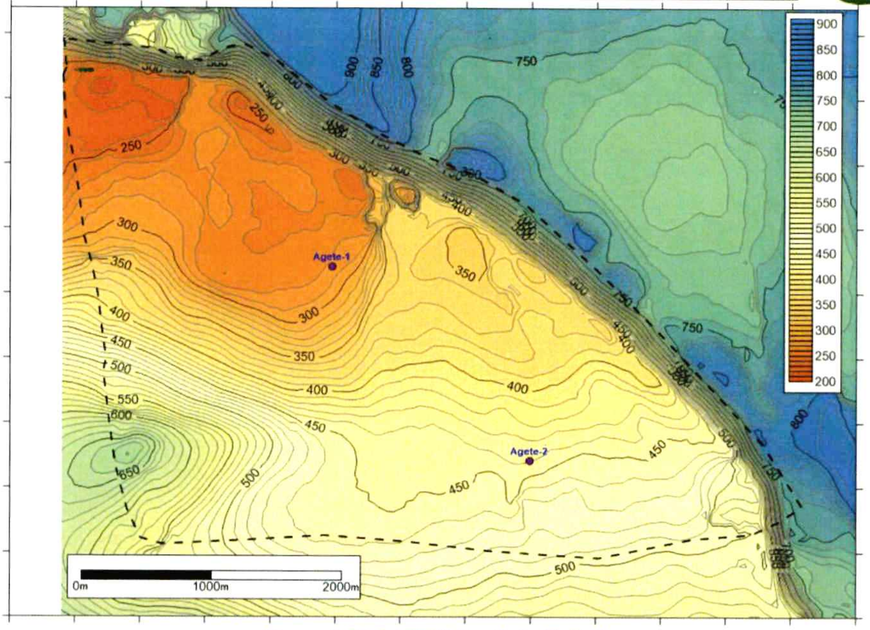
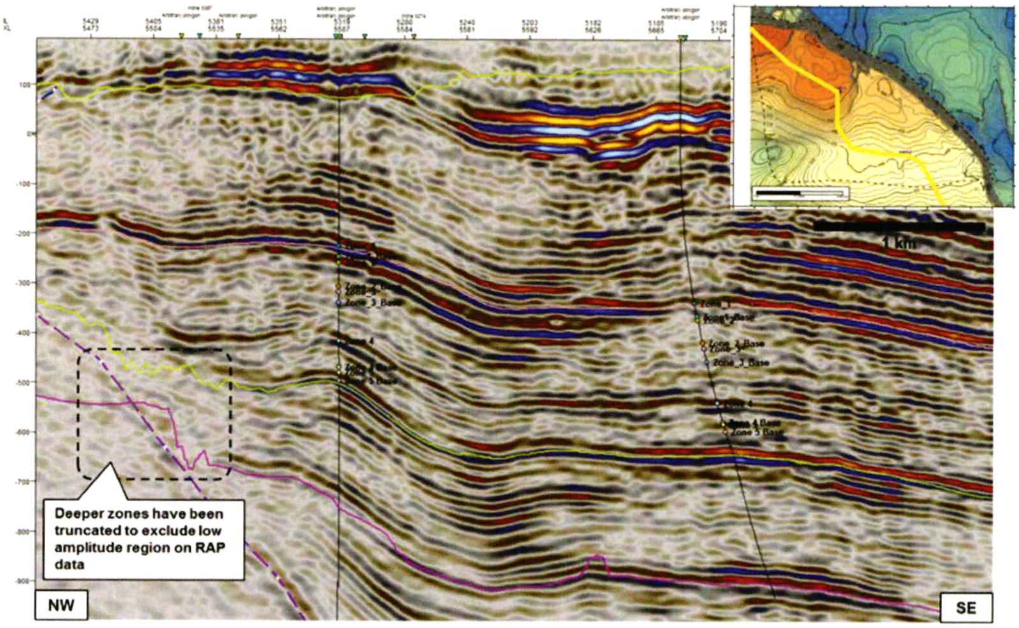


Figure 4-164: LKT80 Depth (mTVDsl)



Deeper zones have been truncated to exclude low amplitude region on RAP data

Figure 4-165: Agete dip line KE10BB-2012-43AOC

Well Agete-1 discovered wet gas and hydrocarbon indications in the Auwerwer sandstone reservoirs, with the best pay section located in the shallow section between 280 m and 650 m TVDsl. Following the completion of this well, in 2014 another exploration well, Agete-2, was drilled on the Agete structure South East of Agete-1, to appraise the downdip extent of the two hydrocarbon bearing zones encountered in Agete-1, and to explore deeper tight oil pools absent in Agete-1, however, only water bearing sandstones were encountered. The gamma ray signature observed across the reservoirs at both of these wells (Figure 4-166) is suggestive of a high frequency depositional environment with mixed rock types including alluvial, fluvial and lacustrine sediments.

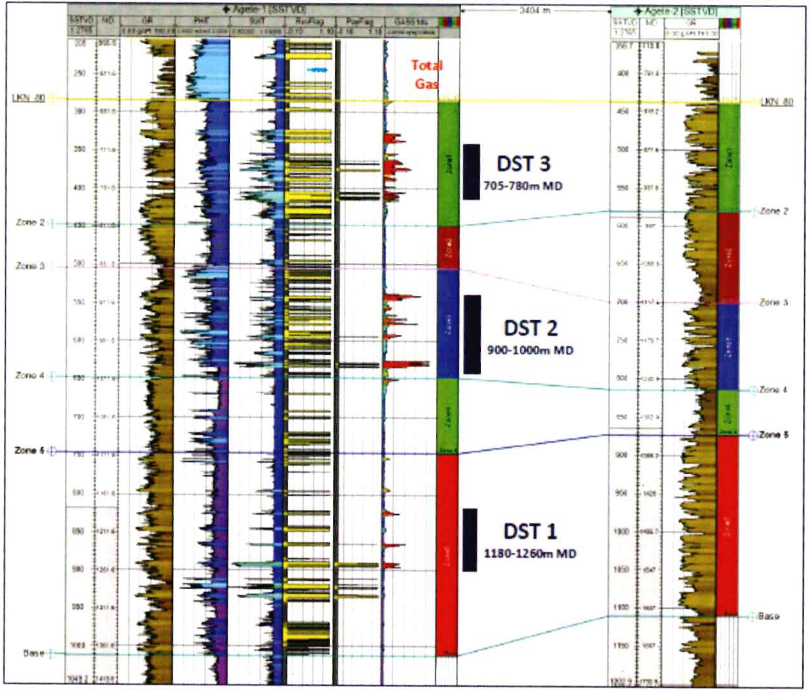


Figure 4-166: Agete-1 & Agete-2 correlation

4.6.6.3 Geophysics

The exploration and appraisal well were drilled based on the interpretation of seven vintage 2D seismic lines that defined the structure. Several iterations of Top volcanics, LKT80, LKT78, LKT 70 and LKT60 horizons have been interpreted on the seismic. Most recently the horizons have been interpreted on 3D seismic and a simple single layer velocity model down to LKT80, with the resultant depth converted grids used for volumetric assessment. Top LKT80 and LKT78 appeared to be well-defined events on the 3D data and were used as top and base structure for Pools 1-3 and Pools 4 & 5 respectively.

4.6.6.4 Petrophysics

A full suite of open hole logs were run across the entire interval of interest for Well Agete-1. Routine core analysis and mercury injection tests have been carried out on core samples. Figure 4-167 shows the core porosity versus air permeability. The methodology for log interpretation is as described in Section 4.4 with petrophysical cut-offs applied (17% porosity and 45% shale volume as a low case and 10% porosity and 55% shale volume as a high case) to obtain values for N/G and porosity.

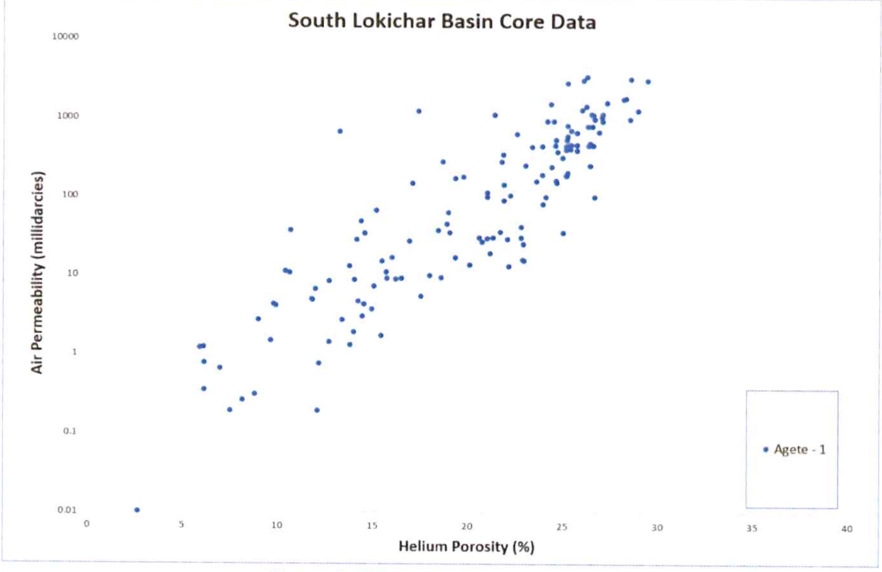


Figure 4-167: Agete-1 core poroperm

Cut-offs were used to obtain low and high N/G and porosity values which were used as P90 and P10 inputs to a normal distribution. A hydrocarbon saturation range of 0.45 / 0.56 / 0.70 (lognormal) was used in the absence of reliable log saturation data, in line with Ngamia and Twiga values. It should be noted that Agete has higher hydrocarbon saturation uncertainty than other fields due to the quality of log data.

Figure 4-168 shows a CPI of Agete-1.

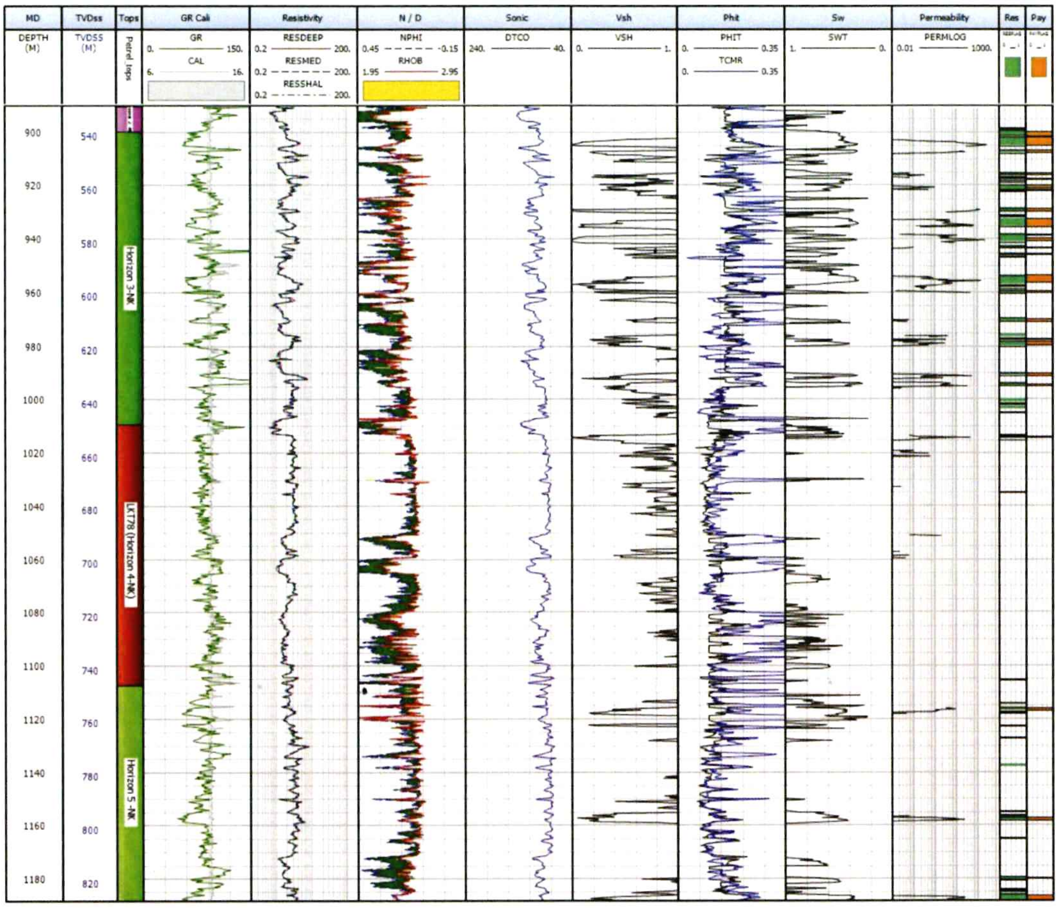


Figure 4-168: Agete-1 CPI

4.6.6.5 Hydrocarbon contacts

An independent zonation based on log and seismic character has been developed and then rationalised against sample and pressure data (Figure 4-169). These are only minor alterations as a result of the mapping on 3D seismic. There are a lack of reliable MDT pressure data and interpretation was hindered by a number of issues. Sampling resulted in numerous low mobility/tight tests and loss of packer seal, with unreliable data points. The ODT from Well Agete-1 and WUT from Well Agete-2 were therefore used for low and high case contacts respectively (Table 4-27). During MDT operations, fluids were pumped at five stations for fluid identification with the RCI tool. One sample was collected for PVT analysis. No samples were collected in Well Agete-2.

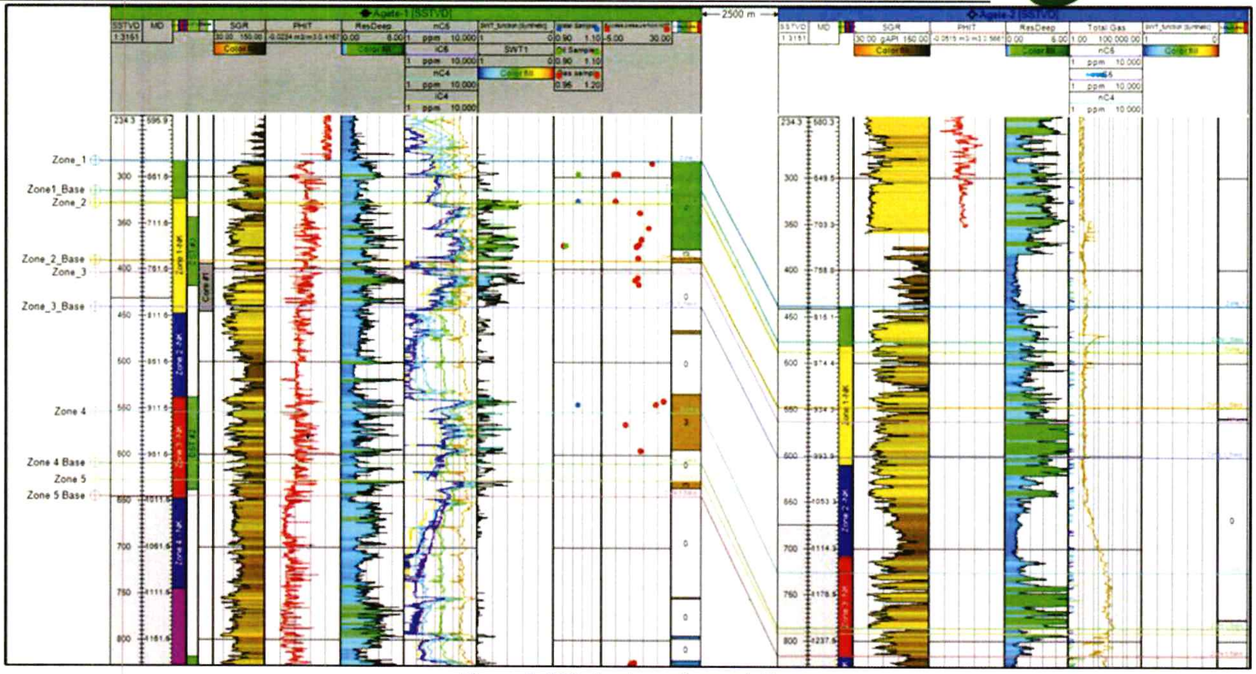


Figure 4-169: Agete well correlation

Table 4-27: Agete contacts used in volumetric calculation

Pool	Low Case	High Case	ODT/WUT	FWL
1	312	436	295 ODT	
2	389	479	373 ODT	
3	436	557		
4	613	693	545 WUT	
5	652	781		

Pool 1: oil sampled at 659m MD (295m TVDss), but min case down to pool section from log

Pool 2: oil sampled at 736m MD (295m TVDss), but min case down to pool section from log

Pool 4: on the basis of DST#2 result (oil and water production along the whole section), ERCE decided to use a NTG scalar to account for water bearing intervals

The lack of reliable MDT pressure excludes MDT interpretation for contact analysis. Contacts are therefore based on log ODTs and structural spill

4.6.6.6 Volumetrics

For all five major oil pools (identified from log data), a low case GRV was obtained by assuming the pool's base (ODT) represented the oil water contact. ERCE's high case assumed a WUT defined by water-bearing Well Agete-2. Updip volumes were constrained by the basin bounding fault and associated splay to the north, west and east (Figure 4-164). Deeper pools were really limited to exclude the low amplitude seismic region adjacent to the basin bounding fault. Low case volumes were also confined to the eastern side of a small NS trending fault ~ 200 m west of Well Agete-1. A lognormal distribution was fitted between low and high case GRVs for probabilistic simulation.

A lognormal recovery factor range of 10% - 17% - 30% has been used to reflect potential recovery assuming a range of inter-well connectivity and development well spacing.

Estimates of hydrocarbons in place and Contingent Resources are detailed in Table 4-28.

Table 4-28: Gross Agete STOIIP & Contingent Resources

Block/ Concession	Field	Reservoir	STOIIP (MMstb)				Gross Resource (MMstb)			
			1C	2C	3C	Mean	1C	2C	3C	Mean
Block 13T	Agete	Pool_1	21.6	40.8	77.3	46.2	3.0	7.1	16.4	8.8
Block 13T	Agete	Pool_2	55.9	89.5	143.4	95.8	7.5	15.5	32.0	18.2
Block 13T	Agete	Pool_3	40.8	69.3	117.6	75.5	5.6	12.0	25.7	14.3
Block 13T	Agete	Pool_4	5.4	9.7	17.3	10.7	0.8	1.7	3.7	2
Block 13T	Agete	Pool_5	1.5	3.0	6.0	3.4	0.2	0.5	1.3	0.7
Total			**125.2**	**212.3**	**361.6**	**231.6**	**17.1**	**36.8**	**79.1**	**44**

4.6.6.7 Production Testing

Three production tests were carried out in Well Agete-1. The DST results are summarised in Table 4-28.

DST#1 tested the deeper section of Well Agete-1 across the interval 1180 m-1260 m MDRT which flowed only water.

DST#2 tested a 100 m gross interval across the whole section of Pool 4 and 10 m at the top of Pool 5. After producing 100% water during the first flow, the water cut progressively reduced to 82%. The interval from which water was produced is not well constrained. At the top of Pool 4, an MDT sample in the main 12¼" hole at 907.5 m pumped mainly water with poor hydrocarbon signatures.

DST#3 tested a 75 m gross interval across Pools 2 and 3. The test flowed dry oil along the entire interval. Over seven days of testing, seven build-up periods were recorded, the first one being considered the most reliable for interpretation as it is preceded by the most stable rate and drawdown measurement. The interpretation highlighted a permeability value lower than core average and possible gas cap support. High GOR values were measured during the test, but not confirmed by the PLT run. Of the 75 m of perforations, flow was computed from 14.6 m during the PLT run: two zones in the middle and at the base of Pool 2, and 4.5m at the top of Pool 3. No contribution to flow from interpreted thin bed pay between Pools 2 and 3 was recorded.

Additional RCI pumping stations confirmed two shallow layers as water bearing (at 586.8 m MD / 224 m TVDsl and at 480.8 m MD / 117.1 m TVDsl) and oil presence in Pool 2 at 736.3 m MD / 373.1 m TVDsl.

Table 4-29: Agete-1 DST results

Well	DST	Depth Interval (m)	Perforation thickness (m)	Flow (stb/d)	Test duration (hours)	KH mdft	PI (bbl/d/psi)	Water Cut (%)
Agete-1 *ESP*	#3	705-780	75	250 (1st flow period)	>6 days, with multiple flow periods	1700	N/A	0
Agete-1 *HRP*	#2	900-1000	100	2200	~24 hrs flow, 30 hrs BU	1500	6-8	down to 82
Agete-1 *HRP*	#1	1180-1260	80	440	~33	1490	0.81	100

4.6.6.8 Fluid Properties

Fluid properties were available from PVT analysis carried out on a repeated MDT sample collected in the 12¼" pilot hole of Well Agete-1. The analysis results are summarised in Table 4-30.

The oil formation volume factor reported in the table has been used in volume calculation considering a range of uncertainty, as samples were only collected in a single pool.

Table 4-30: Agete-1 PVT results

Well	Reservoir	Sample depth (m MD)	Sample depth (m TVDsl)	Phase	Reservoir Pressure (psia)	Saturation pressure (psia)	Bo (rb/stb)	Solution GOR (scf/stb)	Density (g/cc)
Agete-1	Pool 2	736.3	373.7	Oil	881	895	1.18	291	0.786
Agete-1	Pool 2	736.6	374	Oil	881	895	1.18	268	0.786

4.6.6.9 Production Forecasting

Agete production forecasts for the Auwerwer have been generated based on estimates of recovery per well and type curves with initial production rates and decline parameters.

The well count has been developed by dividing the area surrounding the HCPV of the field by the pattern area of a 200m well spacing (0.08 km2) for the Auwerwer and a 1:1 producer:injector ratio expected from an inverted 5 spot pattern. The recoverable volumes per producer are then estimated by dividing the recoverable resource volume by the number of production wells. For the Agete Auwerwer a recoverable volume of 0.5 MMstb per production well is assumed and 74 producers and 74 injectors are planned.

Initial production rates for the production wells have been guided by trends of rate vs hydrocarbon pore thickness from the available simulation models and also trends of initial rate vs 2C resource per well. Decline curve parameters (for both oil and water) have then been derived from trends based on wells of similar net thickness and recoverable volume from the available simulation model results. A full field forecast is built based on the drilling schedule planned. These are combined with the other field forecasts (with simulation and type well forecasts). On a monthly basis the sum of the unconstrained production rates is calculated and the current system constraint (oil, water or gas) established. Production is then cut to honour the limit which is being exceeded by the largest amount. This calculation method is consistent with commercial software such as Petro VR.

It is noted that this methodology allows for the total probabilistically estimated resources to be recovered, however, the well count is potentially conservative. A similar calculation for Ngamia, for example, suggests that 442 wells total would be required, however the simulation model is using 216. Similarly, the Amosing areal methodology would suggest 160 wells compared to 104 planned in the simulator. Gulf is planning to refine the well count through further simulation ahead of executing Phase 2 guided by the results of the Phase 1 drilling and early production.

5 SOUTH LOKICHAR BASIN EXPLORATION AND APPRAISAL PLAN

5.1 Introduction

The priority of appraisal activities will follow an infrastructure-led approach where discoveries closest to existing and expected future infrastructure will be prioritised. A key principle to the sustained development approach is to balance the end of the initial production plateau with the tie-in of incremental production from the development of later reservoirs. To align with this strategy, the proposed South Lokichar Basin exploration and appraisal (E & A) activities will provide additional subsurface, technical, and operational information that is required to support investment decisions following first oil from the Phase 1 development.

Adding new resources through exploration is a key component of sustaining plateau and this Field Development Plan includes a proposal to drill exploratory wells relatively near to existing discoveries. Material success on these prospects can lead to additional exploratory work within the area on similar play types such as the Basin Fans.

This section of the FDP describes four categories of E&A drilling relating to the relative risk and step-out distance from existing accumulations:

1. Field Appraisal: Targets within the (3C) boundary of the existing field outlines, appraisal wells will narrow the range between 1C and 3C but not evaluate additional volumes
2. Near-Field Appraisal: Targets beyond the 3C limits of the field, but directly adjacent to existing areas, these may be found to have common contacts with existing accumulations and add new resources not accounted for in the 3C estimate.
3. Near-Field Exploration: Targets close to existing fields which have a discrete risk element to that of the main accumulation, e.g. different trap, reservoir deposition, sealing facies. If discovered, they may still contain oil directly adjacent to existing accumulations
4. Exploration: Targets further from existing fields which have (multiple) risk elements distinct to those currently proven.

The E & A portion of the FDP is designed to be flexible and is contingent on the results from the Phase 1 development and subsequent balance in operational preferences between maturing the existing resource base and appraising / exploring for additional hydrocarbon volumes.

The focus for E & A activities is likely to centre around developments which have the largest Contingent Resources. The difference between estimated 1C and 3C resources gives a good indication of where field appraisal will be the most beneficial to reducing uncertainty and ultimate converting Contingent Resources to Reserves.

Table 5-1 shows the STOIIP and Contingent Resources estimates for the main South Lokichar basin discoveries and reservoir intervals ranked by 3C – 1C. The top four targets account for >70% of the 3C - 1C resources and therefore form the focus of the field appraisal drilling plan.

Table 5-1: STOIIP and Contingent Resources Estimates ranked by 3C - 1C

Discovery	Reservoir	STOIIP (MMstb)			Gross Resources (MMstb)			
		Low	Best	High	1C	2C	3C	*3C - 1C*
Ngamia	**Auwerwer**	**459**	**680**	**984**	**103**	**160**	**257**	***154***
Etom + Emekuya	**Lokone**	**173**	**327**	**598**	**36**	**80**	**173**	***137***
Amosing	**Auwerwer**	**186**	**252**	**394**	**46**	**71**	**111**	***65***
Agete	**Auwerwer**	**125**	**212**	**362**	**17**	**37**	**79**	***62***
Ekales	Auwerwer	15	49	164	2	9	32	*30*
Twiga	Auwerwer	59	87	170	8	17	37	*29*
Erut	Lokone	37	69	127	6	14	35	*29*
Ngamia	Lokone	74	153	323	5	13	34	*29*
Etom + Emekuya	Auwerwer	51	75	112	10	19	35	*25*
Ewoi	Lokone Shale	7	28	118	1	3	12	*11*
Etuko	Lokone Shale	6	20	67	1	3	11	*10*
Twiga	Lokone	2	7	23	-	1	5	*4*

Although this metric does not capture near field appraisal and exploration opportunities, a review of all fields in the table suggests the most volumetrically significant upsides lie adjacent to the largest fields (Ngamia and Amosing). This is generally because the vertical and lateral extents of the closures in these fields are currently not well constrained, with broader macro-closures and multiple faults which may provide additional compartments.

Outside of near-field E & A, numerous exploration targets exist within the South Lokichar basin, however the majority of these lie outside the core focus area of this FDP. Six closer targets have been included as potential drill candidates due to their proximity to existing discoveries. A summary of these, as well as the near-field exploration targets is provided in Figure 5-1. On the eastern side of the basin, the least appraised region is in the Sungura Terraces area, where there is currently very limited 2D seismic coverage. The FDP focuses on shooting infill seismic within this area, before maturing any targets to drill-ready status.

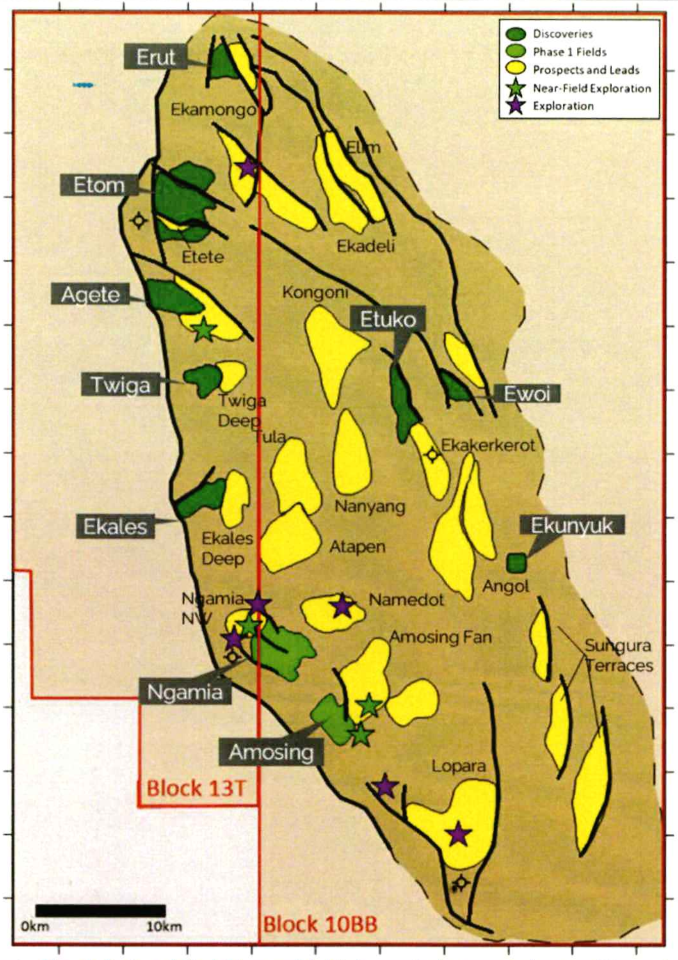


Figure 5-1: Exploration prospects / leads in South Lokichar, with high-graded targets close to Phase 1 development fields highlighted

The four fields with the most upside potential comprise Ngamia Auwerwer, Amosing Auwerwer, Etom Lokone and Agete Auwerwer. Each field and surrounding area have been screened for potential E & A well locations for each of the four well types (Field Appraisal, Near-field Appraisal, Near field exploration and exploration).

5.2 Drilling Opportunities

Table 5-2 provides a summary of possible E&A locations with a qualitative view of risk and volumes associated with each target. This list comprises 25 wells, out of which eight (in bold) are proposed to be prioritized. These eight wells are selected across the fields, attempting to balance the risks and rewards/volumes.

It is to be noted that these proposed wells are contingent on the successful outcome of prior appraisal work, and it is possible that some of the wells shown will not be implemented. However, it is also likely that success in some of the activities will support additional activities not currently captured in Table *5-2*. This sequence is subject to change based on early production data, risk appetite and additional subsurface insight. There are two additional fields (Ekales and Twiga) currently part of the Phase 2 development schedule which do not have dedicated E & A wells associated with them, this is due to the expectation that development drilling will sufficiently appraise the extents of these fields, and there appears to be little additional upside nearby.

Aside from the Phase 1 developments in Amosing and Ngamia, Etom is a priority because it has a potentially large resource in the Lokone formation, but this will likely require stimulation and/or improved completion methods to achieve commercial flow rates. A successful development at Etom would also provide a northern hub and key connection point for Erut and northern exploration prospects, where a closer tie-in to infrastructure would significantly lower capex for development

Exploration wells proposed here compliment both the development and appraisal strategies since learnings could open plays that extend across both areas. As shown in Figure 5-1, there are a significant number of exploration prospects remaining, however, many are based on play types that are unproven. The exploration wells proposed here will target prospects that are close to the developed fields and their infrastructure, have significant resource potential, and could de-risk a significant number of remaining prospects by opening new play types or fairways.

Although the Phase 1 development well locations typically target the lowest risk, core area of the field, pattern flood results in Amosing are likely to provide additional insight into the extent of the non-net alluvial fan. For this reason, some of the Amosing FA and NFA locations are directly dependent on these results. Aside from this, the proposed high graded wells have been selected according to the following three concepts:

1. Risk: Dry hole risk (either through encountering water-bearing or absent reservoir) represents a key discriminator for drilling, with the highest likelihood locations targeted in preference. This is aligned with the FDP strategy of prioritising a level of sustained baseline production ahead of trying to aggressively grow the resources base
2. Volume: The drilling preference factors in expected volumetric outcome in a success case. This is currently a qualitative assessment, based on lateral segment extent and total expected and column height (factoring in stacked reservoirs)
3. Subsurface information: Typically, wells are drilled in increasing distance from the core area, allowing for important insights into trap configurations, sediment distribution and velocity model to be obtained from lower risk wells. This increased subsurface knowledge can help derisk targets later in the sequence and/or be used to adjust future drilling locations / order. Exploration wells which target new plays will de-risk multiple additional opportunities if successful.

Table 5-2: Exploration and Appraisal Drilling Summary

Name	Field	Type	Location	Risk	Volumes
Ngamia FA North	**Ngamia**	**FA**	**North**	**Low**	**Medium**
Ngamia FA South	Ngamia	FA	South	Low	Medium
Ngamia NFA NW	**Ngamia**	**NFA**	**NW**	**Medium**	**High**
Ngamia NFA SW	Ngamia	NFA	SW	Medium	Medium
Ngamia NFE West	Ngamia	NFE	West	High	Medium
Ngamia Exp Far NW	Ngamia	Exp	Far NW	High	High
Ngamia Exp Far SW	Ngamia	Exp	Far SW	High	High
Namedot	Ngamia	Exp	-	Very High	Low
Amosing FA North	**Amosing**	**FA**	**North**	**Low**	**Medium**
Amosing FA Central	Amosing	FA	Central	Medium	Medium
Amosing FA South	Amosing	FA	South	Medium	Low
Amosing NFA South	**Amosing**	**NFA**	**South**	**Medium**	**High**
Amosing NFA North	Amosing	NFA	North	Medium	Medium
Amosing NFA East	Amosing	NFA	East	Medium	Low
Amosing NFE Far SE	Amosing	NFE	Far SE	Medium	Medium
Amosing Fan	**Amosing**	**NFE**	**North**	**High**	**Medium**
Lopara North	**Amosing**	**Exp**	**-**	**High**	**Very High**
Lopara	**Amosing**	**Exp**	**-**	**Very High**	**Very High**
Etete	**Etom**	**FA**	**South**	**Low**	**High**
Etom FA West	Etom	FA	West	Low	Medium
Etom FA East	Etom	FA	East	Low	Low
Ekamongo	Etom	Exp	-	High	Medium
Agete FA East	Agete	FA	East	Low	Medium
Agete FA West	Agete	FA	West	Low	Low
Agete NFE South	Agete	NFE	South	Medium	Medium

5.3 Scheduling and Costs

An indicative schedule for the eight high-graded drilling targets is provided in Figure 5-2. The wells are planned to be drilled sequentially over the course of approximately eight years commencing in 2032. An estimated average cost of each well is 8-9 million USD. As mentioned in previous sections, drilling sequence and timing are subject to change and are contingent on the firm programme based on additional surface and subsurface considerations.

As shown in Table 7-2, Etom has the highest number of planned wells of all the fields (334). One of the proposed exploration targets is in the Etom field (Etete). It may be perceived that one exploration well is unlikely to provide sufficient information to commit to the full development of the Etom field with 334 wells, but, in reality, the results of the initial tranche of development wells will provide an indication of how the field is performing relative to expectations, allowing for a revised development strategy and, if necessary, a reduced number of wells.

A 2D infill campaign to derisk the Sungura Terrace prospects on the eastern side of the basin is scheduled for 2035, with an estimated total cost of approximately 1 million USD including acquisition, processing and interpretation as described in Section 5.9. This brings the total E & A spend to approximately 77.5 million USD. The results of this additional seismic information will inform the size and chance of success of Sungura prospectivity. If results are favourable, an additional exploration well or substitution of another of the higher risk targets (Lopara or Amosing Fan) may be warranted.

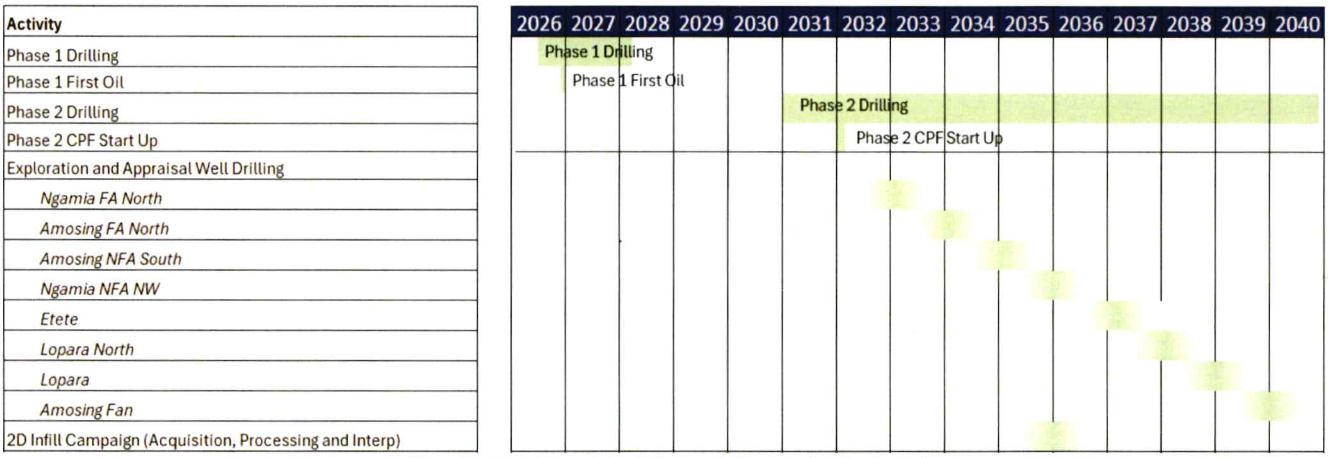


Figure 5-2: Indicative E & A Schedule for drilling and seismic activities

5.4 Ngamia

5.4.1 Summary

Ngamia was the first discovery in the South Lokichar basin and has the most well penetrations (11) of any field to date. However, due to its segmented, multi-level composition, the accumulation remains under appraised.

Eight wells are proposed in the Ngamia E & A campaign, comprising two field appraisal (FA), two Near-field Appraisal (NFA), one Near field Exploration (NFE) and three exploration wells. A summary of the well locations is provided in Figure 5-3 with seismic lines through northern and south E & A well locations shown in Figure 5-4 and Figure 5-5 respectively.

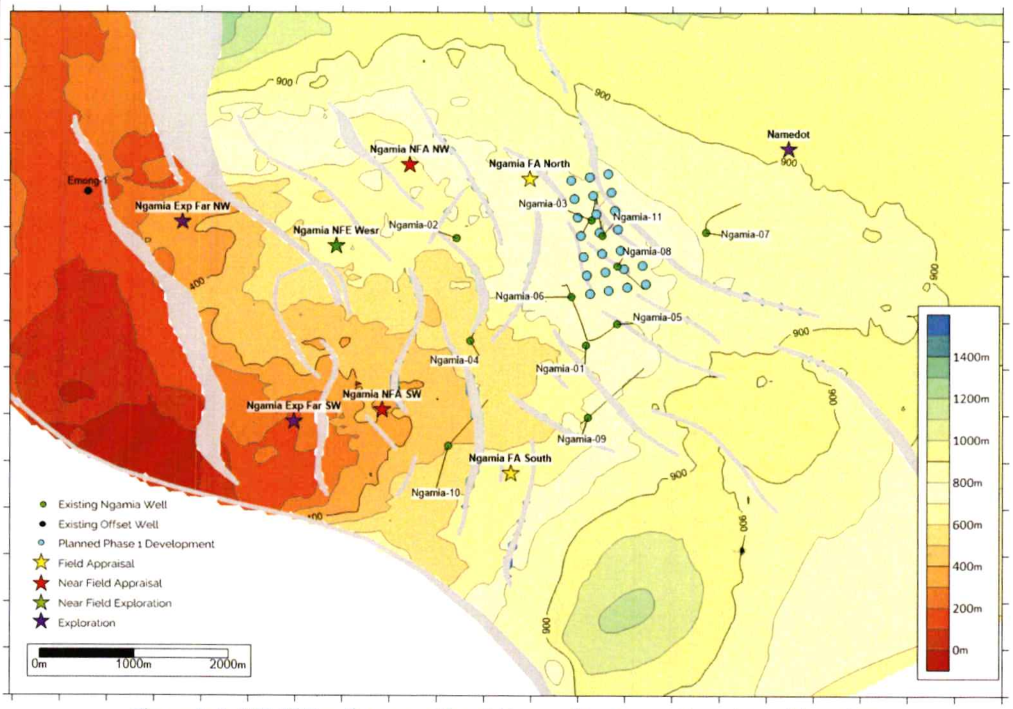


Figure 5-3: LKT 78 Depth map with existing and proposed Ngamia well locations

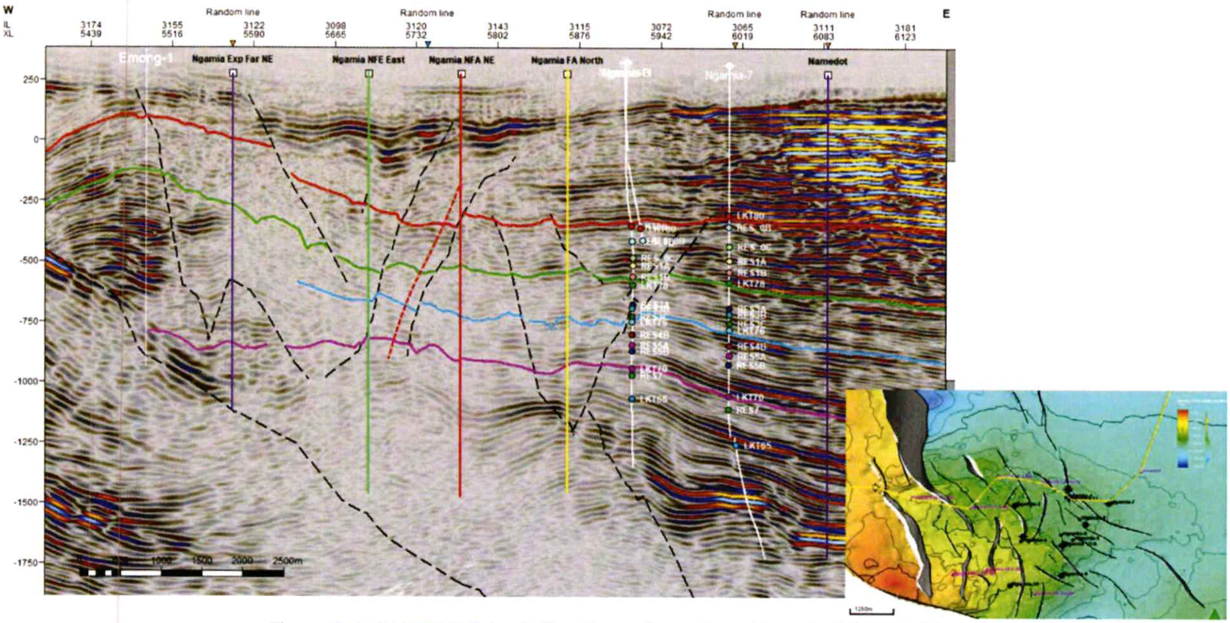


Figure 5-4: W-E TWT Seismic line through northern Ngamia E & A Well Locations

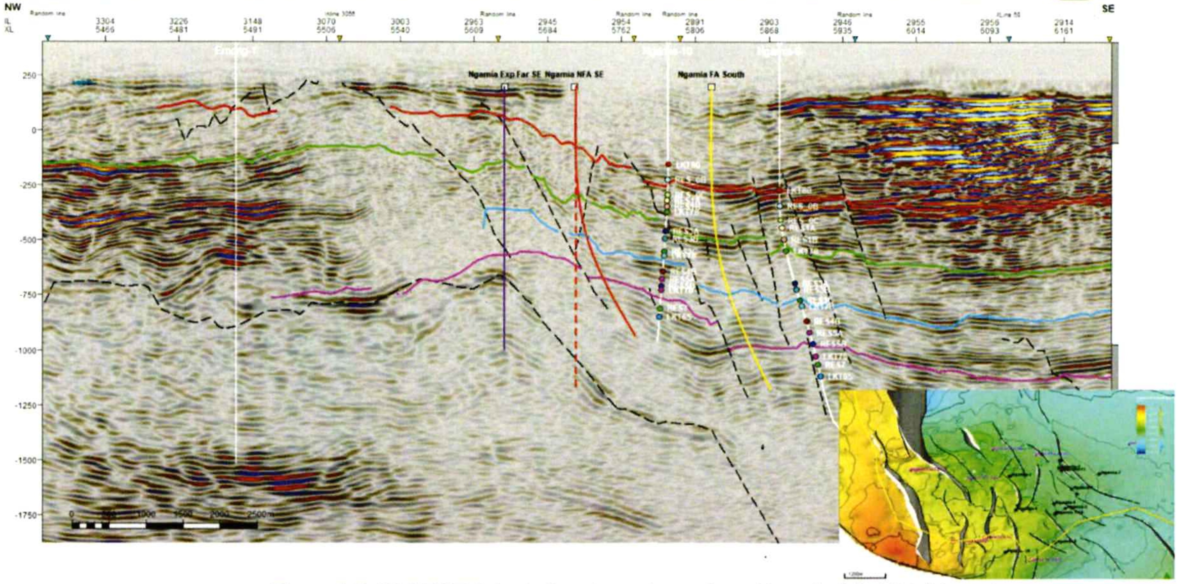


Figure 5-5: W-E TWT Seismic line through southern Ngamia E & A Well Locations

5.4.2 Field Appraisal

Two targets have been selected for appraisal of the Ngamia Field, Ngamia FA North and South. Both target undrilled fault segments, which are included in 3C volumes, but excluded from 1C.

The northern well may share common contacts with the segment drilled by Ngamia-3 and Ngamia-11, both of which encountered some of the thickest hydrocarbon columns on the field. Following additional forensic fault mapping and uncertainty study, the well location may be refined, with a deviated trajectory possible.

The segment targeted by Ngamia FA south may share common contacts with that drilled by Ngamia-09 or Ngamia-10, it is currently placed approximately 1.5k m from the basin bounding fault, with the aim to avoid drilling the non-net alluvial fan facies encountered elsewhere in the South Lokichar basin. The location could be further refined through seismic amplitude and velocity analysis.

5.4.3 Near-Field Appraisal

Two NFA wells have been selected based on their proximity to the main field across what appear to be low throw faults, as well as level or updip of existing hydrocarbon bearing wells.

Ngamia NFA NW drills into one or two fault segments NW of Ngamia-2. A single vertical well may only appraise one of the two fault blocks; however, the location/presence of the segmenting fault is highly uncertain due to the low-quality seismic data in the area. An additional deviated well path could be added depending on the results and testing of the vertical borehole.

Ngamia NFA SW drills updip of Ngamia-10, across a potential segmenting fault. The proposed well is located a similar distance from the basin bounding fault as Ngamia-10 to attempt to avoid the non-net alluvial facies

5.4.4 Near-Field Exploration

A single NFE well is planned approximately 1.5 km due west of Ngamia-2. This well relies on an updip trap against a major splay of the basin bounding fault which is poorly imaged through the reservoir on seismic data and can be best seen in the offsets associated with the overburden. This is in contrast to the existing accumulations in Ngamia, which are likely to be trapped by smaller internal faults bounding each of the oil-bearing segments. The well is currently proposed as vertical, however a deviated path running parallel to the dip of the splay fault would enable reservoir intersections at more crestal positions, although this must be weighed against the likelihood of encountering non-net alluvial fan facies.

5.4.5 Exploration

Three exploration wells are with the current plan, with Ngamia Exp Far NW & SW targeting two separate structural noses updip from the existing Ngamia accumulation. They lie downdip of the Emong-1 well, which encountered tight reservoir with oil shows. These wells will target facies which appear seismically distinct from that at Emong-1, aiming to encounter similar fluvial deltaic reservoirs to those within Ngamia Field. There is also potential for a large-throw fault to separate the Emong-1 area from that targeted by the exploration wells.

The third and final exploration well in the drilling order is the Tullow target Namedot. This appears to target possible basin floor fan facies separated by a deep fault from the main accumulation. Namedot's location will also allow appraisal of the shallower intervals which may be above the Ngamia OWCs in some reservoirs depending on the velocity model and seismic interpretation used. Namedot requires additional seismic review before it can be derisked sufficiently to be a drilling candidate.

5.5 Amosing

5.5.1 Summary

Amosing has seven wells drilled to date. The last two of these (Amosing-6 and Amosing-7) encountered non-net alluvial fan facies close to the main basin bounding fault. A key outstanding uncertainty on the Amosing field is the lateral extent of this non-net facies and whether it is a sharp boundary or a gradational depositional edge. Three of the proposed appraisal wells plan to test the alluvial fan edge, however they are towards the end of the drilling schedule due to the likely small uplift in volumes resulting from a successful outcome, and viability dependent on development drilling results. The other key uncertainty is the trapping method and overall accumulation extent to the NE and southern directions. With the currently assigned pool boundaries, mapping and velocity modelling, there is in sufficient relief downdip of existing wells to close the structure, especially at the shallower levels. There is also no large-scale faulting visible on seismic near to the current mid-case field boundaries to provide a robust trap. Stratigraphic pinchout is possible, however current models predict a non-net extent running roughly parallel to the basin bounding fault, leaving room for a potential sand fairway above contact to be appraised south and north east of the field. Currently fault and horizon mapping across this area is a hybrid of multiple datasets, which lack resolution in some prospective areas. A consistent detailed regional interpretation should be undertaken before exploration drilling locations are finalised.

Ten wells are proposed in the Amosing E & A campaign, comprising three field appraisal (FA), three Near-field Appraisal (NFA), two Near field Exploration (NFE) and two exploration wells. A summary of the well locations is provided in Figure 5-6 with exploration wells added. A seismic line through E & A well locations shown in Figure 5-7.

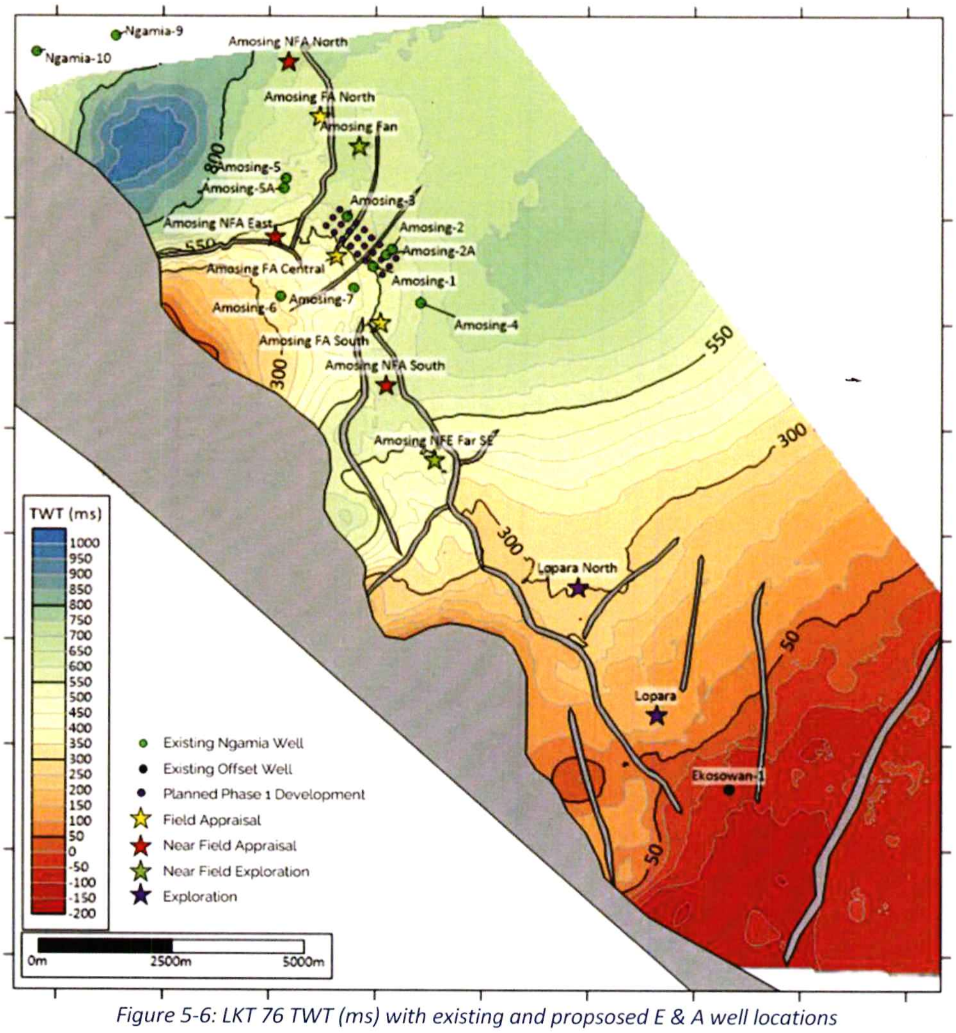


Figure 5-6: LKT 76 TWT (ms) with existing and propsosed E & A well locations

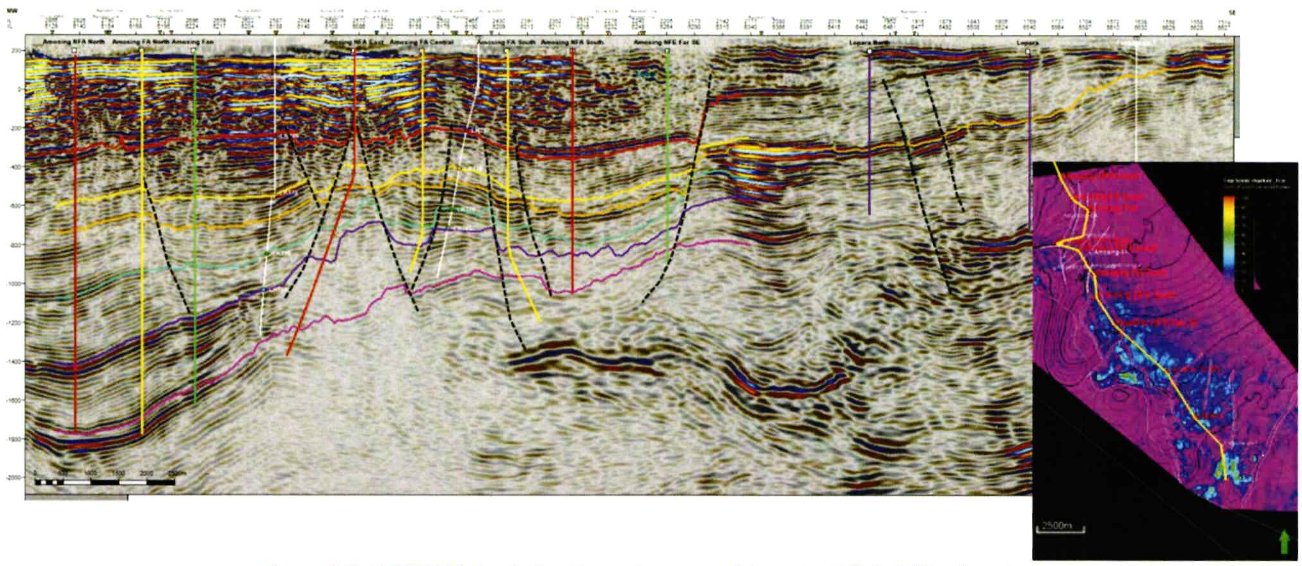


Figure 5-7: N-S TWT Seismic line through proposed Amosing E & A drilling locations

5.5.2 Field Appraisal

Three field appraisal locations have been selected on Amosing in the north, central and south of the field. The northern target is the most favourable of the three, proving up a relatively large volume if successful and potentially extending the oil-bearing segment penetrated by Amosing-5 approximately 2km to the NW. The well targets a structural nose, separated by what appears to be a relatively minor discontinuity on seismic, providing a high likelihood of success. The deepest section of the well also penetrates some reflectors which represent a downdip expression of those targeted by the Amosing Fan exploration well. Results from Amosing FA North will therefore provide useful information to derisk this target.

FA Central and South both target the proximal western edge of Amosing, but drilling is contingent on encouraging results from Phase-1 development pattern drilling, which may (through direct penetration or inferred via production performance) provide a greater control on the eastern extent of the alluvial fan. Proposed drilling trajectories are deviated such that they remain within the same mapped segment throughout the targeted interval.

5.5.3 Near-Field Appraisal

Three NFA locations have been identified, with the aim to prove up increased extents of the Amosing accumulation. The southern target presents the largest potential uplift in volumes, testing whether oil is located at the saddle point between the Amosing structural nose and the adjacent area rising updip to the south. The well aims to penetrate the structure in a sufficiently updip location to encounter a reasonable oil column, while being located far enough away from the basin bounding fault so as to minimise the likelihood of encountering non-net alluvial fan facies. Currently, the well targets the crest of a local structural saddle and prognosed depth is similar to Amosing-4 at LKT-78 level. Further refinement of the location is recommended following FA results, as well as further seismic and velocity analysis.

NFA North is highly dependent on FA Forth and represents a downdip appraisal at similar depths to oil-bearing intervals further south in the field. The well would target Amosing sediments at a location most distal on the structure to date, providing a key calibration point for depositional modelling. A deep TD of this well or Amosing FA north would also allow for facies potentially similar to that targeted by Amosing Fan to be appraised, albeit in a downdip location.

NFA East would only be drilled following a successful Phase 1 development campaign and field appraisal results suggesting a limited outboard extent of the alluvial fan facies. The well would target the updip section of the Amosing-5 segment.

5.5.4 Near-Field Exploration

Two near-field exploration wells are proposed near Amosing. NFE Far SE targets the area updip past the structural saddle to the south of Amosing. The target is dip closed to the north, fault bound to the South and north by either the main basin bounding fault or major splays of it. In the event of a successful NFA South result, there is a scenario that in which this well finds an accumulation in direct communication with the Amosing field.

Amosing Fan was a target identified in the previous FDP which targets amplitude-driven basin floor fan facies. tied to oil and gas bearing sandstones penetrated in Amosing-2 and -3. The increase in seismic amplitudes may be indicative of improved reservoir quality. The well will test a combination structural- stratigraphic trap that has significant aerial extent, and if successful, could open a new play in the basin. The amplitude map in Figure 5-8 shows the Amosing Fan target as a bright seismic amplitude anomaly within the Lokone Formation. Another similar fan-shaped anomaly is present to the north adjacent to the Ekales field, and a smaller anomaly exists within the Ngamia field. This well will also appraise the shallower Auwerwer reservoirs at a point where some may still lie above contact.

Amplitude Map of regional LKT 65 Marker

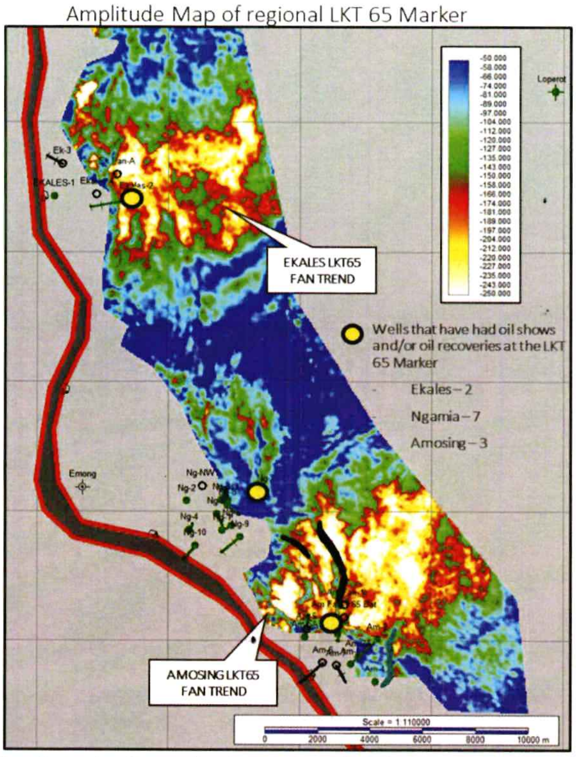


Figure 5-8: Map showing seismic amplitudes extracted at the LKT-65 marker within the Lokone Shale

5.5.5 Exploration

Two exploration wells are proposed to the South of Amosing. Lopara was previously identified, while Lopara North represents an additional trap, located closer to the Amosing field. Both are mapped as three-way traps bounded on the western side by the South Lokichar Rift-bounding fault, and on the eastern side by a seismically mapped westward dipping normal fault. Lopara may also be helped by a stratigraphic trapping component evidenced by results of the Ekosowan-1 well immediately south of the proposed Lopara-1 location, which encountered several hundred meters of tight rift facies with oil and gas shows. The seismic interpretation shown in Figure 5-7 shows a clear change in seismic amplitudes between Ekosowan and the Lopara North / Lopara proposed locations, which is potentially due to increase in reservoir quality sandstones. The package at Lopara North appears thicker and brighter, however caution must be taken to ascertain facies pre-drill, given the results of Emong-1 to the north which drilled similar brights and encountered non-reservoir. The current Lopara North well is heavily deviated to target multiple layers close to where they abut the mapped fault splay. Improved seismic mapping and depositional model may help refine this exact trajectory. The amplitude map in Figure 5-8, which is an extraction along LKT76 interpretation shows bright amplitude anomaly in Lopara and Lopara North, also in other Amosing fan targets. Fault interpretation also indicates possible trap separating the exploration targets.

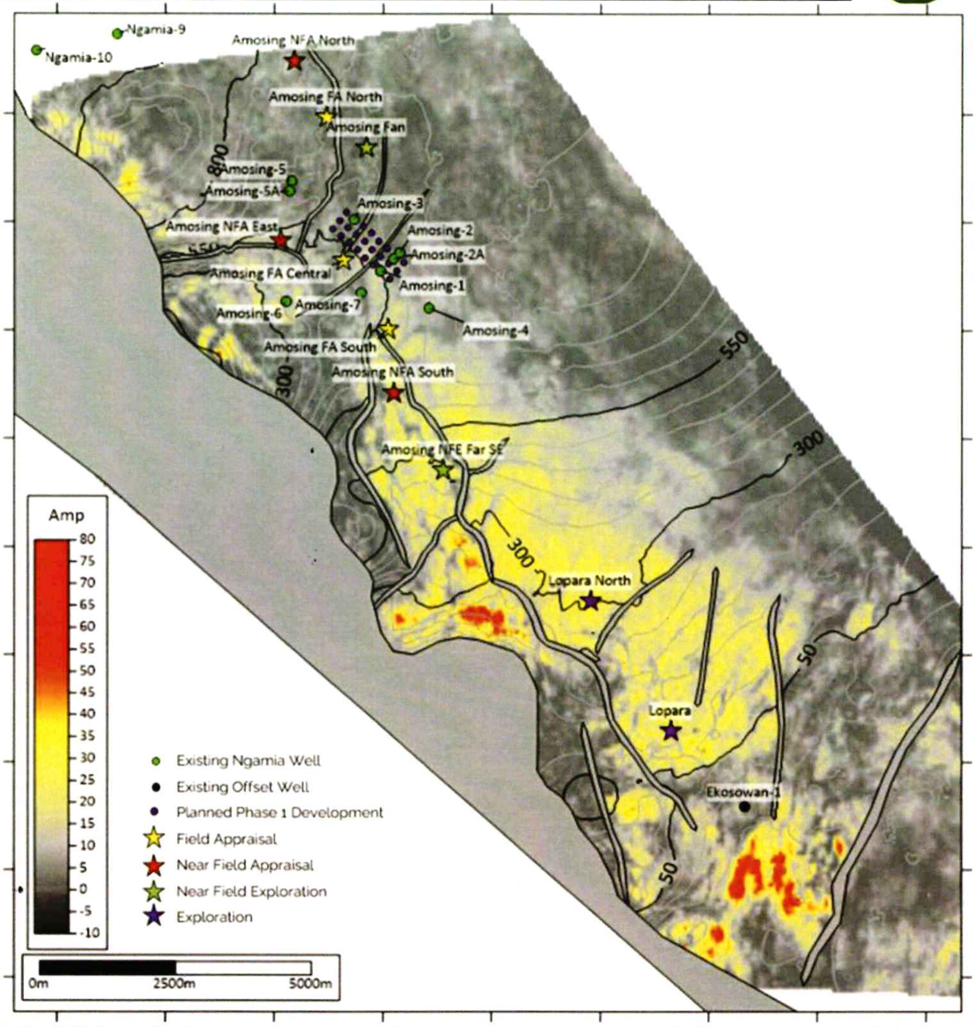


Figure 5-9: LKT 76 amplitude extraction potentially showing changes in reservoir facies across the wider Amosing area

5.6 Etom

5.6.1 Summary

The Etom reservoirs have four penetrations including the Northern Emekuya well, however the tighter structural nature of the accumulation means the lateral extents are better constrained than in Ngamia and Amosing, meaning less appraisal drilling is required. A key uncertainty within Etom is the productivity of the Lokone reservoirs which, although having improved poro-perm characteristics compared with the Lokone in Ngamia, may behave differently to the overlying Auwerwer formation. This will be appraised through the drilling of initial development wells in the field, as opposed to dedicated E & A activities.. Well Etom-3 encountered non-net alluvial facies, and in a similar vein to Ngamia and Amosing, additional appraisal is required to delineate its extent. All three proposed field appraisal wells focus on the larger Lokone interval and comprise volume which is included within high case estimates, representing a high likelihood of success for these wells. Each penetrates an undrilled segment in the field. A single exploration well targeting the northern Ekamongo prospect is also proposed. All four E & A well have an additional secondary target in the overlying Auwerwer formation.

A summary of the well locations with exploration wells added in Figure 5-10. A seismic line through E & A well locations is shown in Figure 5-11.

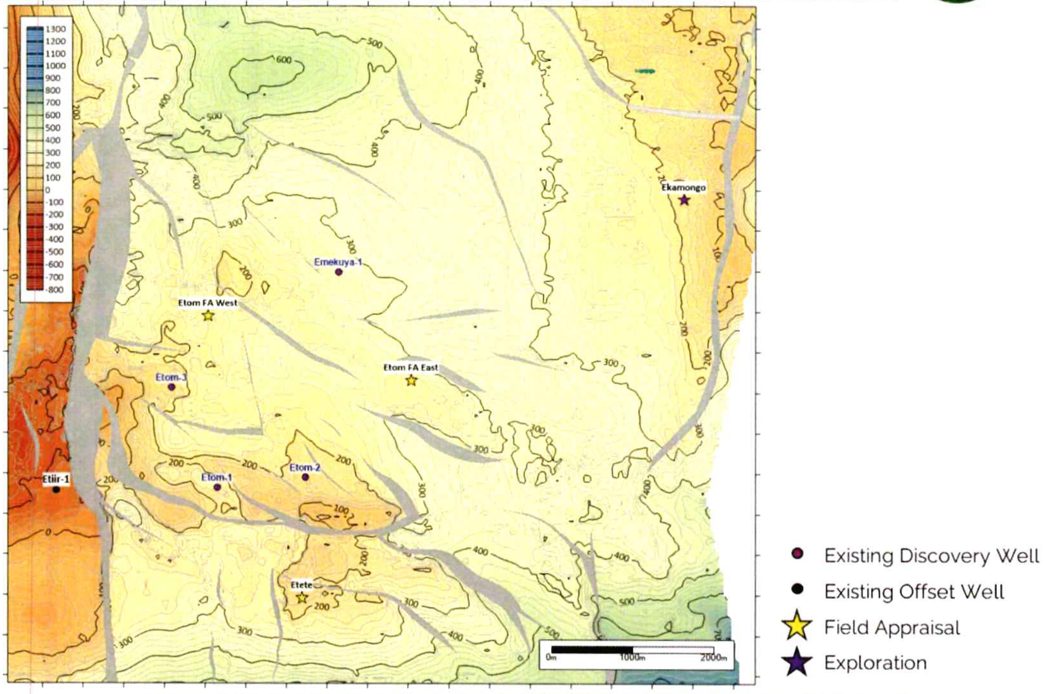


Figure 5-10: Etom Lokone Shale Depth (m) with existing and proposed E & A wells

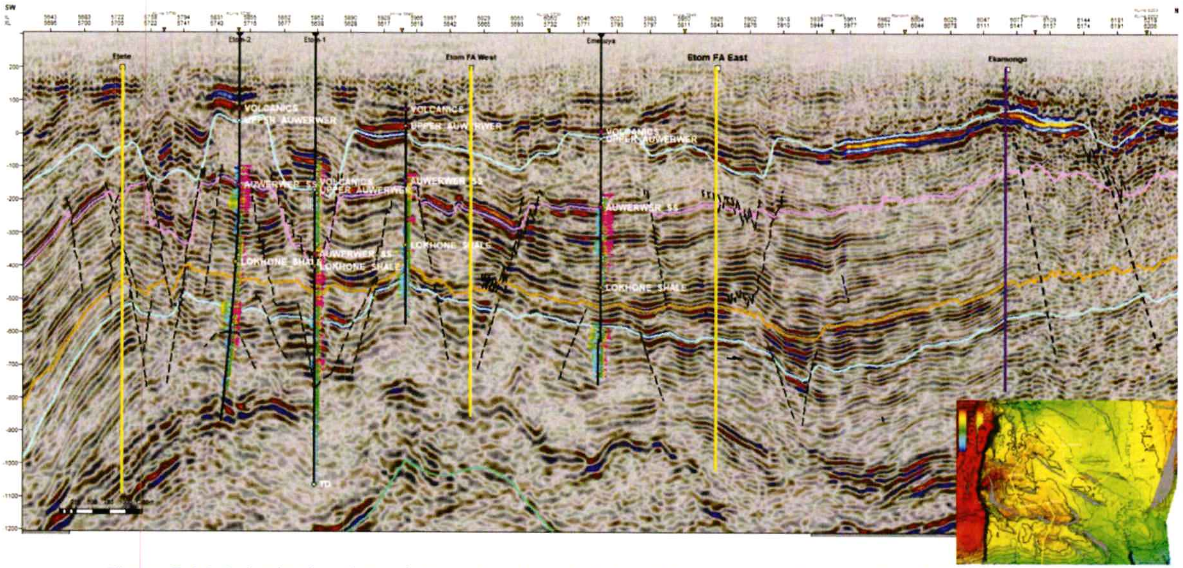


Figure 5-11: Seismic Line through Etom-Emekuya E & A well locations; with saturation (left) and porosity (right) logs

5.6.2 Field appraisal

Three field appraisal wells are planned within the Etom-Emekuya Lokone accumulation. The Etete target lies approximately 1500m due South of the Etom-2 well, and is separated from the main field by a seismically mapped fault with variable throw along its length. The proposed well location is at the crest of this fault segment, sufficiently far away from the basin-bounding fault to minimise the risk of encountering non-net facies. If the fault throw is insufficient to seal this segment, contacts will be in line with those encountered by Etom-1 and -2. There is also some internal faulting in this area, which may compartmentalise the segment further, requiring additional appraisal. The current well is planned to be vertical, crossing through one of these smaller internal faults within the Auwerwer section. An alternative option would be to deviate the well down the fault plane. This well will also test an isolated closure at Auwerwer level.

Etom FA West targets a relatively large undrilled fault segment along strike from Etom-3 which encountered non-net facies. Seismic amplitudes at the Lokone interval suggest this to be a more favourable location with facies more similar to that encountered at Etom-1 and -2. The well is located at a crestal location to maximise potential hydrocarbon column. It also tags a local high at Auwerwer level.

Etom FA East targets a smaller, lower relief fault compartment immediately NE of the Etom-1 and Etom-2 segment and due east of the Emekuya well. Contacts could be aligned with either compartment, or be entirely isolated, with a new contact set. If a shallower structure, and/or deep contacts are encountered, further appraisal may be suitable further east. At Auwerwer level, the well targets a narrow crestal ridge which is potentially up dip of Emekuya-1 and in the same compartment. This well also tags some brights in the deeper Lokone section which pinchout updip of the well and have not currently been targeted.

5.6.3 Exploration

One exploration well is proposed to target the previously identified Ekamongo prospect which lies north-west across a structural saddle from Emekuya. At Lokone level, the prospect is the two-way dip closed structure with fault seal provided by an N-S trending fault to the east and multiple E-W trending smaller fault splays to the north. There is an additional smaller throw fault which may divide the prospect into two segments. a successful result would lead to additional appraisal further north. At Auwerwer level, the fault splays still present as possible traps. The structure is also mapped to close towards the north at this level, although seismic quality is poor.

5.7 Agete

5.7.1 Summary

The Agete Auwerwer reservoirs have been drilled by only two wells to date, one of which encountered water-bearing reservoir; the fault bounds, and narrow contact range leave relatively little room for additional appraisal. Much of the volumetric uncertainly lies in the unknown reservoir quality towards the basin bounding fault to the west. Two field appraisal wells and one near-field exploration target are proposed.

A summary of the well locations is provided in Figure 5-12. A seismic line through E & A well locations shown in Figure 5-13.

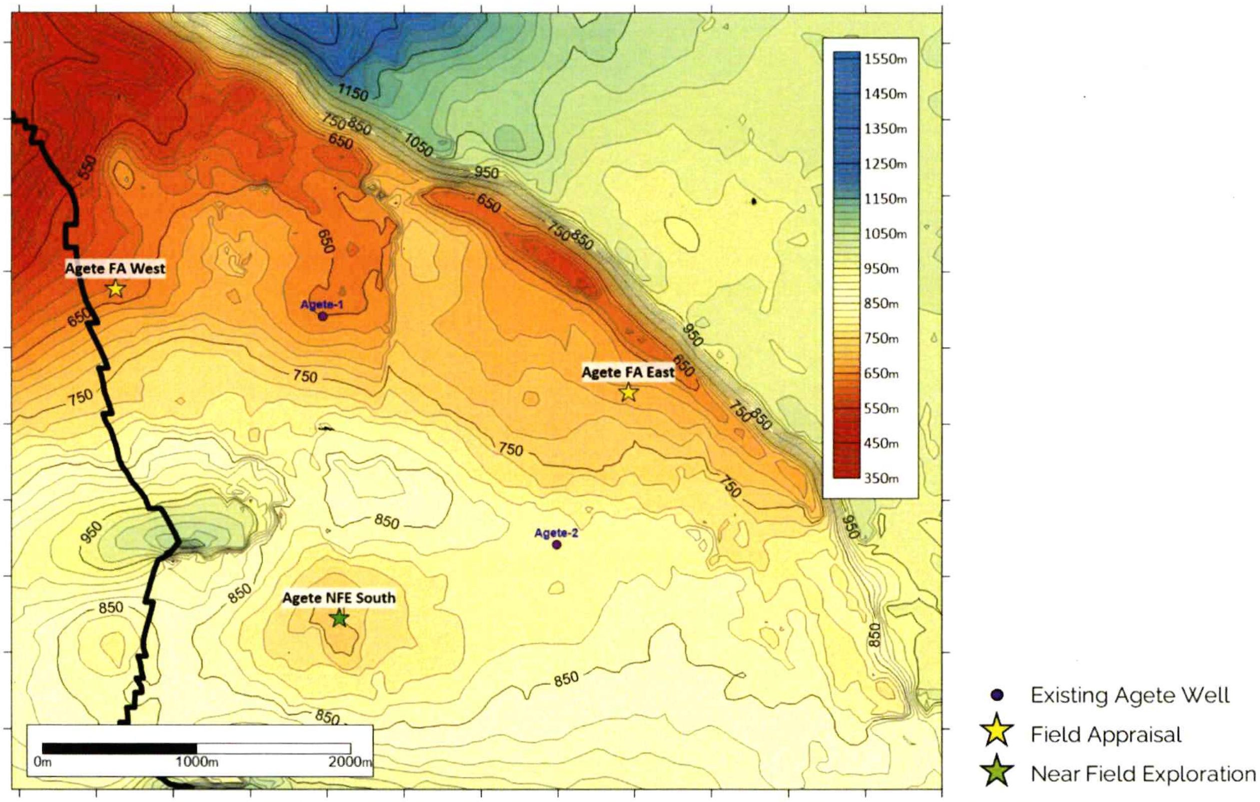


Figure 5-12: Agete LKT78 Depth Surface with basin bounding fault trace to West and E & A Locations

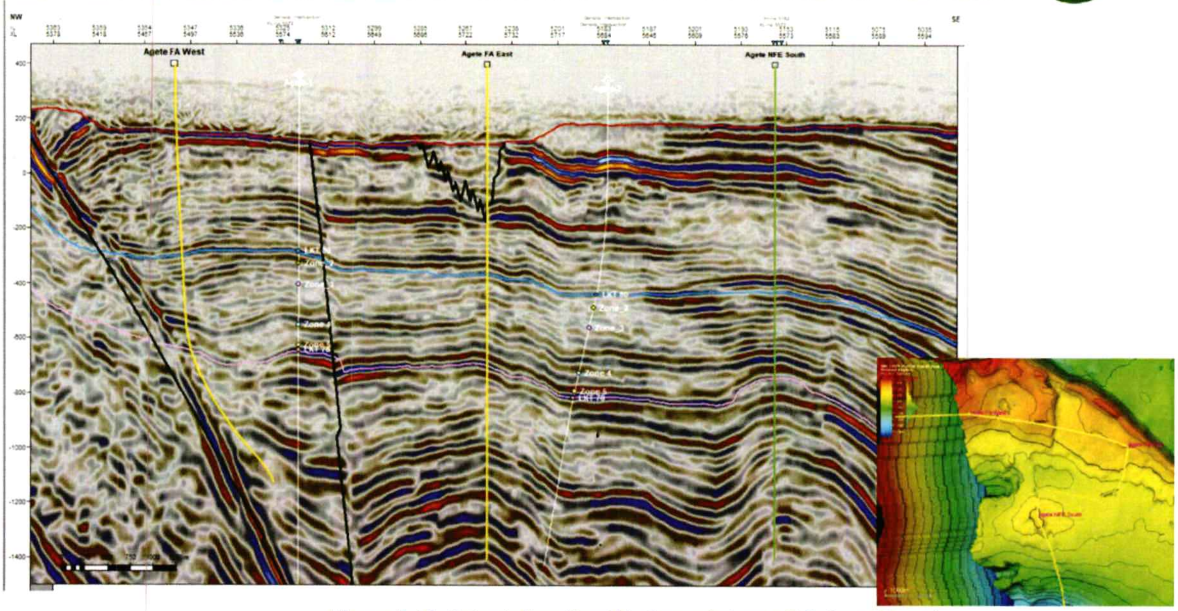


Figure 5-13: Seismic line (Depth) through Agete E & A well locations

5.7.2 Field appraisal

Two FA wells are proposed to the east and west along strike from well Agete-1. Agete FA west is located updip of Agete-2 and designed to prove up the eastern compartment of the field which is separated from the proven accumulation by a small NS trending fault. The well location is currently selected at the midpoint between the structural crest and expected contacts to try and best appraise the contact level.

A western field appraisal well would be used to delineate the extent of any non-net alluvial fan facies. Further seismic and velocity analysis would help to place the western well to maximise appraisal information. The current proposed trajectory deviates close to the basin bounding fault, as seismic character looks similar to Agete-1 as opposed to the more bleached out or tramline reflectivity associated with non-net facies encountered elsewhere in the basin.

5.7.3 Near-field exploration

A single well, Agete NFE south, targets an Auwerwer four-way dip closure which isolated from the main Agete field based on current seismic interpretation and velocity modelling. Structural relief increases with depth, with a structural relief of 75m at LKT78 level.

5.8 Twiga and Ekales

The other fields high-graded for development are Twiga and Ekales. Currently, no E & A activity is proposed within the vicinity of these fields, this is due to the fields themselves expected to be sufficiently appraised through development drilling. Figure 5-14 shows the high case extents of both fields are drilled out through the proposed well pattern. Both structures comprise relatively narrow structural noses with steep dips to the North and South. Alluvial fan extents have been appraised by Twiga 2A and Ekales-1 wells. The internal faulting of both fields is also lower, allowing for little potential for upside in terms of unpenetrated fault blocks.

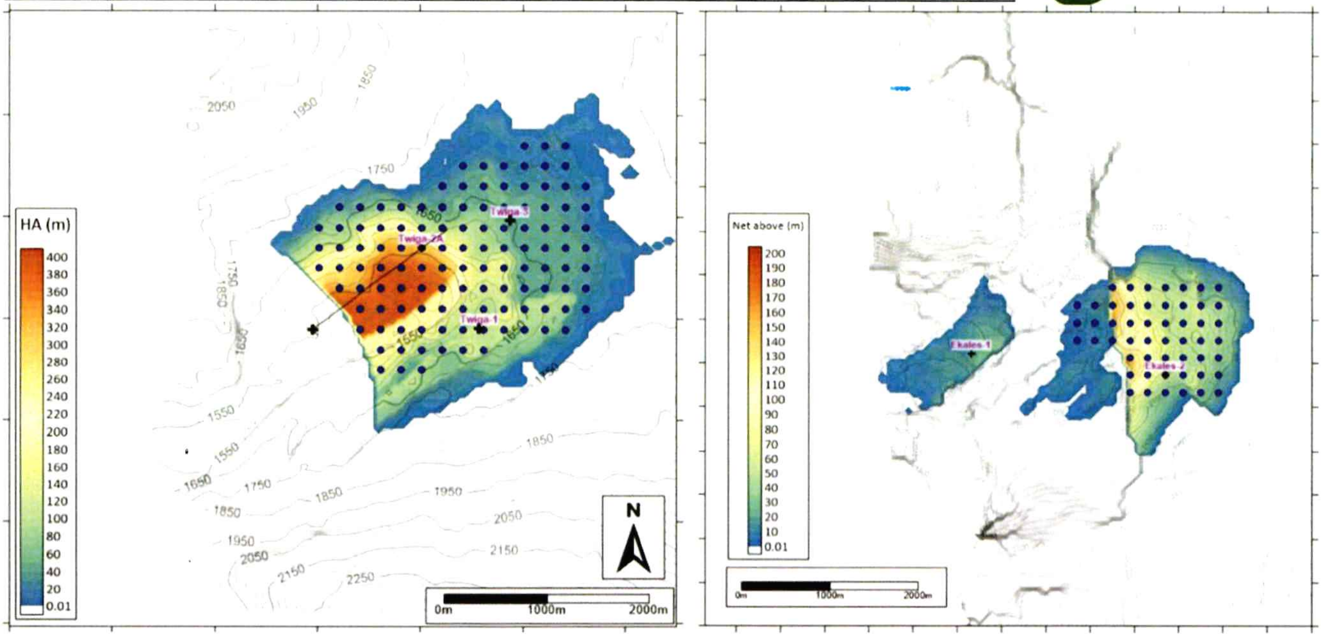


Figure 5-14: High case net pay maps for Twiga (left) and Ekales (Right) with notional pattern drilling locations

5.9 Sungura Terraces

Sungura terraces are undrilled prospects located south of the Ekunyuk discovery (Figure 5-15). They are comprised three separate three-way dip closures. Currently there are a limited number of 2D seismic lines covering the prospects.

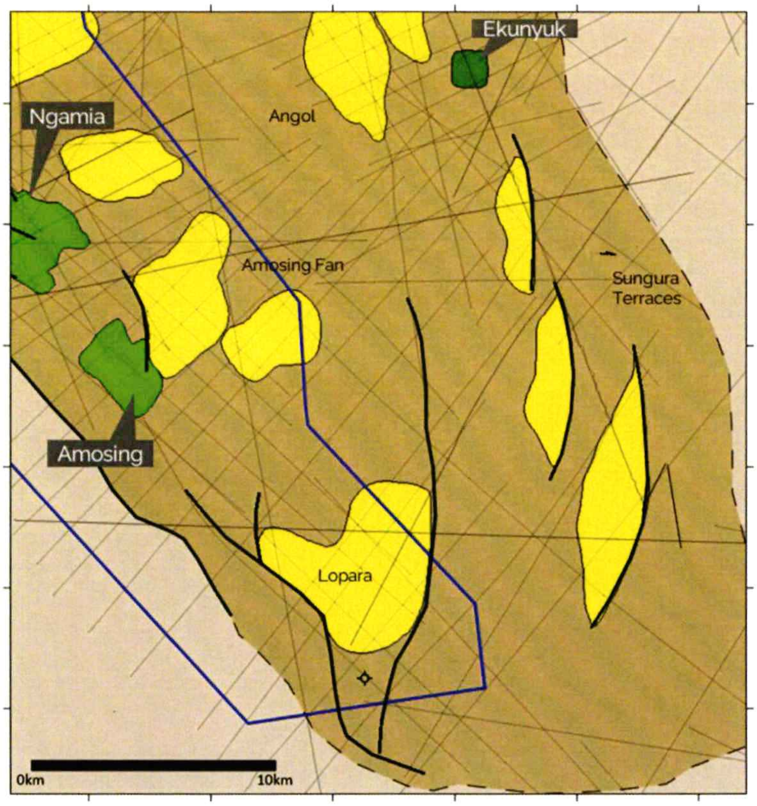


Figure 5-15: Map showing southern leads / prospects in yellow, existing fields in green and seismic outlines (blue 3D, grey 2D)

A seismic line from Ekunyuk well to the prospective area is shown in Figure 5-16. A further east-west seismic line is shown in Figure 5-17. The interval of interest is LKT 60 (Lokone formation).

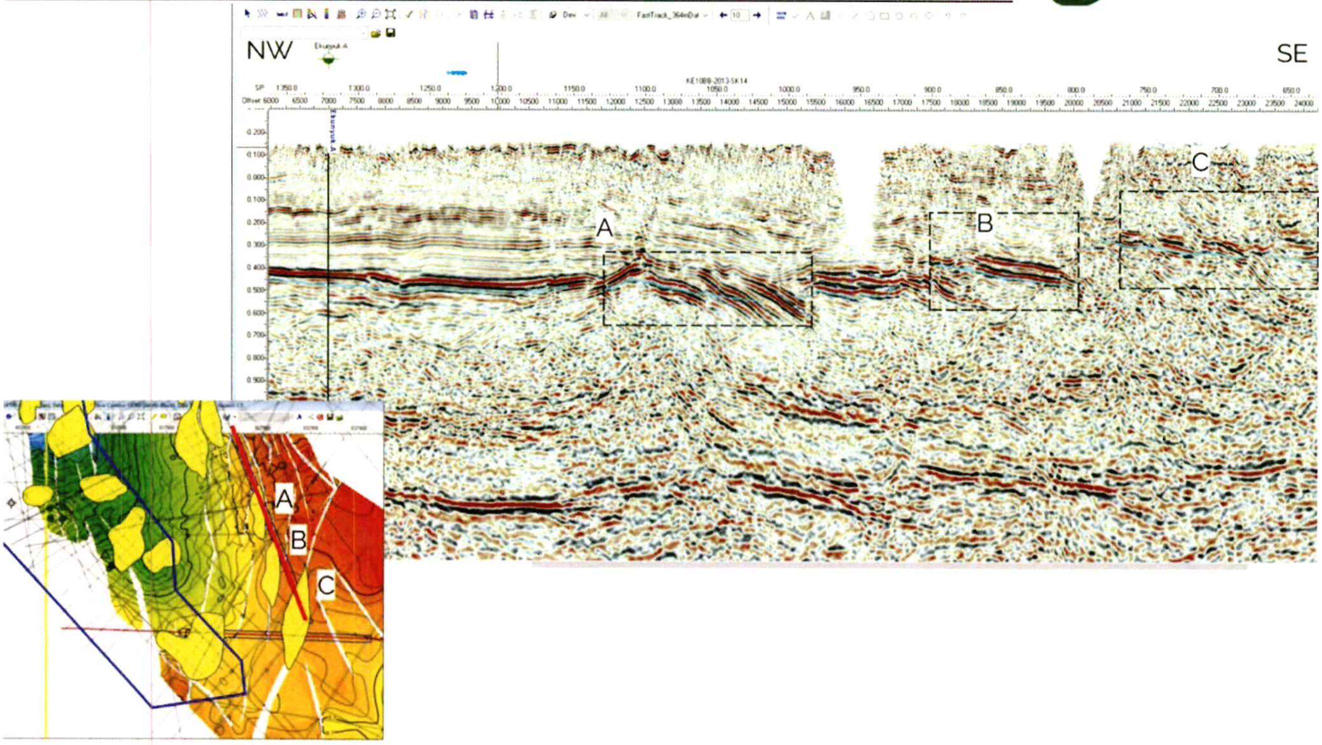


Figure 5-16: 2D Seismic Line from Ekunyuk to Sungura Terraces Leads

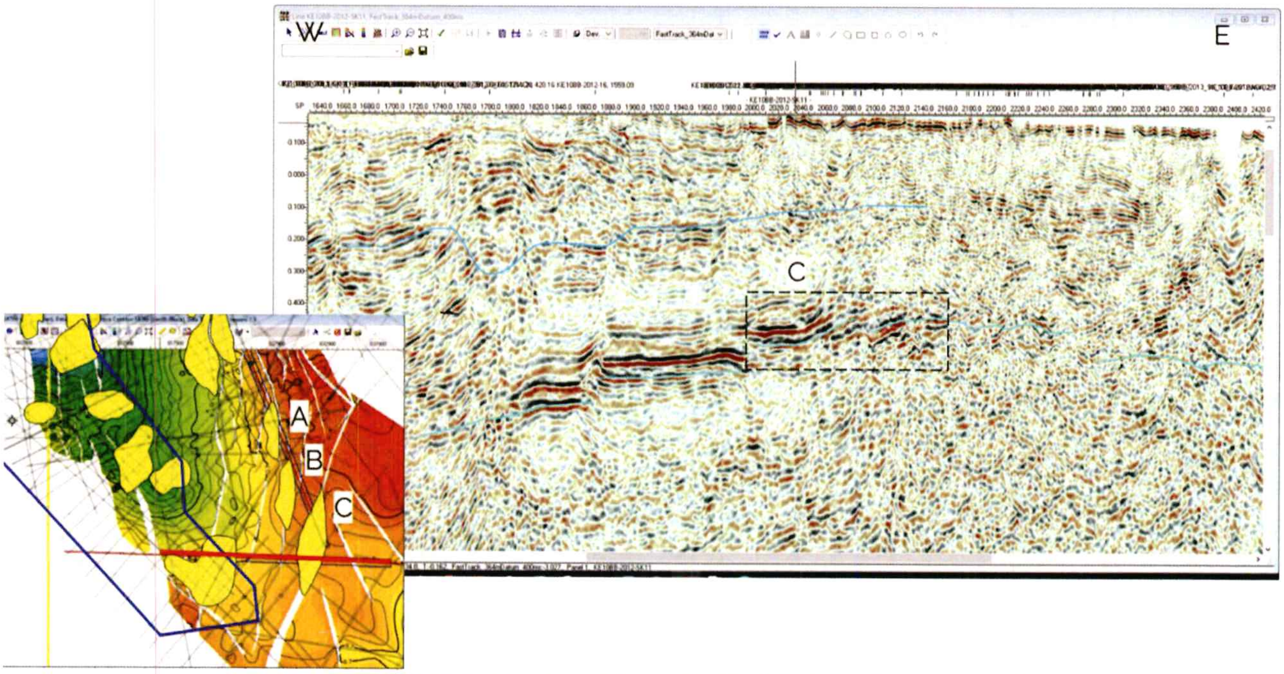


Figure 5-17: 2D Seismic Line from through the Southern Sungura Terraces Lead

Presence of pay in Ekunyuk indicates working petroleum source and migration elements. While there is some risk in reservoir as Lokone formation is generally poorer than Auwerwer formation, there has been indication of good reservoir in Lokone as discovered in Etom. Trap is the main risk in the Sungura terraces, especially due to limited 2D seismic line coverage. Five new 2D seismic lines are proposed (Figure 5-18, lines shown in pink), in order to improve structural interpretation in the area and de-risk the trapping element. The total length of the 2D seismic lines is roughly 50 km. Table 5-3 shows approximate cost associated with the new seismic acquisition.

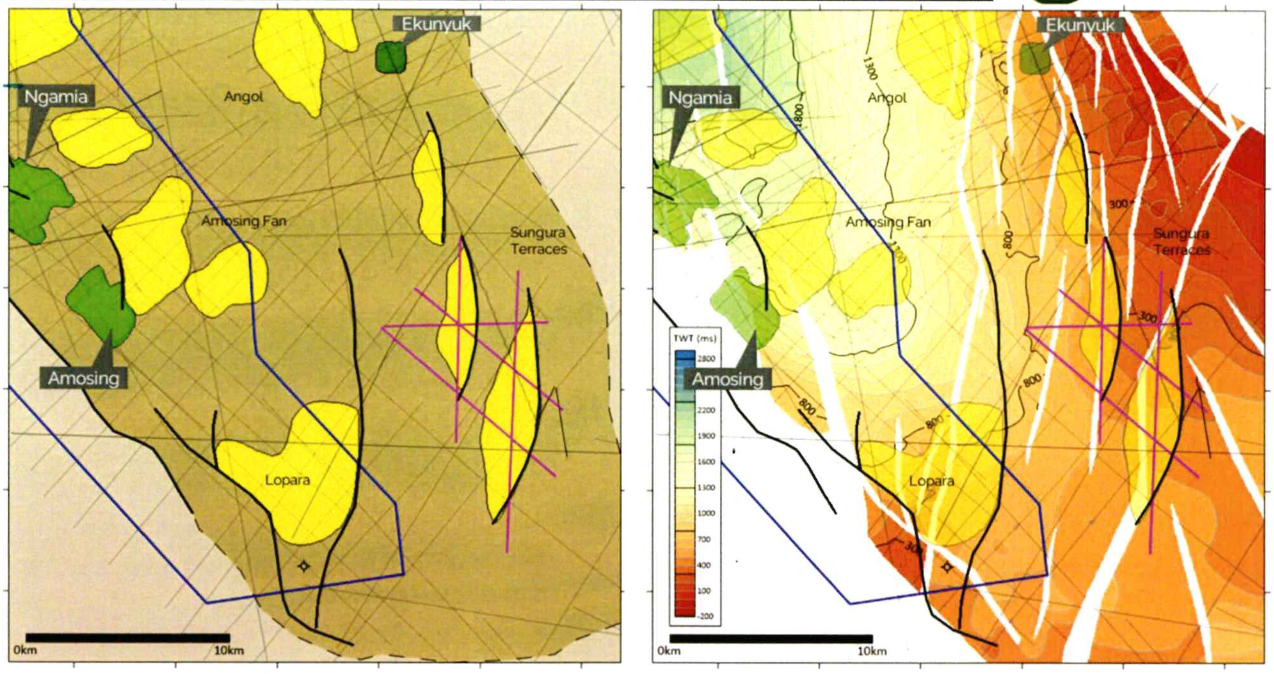


Figure 5-18: Proposed 2D Seismic Lines (in pink) through Sungura Terraces leads on lead map (left) and LKT60 TWT (right)

Table 5-3: Cost estimates for 2D seismic programme across the Sungura Terraces leads

Item	Cost assumption (US$/km)	Cost for 50 km line (US$)
2D Seismic Acquisition	16,500	825,000
2D Seismic Processing	500	25,000
Interpretation	200	10,000
Total (US$)		860,000

6 PRODUCTION FORECASTING AND RESERVES

Production forecasts have been built for the two phases of planned development of Blocks 13T and 10BB using a combination of simulation modelling and analogue type curves.

Phase 1 of the project is designed to generate early production from the blocks, develop the export capability and gather reservoir data to optimise the further development of the basin. Key information will be the response of the production wells to continuous water injection, the time of water breakthrough and the development of water cut. Additionally, the performance of artificial lift and maintaining heat in the crude through the production system will be analysed. The plan calls for production and injection through 48 wells, with 24 in Amosing and 24 in Ngamia, to be drilled from a total of four well pads. To accelerate first oil, existing wells will be used as far as possible and the pattern flood anchored to these locations. These wells have been suspended with the lower completions in place and, in some cases, with artificial lift pumps in the well. In Amosing, Wells Am-1, Am-2A and Am-3 are planned to be used, with Ng-3 and Ng-11 used in Ngamia. The remaining wells will be drilled using a single rig with work commencing in the second half of 2026. The wells will be produced through two Early Production Facilities (EPF) located in each field. These are planned to have a nominal capacity of 10,000 stb/d of oil each.

These EPFs are planned be used from December 2026 to the start of 2032 when a Central Processing Facility (CPF) is planned to be available with increased capacity to allow for the further development of the basin. Ahead of the CPF being commissioned, further drilling of the Amosing and Ngamia and Twiga fields is planned using three drilling rigs to maintain the plateau for as long as possible. Drilling is planned to commence in early 2031 with pads being drilled and completed prior to being brought onto production. Pads available ahead of the CPF commissioning are planned to be tied into the EPF system to maximise dry oil production.

For the fields to be developed under Phase 1 and the early part of the Phase 2 (Amosing, Ngamia and Twiga), development forecasts have been based on the results of dynamic reservoir simulation models described in Sections 4.6.1.12, 4.6.2.9 and 4.6.3.10 . The extended production history of the Amosing and Ngamia Early Oil Production System (EOPS) and the Ngamia water injection trial were used to improve the calibration of those reservoir models. The Twiga model has used DST results to improve the calibration of the permeability array. For the later fields to be developed (Ekales, Agete and Etom) forecasts have been based on well production type curves based on initial rates and decline factors derived from simulation model results.

For Phase 1, the simulation models have been run separately for Amosing and Ngamia constrained to the planned limits of the EPF systems. As the production is routed to the CPF the simulations are run unconstrained with no field capacity limits but with wells scheduled according to the drilling schedule. The simulation results are used as production potential curves for oil, gas and water vs. cumulative oil recovered. These are combined with the type wells based on the planned drilling schedule. On a monthly basis the sum of the unconstrained production rates is calculated and the current system constraint (oil, water or gas) established. Production is then cut to match the first / largest broken constraint. The calculation method is consistent with commercial software such as Petro VR.

GEBV recognises that performance of the field under sustained water injection is one of the key uncertainties of the project. The phased approach is driven by the need for performance data which can be used to optimize the remainder of the Ngamia and Amosing developments and the other Phase 2 fields. In the event of well performance being lower than currently modelled the mitigation strategy will be to identify the major issues and adapt the development plan accordingly. The main foreseeable challenges are:-

- Lack of well productivity which would require additional wells to be drilled to maintain a 20 kstb/d plateau. This would require an increase in CAPEX which is not quantifiable at this stage.
- Earlier than expected water breakthrough which may be severe enough to require mitigation through water shut-off. Options for controlling zones with high watercut would require data from PLT operations. Zonal isolation options are discussed in Appendix D (Section 17).

6.1.1 Network Description

Figure 6-1 shows a representation of how the fields are connected through the constraint calculations. The initial simulation models for the Phase 1 production are run constrained by the planned EPF limits. This is appropriate as Ngamia and Amosing's production is not commingled. As the basin moves towards Phase 2, the CPF becomes available and multiple fields are sharing the facilities the calculation is adjusted. Table 6-1 shows a summary of the key constraints. This is the system represented in the constraints model.

Table 6-1: Model Central Processing Facility Constraints

Central Processing Facility Oil Processing Capacity (Stb/d)	54,350
Annualised Average CPF Oil Plateau (Stb/d)	50,000
Annualised Average Water Handling Capacity (Bwpd)	200,000
Facility Average Operating Uptime	92%
Well Uptime	95%

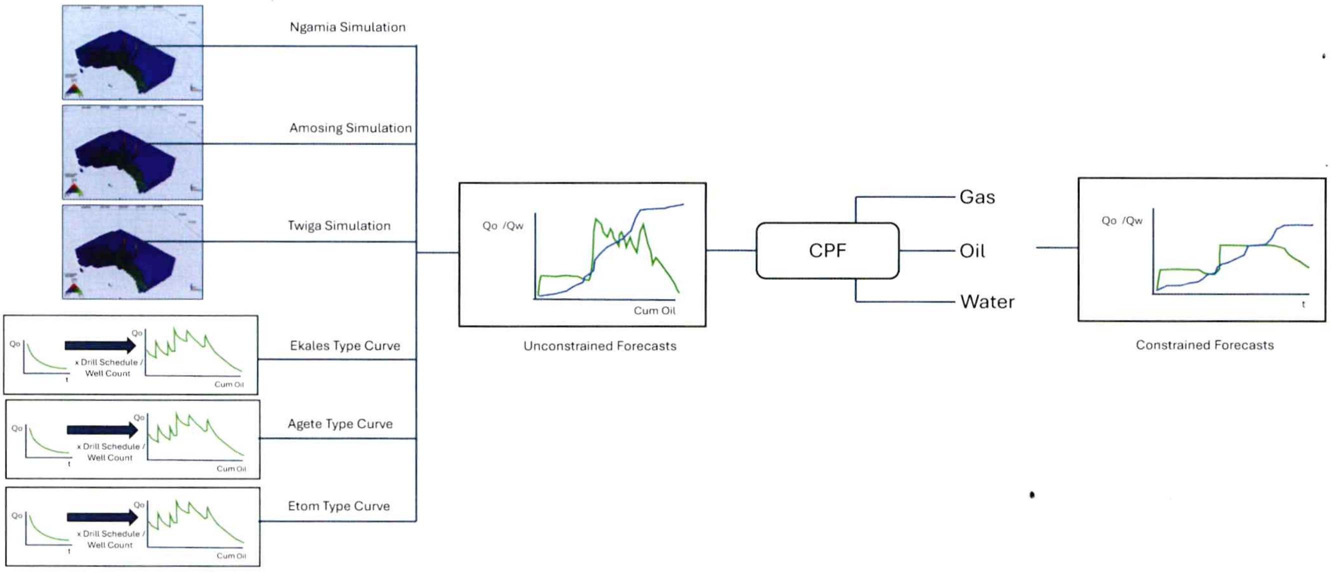


Figure 6-1: Schematic of Forecast Modelling Configuration

The (unconstrained) production tables of rates vs cumulative oil are exported from the simulation models for Ngamia, Amosing and Twiga. For the Ekales, Agete and Etom fields similar tables are constructed by using well type curves combined with the drilling schedule to develop a field level forecast. The artificial lift type is implicit in the well production table used for look-up purposes. Phase 1 wells in Amosing and Ngamia are planned to have ESPs installed to simplify the system and avoid processing the large volumes of power fluid required by jet pumps through the EPF facilities. As the CPF becomes available there may be an opportunity to use jet pumps in new wells to take advantage of spare ullage in the water handling and pumping systems. For Twiga and Agete due to the distance from the CPF, it is anticipated the ESPs will be run in all wells to allow for back pressure through the pipeline system to be overcome. When Etom is developed, multiphase pumping may be implemented in the flowline network to allow lower wellhead back pressures to be realised.

The well production profiles from the tNavigator models assume that wells are produced to 97% water cut and are then shut in. Similarly, the well type curves produce to 97% water cut. They are not re-opened once production has ceased.

Although there is the potential for production optimisation with selective isolations in producers and injectors, these are not included in the base production forecasts. Given the nature of artificial lift required, production logging or other types of accurate well monitoring are believed to be challenging and identification of watered out zones in producers is not considered to be routine. However, ESP type completions may be able to use Y tools to allow for some logging and monitoring to take place, depending on pump size used.

6.1.2 Development Schedule

Initial development will use the key Amosing and Ngamia Auwerwer fields. Phase 1 drilling is expected to commence in H2 2026 to allow for early production and data gathering. The initial wells will be drilled from the Amosing-1 pad before moving to Ngamia and drilling the 22 wells planned there. Finally, in phase 1, the second Amosing pad and a final 3 wells on the

Amosing-1 pad will be drilled and completed to bring the total number of wells to 48. In order to drill the significant number of wells required three drilling rigs have been assumed with Phase 2 drilling commencing at the start of 2031. In Phase 2, to maximise drilling productivity and to minimize rig move times, all planned wells in each pad will be drilled before moving to the next pad. It has been planned that the completion of the wells will be done with a smaller, dedicated completion rig to minimize costs. The pad order is designed to move away from the core, Phase 1 wells to move distal pads targeting thinner hydrocarbon thicknesses in later years. Initial drilling at each reservoir is focused where the hydrocarbon column height thickness is at its greatest and well productivity is maximised.

The current development plan envisages an inverted five-spot pattern to provide pressure support through water injection from day one to support oil production. In the drilling program, water injection wells are drilled in the same well batch as the associated producers to ensure that the producer-injector ratio is maintained at one.

Figure 6-2 shows the drilling schedule associated with the field development. Drilling begins in 2026 and is initially focused on the best quality areas of Amosing and Ngamia. Phase 2 drilling begins in 2031 and continues to maintain the 50,000 stb/d plateau

For fields on production, the constraints system will produce at the facilities oil capacity and maintain the oil plateau as long as no other constraints are contravened (i.e. water handling capacity). When a constraint has been reached within the model, the system will reduce all fields in proportion to their field potential to honour all system constraints. The constraint calculations cannot perform production optimisation routines, and it has no logical capability to prioritise low water cut production if the oil plateau cannot be achieved due to excess water production. The combined production forecast for all fields is shown in Figure 6-3.

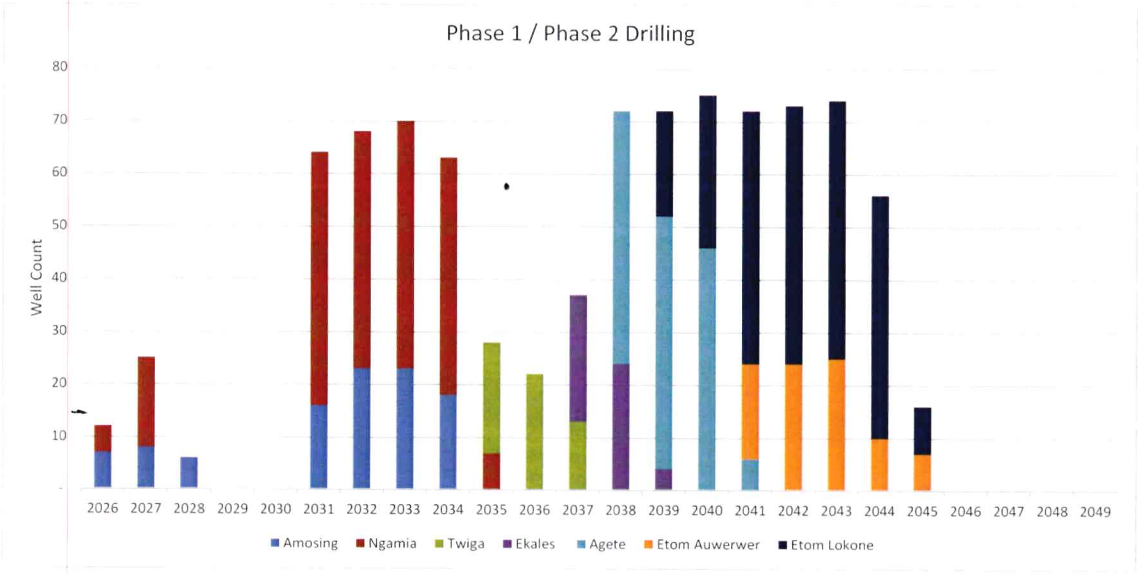


Figure 6-2: Drilling Schedule

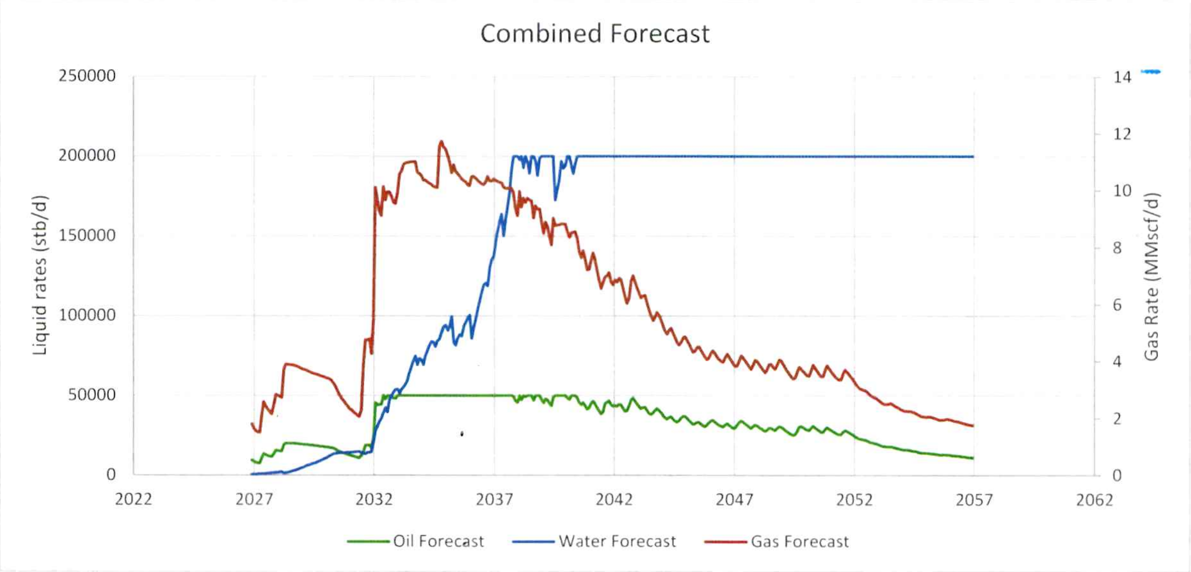


Figure 6-3: South Lokichar Basin Production Forecast

6.1.3 Resources Summary

Table 6-2 shows a summary of the STOIIP, total 1C, 2C and 3C resource volumes and the Best Estimate resources to the end of the licence for the development plans described in the previous sections.

Table 6-2: 1C, 2C and 3C Full Basin STOIIP and Contingent Resources

Field / Discovery	Reservoir	Gross STOIIP (MMstb)			Gross Life Of Field Resources (MMstb)			Best Estimate Resources to End of Licence (MMstb)
		Low	Best	High	Low	Mid	High	2C
Amosing	Auwerwer	186.0	252.0	394.0	46.4	71.9	114.1	54.3
Ngamia	Auwerwer	459.0	680.0	984.0	103.9	161.9	262.2	134.1
Twiga	Auwerwer	59.0	87.0	170.0	8.3	18.3	41.7	12.6
Ekales	Auwerwer	15.0	49.0	164.0	2.3	8.5	32.0	8.5
Agete	Auwerwer	125.0	212.0	362.0	17.1	36.8	79.1	36.5
Etom	Auwerwer	51.0	75.0	112.0	9.8	18.5	34.7	16.5
Etom - Emekuya	Lokone	173.0	327.0	598.0	36.0	80.0	173.2	63.4
Total		1,068.0	1,682.0	2,784.0	223.8	395.9	737.0	325.9

Notes:

- Resources to end of licence are produced through constrained forecasts to the end of December 2051.

6.2 Field management

6.2.1 Gas Usage / Storage

The South Lokichar Basin development will use solution gas from the developed oil reservoirs for power generation as well as for heating in direct fire burners during both the Phase 1 EPFs and the Phase 2 Central Processing Facility. For Phase 1 most of the gas is planned to be used for power generation as part of the EPF systems to provide the maximum amount of electrical power. Some of the gas will be utilized in the direct fire burners for heating and part of the gas will also be utilised as blanketing gas for the oil storage tanks. The project basis is to have no routine flaring other than startup, process upset and emergency situations. The only gas flared in routine will be if it's not an economically viable option to utilise the gas or recover and store it based on the cost benefit analysis e.g. very low-pressure vent and blanketing gas from the tanks.

The current estimates for power required at the CPF for Phase 2 are approximately 34 MW which will require an estimated 10.8 MMscf/d of gas to produce. GEBV's Phase2 production forecasts suggest that the gas production and usage is initially relatively well balanced with a slight deficit in gas to generate the estimated power (Figure 6-4).

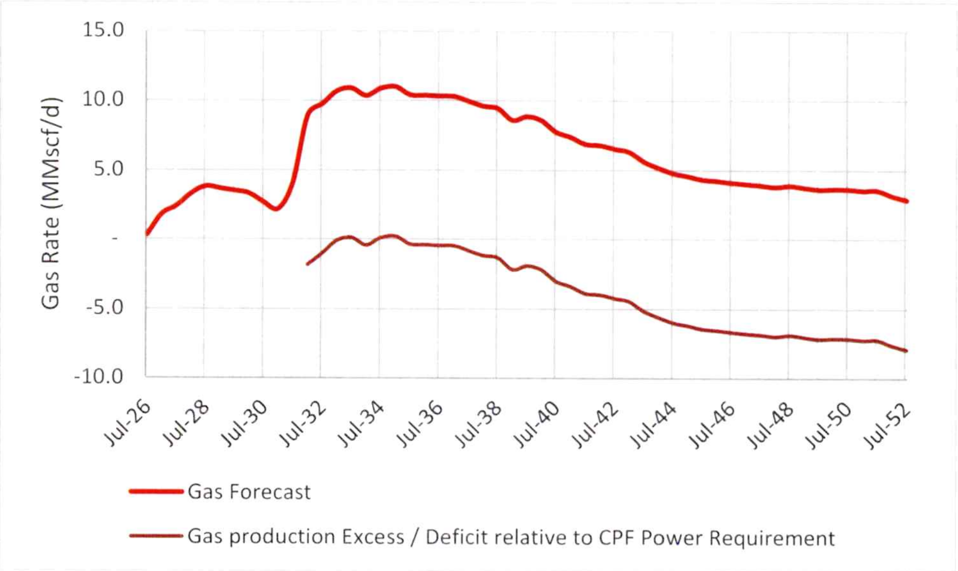


Figure 6-4: South Lokichar Forecast Excess Gas Production

It is planned for all possible gas to be used for power with any shortfall being made up through power import from the Kenyan National Grid or through diesel generation. Additionally, some gas resources have been identified within the fields planned for development in Phase 2 with gas caps observed in Ngamia, Amosing, Twiga and Etom.

Given the CPF location in the Ngamia area the key gas sands which could be used to produce additional gas, or store gas in the event of an excess are those in the Ngamia field. Gas has been logged in the Z0b, Z1a and Z1b Auwerwer sands in Wells Ngamia-2, -3, -4, -6, -8 and -11 (Figure 6-5) and in the Lokone in Well Ngamia-4. The Auwerwer sands re estimated to contain approximately 7.5 Bscf of gas.

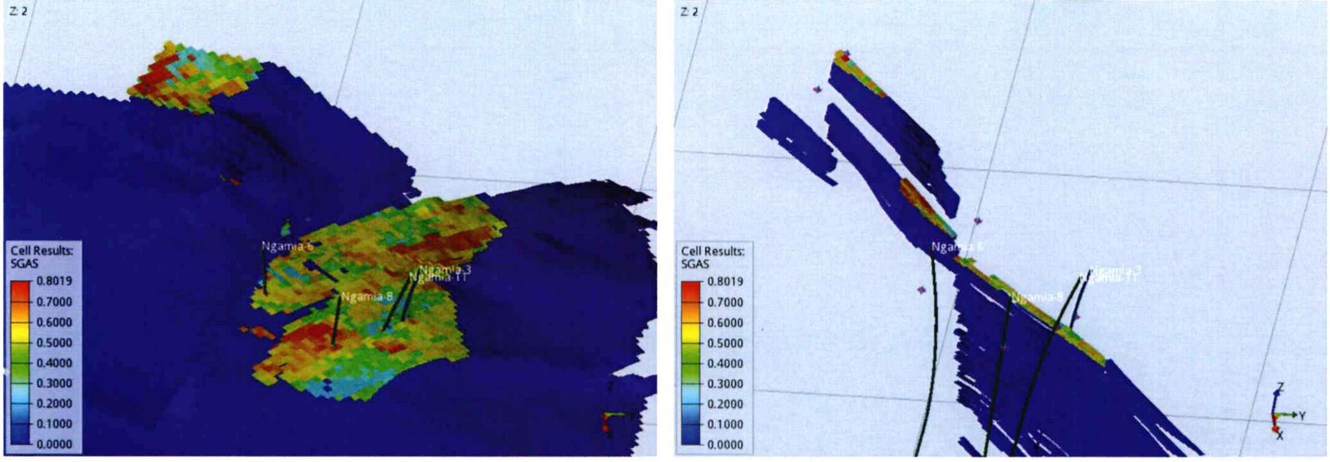


Figure 6-5: Model Gas Saturation and cross section around Ngamia-3, -6, -8 and -11

The phased development also means that wells in the Phase 1 area are expected to go through the gas caps associated with the Ngamia-3 / Ngamia-11 area (Figure 6-6). Depending on the precise timing of the requirements for further gas production wells which have watered out may be recompleted for gas cap production or storage. For example, simulation forecast Phase 1 wells Ng_P1, Ng_P4 and Ng_P2 which shut in in 2042, 2044 and 2045 respectively are all expected to be available for recompletion to gas production or injection to allow for efficient gas utilisation. Alternatively, Wells Ngamia-6 and Ngamia-8 have both encountered gas saturated sands in the Z0 and are not planned to be used in the pattern, waterflood development and would be available for gas storage, if required.

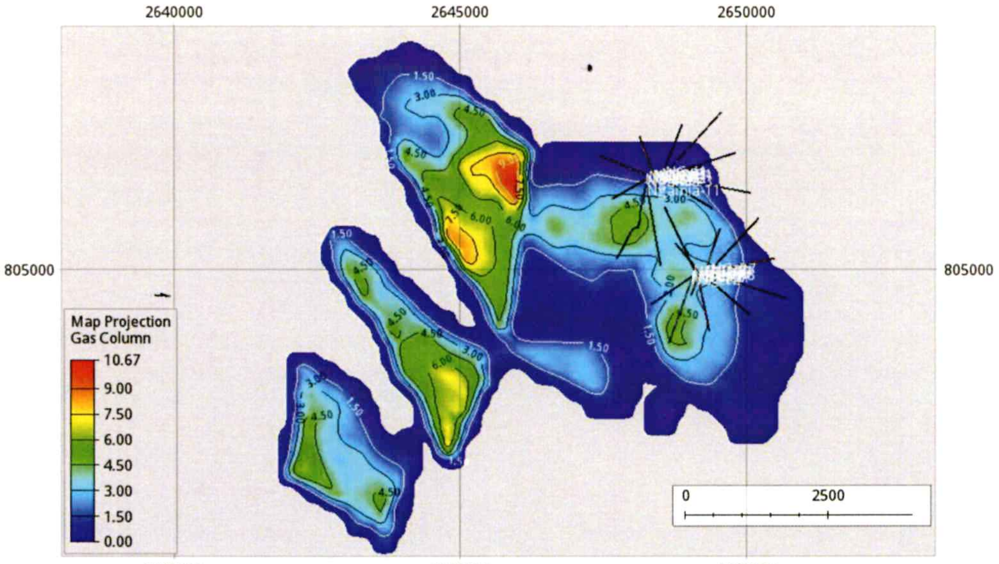


Figure 6-6; Net Gas hydrocarbon thickness (ft) around Phase 1 wells

Logs acquired during the Phase 1 drilling will be used to more precisely define the available GIIP for both production and storage, if needed. Prior to the phase 2 development, and following the FEED and detailed design of the CPF a more precise view of the required gas volumes for power and, potentially, storage will be known. Furthermore, the production data and history matched models from the Phase1 production will allow a better definition of the gas balance through Phase 2 allowing the most efficient use of the available gas resources and minimise any flaring required.

6.2.2 Enhanced oil recovery philosophy

The viscosity range of oil within the South Lokichar Basin (3 cp to 35 cp) presents a moderate to good mobility ratio to waterflood. Although most Lokichar reservoir fluids fall at the low end of this range, the shallowest intervals of Ngamia Auwerwer and Etom Auwerwer have measured viscosities of 13 cp and 35 cp respectively. In polymer flooding, the displacing injected water is enhanced with a polymer to increase the water viscosity. This method, where a suitable polymer has been selected, improves both vertical and areal sweep within the reservoir due to the better oil/water mobility ratio. The Etom Auwerwer reservoir may be ideally suited to this technique because of the materially higher oil viscosity and the very good reservoir permeability.

A suitability screening study in 2016 performed by Intratech[2] concluded that the majority of South Lokichar reservoirs would be suitable for polymer flooding, based on several key criteria including oil viscosity, reservoir permeability, temperature, and formation water quality. The study identified several suitable polymers that would be effective in the Auwerwer reservoirs and were demonstrated to be non-damaging in core plugs. Additional coreflood work and pilot/injection trials would be required prior to a decision on fieldwide implementation.

6.3 Well and Reservoir Management Plan

The South Lokichar Basin Well and Reservoir Management Plan (WRMP) describes the measures that will be put in place to maximise economic recovery from the South Lokichar reservoirs in the face of static and dynamic uncertainties.[3] The WRMP summarises the development's key subsurface uncertainties, risks and opportunities and presents options and activities to manage those. The WRMP also presents a high-level summary of expected data acquisition activities as part of the development. The draft WRMP is attached to this FDP as Appendix E.

Development of the South Lokichar Basin reservoirs will be using batch-drilled, deviated producers and injectors drilled from a set of multiwell wellpads. To reduce rig move times and drilling cost, all wells on a pad will be drilled by one of the South Lokichar drilling rigs in a single program. Well completions will be run by a dedicated completion rig once drilling operations on a slot are concluded. All wells will have been drilled and completed on a pad before that pad has been hooked up and production begins. Producers and injectors will initially be perforated across all hydrocarbon bearing intervals, subject to a minimum 10m stand-off from water and gas contacts, to maximise production and enable the plateau rate of 50,000 bbl/d to be achieved. Acquisition and analysis of drilling and well log data will be essential to the correct identification of hydrocarbon bearing zones and the selection of perforation intervals for each well. The well database for each well pad and each reservoir will grow as drilling progresses. It is critical that the database is properly maintained and used to optimise the completion intervals selected for the production and injection wells.

Due to the relatively low compressibility of the South Lokichar reservoir oil and uncertainty regarding aquifer pressure support, water injection will be required from the start of production. A key issue to be managed during the operating life of the field will be conformance control and difficulties associated with efficiently managing the waterflood of multiple vertically stacked oil pools. Reservoir modelling work has shown that the recovery efficiency of individual hydrocarbon zones within the Auwerwer reservoir can significant due to permeability contrast. It has been demonstrated using the simulation models and seen in analogues that the fraction of STOIIP recovered from a given reservoir unit is strongly linked to the number of pore volumes injected. All producers will be completed with artificial lift in the form of either ESPs, PCPs or jet pumps which will make the running of routine PLTs challenging to determine the location of oil, water and gas production within the well. Production wells may be production logged if Y tools are used with ESPs or jet pump orifices are removed and temporary gas lift is applied. Injection wells may be logged using a PLT to identify those zones that are taking the highest proportion of water.

Oil and water-soluble tracers offer the best alternative to PLTs for the purpose of identifying high water cut zones in wells. This opportunity will be evaluated further during the Execute phase of the project. A comprehensive list of surveillance technologies is listed in Appendix C.

The Amosing and Ngamia EWT wells have sophisticated completions installed that permit multiple producing zones to be produced or isolated independently using a surface-controlled interval control valves (ICVs). While these offer great flexibility to manage water breakthrough in the wells, the cost and complexity would be prohibitive for full field implementation.

Appendix D shows the zonal isolation options that have been considered for the development. As described above, wells will be perforated across multiple zones and produced commingled. Isolation options once high levels of water breakthrough have been identified include casing patches and multi-zone lower completions with selectable isolation through sliding side doors (SSDs).

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[2] "EOR Screening, Chemical Selection, and Laboratory Studies for Amosing and Ngamia Fields". Intratech Inc. USA, 15th October, 2016.

[3] "South Lokichar Basin Well and Reservoir Management Plan" (Draft September 2025)

Pressure measurements in the wells will provide a primary tool to characterise connectivity within the reservoirs, albeit an average value across multiple zones. Memory gauges can be run routinely on slickline in injection wells and surface readout pressure gauges will be included as a monitoring tool on all ESPs. Annulus level sounding will be used on packerless wells to determine flowing pressures and monitor shut-in pressures.

A critical part of the waterflood surveillance programme will be regularly scheduled routine well production tests using multiphase flow meters (MPFM) that will provide oil, water and gas rates. All water injection wells will have online, continuous rate metering. Regular fluid sampling (produced oil, tracer concentration, and produced and injected water) will provide data on produced oil and water properties over time and will ensure that injected water is up to specification. Pressure build-up and fall-off tests will be conducted opportunistically during scheduled and unplanned well and field shutdowns. Subject to availability of production capacity to meet production targets, additional pressure build-ups will be conducted.

The WRMP describes the frequency and content of periodic data acquisition and asset performance reviews.

7 DRILLING AND COMPLETIONS

Development drilling will be undertaken in two phases, the first phase aims to ramp up production to 20 kstb/d and the second phase to take production to 50 kstb/d (Table 7-1). A total of 910 development wells will be constructed across the two phases consisting of 905 new wells and 5 re-completed wells.

Phase 1 utilizes one drilling rig to drill 43 new wells and one workover rig to complete the new 43 wells and recomplete five existing wells. In this phase only Ngamia, and Amosing fields will used. The methodology to be employed is a multi-well pad-based factory drilling and completion approach.

Phase 2 will utilize three drilling rigs and two workover rigs to drill and complete a further 862 wells across Amosing, Ngamia, Twiga, Ekales, Agete and Etom. The objective is to maintain plateau production levels of 50 kstb/d for as long as possible.

The drilling rigs will have the ability to be moved efficiently from well to well on a pad to minimize time between activities. At some stage during the field life it is possible that both a drilling rig and workover rig may be required on a cluster location at one time and this will therefore be allowed for in the well pad design. All drilling related equipment are designed to prevent uncontrolled discharge. Normal operational waste, drilled cuttings and operational fluids, are to be collected in dedicated above ground containers and sent out of the well pad / field area in a proper & approved facility with adequate treatment and disposal.

A separate program has been developed appraise a mixture of low risk near field appraisal and higher risk prospectivity to assiset in extending the developent of the licences beyond the volumes developed by this FDP (see Section 5).

The CAPEX and OPEX associated with these programs are a substantial proportion of the overall project CAPEX and OPEX. Consequently, preparation of robust CAPEX and OPEX forecasts are important in the pre-development planning process.

The objectives of the well design and operating philosophy are:

- Drill & complete (D&C) wells in accordance with operator policies, jurisdictional regulations and good industry practice
- Ensure the safety of personnel and equipment associated with the D&C activities
- Deliver wells with minimal formation damage and capable of meeting the required performance targets for production and injection
- Optimise the per well cost for D&C activities, while ensuring long-term well integrity and zonal isolation
- Reduce D&C footprint and environmental impact by utilizing multi-well pads to construct the development wells
- Use latest technology and equipment standardization to enhance operational safety and efficiency

The well engineering planning work is broken down, for the purposes of this document, into two workstreams: drilling and completions.

7.1 Drilling

Phase 1 wells will be drilled on 4 drilling pads; each pad having 12 wells (6 oil producers and 6 water injectors) (Table 7-1, Figure 7-1). The drilling rig will drill all wells on a pad before moving to the next pad in the sequence. To avoid SIMOPS, the work-over rig will start installing completions on the pad after the drilling rig has moved to the next pad.

Phase 2 wells will be drilled and completed with three drilling rigs and two work-over rigs. The well per pad count for Phase 2 will be optimized, if required, to allow for up to 24 wells from a single pad (Table 7-2).

The drilling rigs will have the ability to move efficiently on the well pad locations in minimal time between wells (with below ground wellheads) with minimal equipment relocation.

Table 7-1: Phase-1 Total wells

Field	No. of Well pads	No. of Wells
Ngamia	2	24
Amosing	2	24

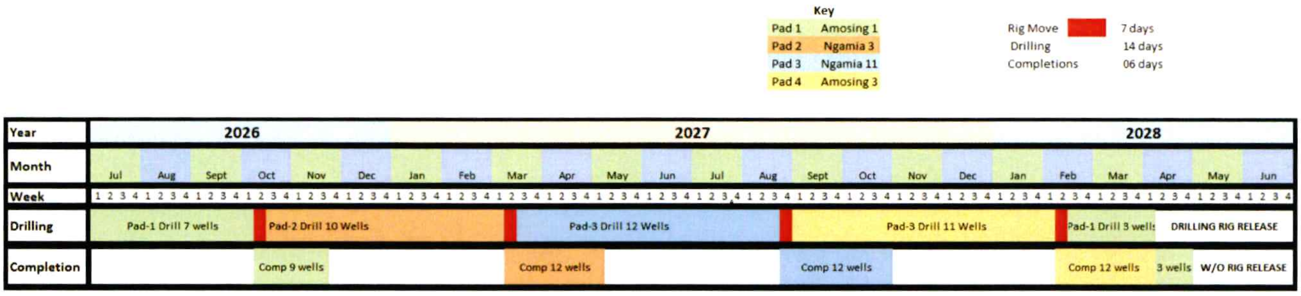


Figure 7-1: Phase 1 Drilling Schedule

Table 7-2: Phase 2 Total Wells

Field	No. of Well pads	No. of Wells
Ngamia	16	192
Amosing	7	80
Twiga	5	56
Ekales	5	52
Agete	13	148
Etom (Auwerwer & Lokone)	28	334

7.1.1 Pad Drilling

The Operator will implement a multi-well pad approach for the development campaign. It will combine the advantages of a fast moving, automated drilling rig with drilling of all wells from selected surface locations or pads. It will replicate a manufacturing facility's assembly line where wells will be delivered as part of a factory drilling process. Using this approach, one rig can be deployed to drill and prepare wells sequentially with minimum inter-well rig-move time. Such reduced rig move time is facilitated by the non-requirement for a typical equipment rig-down and rig-up cycle during inter-well moves on a single pad. The main drilling package including substructure, BOP stack, mud process tanks (with shale shakers, degassers), can be moved from one well to next on the same well pad, with the drilling mast remaining erect with full setback load, without requiring to be rigged down between wells. Also, while moving the main drilling package over successive wells, a large proportion of rig operating equipment (including generators, mud-pits and pumps) will remain parked in one position on the well site while moving the drilling package over successive wells, without requiring to be moved with the drilling package.

This approach has proven successful in analogous fields worldwide. The key drivers are:

- Reducing Land impact – Cluster drilling of 12 wells from a single pad significantly reduces the land requirement for the project and therefore has a positive environmental and social impact. The well clustering also allows for modularization of surface facilities and the supporting network during the commissioning phase. Furthermore, the pad design is capable to fully capitalize upon the benefits of Drilling Systems Automation, when found suitable for the campaign
- Total Well Cost impact – Average per well cost increase due to a higher proportion of deviated wells is offset by reduced rig move times as well as lower well hook-up and operating costs compared to single vertical well sites

- Flow Assurance – Multi-well pads and their associated central injection and production manifolds allow efficient implementation of heat management for flow assurance. Every pad will have a supply of hot, high pressure water for injection. The central, modularised manifolds then connect the wells to the Central Processing Facility (CPF) via a pipeline network

- Safeguarding - Overall security and safety of facilities and personnel will also be improved by using multi-well pads due to the reduced number of locations

- Other benefits from using a multi-well pad layout as opposed to single pad vertical wells are:
    - Well monitoring and control, instrumentation and deployment of utilities such as power, chemicals and data gathering
    - Increased artificial lift selection options compared to those for single well pads; e.g., common electrical systems for the ESP applications, common fluid supply header for injectors, hot water circulation, etc.
    - Considerably reduced number of rig moves leading to reduced rig-move man-hours and therefore limited exposure of crew to heavy loads and associated lifting equipment
    - Centralised EOR application, if used in the future, will be much more efficient with multi-well pads.

The selection and design of pads is based upon the following considerations:

- Utilizing existing Exploration and Appraisal locations, wherever possible
- Accommodating up to 12 slots (8 m apart) on 1 row at all Firm pads. A typical pad design is shown in Figure 7-2
- Incorporating existing wells into the pad drilling template on the pre-existing locations
- Optimization of well trajectories to suit the factory drilling of Foundation Firm wells

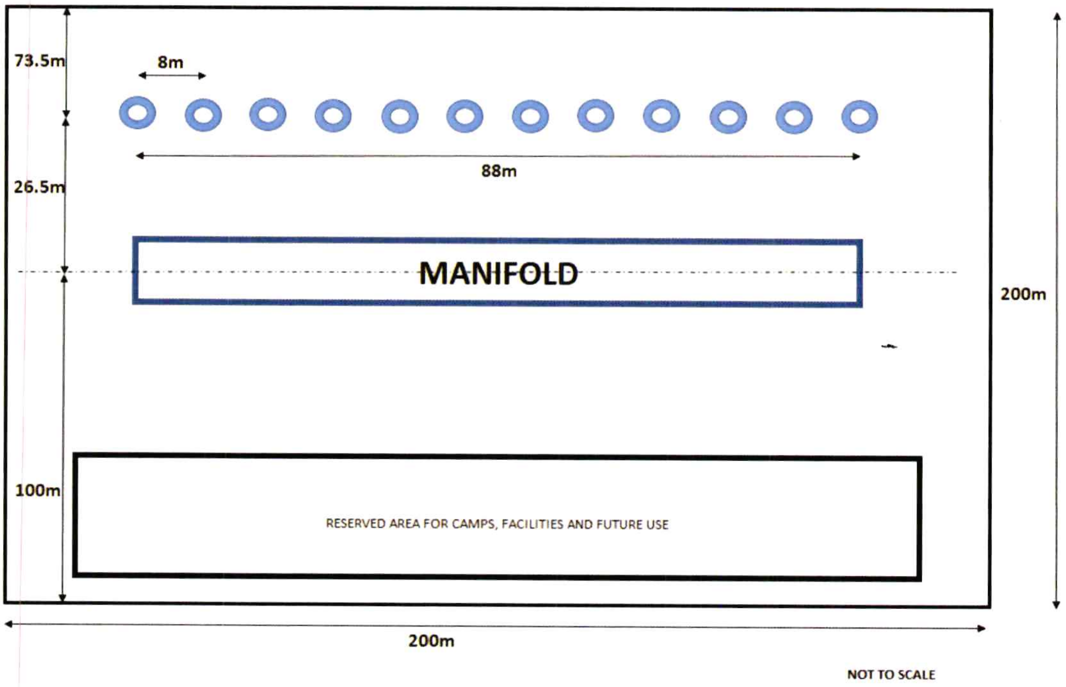


Figure 7-2: Typical development drilling pad

7.1.2 Well Trajectories

The well trajectories for all the development wells have been designed on a proprietary directional planning platform. This platform has been specifically developed by the industry to optimally allocate slots and populate trajectories based upon user defined common set points for hundreds of wells.

The key points to note are:

- The slot allocation has been done to allow the drilling rigs to move over consecutive slots to drill wells, one after the other without any 'slot-breaks' in between. Due consideration has also been given to optimize anti-collision
- A 5-spot well pattern with a 200m well spacing at top of reservoir
- Wells were initially designed to be vertical through the reservoir section, but S-shaped designs were limiting the choice of artificial lift type. The final designs have therefore been built to target the reservoir at a 20 degree inclination, and thereafter gradually drop to vertical by well TD.

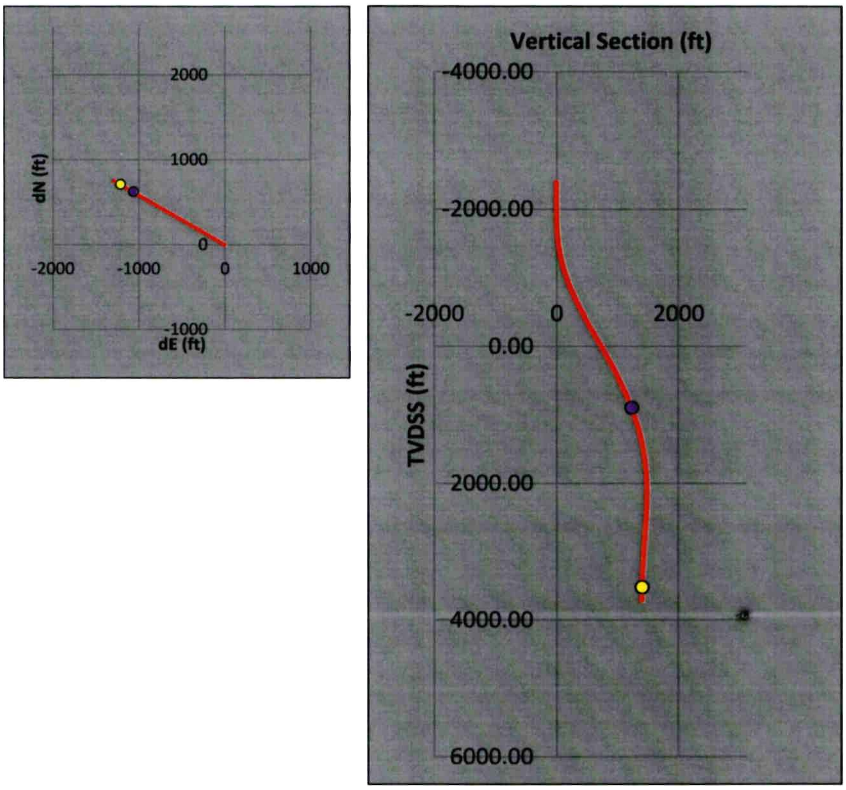


Figure 7-3: Typical development well deviation profile, areal and vertical section

The well trajectories will be either 'build and hold' (J-Shape) or S-Shape (Figure 7-3) depending upon combined drilling and subsurface considerations. Azimuthal changes will be avoided, wherever possible. The typical section views for the directional planning work carried out for the available subsurface definition are shown in Figure 7-4.

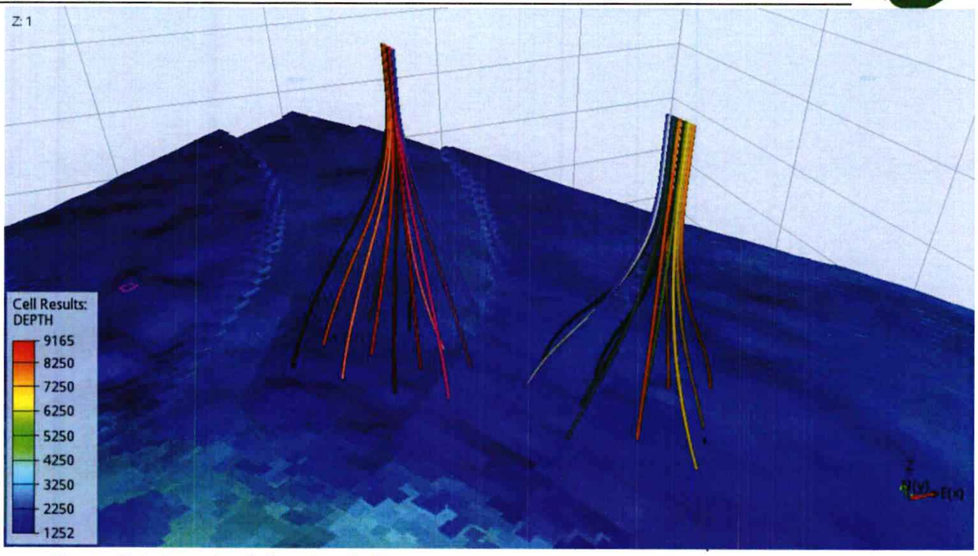


Figure 7-4: Sample of directional planning – Amosing Phase 1 Wells at Top Zone 1, depth grid

7.1.3 Hole and Casing Sizes

Wells will be designed based on an inside-out approach where tubing size shall dictate the production casing and the corresponding hole sizes. Tubing size selection is based on required production / injection capacity and the choice of artificial lift. The aim of the sizing philosophy is to slim down the wellbore size, to reduce cuttings generation/consumables, and to standardize the designs across all fields to bring economies of scale in procurement.

The well architecture consists of 3 casing strings (Figure 7-5). Table 7-3 below lists the final sizes selected.

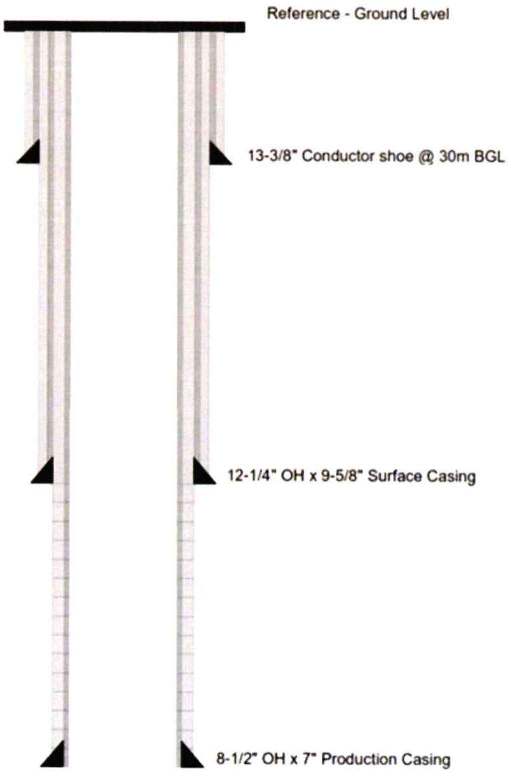


Figure 7-5: Illustrative Well Architecture

Table 7-3: Tubing and casing sizing selection matrix

Well Type	Completion			Casing Size			
	Design	A-Annulus Isolation	Tubing Size	Conductor	Surface	Production Casing	Production Liner
Oil Producer Moderate Rate (1000-2000 blpd)	Tubing Retrievable ESP	None	4-1/2"	13 3/8"	9-5/8"	7"	None
	Tubing Retrievable ESP	Yes Packer	3-1/2"	13 3/8"	9-5/8"	7"	None
Oil Producer High Rate (>2000 blpd)	Tubing Retrievable ESP	Yes Packer	3-1/2"	13 3/8"	9-5/8"	7"	None
Water Injector	Default Design	None	None	13.3/8"	9-5/8"	7"	None

7.1.4 Casing and Tubing Design

The casing and tubing designs being proposed for the FDP wells have been developed from successfully implemented casing schemes during the exploration and appraisal drilling campaign. Proposed designs reflect the evolution of well design over a period of field learning through the exploration and appraisal campaign, which has culminated in better understanding of subsurface lithology and drilling conditions, among other well construction realities, and developed mitigations thereto for each field. This improved understanding of relevant subsurface realities together with better defined selection of reservoir targets, has allowed casing and tubular requirements to be defined with an increased level of precision.

Casing and tubing stress analysis to support the design for the first three fields to be drilled (Ngamia, Amosing and Twiga) have been carried out on industry-standard software for each well type (producer and injector). Designs were checked against maximum anticipated loads which will be imposed on each tubular string during well construction and post construction well life cycle. The final designs with the approximate depths of each hole section can be found in Table 7-4.

Table 7-4: Approximate Hole section Depths (Ngamia, Amosing and Twiga)

Casing and Tubing Design		Tentative Field Specific Average Depths (in meters)					
Tubular Type	Tubular Specification	Ngamia		Amosing		Twiga	
		Prod.	Inj.	Prod.	Inj.	Prod.	Inj.
Conductor Casing	13.3/8", 54.5#, K55, BTC	30.0	30.0	30.0	30.0	30.0	30.0
Surface Casing	9.5/8", 36#, K55, BTC	849.0	849.0	720.0	720.0	1,055.0	1,058.0
Production Casing	7", 23#/26#, L80 1Cr /13Cr, API or Premium*	1,808.0	-	-	-	-	-
	7", 23#/26#, L80 1Cr, API or Premium	-	1,812.0	2,187.0	2,188.0	2,614.0	2,617.0
Production Tubing	4.1/2", 11.6#, L80 1Cr/13Cr, Premium*	~1090	-	~920	-	~1500	-
*13CR Only in Hydrocarbon Wet Sections of Ngamia High CO_2 Wells							

The casing and tubing stress analysis for planned wells in Agete, Ekales and Etom fields will be commissioned as soon reasonably practicable, using industry-standard software for each well type (producer and injector). A preliminary design with field specific average well depths is as provided in Table 7-5.

Table 7-5: Preliminary Casing and Tubing design (Agete, Ekales and Etom field)

Casing and Tubing Design		Tentative Field Specific Average Depths (In meters)							
Tubular Type	Tubular Specification	Agete		Ekales		Etom Auwerwer		Etom Lokone	
		Prod.	Inj.	Prod.	Inj.	Prod.	Inj.	Prod.	Inj.
Conductor	13.3/8", 54.5#, K55, BTC	30.0	30.0	30.0	30.0			30.0	30.0
Surface Casing	9.5/8", 36#, K55, BTC	770.0	770.0	1,420.0	1,420.0	610.0	610.0	610.0	610.0
Production Casing	7", 23#/26#, L80 1Cr /13Cr, API or Premium*	1,370.0	-	1,750.0	-	820.0		1,330.0	-
	7", 23#/26#, L80 1Cr,	-	1,370.0		1,750.0		820.0		1,330.0
Production Tubing	4.1/2", 11.6#, L80 1Cr/13Cr, API or Premium*	~970	-	~1620	-	700.0		~700	-
*13CR only in Hydrocarbon Wet Sections of High CO_2 Agete Wells									

7.1.5 Wellhead / Christmas Tree Design

All the wells will be equipped with a Wellhead and Christmas tree for pressure control and well intervention access.

To minimize stack up height and operational flat line time during well construction, and therefore minimize CAPEX / OPEX by reducing required cellar depth and total well construction time, a slim line compact unitized wellhead / horizontal tree design will be adopted. Key features:

- Each cellar to house 1 well (injectors or producers)
- Unitized wellhead to have the capability of landing 2 casing strings
- The depth of the cellar to be such that the wellhead and Xmas tree stack are housed completely inside the cellar (fully submerged), thereby allowing the cellar top to be in level with the ground. This will improve rig skidding performance and installation as well as reducing visual impact.

A horizontal X-mas tree will facilitate workovers by eliminating the need to remove the Xmas tree prior to installing the BOP (well control equipment). Furthermore, it will allow minimization of production shortfalls associated to workovers by eliminating the need to dismantle surface flow lines to remove Xmas trees to gain access to the well.

The conceptual design is shown in Figure 7-6.

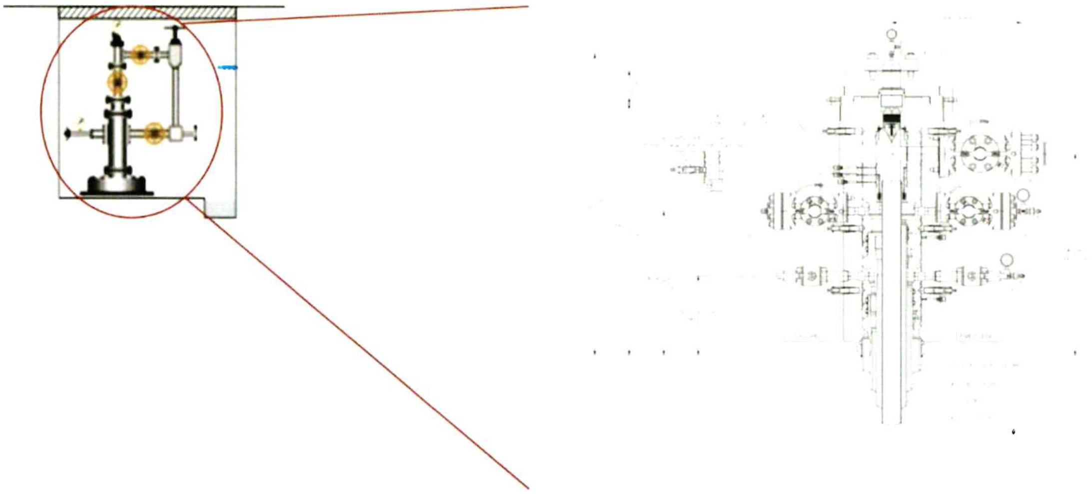


Figure 7-6: Cellar schematic and a typical wellhead / Xmas tree stack up diagram

7.1.6 Drilling Fluids Design

The drilling fluid philosophy evolved during the Exploration and Appraisal campaigns, through various single phase inhibited Water Based Mud (WBM) systems to a mixed-system drilling fluid approach. This approach envisages two types of drilling fluids for the initial program:

- Potassium Sulphate Polymer Water Based Mud (WBM) for drilling surface hole-sections
    - ~ 9.5 ppg mud weight
    - Low cost and moderately inhibitive for drilling reactive and potentially loss-prone surface sections, including volcanics
    - Designed to avoid contamination to the shallow aquifers
    - Water is the continuous phase and includes a non-chloride-based salt for inhibition

- Synthetic Oil Based Mud (SOBM) for drilling production hole-sections
    - ~10.5 ppg mud weight
    - Highly inhibitive; designed to minimize formation damage and shale reactivity, providing wellbore stability
    - Residual mud is re-usable from well to well; giving significant cost savings on product usage and mitigate the costs of waste fluids disposal
    - Environmentally acceptable through zero-discharge of fluids to the environment, furthermore synthetic oil used has superior aerobic biodegradable attributes
    - Synthetic Oil based Mud is a two-phase system with a continuous phase of synthetic oil suspending minute brine droplets in the emulsion. This non-reactive, highly inhibitive quality provides superior wellbore stability

The drilling rigs will have custom designed mud handling systems with the latest generation shale shakers and other solids processing equipment. These systems will include bespoke mud tank designs and pipework to optimise system changeovers, minimise mud-solids discoveries, and reduce pit clean-up times.

The treatment of the cuttings as well as recycling / disposal of the drilling fluids for both the sections will be different, depending upon the base used (oil or water). The strategy is outlined below:

- Surface Section (WBM)
    - Cuttings – mixed with native soil in 1:3 (cuttings: soil) and buried around the well pad
    - Drilling Fluid – dewatered, recovered water reused and solids residue disposed with WBM cuttings

- Production Section (SOBM)
    - Cuttings – SOBM contaminated drill-cuttings transferred to the integrated waste management facility for thermal treatment prior to disposal at the engineered landfill
    - Drilling Fluid – conditioned and integrated into SOBM inventory for reuse
    -

7.1.7 Cement Design

The drilling of both the surface and the production sections will be followed by lowering and cementing of surface and production casings respectively. Since cementing is critical to long term well integrity and zonal isolation of reservoirs, the cement design will meet the following objectives as a minimum:

- Surface Section
    - Provide long term competent cement around the surface casing shoe
    - Provide structural support during the drilling operations
    - Isolate freshwater aquifers
- Production Section
    - Achieve the planned cement rise in the annulus (150 m inside the surface casing)
    - Achieve the maximum possible coverage around the casing with cement
    - Maintain long term well integrity and zonal isolation during production and injection operations and the cyclic loads resulting thereof.

7.1.8 Wells' Time and Cost Estimates

The drilling and completions aspects of the field development have been configured as a segregated 'batch' drill and 'batch' complete campaign. Well construction will commence with a 'drill, case and suspend' drilling phase using a drilling rig, followed by a separate 'cleanout, perforate, complete and suspend' completion phase using a completion/workover rig. This approach best optimises well construction delivery efficiency, particularly as it relates to delivering First Oil. The wells' time and cost estimates have been developed to ensure this batching configuration and associated requirements will be appropriately catered for.

7.1.8.1 Time Estimate

Drilling - FDP operations sequence (all fields)

- Rig move & rig up – 0.5 days
- Spud & Drill 12-1/4" surface hole and set 9.5/8" surface casing – 4.75 days
- Drill 8-1/2" hole to well TD and set 7" production casing – 7 days
- Suspend well for completions scope – 0.25 days

Table 7-6: Well Time breakdown estimate

Operations	Dev. Wells (hrs.)	Dev. Wells (Days)
Rig Move	8.0	0.3
Install BOP	6.0	0.3
M/Up 12-1/4" BHA	3.0	0.1
12-1/4" hole drilling	72.0	3.0
12-1/4" hole reaming	-	-
12-1/4" connections	-	-
12-1/4" circulation	4.0	0.2
12-1/4" POOH	6.0	0.3
L/d BHA	1.0	-
Rig up and prepare to run casing	5.0	0.2
Run 9-5/8" Casing	10.0	0.4
Circulate + Cement 9-5/8" casing	7.0	0.3
P/up drill-pipe	2.0	0.1
M/up 8-1/2" BHA	3.0	0.1
RIH 8-1/2"	3.0	0.1
Drill out + FST	6.0	0.3
8-1/2" hole drilling	90.0	3.8
8-1/2" hole reaming	-	-
8-1/2" connections	-	-
8-1/2" circulation	2.0	0.1
8-1/2" POOH	12.0	0.5
L/d BHA	1.0	-
8-1/2" LDDP	2.0	0.1
Rig up and prepare to run casing	6.0	0.3
Run 7" Casing	30.0	1.3
Circulate + Cement 7" casing	12.0	0.5
Clean & Release Rig	8.0	0.3
Well Duration	**299.0**	**12.5**

Base line (problem-free) drilling timings (12.5 days) were developed for each operational step within the sequence, for each well, based on drilling experience during the exploration and appraisal campaign, combined with deliverable efficiencies from multi-well pad drilling especially minimal rig move times.

A learning curve risk component was applied to the baseline drilling timings to allow for operational inefficiencies which will normally characterize the start-up phase of new development drilling projects such as this one. In addition, an 8% NPT allowance and additional 5% contingency were applied to drilling timings, based on experience during the appraisal phase, to cover NPT and unplanned events such as rig down time, hole problems, equipment failures. Derived drilling timings of 14 days were then used to develop drilling cost estimates for the FDP wells.

Completions – FDP operations sequence

- Rig move & rig up, wellbore cleanout, cement bond evaluation logging and perforate (TCP)
- Run completion string and suspend well (for production hook-up)

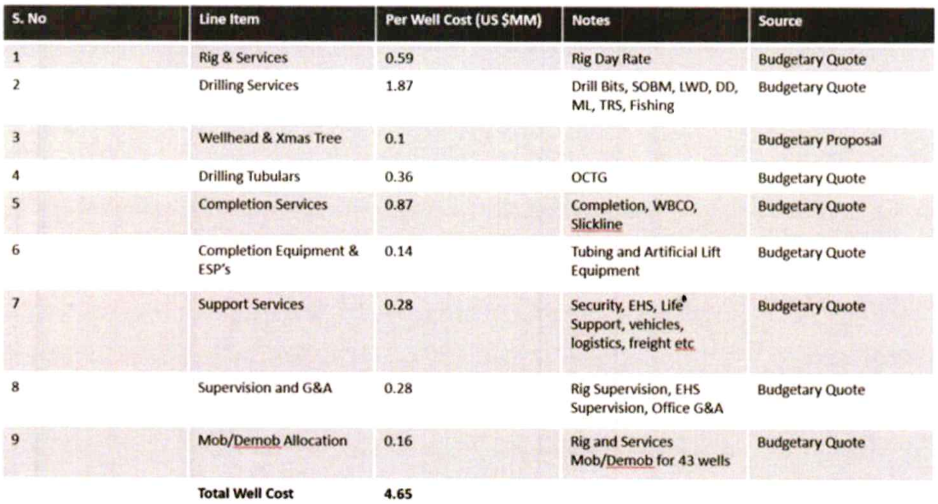
Completion timings were also developed based on deploying automated, highly mobile completion rigs similar to the drilling aspect, however envisaged performance during each operational step has been benchmarked against actual performance for similar operations from comparable development projects elsewhere in the world, where multi-well pad drilling and completions operations have been deployed successfully.

7.1.8.2 Cost Estimate

Rates used to develop an estimate of drilling & completion CAPEX are based on a combination of market quotes for a drilling rig and integrated drilling & completion services for a 43 well campaign and FDP costs for tubulars and other equipment escalated based on the commodities price indices. The Phase 1 well cost estimates might be higher than the Phase 2 costs due to the smaller well scope and the market escalations. However, significant efforts are being made to reduce and optimize the well costs through a competitive tendering process. Additionally, Phase-2 will benefit from the lessons/ learning curve carried over from Phase 1 which will further refine the time and cost estimates

A summary of estimated costs to drill and complete proposed development wells is provided in Table 7-7. These cost estimates reflect a class 4 level cost estimate (AACE), which will be refined with improved understanding of the follow-on fields.

Table 7-7: Cost estimate (Initial)



S. No	Line Item	Per Well Cost (US $MM)	Notes	Source
1	Rig & Services	0.59	Rig Day Rate	Budgetary Quote
2	Drilling Services	1.87	Drill Bits, SOBM, LWD, DD, ML, TRS, Fishing	Budgetary Quote
3	Wellhead & Xmas Tree	0.1		Budgetary Proposal
4	Drilling Tubulars	0.36	OCTG	Budgetary Quote
5	Completion Services	0.87	Completion, WBCO, Slickline	Budgetary Quote
6	Completion Equipment & ESP's	0.14	Tubing and Artificial Lift Equipment	Budgetary Quote
7	Support Services	0.28	Security, EHS, Life Support, vehicles, logistics, freight etc	Budgetary Quote
8	Supervision and G&A	0.28	Rig Supervision, EHS Supervision, Office G&A	Budgetary Quote
9	Mob/Demob Allocation	0.16	Rig and Services Mob/Demob for 43 wells	Budgetary Quote
	Total Well Cost	**4.65**		

7.1.9 Drilling Risk

The South Lokichar Basin has proven to be challenging during the drilling of the 44 exploration and appraisal wells drilled in the past. Two of the major problems encountered are:

- Severe mud losses in fractures, volcanics, rubble zones and faults
- Significant hole problems due to wellbore instability in shale formations

To mitigate the above risks during Foundation Firm development drilling, surface hole sections will be drilled with inhibited WBM and production hole sections will be drilled with SOBM. Furthermore, engineering studies have been carried out to improve the understanding of formations and their behaviour while drilling.

Additionally, the latest available technologies mentioned below will be utilized, when required, to reduce the drilling risks and improve performance:

- Rotary steerable systems / slick motor assemblies
- Logging while drilling (LWD)
- Electromagnetic telemetry systems (EMT)
- Rig Automation
- Engineered lost circulation material (LCM)
- Fit for purpose cement slurries

7.1.10 Well Life

The producing life of a well is expected to be no more than 25 years. Recovery will be maximised by producing at up to 97% water cut. The completion life will be shorter than the well life due to the potential for failure of the artificial lift, unsuitability of lift to changing well conditions, corrosion, and or mechanical problems. There will be workovers such as water shut off, well surveillance, sand-face completion failures and pump replacements. Notwithstanding the above, artificial lift and completion design will be aimed at maximising reliability to minimise failure related workovers.

7.2 Completions

Key design drivers are the following:

- Relatively shallow deviated wells
- Semi-viscous oil with risk of wax appearance, may require a means to heat up the tubing to allow it to flow after a shut down, and also in steady state production.
- Artificial lift required from production onset
- Corrosion risk from Carbon dioxide (CO2) content in associated gas
- Possible future sand control requirements
- Water injection is planned to maintain reservoir pressure with consideration for early water breakthrough.
- Periodic work-overs required for artificial lift pump maintenance

7.2.1 Production Well Completions

Factors that will determine recommended production well completion designs are:

- Production casing size (currently planned as 7" for all production wells)
- Allowance for potential retrofit of sand control equipment
- Well performance and artificial lift type
- Flow assurance provisions
- Reservoir management and data acquisition strategy for both production and water injection wells i.e., commingling or full zone selectivity

The design production rate for the wells is expected to be up to 3,000 barrels of fluid per day. Given the low reservoir energy, expected early water break through and low GOR, the production wells will have artificial lift installed as an integral part of the initial completion.

To minimise OPEX, the options for wireline or rod rig deployable insert artificial lift systems will be evaluated. The tubing size for all production wells will be $3^1/_2$" (tubing conveyed ESP only) and $4^1/_2$" (all other wells). Well performance, artificial lift and flow assurance provisions will be further optimized during the detailed design phase.

7.2.2 Materials Selection

The majority of the reservoir fluids have low carbon dioxide (CO_2) content. A detailed corrosion and metallurgy study has been conducted which supports the use of L-80 low alloy (1 Cr) carbon steel for both production and water injection wells. However, some reservoir fluids have elevated CO_2 content (up to 80 mol%) and therefore the metallurgy of the flow wetted tubulars in these wells will have to be modified accordingly, with 13 Cr CRA material or equivalent a likely choice.

Provision will be made in the well completion design to allow continuous and or batch dosing of corrosion inhibitor if required. Any elastomers deployed will be optimised for the low reservoir temperature, CO_2 content and the presence of diesel and sweet crude. The elastomer product selection will be made after detailed desktop and laboratory-based study work.

7.2.3 Flow Assurance

The crude to be produced from these fields has a high pour point and wax appearance temperatures close to reservoir temperatures in the shallowest zones. Detailed wellbore heating and wax deposition studies indicate that downhole electric heating will not be required.

Hot water circulation will be the primary applied flow assurance method, supplemented by downhole and surface demulsifier injection if required. Studies also indicate that well start up after extended shutdowns will not pose a problem as the estimated gel strength of solidified crude will be able to be broken on downhole pump start-up.

The above measures are expected to allow the wells to be operated successfully under all producing conditions.

7.2.4 Sandface Completion

For the majority of the Auwerwer reservoirs, the base case sand face completion will be cemented and perforated casing. Sanding studies have shown that the Auwerwer reservoirs have low to moderate strength and that this sand face completion concept has an acceptable risk profile.

Any residual risk can be mitigated by design of perforating guns to avoid perforating any potentially lower strength intervals. The base case well design will employ a single trip 'shoot and pull' approach with tubing conveyed perforating guns (TCP) run in an engineered perforating fluid designed to minimise formation damage.

The perforating strategy will be refined through a testing programme principally designed to optimize the perforating strategy for water injection wells. However, the initial results of this testing programme indicate that the strategy could be applied to all development wells. No sand control equipment is planned for installation in the initial completions.

7.2.5 Completion Design

Completions are initially envisaged to be fully commingled for both production and water injection wells. Figure 7-7. Subsurface studies to date have not provided sufficient justification to support installation of a fully zone selective completion. Information gathered from the Ngamia-11 water injection trial and the available well performance data to date from the EOPS phase supports this strategy.

A fully commingled completion will employ tubing conveyed or insert artificial lift and may have a vented annulus. It is anticipated that zone selective completions may be retro-fitted to effectively manage injection water distribution. The data acquired after production start-up will inform any subsequent selective completion installation decisions.

A fully zone selective completion will typically comprise isolation packers and mechanically operated sliding sleeves to allow simple control of flow from / into individual zones. The use of inflow control devices (ICD) and water injection regulator valves remains a possibility for effective downhole fluid distribution.

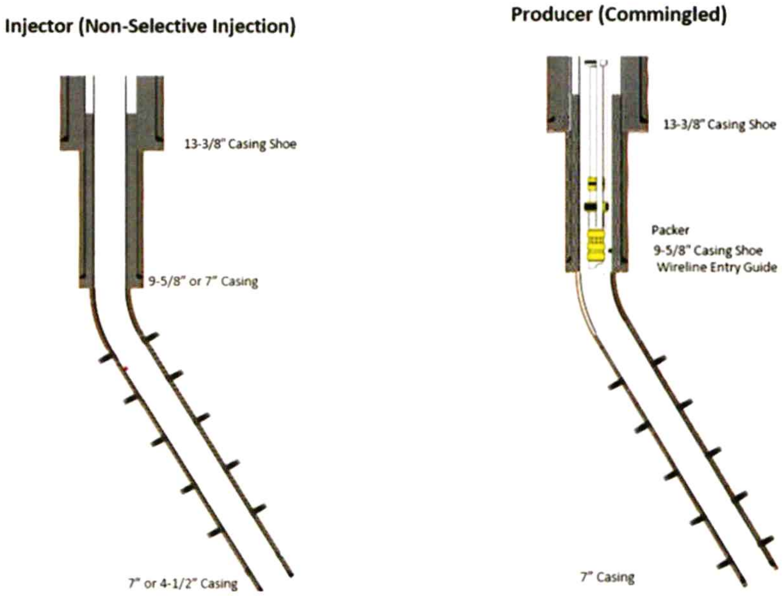


Figure 7-7: Non-zone selective ESP completion schematic (left) Co-mingled ESP completion schematic (right)

7.2.6 Artificial Lift

Preliminary selection of artificial lift is based on detailed studies considering expected well productivity, fluid properties / flow assurance, wellhead pressure, sanding risk and Gas Volume Fraction (GVF) at the pump intake. Electric Submersible Pumps ("ESP") have been selected as the main mode of artificial lift for the expected liquid production ranges.

Progressing Cavity Pumps ("PCP") were found to have similar lift properties to the ESP but were lower ranked as a base case due to the risk of rod-tubing wear and the anticipated learning curve associated with elastomer selection and rotor-stator fit on the relatively small scale development of Phase 1. They have been retained as a design option should initial well rates or conditions change during early production and should be considered further for the full scale field development.

The artificial lift studies showed that jet pumping could be employed as the initial method of artificial lift in both Amosing and Ngamia fields and would have significant benefits in terms of reliability and ensuring the produced fluid is well above the emulsion inversion point. However, jet pumping these fields would triple the liquid handling and water injection requirements of the Phase 1 facilities and was therefore discounted on economic grounds. Jet pumping Amosing and Ngamia will be reviewed for the subsequent full field development in case there is potential to take advantage of spare capacity in the water injection and handling systems of the CPF.

High viscosity emulsions have been identified as a key risk for the Amosing and Ngamia fluids, the ESP wells will therefore include facility for downhole (below pump) demulsifier injection. Due to the reservoir complexity and risk of poor pressure support in some zones, the ESP design will consider advanced gas handlers to manage possible high Gas Volume Fraction ("GVF") at the pump intake. Given the potential for solids production from the cased & perforated lower completion, it is recommended to consider the use of Abrasion Resistant ("AR") materials for the ESP construction. The ESP wells will be completed with 3 ½" tubing and a Side Pocket Mandrel ("SPM") / circulating Sliding Side Door ("SSD") above a production packer. This will be used to circulate out the tubing contents for extended shut in periods. These wells will have a nipple profile below the packer depth to accept a deep-set plug for longer term well isolation.

Routine production logging is not expected to be used although selected wells completed with ESPs are planned be fitted with a Y-tool providing access to the reservoir section below the pump. For any wells completed with alternative artificial lift methods (PCPs and jet pumps) access to the reservoir section would require the completion to be pulled and so produciton logging in wells completed in this manner is not expected.

Several well safety systems will be incorporated into all well designs. The tubing hanger will allow the installation of a two-way check valve, back pressure valve or crown plug for well isolation and work-over operations. The tubing hanger will incorporate an extended neck seal to seal inside the tubing head adaptor.

Current base case tree designs employ a 'horizontal' style spool with no valves in the vertical bore. The tubing hanger profile mentioned above will accommodate a crown plug.

The tubing conveyed ESP well trees may have a swab valve and an actuated flow wing valve and a production choke. Insert artificial lift (e.g. slick-line or cable deployed ESPs) has the advantage of not requiring the tubing to be retrieved to change the pump. It is not anticipated this technology would be used for the Phase 1 development but will be considered for the full field development.

7.2.7 Injection Well Completions

The injectors are planned to be wells with 7" casing monobore (Figure 7-8). If the requirement for zonal flow control is considered critical, options will be evaluated to install a 4-1/2" selective sand face completion inside the injector wells. There will be no tubing installed in initial injection well completions and injection will be fully commingled.

The production casing and completion material will be 1 Cr low alloy carbon steel as identified in the Corrosion and Metallurgy study.

The injection wells will be designed to handle water injection under both matrix and fracturing conditions. The Ngamia-11 water injection trial provided the opportunity to test water injection regulator valves in a zone selective completion. These regulator valves allow precise management of injection volumes into specific zones and the trial provided important information about the potential for wider deployment in zone selective development injection wells.

Several well safety systems will be incorporated into the design of the water injection wells. A non-profile type slick line set plug would be used as mechanical barrier. Since no nipple profile is required for setting this type of plug, the plug can be set anywhere in the casing as desired. The metallurgy will be compatible with the tubing completion material. Fail safe close flow wing valves will be the primary safety system.

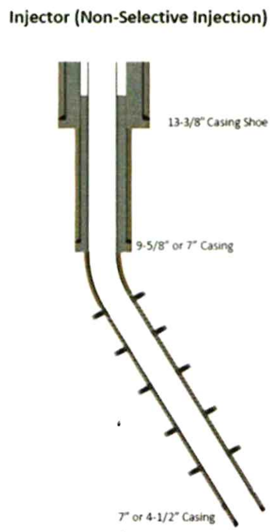


Figure 7-8: Monobore Water Injector co-mingled completion schematic

7.2.8 Hydraulic Stimulation

The injection trials into the Amosing-3 and Ngamia-5 wells provided contrasting data sets. Effective injection into Amosing-3 was only achieved under fracturing conditions after stimulation and surfactant treatments. In contrast, one of the zones used during the Ngamia-5 injection trial easily accepted the required injection rates under matrix injection conditions. Matrix injection was achieved during the Ngamia-11 water injection trial.

In both cases, acidisation and surfactant treatments resulted in improved injectivity. The water injection system will provide hot water for injection to each well pad at pressures up to 195 bara, which will be more than sufficient to induce fracturing in all zones, if required. The base case expectation is that water injection will be maintained under matrix conditions.

7.2.9 Surface Flow Control

The principal factor governing the configuration of the surface tree / wellheads is to ensure that the well cellars are as shallow as possible. Aside from this the surface flow control / tree design is governed by the type of artificial lift which is installed.

Wells completed with ESPs will have a crown plug installed in the tubing hanger above the production flowline and a tree cap. Interventions in these wells will be executed after removing the tree cap and rigging up a dual work valve on the tree.

To standardise the design, all surface trees will be a nominal 3-1/8", 5,000 psi WP rated and will be of 'horizontal' spool type. Horizontal trees are the base case being considered to minimise the required cellar depth and therefore provide some cost saving on civils / pad preparation.

Regardless of the type of surface tree selected, access to the A annulus must be provided to permit tubing circulation in ESP wells. There also needs to be sufficient clearance between annulus access valves and the cellar walls to permit rig-up and operation of a VR (Valve Removal) plug lubricator. This may influence tree / wellhead orientation in the cellar

7.2.10 Workovers

During the field life, workovers will be carried out principally on oil production wells to replace out of service downhole pumping assemblies. SIMOPS will then take place and strict rules will be followed to prevent surface and downhole incidents while minimizing production losses. Some workovers may be carried out in water injector wells if deemed necessary, to restore injectivity index for example, but are unlikely to require significant mechanical intervention.

Average ESP run life prior to maintenance and/or change-out is expected to be approximately three years based on manufacturer's Mean Time Between Failure data (MTBF). With optimum downhole running conditions and minimal sand production, the pumps may be able to last longer than this average.

Rig-less interventions may be planned for various interventions using slick-line, coiled tubing, etc. with typical scopes are tubing scraping, SAS cleaning, etc.

7.2.11 Wells Decommissioning

After field production ceases, all wells will be decommissioned in accordance with appropriate Statutes, Kenyan Regulations and recognized international industry standards. The productive horizons will be isolated with cement. The wellheads will be removed, and the structures dismantled and disposed of properly. The wells will be permanently plugged with cement and abandoned in such a way to protect groundwater resources. Well casings will be cut off below ground, capped, and backfilled. Well pads will be removed and integrated into surrounding terrain. The land surface will be re-contoured and appropriate vegetation will be planted to prevent soil erosion.

8 SURFACE FACILITIES AND OPERATIONS

8.1 Introduction

In order to accelerate commercial production, Gulf Energy has planned a phased development approach, with a view to achieving First Oil as early as possible. A Concept Select has been completed for a 20 kstb/d, predominantly OPEX based, Early Production Facility (EPF) solution for a primary production period of five years (Phase 1), whilst preparing to increase production to 50 kstb/d through a second phase of development using a Central Processing Facility (CPF).

Phase 1 will involve two processing EPF's on a rented basis each producing ~10 kstb/d of crude oil, accelerated drilling will be completed on some of the existing wellpads of Amosing 1, Amosing 3 & Ngamia 3 and a new well pad named Ngamia 11 all of which are on Block 10BB. A total of 24 wells will be utilized for production and similar number for water injection of the initial production phase. The transportation of crude oil to Mombasa will be carried out using c.600 trucks leveraging KPRL/KPA infrastructure for storage & export. Subject to GOK approvals, technical readiness can be achieved by late 2026.

After five years of the Initial phase production the Production will be ramped up to produce 50 kstb/d. This phase of Ramp-Up development is based on a CPF, located within the Ngamia field, for efficient heat integration, utilities, storage, waste management, laydown/warehousing and accommodation. Remote well pads connect to the CPF via a network of flowlines with the final export of the oil will be carried out via rail.

The development concept provides a scalable system that can be expanded to accommodate additional wellpads and fields by simple expansion of the gathering system. The design is supported by engineering studies and detailed vendor engagement.

8.2 Design Evolution

The technical work to date has been a collaboration between the subsurface and facilities teams to define the optimum development concept. As the concept matured, alternative options have been evaluated and discarded. The high-level decisions which frame the final facilities development concept over life of the field are summarized as following:

- Two EPF Facilities: Each having capacity of 10 kstb/d; one facility at Amosing 1 well pad and the second one at Ngamia 03 well pad which will be able to process cumulative liquids of 30 kblpd per day. This is to support early oil production of 20 kstb/d for the first five years
- A single CPF of 50 kstb/d will be selected completed and started during year 5 of the production once further drilling been completed.
- Multiphase transport to the CPF reduces the flowline count throughout the network compared to single phase transfer
- Excess gas management - Excess gas will be utilized for the power generation and the surplus will be re-injected into suitable target reservoirs, preventing the requirement for continuous flaring during normal operation. The gas injection wells included for disposal will be used when the facility would be gas deficient to provide an additional gas supply (gas flowback) to the facility and limit the power import from the grid
- Power generation selection is gas generators fueled by associated or produced gas from production. Gas flowback from the gas injection wells is also used to generate additional power and minimise the power import from the grid. This combination provided the most efficient generation of heat and power throughout the life of operation. A connection to the local power grid is required to allow for power import in the event of a shortfall.
- Flow assurance will be considered to maintain the crude above wax appearance and to deal with potential emulsion issues in both the initial production and Phase 2 production facilities.
- Produced water will be treated and reinjected back into the formation via the injection wells for reservoir pressure maintenance and sweep.

8.3 Processing Facilities Concept

The detail design of the surface facilities for the initial phase of 20 kstb/d and later phase of 50 kstb/d will be completed based on the peak flow rates as shown in Table 8-1 and Table 8-2 respectively.

Table 8-1: Fluid Capacities for Phase 1

Parameters	Peak Flowrates	Units
Oil Production	20,000	stb/d
Produced Water	Year 1-5: 30,000	bwpd
Gas	5	MMscfd
Make-Up Water	30,000	bwpd

Table 8-2: Fluid Capacities for Phase 2

Parameters	Peak Flowrates	Units
Oil Production	50,000	stb/d
Produced Water	Year 5-25: 200,000	bwpd
Gas	20	MMscfd
Make-Up Water	75,000	bwpd

8.3.1 Early Oil Processing Facility (Phase 1)

During Phase 1 oil will be produced from Block 10BB from total of 24 producers wells and water injection will be carried out at the same time into 24 injectors wells. Four well pads will be utilized for drilling and each well pad will be completed with 6 producers and 6 injectors. Where possible existing wells completed during the EOPS project will be utilized to minimise additional drilling. These well pads will be Amosing 1, Amosing 3, Ngamia 3 and a new pad, Ngamia 11 as shown in Figure 8-1.

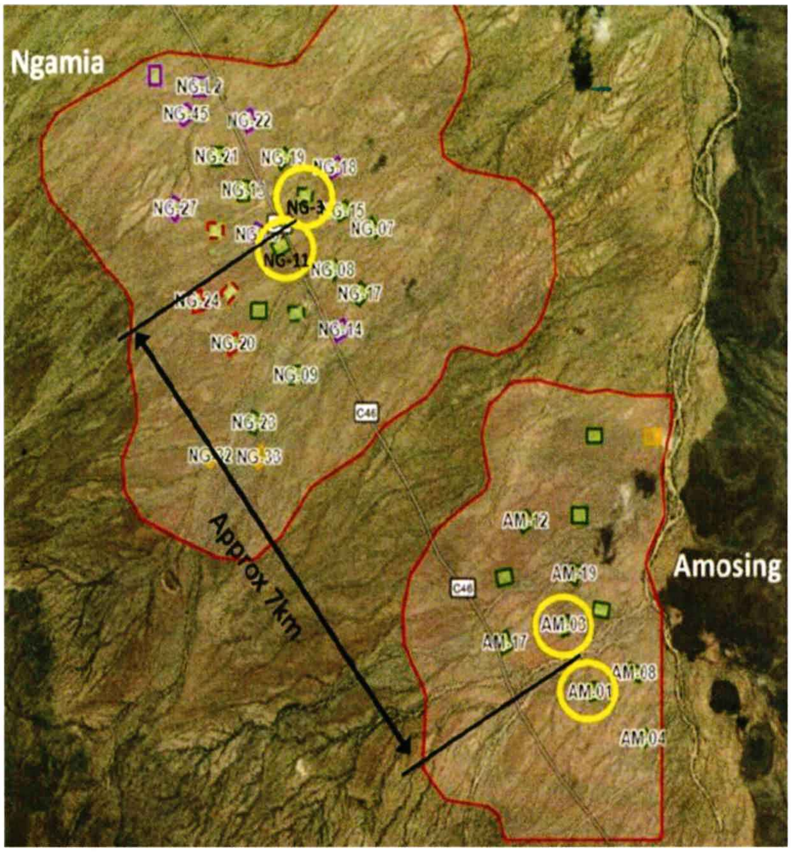


Figure 8-1: Wellpads layout for Initial Early oil Production

The facilities will be designed to meet the following specifications in Table 8-3.

Table 8-3: Showing the facilities capacity and design specifications

Oil Rate	10,000 stb/d
Gas Rate	3.5 - 4 MMscfd
Prod. Water Rate	14,000 bwpd
Water Injection max	14,000 bwpd
Wax Content	30-33%
Wax appearance Temp	62 – 67 degC
Wax disappearance Temp.	74 – 76 degC
Pour Point	42 – 48 degC
RVP requirement	0.69 bara
TVP	0.76 bara at 76 degC
BSW	0.5 vol%
Salt	50 lb/Mbbl
Delivery Oil Temp	80 °C
Delivery Pressure	10 barg

8.3.1.1 Description of the Initial Early Oil Facilities (Phase 1)

The EPF configurations for the Amosing Field and the Ngamia Field (Figure 8-2) will be very similar and the key components and design features are outlined in the following paragraphs.

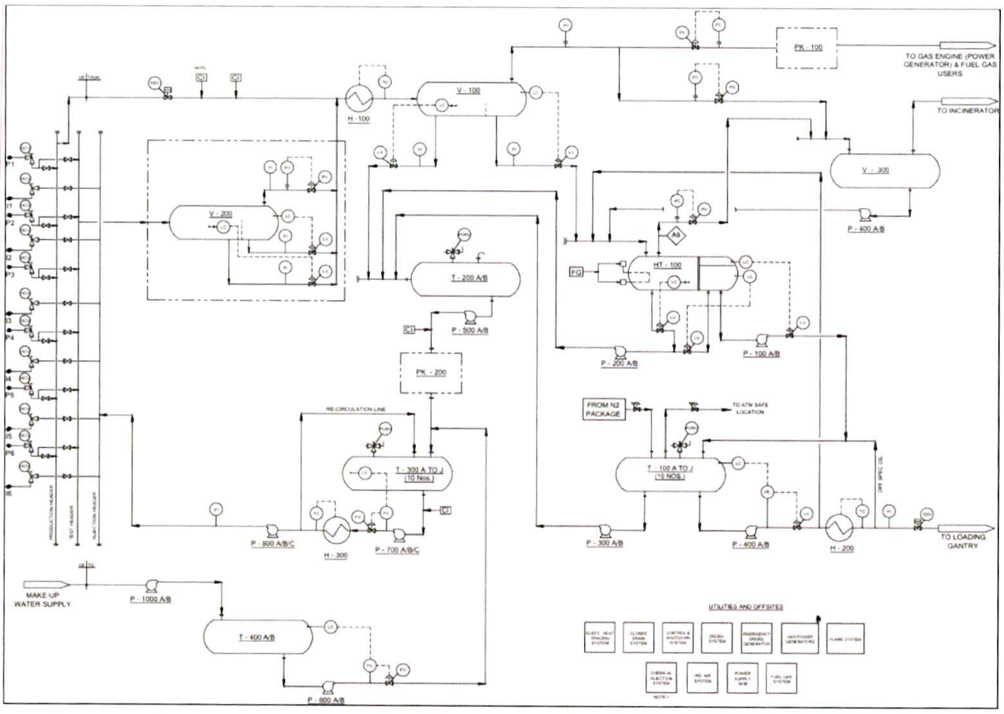


Figure 8-2: Process Flow Diagram (PFD) for the Phase 1 oil facilities

8.3.2 Pipeline from Well pad to EPF

From each well, the production effluent is planned to be artificially lifted with Electrical Submersible Pumps (ESP) . Production from different wells are gathered to one wellpad (2 pads in Amosing field and 2 pads in Ngamia field) from where it's further routed to the early processing facilities. The pipelines will be heat-traced to ensure flow assurance and mitigate wax formation, with provisions in place to allow flushing of line contents during extended shutdowns.

8.3.3 Three Phase Separation

At the EPF inlet, the effluent is heated to above the wax appearance temperature. Subsequently, the well effluent is conveyed to the first-stage separator. This separator is a three-phase horizontal unit designed to separate flashed gas, oil, and water. The outputs from this separator are as follows:

- The flashed gas is directed to the fuel gas network in routine operations or to the high-pressure flare (during startup or abnormal operations only).
- The water is routed to the produced water tank and then further water treatment.
- The crude oil is forwarded to the second-stage heaters and separators.

The further stages of separation are intended to stabilize the crude oil by achieving the targeted Reid Vapor Pressure (RVP) and True Vapor Pressure (TVP), as well as to reduce the BS&W content to below 8-10% by volume.

8.3.4 Crude Dehydration (Heater Treater)

The dehydrator is an electrostatic coalescer designed to facilitate the separation of produced water and crude oil. It is a horizontal vessel equipped with high-voltage electrodes that promote the coalescence and separation process. This stage is specifically designed to reduce the Basic Sediment and Water (BS&W) content as well as the salt concentration in the crude oil. The application of an electrical charge to the crude oil causes particles from the discontinuous phase to migrate, become electrically charged, and be attracted to oppositely charged particles, thereby enhancing separation.

The separated produced water is discharged under interface level control and is subsequently routed to the Produced Water Surge Tank. The treated crude oil, with a Basic Sediment and Water (BS&W) content of less than 0.5% by volume, flows from the dehydrator under pressure control. The dehydrator operates at a pressure higher than the crude oil's bubble point, and at a temperature of 87 °C. From the Dehydrator, the crude is directed to the final crude oil storage tank.

8.3.5 Water treatment

Produced water from separation and dehydrator, and possibly crude storage, is transferred to the Produced Water tank. Any free oil settling in this tank can be periodically pumped to the Slope tank. Water from the Produced Water Surge Tank is pumped to the Water Treatment unit for further processing. The oil droplets are separated from water by filtration and floatation. The clean water is withdrawn from the vessel's bottom under pressure control. A media filtration unit: composed of two vessels equipped with fixed media filters for finishing the water treatment and meeting the oil-in-water requirement for water reinjection. The multi-stage design allows for high separation efficiency in a compact footprint.

8.3.6 Water Injection

The treated water from the Produced treatment package is transferred to the Produced Water Storage Tank, which acts a buffer for the system volume. Water is then boosted to 190 barg for water injection via the Water Booster Pumps (2x100%) and Injection Water Pumps (2x100%).

8.3.7 Crude Oil Storage and Transfer

Stabilized & dehydrated hot crude oil from the dehydrator package is routed to the existing on-site Crude Oil Storage Tanks under level control, via the crude pre-heater for cooling for storage. To prevent wax formation, each storage tank is equipped with a steam coil designed to maintain the crude oil temperature above the wax appearance temperature. Steam is provided for heat from a steam generator. Crude from the storage tanks is offloaded to tanker trucks by the Tanker Loading Pumps after metering using bottom loading arms at four (4) loading bays. Loading operations will take place at night due to travel restrictions between 6 pm and 6 am. The crude oil will be trucked to Mombasa port. Bottom loading gantry are considered in the design for safety.

8.3.8 Wax Mitigation

Wax appearance temperature and disappearance temperature being high (64.5 ~ 76.2°C), the temperature of crude oil lines will be maintained above the wax appearance temp (WAT) throughout the system. Stagnant sections like instrument impulse lines, PSV inlet lines, critical instrument tapings and bridles, drain lines and piping dead legs will be electrically heat traced to avoid wax formation due to heat loss to ambient.

During extended shutdowns, oil shall be displaced to the storage tanks and the system flushed with hot water or diesel where necessary to minimize the heat tracing power and diesel consumption requirements. In order to mitigate the risk of wax deposition during periods when the wells are shut in and fluid flow is interrupted, arrangements will be provided part of the design to flush the flow lines back to the early oil facility as preventive measure to avoid wax buildup and maintain flowline integrity. The flushing process involves. Requirements for flushing frequency, water / diesel volume, and potential alternatives such as heat tracing will be evaluated and finalized during the detailed engineering phase.

8.3.9 Power Generation

For a proposed facility, a dedicated Gas Power Generation system on N+1 basis is considered for each EPF. Similarly, a Diesel generator is considered for Black Start-up/Emergency. Produced gas will be treated in a Fuel Gas Conditioning system which mainly comprises of Fuel Gas KO drum, Electrical heater, heavy hydrocarbon removal, particulate matter/aerosol filters etc. Details of the same will be finalized during detail engineering stage. Selection of Gas generator supplier will be made carefully considering fuel gas compositions, emissions and turndown capacity. Finally, a connection will be required from the national grid as well to the main camp and main facilities sites.

8.3.10 Venting and Flaring

The venting and flare systems are designed to safely dispose of hydrocarbon gases released from the process during normal operation e.g. atmospheric pressure venting and under plant startup-up, emergency and process upset situations. The flare system is to be a ground flare. All discharges from atmospheric vents shall be routed to a safe location. However, during routine operations, hydrocarbon gas will be utilized for power generation as well as fuel gas to the direct heating burners. Any low-pressure gas which cannot be utilised nor economically viable to process and store or re-inject will be routed to the flare.

8.3.11 Closed Drain

The open drain system should be minimized as far as practicable. As a minimum, all skids shall be provided with a drip tray and a low point to allow for connection to a vacuum truck or hard piped to an open drain system.

8.3.12 Utilities

The following utility packages are provided to support the facility:

- Fuel Gas Package
- Flare system
- Closed Drain Drum & Pumps
- Instrument Air Package
- Chemical Injection Pump Skids
- Diesel storage tank and pumps
- Nitrogen bottle rack

The flash gas stream from the HP Separator is routed to Fuel Gas Package via pressure control valve. The flashed gas stream is first sent to Fuel Gas Scrubber to separate out the condensed liquids. The Fuel Gas Scrubber is a vertical two-phase separator operating at ~6 barg. Fuel gas header pressure is maintained by a downstream pressure control valve. Fuel gas will be used for power generation and heating, blanket gas and purging.

A single flare system will be installed to collect any excess gas during process upsets along with any emergency discharges from PSVs and route these to the flare KO drum. Gas from the flare KO drum will be routed to the flare system for safe disposal and any liquids will be pumped to the LP Separator. Flare gas is routed to the Enclosed Ground Flare for disposal. The ground flare is an enclosed flare stack with multiple flare tips, air control dampers and ignition pilots. The flare KO drum shall also be sized to provide volume for closed drain liquid. When draining is necessary, the vessel inventory will be reduced to low level and nitrogen will be used for pressurized draining. Drained fluids are then returned to the process using the Flare KO Pumps. As the closed drain system is to be flushed under pressure (N2 sweep), all closed drain pipework is above ground.

Compressed air for the EPF users will be provided by a dedicated instrument and utility air package. The package will be of conventional, OEM standard design and consist of lead/lag air compressors, 2 x 100% instrument air dryers and 1 x 100% instrument air receiver.

Chemical injection pump skids will be provided for the following chemicals:

- Corrosion Inhibitor
- Demulsifier
- Deoiler / water clarifier
- H2S Scavenger Injection (Amosing 2A)

8.3.13 Electrical & Control System Description

8.3.13.1 Area Classification

Hazardous area classification shall be undertaken, and all hazardous area field instruments & electrical equipment shall be designed to Zone 2, Group IIA, and T3 Hazardous area (IEC or ATEX). Safe area instruments & equipment shall be non-hazardous area certified.

The facility shall include electrical power generation sufficient to meet the demands of the facility, in the form of a N+1 engine generators. Electrical distribution will be provided by a Low Voltage (LV) Motor Control Center (MCC). The MCC, switchgear and other electrical equipment will be installed in a prefabricated containerized electrical cabin.

8.3.13.2 Control & Shutdown System

The facility shall work interestedly to oversee the following subsystems:

- Process control, alarm, and monitoring
- Emergency shutdown system (ESD) for emergency shutdown, executive action, and trips
- Fire & gas system (FGS) to detect the occurrence of fire/flame

Fire and gas detection will be provided by means of field mounted IR type fire and flammable gas detectors strategically located throughout the facility. Fire and gas detection will result in facility shutdown, depressurization etc. as defined on the C&E matrix. Internal communication at the facility will be via handheld radio.

8.3.14 Laboratory

A lab cabin will be provided and will provisionally include the following equipment as minimum for on-site performance monitoring or troubleshooting:

- BS&W analyser Oil BS&W
- RVP analysis Oil RVP
- Oil-in-water analysis Produced water OIW

Analyzing equipment will be provided in accordance with fit for purpose OEM standard specifications.

8.3.15 Fire Fighting Philosophy

The EPF is designed based on a "burn-down" philosophy. As a result, no dedicated active firefighting system has been provided within the EPF infrastructure. Portable fire extinguishers will be strategically placed throughout the facility to address small-scale or incipient fires and to provide first response capability. Containerized cabins for control & electrical rooms will have smoke and fire detectors connected to facility F&G system. Detection will result in facility alarm, and no passive fire protection (PFP) is considered for the early production facilities. There will be a standby firefighting truck at the site to deal with fire based emergencies.

8.4 Central Processing Facility (CPF) for Ramp-up Production (Phase 2)

The principal purposes of the CPF will be to:

- To increase the production by addition by brining online wells from different fields
- Have a central single processing facility (hub) which will be installed on permanent basis to serve over life of the field
- Separate the crude oil from the produced water and associated gas
- Stabilize and dewater the crude oil to meet the crude export specification
- Treat the produced water and make-up water to meet the required re-injection specification
- Utilize associated gas for generation of electrical power
- Re-inject excess gas into the reservoir preventing the requirement for continuous flaring during normal operation

The Central processing facility (CPF) in the second phase of development will be capable of processing the oil, gas and water as indicated in Table 8-4. Produced fluids from each field will be transported via infield gathering network to a CPF situated in the Ngamia area. Well pads at the field locations are not normally manned and only attended with routine surveillance visits. Control and monitoring of key parameters is from the Main Control Room in the CPF.

Table 8-4: CPF capacities for the Phase 2 Development

Phase 2 Facilities (6 Monthly Average Maximums)		
Oil	50,000	stb/d
Water	200,000	stb/d
Water Import	55,392	stb/d
Total Liquid	246,800	stb/d
Gas	16.9	MMscf/d

The gathering network will be buried. The southern fields will have four trunklines, one trunkline each for Ngamia, Ekales, Amosing, Twiga. The northern fields have a single trunkline from Etom and Agete. Smaller flowlines connect individual well pads and to the trunklines. The production trunklines and flowlines are designed for pigging.

Water used for injection will be a mix of treated produced and make-up water. Make-up water will be delivered to the CPF via a dedicated pipeline running from a new abstraction facility at the Turkwel reservoir.

The surface facilities require a supply of power and heat to support production. Electrical power will be generated at the CPF utilizing produced and associated natural gas as the primary fuel. Power users will include artificial lift, water injection pumping, gas compression, electrical loads for the CPF and Central Facilities Area (CFA).

Electrical power will be supplied from the CPF substation to the well pads via overhead transmission lines (OHTL) which will follow the right of way of the pipeline networks. The routing will be finalized during detailed design.

The aim of the facility is to be self-sufficient in terms of power generation and heating, however due to peak demand exceeding installed capacity, an external power source is required. To ensure a secure supply of power is available through the life of the development, a connection to the Kenyan grid is required from day one of the facility operation.

The processing facilities will be designed to optimally handle life of field production profiles. The size of equipment will be maximized to remain within the constraints set by the transportation envelope. Representative crude properties for fields are shown in Table 8-5. These are average values per field.

Table 8-5: Field crude properties

Parameters	Ngamia	Amosing	Twiga	Ekales	Agete	Etom	Units
Pour Point	44 – 48	39 – 42	42 – 45	33-39	36-39	45-51	°C
Wax Appearance Temp	64.5	62.0	67.0	60.0	59.0	63.0	°C
Oil Gravity	31.2	31.6	32.7	34.0	37.1	31.3	°API
Gas Oil Ratio	165 - 197	172 - 187	130-150	154-205	89-149	93-114	scf/bbl

Due to the nature of the oil properties a robust wax management strategy will be required from the reservoir up to and through the processing and export facilities. For the production wells, the system will be designed to maintain a flowing temperature above the WAT at a minimum temperature of 64°C. Detailed wellbore heating and wax deposition studies indicate that downhole electric heating will not be required. Chemicals and demulsifer injection will be the primary flow assurance strategy to mitigate the wax. Hot water circulation will be utilized when required after a long period of shutdown, however the selection of the artificial lift has been optimized to avoid a need for the hot water at the production wells. ESP/ESPCP's will be selected as the main artificial lift mechanism for various reasons especially this will enhance the productivity, reduce the OPEX and CAPEX over the life of the field. The injection wells are designed for hot injection water to ensure that the injection temperature at the sand face is above the wax dissolution temperature.

In the CPF, pipework and vessels will be insulated, and heat traced where required to retain heat within the process. The temperature throughout the oil separation train is maintained above the Wax Appearance Temperature (WAT). Any wax particles which are present in the production fluids will be re-dissolved in the first stage separator by heating to a temperature above the wax dissolution temperature (WDT). The separation system will use a hot water recycling loop to condition the fluid mix to 80% water cut to achieve the BS&W specification. There will be provision for demulsifier injection as required. After oil-water separation and oil stabilisation, the oil will be cooled and stored at 64°C (WAT) in the CPF oil storage tank. The process system and storage tanks will have the capability to heat up to 76°C (WDT) should any wax build-up be observed.

8.4.1 Description of the Ramp-up Production Facilities (Phase 2)

During the production ramp-up phase the fluid produced from the wells will be processed via the CPF (Figure 8-3). The key processing components and design features of the CPF are described in the following paragraphs.

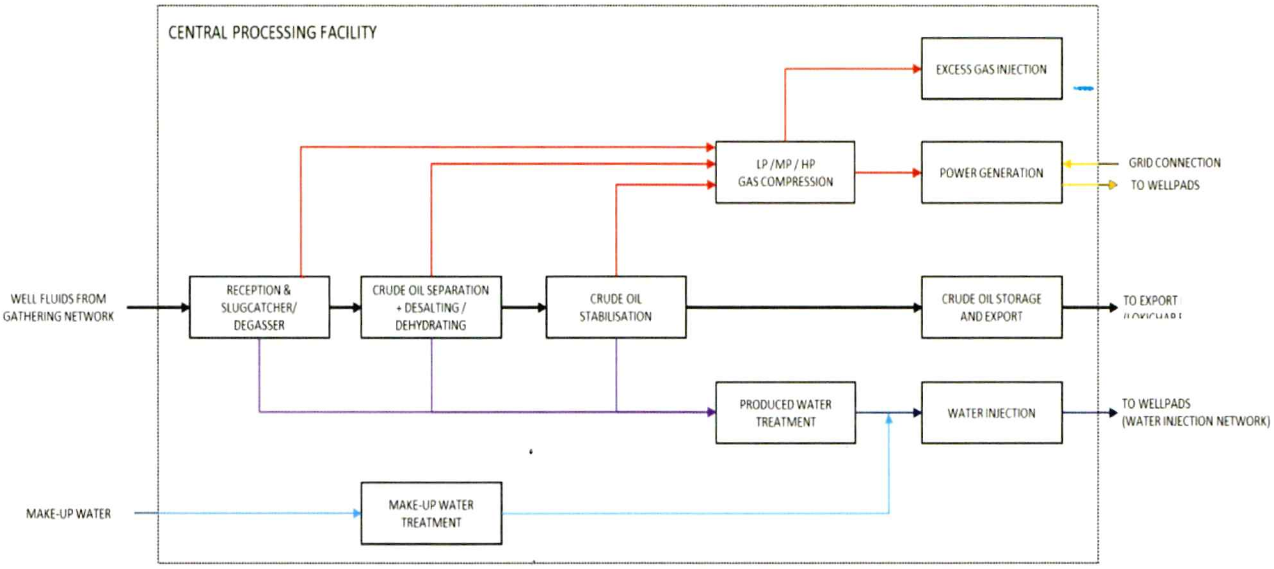


Figure 8-3: CPF overall block flow diagram (FEED phase)

8.4.2 Slug Catcher / Degasser vessels

The reservoir fluids from the five trunklines will arrive at the CPF at approximately 10 barg. The combined fluids will be split between three slug catchers / degassers which perform bulk three-phase separation and collect any slugs which may develop in the pipeline. The water will be routed to the produced water treatment system, the gas will be routed to compression and the wet oil is routed to the crude oil separation system. Provision for sand jetting and sand removal facilities will be provided in the slug catcher / degasser vessels. Sand removed during jetting will be sent to the Primary Sludge Tank for further processing.

8.4.3 Crude Oil Separation and Stabilisation

The crude oil separation unit will be designed to:

- Break emulsions for oil water separation by using demulsifiers and heat tracing where required
- Process the crude to encompass dewatering, degassing and stabilisation using a staged process

The fluids leaving each slug catcher / degasser will be fed directly to one of three parallel crude oil separation trains. Each train will mainly comprise a 1st stage separator, hot water recycling pump and heater. The oil will be combined, and the flow will be split to two parallel dehydrators/desalters. The oil will then be commingled and stabilised.

The 1st stage separator will be a three-phase separator designed to separate the bulk of the produced water. A portion of the produced water outlet stream will be used to artificially increase the water cut to 80% at the separator inlet to aid emulsion breaking and separation. The water will be pumped via the Hot Water Recycle Pump. The hot water recycle loop will be pumped through a Recycle Water Heater to achieve the wax disappearance temperature (WDT) of 76°C in the combined inlet fluids to melt any wax that may be present. The separated water will be routed to the produced water treatment train and the flash gas will be routed to compression. Provision for sand jetting and sand removal facilities will be provided in the 1st stage separators.

The crude oil from the separator will be routed to the dehydrator/desalter where further separation of the crude oil / water emulsion will be achieved by electrostatic coalescence and the BS&W and salt content will be reduced. The produced water will be routed for treatment prior to re-injection.

The crude oil will then be sent to the heater prior to the stabiliser. The heater and stabiliser are designed to achieve a target TVP specification suitable for storage (Table 8-6).

Table 8-6: Crude oil product specifications

Parameter	Value
Maximum Reid Vapour Pressure Referenced at 100°F	10 psia
Maximum True Vapour Pressure at Storage Temperature	0.76 bara
Maximum Co_2 Content	0.1 mol%
Maximum Bulk Sand And Water (BS&W)	0.5 vol%
Maximum Salinity	50 lb/Mbbl
Maximum Total Sulphur	0.1 wt%
Maximum/Minimum Delivery Temperature	64 / 76 °C
Maximum/Minimum Delivery Pressure	5 / 10 barg

8.4.4 Crude Oil Storage and Export

On-spec oil will be routed to the On-Spec Crude Oil Storage tanks. The tanks will be provided with insulation and heating coils to maintain the crude oil temperature. Three days of crude oil storage will be available in five tanks. Online analysis at the inlet to the storage tanks will allow for the crude oil quality (TVP and BS&W) to be verified before dispatch via roads / rail. The crude oil export will be pumped and metered to fiscal quality in the oil export metering package before entering loading onto the tankers.

Off-spec oil will be diverted to the Off-Spec Crude Oil Storage fixed roof tank. When capacity allows the oil may be pumped back to the inlet production manifold for reprocessing. The Off-Spec Crude Oil Storage Tank is also key for start-up and shut- down as it provides a facility to drain or flush portions of the gathering network.

8.4.5 Associated Gas

Three stages of gas compression are proposed based on the operating pressures of the oil separation process. Associated gas production will be used as fuel gas for power generation. The heating of the make-up water will be the largest process heating duty.

In the initial years of operation, the predicted associated gas flowrate is similar to the required demand for fuel gas. The remaining gas (excess gas) declines over the life of the field until the facility becomes gas deficient. No continuous flaring during normal operations is planned. As the field becomes gas deficient the ability to recomplete the initial Phase 1 wells to provide access to known gas accumulations may be used to offset OPEX costs associated with power import (Section 6.2.1).

8.4.6 Produced Water

The produced water is treated and then combined with the makeup water from the Turkwell Dam and reinjected to the reservoir. The produced water will be separated from the crude oil and treated to meet the specification for re-injection water.

The make-up water will also be treated and heated up to the minimum injection water temperature. The two water streams will then be combined and pumped back into the reservoirs at a suitable matrix injection pressure. Produced water from all sources will be combined and routed to the produced water treatment system. Due to the tight solids water specification three stages of water treatment are required.

The recommended solution is primary treatment of produced water degassing followed by produced water settling tanks; secondary treatment of induced gas flotation (IGF); tertiary treatment of multimedia (nutshell) filters to meet the required specification. Off specification water will be routed to the Off-Spec Water Tank or disposed in a waste disposal well.

8.4.7 Water Injection

The treated produced water will be combined with treated make-up water en-route to a single water injection buffer tank. The injection water is pumped via two stages of pumps (booster and injection pumps) to meet the required discharge pressure. The injection water will be exported from the CPF at 210 barg feeding two trunklines before distribution to the individual well pads. The target temperature is above 90 °C in the initial years of operation, after which the well pad temperature requirements are relaxed.

8.4.8 Utilities

The development has a high power and heat demand per barrel of oil produced due to the requirement to provide artificial lift, manage high water cut and the reservoir fluids high wax content. Emergency power supply will be provided by a diesel power generator set which automatically starts to supply emergency and essential loads to the CPF in the event of main power disturbance / failure. It will provide power back up in the event of the unavailability of either main generation or grid supply.

Heat integration will be optimized to minimise energy consumption. Hot stabilised oil will be cooled against produced water and make-up water streams to recover heat back-into the process. Process heating will be provided by a pressurised closed-loop system using a mineral oil-based heating medium.

An overview of the CPF layout is provided in Figure 8-4.

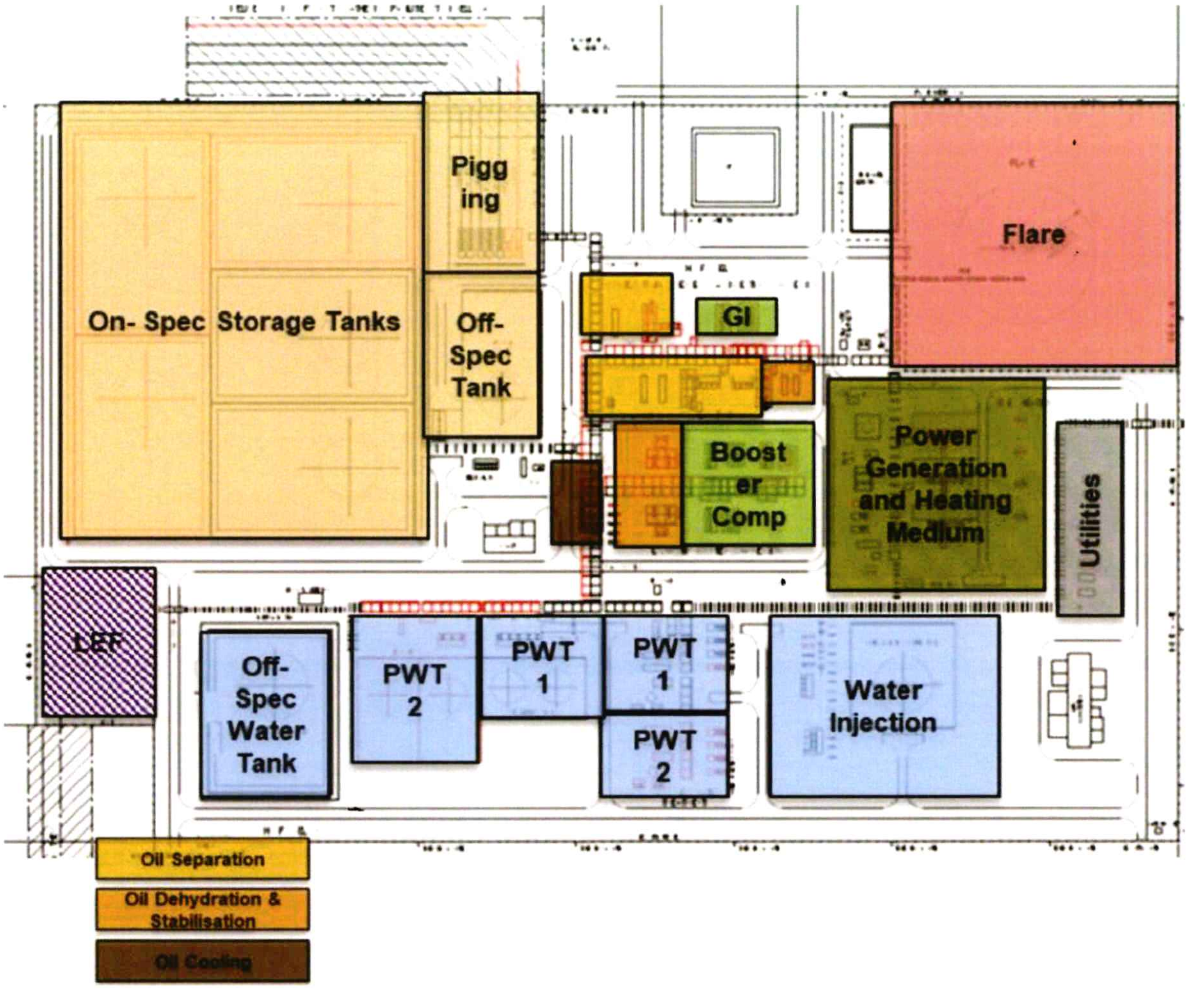


Figure 8-4: CPF layout

8.4.9 Transportation Export

The crude oil produced during Phase 2 will be transported by oil road tankers / rail from Lokichar to the KPRL refinery for storage and further export via the jetty. The export and transportation details are covered separately in Section 9.

8.4.10 Technical Safety

The CPF facilities shall be designed, engineered, built, installed and commissioned in accordance with the applicable Codes, Standards, Specifications and local Regulatory requirements and industry good practice. The project has completed the following as part of the FEED Hazard and Operability (HAZOP), Quantitative Risk Assessment (QRA), Hazard Identification (HAZID), Environmental Impact Identification (ENVID); Inherently Safer Design (ISD) principles; Fire and Explosion Hazard Analysis, and Safety Integrity Level (SIL) / Layer of Protection Analysis (LOPA).

8.4.11 Integrated Control and Safety System

The Phase 1 EPFs will have safety control system to ensure that the process remains within the design envelope. This system will be simplified fit for purpose pneumatic or equivalent control system which will have executive actions based on the designed cause and effects (C&E). However, for the Phase 2 development an Integrated Control and Safety System (ICSS) will be used for control and safeguarding of the well pads and CPF. The ICSS is the overall integrated automation system which will comprise the Process Control System (PCS), Emergency Shutdown System (ESD) and Fire and Gas System (FGS).

8.4.12 Telecommunications Systems

The Telecommunication system shall provide safe, secure and reliable communications for the manned and unmanned facilities. It provides the main and alternate (back-up) communication links to maintain the safety, integrity and security of voice, data and video circuits between the facilities. The telecommunication and security systems will provide the means of remotely monitoring and managing the complete range of activities undertaken in and around the CFA facilities.

8.4.13 Central Facilities Area

The Central Facilities Area (CFA) will be the center of construction activities with construction activities occurring at the CFA, well pads, make-up water abstraction/pipeline, infield infrastructure and infield network locations. The main construction camp, laydown area, CPF, waste management, permanent camp and drilling support facilities will be located at the CFA. The CFA layout developed during the FEED phase is shown in Figure 8-5.

The CFA will include the CPF, integrated waste management facility, permanent camp, ancillary area (warehousing, workshops, fuel station, medical facility, emergency response facility). The central facilities area will also include an area for drilling requirements and temporary facilities to support construction including a main camp, main drilling camp area and construction laydown area.

The infield access roads consist of public roads, spur roads and facilities internal roads. High traffic roads shall be surfaced with asphalt whilst gravel shall be utilized for lower traffic roads. Where practical it is intended to align the roads with the inter-connecting network corridor. To support the construction and operations phases an airstrip and associated facilities will be required.

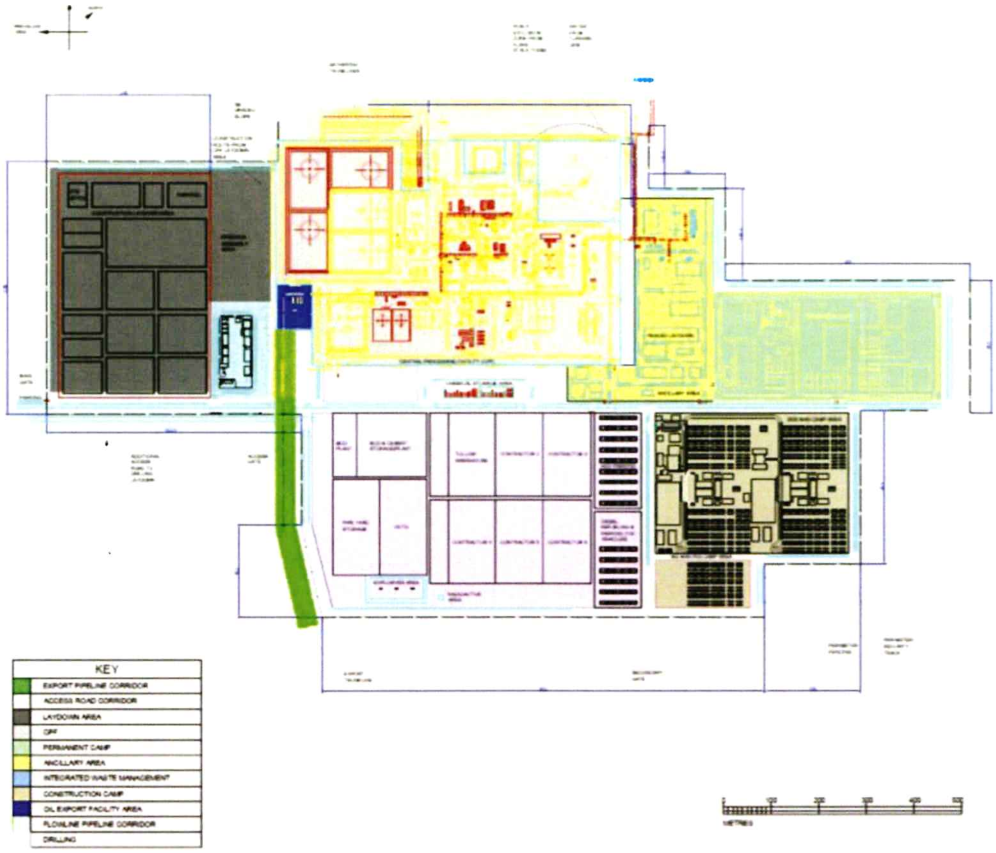


Figure 8-5: Central Facilities Area overview

8.4.14 Water Requirements

The Turkwel Dam has been selected as the preferred option for a strategic water supply (Figure 8-6). The make-up water will be used to supply the Central Facilities Area (CFA) and local communities with the required water demand.

Construction water will initially be provided from groundwater boreholes, prior to completion of the Turkwel Dam pipeline. Presently the water source prior to first oil is the 10 existing water production boreholes in the South Lokichar area. If they were all brought into service, the total yield would be 1,560 m^3/d, 9,812 bwpd.

Forecast construction water demand will exceed the available borehole capacity, therefore it is of critical importance that the make-up water pipeline and associated infrastructure is installed in time to meet the project water demands. If required, a temporary water extraction point at an alternative location will be used to transport water via truck.

The peak make-up water requirement is 60k bwpd. The peak water production during later stage of the project is 200,000 bwpd which will be treated and then reinjected for reservoir sweep and voidage replacement. The additional make up water will be added from the Turkwell dam water where the peak requirements are estimated 60,000 bwpd.

The make-up water pipeline will include six community offtakes along the route. The supply of water to communities will be maximized within the hydraulics of the system ensuring that the project water demand can always be satisfied. Development of the community offtakes and reticulation systems will be managed by the responsible Government bodies.

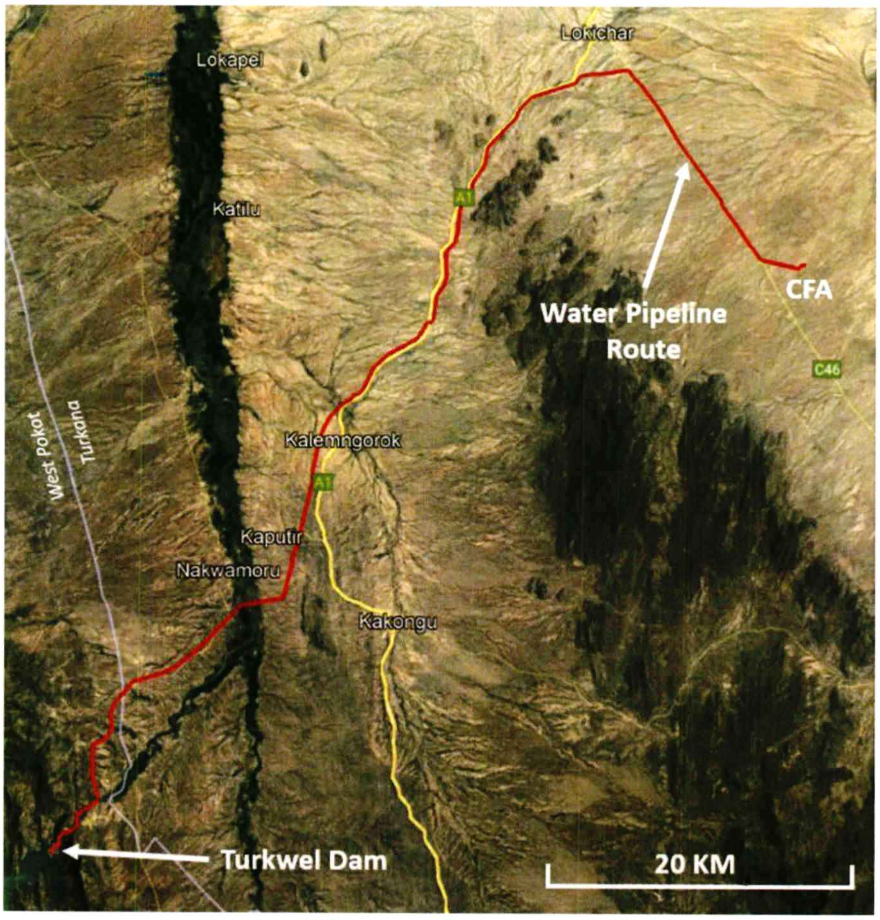


Figure 8-6: Make up water supply pipeline route

8.4.15 Power requirements

The bulk of the project power requirements are generated by gas generators powered by associated gas. However, for periods of peak demand and as a back-up when these are not available, a connection to the Kenyan grid is necessary. Grid connections are required in Turkwel Dam for water abstraction and the CFA, including the CPF, well pads and camps infrastructure. The Phase 1 EPF facilities are conceptually designed to consume 4MW per facility which translates into 8MW for both EPF facilities. The Phase 2 Central Processing Facility (CPF) is expected to have a peak power demand of 34 MW.

The Water Abstraction Area will be located at the Turkwel hydropower reservoir. The Water Abstraction Area requires power to pump water for water abstraction from the reservoir. Power will be distributed to the following users in the CFA and at the well pads:

- Artificial lift for well production
- CPF – Oil processing, water treatment and injection
- Accommodation camps
- Associated Infrastructure – Drilling and construction laydown areas, Waste Management facility and Ancillary Area
- Lokichar Export Facility (LEF) – 1st Pump station of the Midstream Export Pipeline located at the CFA

A local substation will be constructed by KETRACO, local to the CFA, as part of the Turkwel to Lokichogio transmission line expansion project. The substation will contain a 220kV/ 33kV stepdown transformer. The EPCC Contractor shall be responsible for all design and installation of equipment from the secondary side 220kV/ 33kV transformer.

8.4.16 Project Execution Methodology

The Upstream Project will be executed by a single Engineering, Procurement, Construction and Commissioning (EPCC) contractor. This will minimise the number of project interfaces and provide greater control of the project cost and schedule. The EPCC costs form part of the Upstream Capex. To assist with management of the EPCC contractor, a Project Management Consultant (PMC) will be appointed to provide the necessary personnel, processes and quality assurance systems to ensure the EPCC contractor designs, builds and commissions the facilities as per the basis of design and detailed contract requirements.

The PMC will manage the key interfaces between the EPCC, the Well Engineering contractors, and the Midstream Project.

8.4.17 Logistics – Interface between Upstream and Midstream Projects

The logistics and transportation required for a project of this size, scale and complexity will require the application of all modes of transport including sea, air, road and rail (Figure 8-7). The remote location of the project site, the condition of current logistics infrastructure and the distances from port and industrial centers add to the complexity of project logistics. Both materials and personnel logistics are required to support the project during the development and production operations phases.

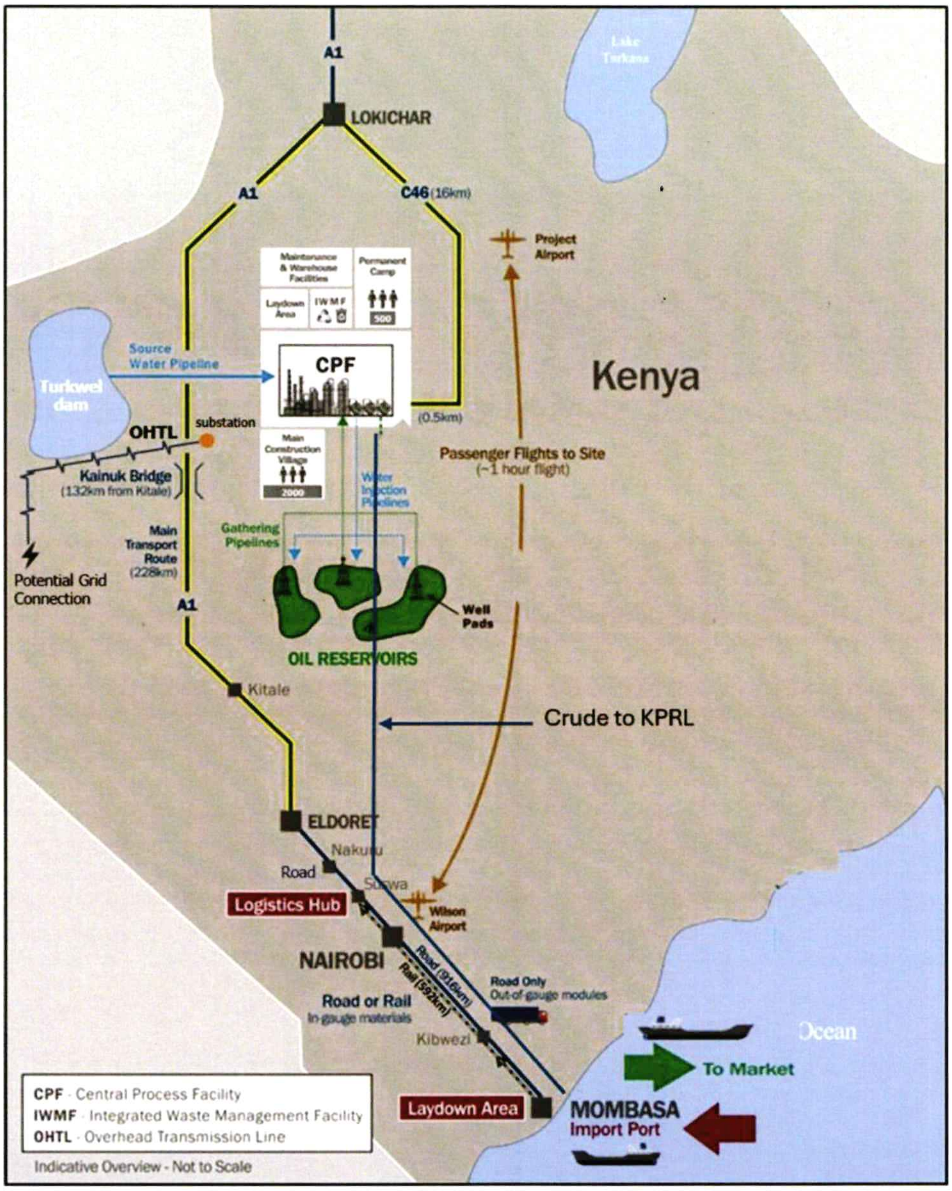


Figure 8-7: Project logistics and transportation infrastructure schematic

The primary port of import for sea cargo will be Mombasa port, with Lamu and Dar es Salaam ports considered as contingency ports. Mombasa port has container and bulk handling facilities and can handle the approximately one million tonnes of project materials expected to pass through the port. To ensure the efficient import of project materials a dedicated project clearing system must be established at the port and at a bonded facility closer to the project site. Mombasa port is approximately 1100 km from the project site and to ensure efficiency of logistics and transportation, it is anticipated that where possible and commercially viable, cargo capable of being accommodated by the Standard Gauge Railway (SGR) will be transported from the port by rail to a bonded facility in Suswa.

The preferred road route to the project site is depicted in Figure 8-7. The route runs from Mombasa port to Nairobi and onwards through the rift to Eldoret via Nakuru. From here the routing follows the A1 to Kitale over the Kainuk Bridge into Turkana County. The road transportation envelope is set out in Figure 8-8 and shown in Table 8-7.

Table 8-7: Maximum Road transportation envelope

Parameter	Maximum Road Limit	Unit of Measure
Maximum Weight	100	tonnes
Maximum Height	5.5	m
Maximum Width	6	m
Maximum Length	25	m

Notes:

1. Maximum tonnage per axle in Kenya = 8 tonnes

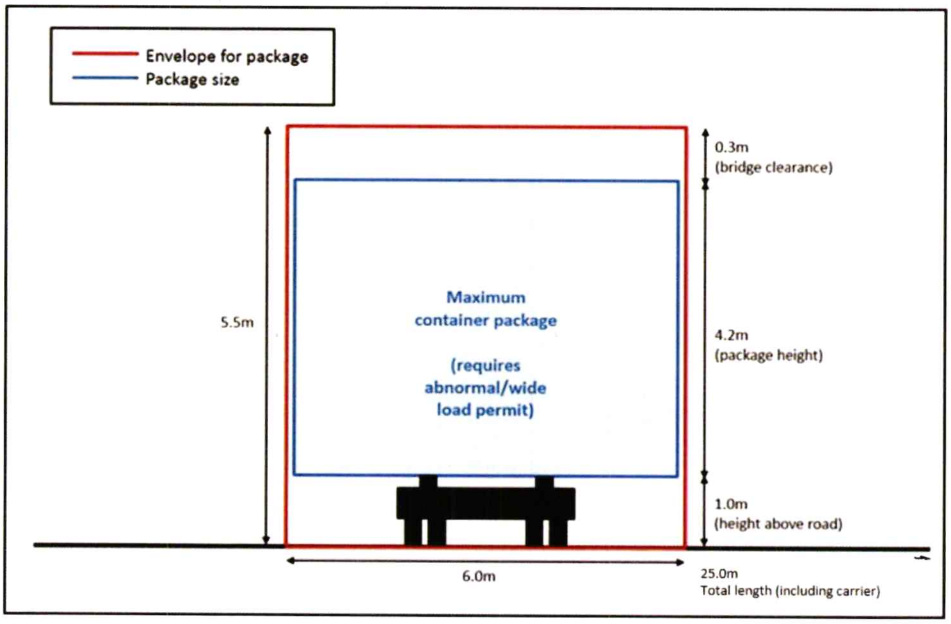


Figure 8-8: Maximum road transportation envelope

The project logistics philosophy is that the Upstream Contractor, Midstream Contractor and Wells Contractors will each manage their own logistics from point of manufacture/collection to the project site location. The Project shall consider establishing a Logistics Coordination Centre in Kenya, to assure that logistics activities are conducted in compliance with project requirements, project schedule and statutory requirements.

8.4.18 Construction Philosophy

The Construction Philosophy for the South Lokichar Project shall support the construction of oil and gas facilities in a remote location. The primary construction goals and objectives are to:

- Construct facilities & infrastructure which are fit for purpose
- Complete the Project in a systematic sequence that supports a safe, efficient, and timely start-up and completion
- Reinforce HSE as a core value and energetically promote a secure work environment with an overall goal to achieve completion of the Project without incident or injury
- Ensure schedule certainty and seamless integration between Engineering, Procurement, Fabrication, Construction, Commissioning, Start-Up, and Initial Operations
- Ensure that the Project is constructed to the required quality standards; and build quality into every step of the work.
- Establish and maintain strong, socially responsible, positive Community Relations

- Comply with the Local Content requirements as per applicable laws, maximise Kenyan employment, training and hiring locally
- Optimise the potential for Kenyan companies to deliver services competitively and competently to the Project
- Minimise disruption to the flora and fauna within the South Lokichar Basin by keeping the temporary works footprint as minimal as feasible, using low noise construction equipment wherever possible and optimising road traffic for construction equipment, labour and materials.

The construction of the South Lokichar Project will require specialised construction capabilities due to the nature and location of the work. The selected EPCC Contractor shall conduct their own Constructability Study, which will examine the availability and suitability of in-country labour and supervision, suitability of in country vendors and subcontractors, access to the site, logistics capabilities, climate and weather conditions, the environmental constraints and requirements and the availability of raw materials. This shall be done as priority upon award to inform the EPCC Contractor's Project Execution Plan. Although these studies have been conducted to date by KJV, it is necessary for the EPCC Contractor to validate and make their own conclusions.

As a priority, following contract award, detailed studies will be conducted by the EPCC Contractor to determine the most efficient and cost-effective construction methodology for the Project. Initial studies indicate that the most cost-effective method is a "hybrid" model comprised of the following:

- Stick Build (traditional construction) majority of structural steel and piping
- Modularised more complex structural steel and piping components (PAR's; PAU's; Skid Mounted) to allow for accelerated completion
- Pre-assembled structural frames and piping for CPF and well pads
- Pre-assembly of main racks for the CPF area at ground level and then lifting into position
- Prefabricated pipe & pre-insulation (for the pipeline network)
- Elements of the civil and piping works shall be considered for prefabricated locally, either at site or regional facilities

The Project will follow the typical construction sequence for onshore facilities:

- Enabling Works: Pioneer camp, quarries, batch plant, temporary water system establishment, access road construction and site preparation
- Early Works: Construction of well pads, CFA & CPF civil works, construction camp and temporary facilities establishment, water abstraction facility/pipeline construction, airfield construction and infrastructure construction
- Main Works: Construction of CPF, ancillary area and well pad facilities, Inter-connecting network, Integrated Waste
- Management facilities (IWMF) and permanent camp
- Commissioning, Testing & Handover at First Oil: Commissioning of First Oil facilities and handover to Operator
- Construction Project Completion & Handover: Completion of post first oil well pads, commissioning of well pads and handover to Operator

The project will develop a quality management system to manage quality through all phases of the project including: engineering, manufacturing and construction. Quality Assurance and Quality Control systems and dedicated Quality Management personnel will be put in place to ensure quality.

8.4.19 Commissioning, Testing & Handover

Commissioning & Testing shall be performed by the EPCC Contractor, witnessed and accepted by the Operator. The overall commissioning & testing of the project shall be optimized by breaking the Unit / Plant into logical Systems and Sub-systems with associated milestones.

Systems Planning Approach

- A system-based planning approach shall be implemented to enable a prioritised structured and systematic approach to allow clear definition of commissioning and subsystems to allow prioritized construction completion, pre-commissioning and commissioning for the planning and execution of Pre-commissioning, Commissioning and Handover.
- The systems planning approach is used to allow:
    - Sequenced checkout to spread the associated workload
    - Construction can proceed in other areas while checkouts/punching are in progress
    - Spreading the workload associated with correction of punch items

8.4.20 Operations Philosophy

The operations philosophy sets out the basis by which the South Lokichar development will be operated and maintained. The operations philosophy sits above more detailed procedures and plans that will be developed prior to start-up and operation of the facilities and will support additional operations and maintenance processes including statutory compliance as they are developed.

The assets will be operated in complete compliance with all applicable laws, regulations, standards and permits including the PSCs, the Contractor's corporate policies and local policies, procedures, specifications, rules, standards and guidelines. The primary operational objectives will be that the facilities will be operated and maintained in a manner that protects the people and the environment whilst at the same time ensuring high production availability. The key is identifying at an early stage the fundamental requirements of operations including lessons learned that are crucial to a successful development. Operations input is key in all stages of the project going forward, to constantly review operations and maintenance implications and to ensure that the operations strategy and philosophies are being met. Operational requirements are primarily based on best practice, lessons learned, and experiences transferred from global operations. This provides the criteria for operation verification in both design and execution; these should include:

- Operating EHS performance will be duly considered and consistently incorporated into design
- Maximum life-of-asset value will be sought through design selections that optimally integrate capital and operating costs
- Operations staff will become highly competent and knowledgeable of the design and operations details in advance of start-up, to more safely and efficiently support commissioning and better prepare for the initial and longer-term operations.

The goal is that the assets should be able to achieve and maintain bench-marked top quartile EHS availability and operating cost (OPEX) performance. The development will be set up as an asset-based production operations organization. The venture set-up related organizational framework for production operations can be divided into the following main categories:

- Nairobi based operational support establishment
- The field establishment lead by Contractor staff employees.
- Externally sourced support services

A detailed Operations resourcing plan will be established prior to the Operate Phase which will be influenced by two key external factors; the green-field nature of the development with an absence of an oil-industry related services industry in Kenya and the Kenyan Government's Policy towards the development of national content.

8.4.21 Decommissioning

This section provides an overview of the decommissioning activities that will be undertaken both after construction and once individual facilities cease operation. Decommissioning refers to the dismantling, decontamination and removal of process equipment and facility structures and any appropriate remediation. The likely decommissioning activities would be focused on:

- Production and injection wells with corresponding well pads
- The inter-connecting network
- Surface facilities in the Central Facility Area
- Other outfield infrastructure

Decommissioning will be undertaken in accordance with Kenyan legislation and applicable standards. Decommissioning costs will be assigned in accordance with the license obligations and have been included in the economic assessment of the development.

Decommissioning costs have been based on an allowance of 6% of project CAPEX. Assuming there is no other use for infield and outfield facilities, all structures including production, processing, treatment, storage, pumping, power, and related infrastructure facilities will be dismantled for recycling, sold for scrap, or disposed of properly. During detailed engineering, the design will consider the need to facilitate future decommissioning. The design will also allow for routine monitoring and inspection to ensure that there is sufficient information on the in-situ condition to support decommissioning. Key considerations for decommissioning (both after construction and following the conclusion of operations) may include:

- Site reclamation
- Extent of restoration and revegetation
- Road access
- Disposal of contaminated materials and residues

Decommissioning of the wells, wellheads and well pads can be found in Section 7.2.11.

Buried production pipelines will be drained, cleaned, filled with an inert substance, capped, and abandoned in place, subject to ESIA and regulations approval. If deemed advisable, and following a risk assessment such ESIA, productions pipelines in some locations could be removed at the end of field operations.

All production facilities, and associated equipment, will be dismantled and scrapped, or disposed of in compliance with applicable regulations. Reusable components will be reconditioned or recycled for future use with permission from the government. The actions taken during abandonment of the onshore pipeline will ensure that it does not become a potential source of contamination to surface water or groundwater and will not act as a conduit for surface water or groundwater. Natural vegetation growth will be encouraged along the pipeline land easement. Induced access management controls will be left in place along the pipeline land easement and ownership transferred to the government, as appropriate.

In most cases, roads used by the project are part of the existing infrastructure and no action will be taken. Where a new road adds little or no value to the existing infrastructure, the road will be abandoned and reclaimed, in consultation with the appropriate Roads Authority. Disturbed areas will be returned to natural contours where possible. Areas of high erosion will be identified in the field and treated with special design measures that may include anti-erosion mats or mulching. Compaction of the subsoil will be relieved by scarification in areas of disturbance.

Each site with the potential for hydrocarbon contamination will be identified, characterized, and assessed for contamination. Contaminated soils will be removed and replaced with clean fill or remediated in situ in accordance with applicable regulations and standard industry practices in place at the time of actual decommissioning. Remediation and/or treatment methods will be selected based on proven and effective technologies that will minimize or eliminate the potential for further contamination of the environment.

Containers such as empty drums, portable tanks, and storage bins will be returned to vendors; cleaned and recycled; cleaned and crushed for scrap; or land filled. Fluids and/or sludge from process vessels, storage tanks, and the pipeline will be recovered and properly disposed. Any hazardous materials will be packaged, labelled, and taken to the project's hazardous waste facility for disposal. Project solid waste landfills will comply with a final closure plan.

Decommissioning plans will be developed based on existing legislation, facilities and best practice and will be submitted upfront for approval to Authority.

9 MIDSTREAM PROJECT

9.1 Why Trucking and Rail?

In March 2023, TKBV submitted a Field Development Plan for upstream facilities, wells, and the Lokichar to Lamu Crude Oil Pipeline. The plan estimated a requirement of USD 3.5 billion to achieve first oil, with an expected production rate of 120,000 barrels per day for five to six years. After Total Energies and Africa Oil withdrew from the joint venture, and given challenging market conditions, securing project financing became increasingly difficult. Tullow had emphasized the need for a strategic partner to advance the project. In 2024, the Government of Kenya provided strong support to TKBV in this search, but efforts to secure a new partner were unsuccessful. This was mainly due to the wide range of contingent resources (240–504–971 million barrels over the 25-year contract period) and unfavourable economic conditions in the oil and gas sector, where investors prefer producing assets.

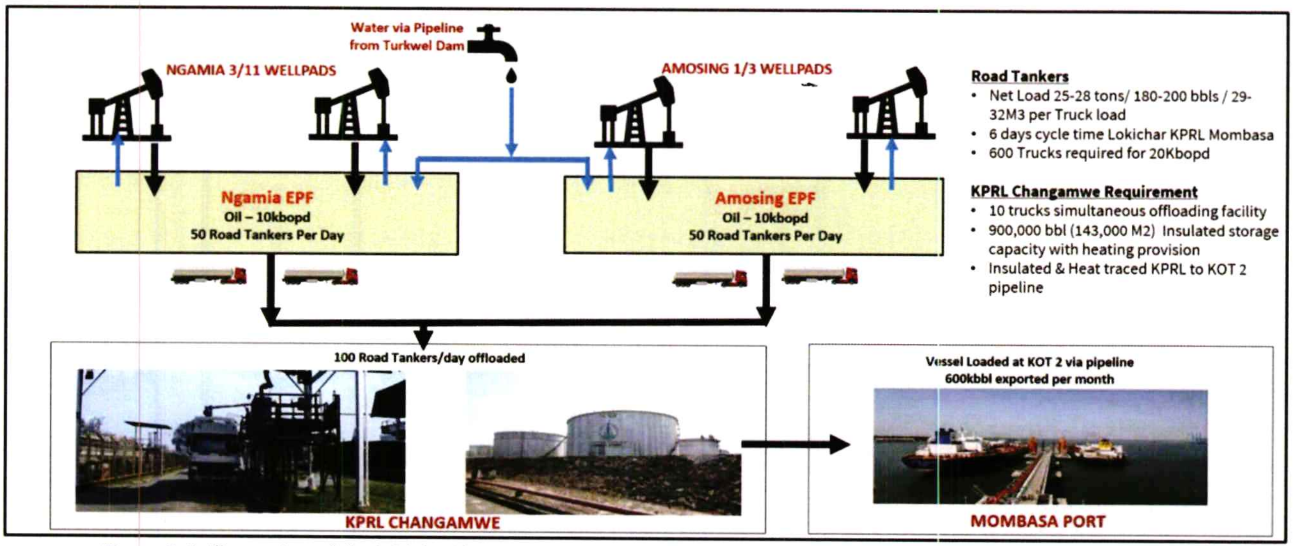
The IHS Kenya Pre-Feasibility Study found that a 70 kstb/d RFCC oil refinery at Lokichar, costing over $2.0 billion, would offer higher economic returns than an export pipeline estimated at $1.5 billion. However, the refinery will face greater challenges in securing financing and reaching FID due to higher capital costs, the wide range of contingent resources, and difficult macroeconomic conditions in the oil and gas sector.

To mitigate risks and commercialize the crude, GEBV proposes a phased development, beginning with production of 20 kstb/d and transportation by truck to KPRL Changamwe for export via the New Kipevu Oil Terminal (KOT2). The initial development envisages production and loading of 20 kstb/d from 2 X 10 kstb/d modular leased EPFs, at each of the two well pads located within the Ngamia and Amosing fields, starting from December 1, 2026, for the first four years, and thereafter increase production to up to 50kstb/d when the required rail infrastructure is ready.

9.2 Midstream Concept Lokichar to KPRL Mombasa

Trucking is the primary evacuation option due to the absence of a railway line to Lokichar and rail wagon offloading facilities at KPRL. The contractor will assess the feasibility of a rail alternative in Phase 2. Processed crude oil will be transported by insulated road tankers from the well pads, approximately 1,100 km from Lokichar to the KPRL facility in Mombasa (Figure 9-1). At peak, about 100 tankers will be loaded daily to transport 20,000 barrels of oil per day to KPRL Mombasa for export storage. The fleet will consist of approximately 600 trucks, based on a six-day round trip. Since Lokichar crude solidifies at room temperature, hence it will be loaded at 80°C and transported in insulated trucks to maintain a liquid state, with an expected temperature loss of 1°C per day. At full production, we expect to export at least one vessel per month, totaling 600,000 barrels.

Initial 20Kbopd - Trucking

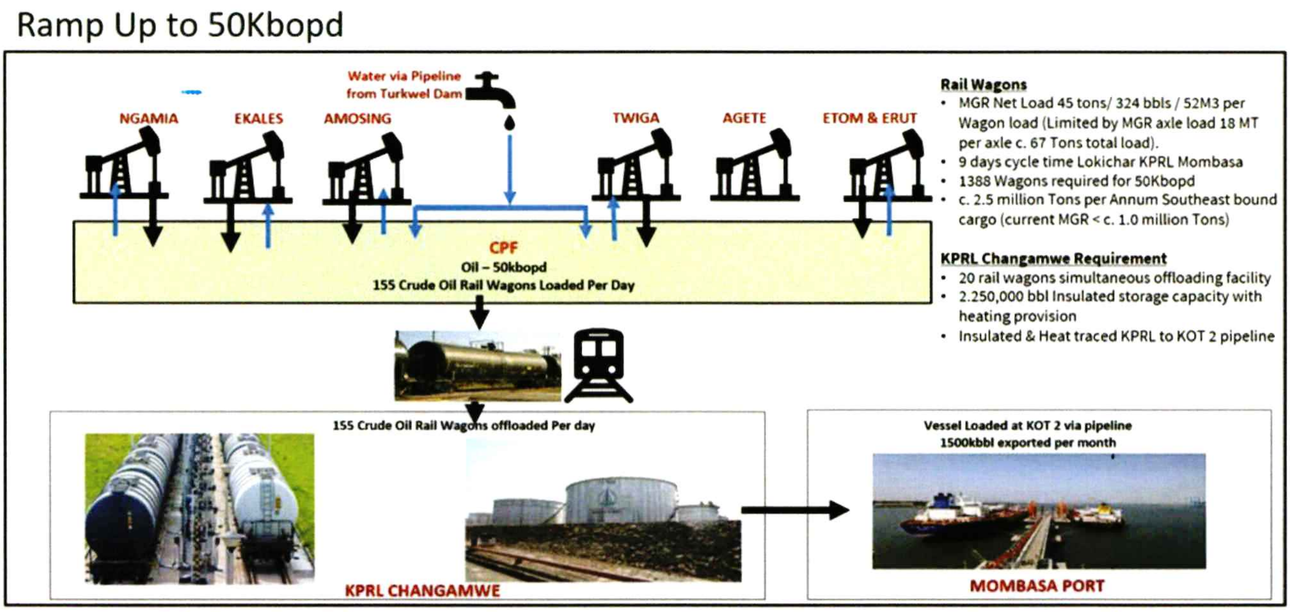


Road Tankers
- Net Load 25-28 tons/ 180-200 bbls / 29-32M3 per Truck load
- 6 days cycle time Lokichar KPRL Mombasa
- 600 Trucks required for 20Kbopd

KPRL Changamwe Requirement
- 10 trucks simultaneous offloading facility
- 900,000 bbl (143,000 M2) Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 9-1: Illustration of the initial midstream concept, outlining the route from Lokichar fields to KPRL in Mombasa.

GEBV requests that GOK provide a railway line in Lokichar, Turkana by H2 2030 to support increasing production to 50,000 stb/d. At this rate, approximately 155 insulated and steam-heated crude wagons will be loaded daily and transported to KPRL Mombasa for offloading and storage (Figure 9-2). We anticipate exporting at least two vessels per month, totaling about 1,500,000 barrels.



Rail Wagons

- MGR Net Load 45 tons/ 324 bbls / 52M3 per Wagon load (Limited by MGR axle load 18 MT per axle c. 67 Tons total load).
- 9 days cycle time Lokichar KPRL Mombasa
- 1388 Wagons required for 50Kbopd
- c. 2.5 million Tons per Annum Southeast bound cargo (current MGR < c. 1.0 million Tons)

KPRL Changamwe Requirement

- 20 rail wagons simultaneous offloading facility
- 2.250,000 bbl Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 9-2: Illustration of the ramp up midstream concept, outlining the rail from Lokichar fields to KPRL in Mombasa.

9.2.1 Road Transport

The proposal is to transport the oil by truck from the production facilities in Lokichar to KPRL Mombasa. Currently, the principal roads that can be used pass through Lokichar, Kitale, Eldoret, Nairobi, and Mombasa as detailed in Table 9-1 below and illustrated in Figure 9-3 :

Table 9-1: Current usable road route distances

From	To	Distance (km)	Highway
Wellpads	Lokichar	25.0	C46
Lokichar	Kitale	214.0	A1
Kitale	Eldoret	72.0	B2
Eldoret	Nairobi	311.0	A104
Nairobi	Mombasa	482.0	A109
Total		**1,104.0**	

Figure 9-3: Current Export Oil Road Tanker Route Map

This route is approximately 1,100 km from the well pads to KPRL Mombasa and is over 75% on National highway class A roads which are developed, managed, rehabilitated and maintained by KeNHA. The C46 road, approximately 25 km from Amosing to Lokichar will need to be upgraded to a class A road. Further, the project requires the completion of construction of Kitale Kapenguria Marich Pass Road and maintenance of the Eldoret Lokichar road.

9.3 Preferred Route

The preferred route for road transportation is depicted in Figure 9-4 below covering 978 km from the well pads to KPRL Mombasa as compared to 1100 km using the current route through Kitale and Eldoret, hence reducing the distance by c. 120 km. The preferred route is 65% and 35% on class A and B/C roads, respectively. 176 km (18%) of the preferred route will need to be converted to a fit for purpose hard pavement road (Ngamia to Amosing 10Km converted from class C to class A road and Amosing to Kinyang 166 km converted from a murram road to a class A road).

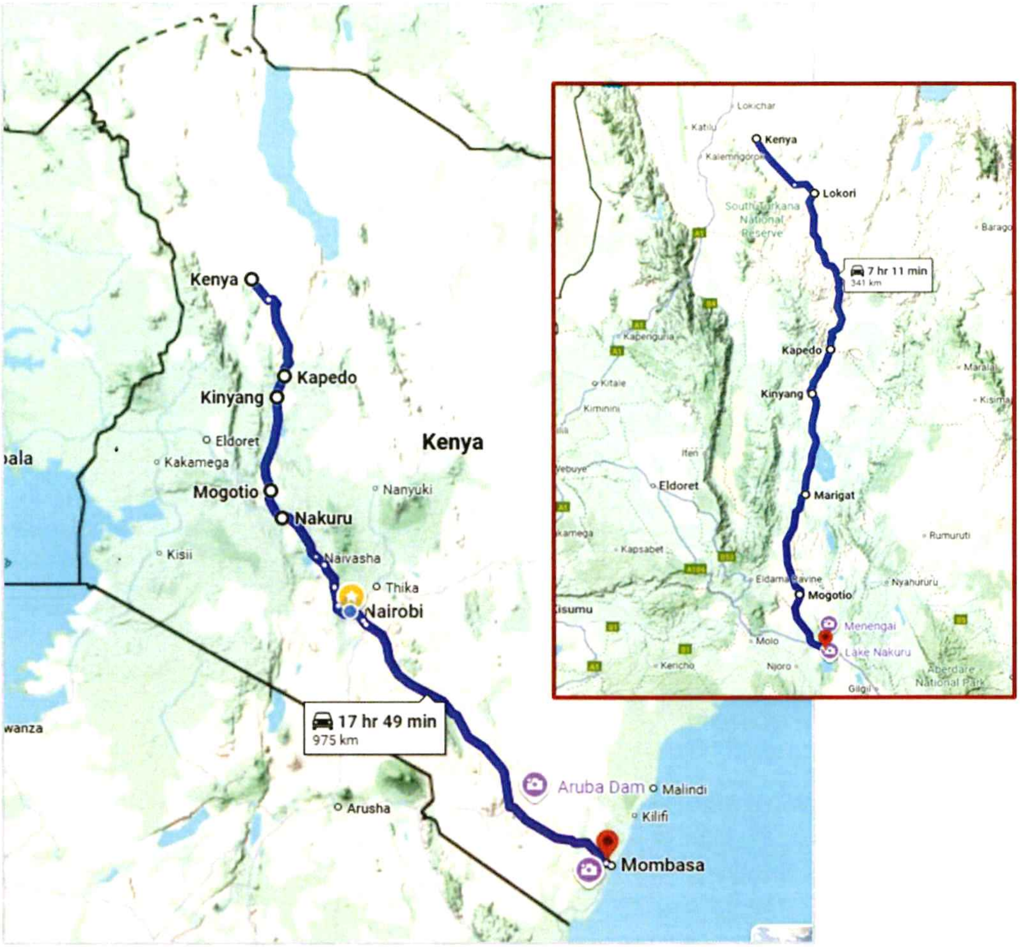


Figure 9-4: Preferred Export Oil Road Tanker Route Map

9.3.1 Recommended Route

Given that the Amosing to Kinyang road (166 km) will need to be constructed to a hard pavement road by 1st December 2026 and it would be desirable to avoid major towns and junctions such as Kitale, Eldoret and Mau Summit, the recommended route (Figure 9-5) is to branch off from the A1 just after Marich Pass towards the Sigor Nakuru Road (B4) and drive past Sigor, Lomut, Kolowa, Carpello, Chemolingot, Kinyang, Nginyang, Marigat, Mogotio, Nakuru, Mombasa. This route will reduce the distance to Mombasa by approximately 50 km while avoiding passing through major towns such as Kitale and Eldoret. Apart from the requirement to upgrade the C46 road approximately 25 km from Amosing to Lokichar from a class C road to a class A road, the following work will need to be completed - (1) completion of construction work Chemelingot to Lomut (c. 94 km) and (2) construction of tarmac road from Marich Pass to Lomut (c. 25 km).

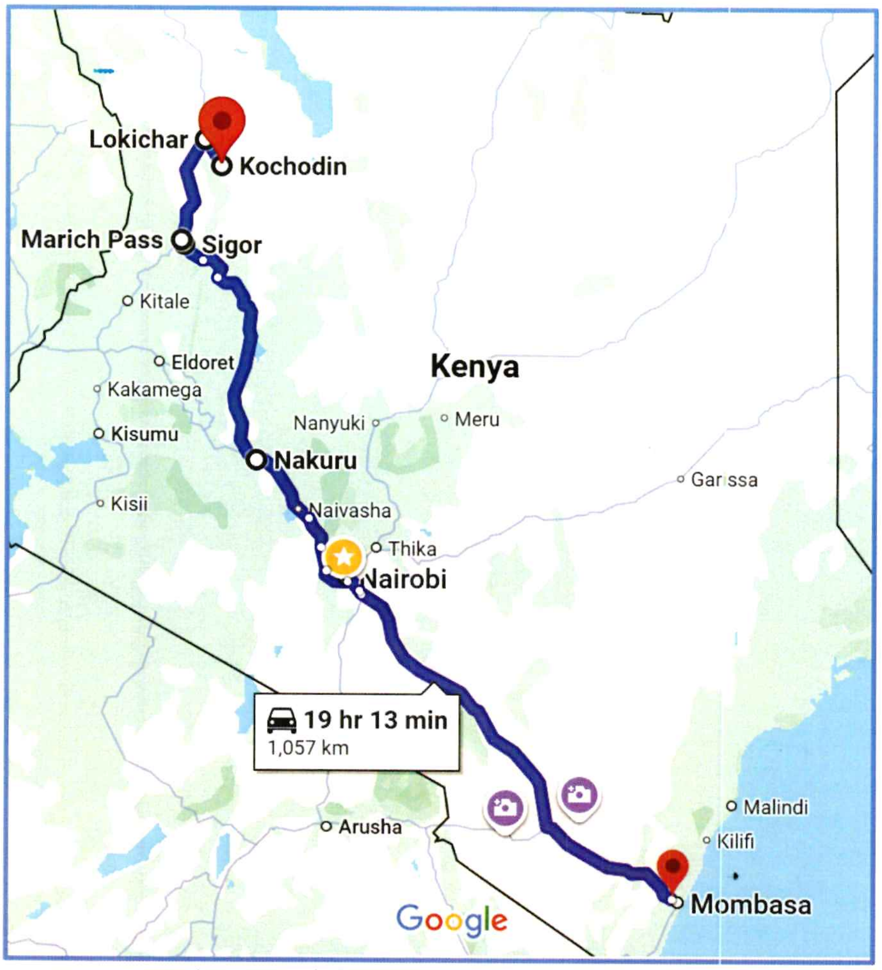


Figure 9-5: Lokichar to Mombasa recommended route

9.3.2 Road Condition

Table 9-2 shows the preferred route road condition. The assumption is that, as per KeNHA's mandate, KeNHA will manage, develop, rehabilitate and maintain quality national trunk roads for prosperity.

Table 9-2: GEBV Preferred road route distances and condition

Road	Distance (km)	Class	Condition
Ngamia to Amosing	10.0	C46	Tarmac road with several luggas
Amosing – Lokori	37.0	C113	Murram road
Lokori– Kapedo	100.0	C113	Murram road in bad condition
Kapedo – Kinyang	29.0	C113	Murram in bad condition
Kinyang – Marigat – Mogotio – Nakuru	162.0	C113/B4	Tarmac Road
Nakuru - Mombasa	637.0	A104	National Highway
Approximate Total	975.0		

Table 9-3 shows the recommended route road condition. Road construction is ongoing from Kinyang to Sigor.

Table 9-3: Recommended road route distances and condition

Road	Distance KM	Class	Condition
Amosing to Lokichar	30.0	C46	Tarmac road with several luggas
Lokichar to Marich Pass	113.0	A1	Maintenance required
Marich Pass to Sigor	7.0	B4	Under Construction
Sigor to Kinyang	112.0	B4	Under construction
Kinyang – Marigat – Mogotio – Nakuru	158.0	B4	Tarmac Road
Nakuru - Mombasa	637.0	A104	National Highway
Total Approximately	1,057.0		

9.3.3 Road Repairs

Tarmac road construction is required staring from Amosing to Kinyang c.166 km to bring the preferred route up to an acceptable standard for the anticipated road traffic. Further the road from Lokichar to Amosing will need to be converted to a class A road from a class C road. Additionally, a deceleration lane is required for trucks to safely enter the selected gate at KPRL.

For the current available route, we note that road construction is ongoing between Kitale and Marich Pass and these will need to be completed for safe usage of the road. For the recommended route the following work is required: (1) completion of construction work Chemelingot to Lomut (c. 94 km) and (2) construction of tarmac road from Marich Pass to Lomut (c. 25 km).

At KPRL Changamwe, a deceleration lane is required for safety and to ensure that other road users are not inconvenienced.

9.3.4 Alternative Routes

Alternative routes exist along the various sections of the road which will allow for the trucks to continue delivering crude oil from Lokichar to KPRL Mombasa (Figure 9-6). It is envisioned that the Rironi Mau Summit road could be under construction at the start of the project. Several routes exist to bypass potential bottlenecks however the distance traveled is bound to increase.

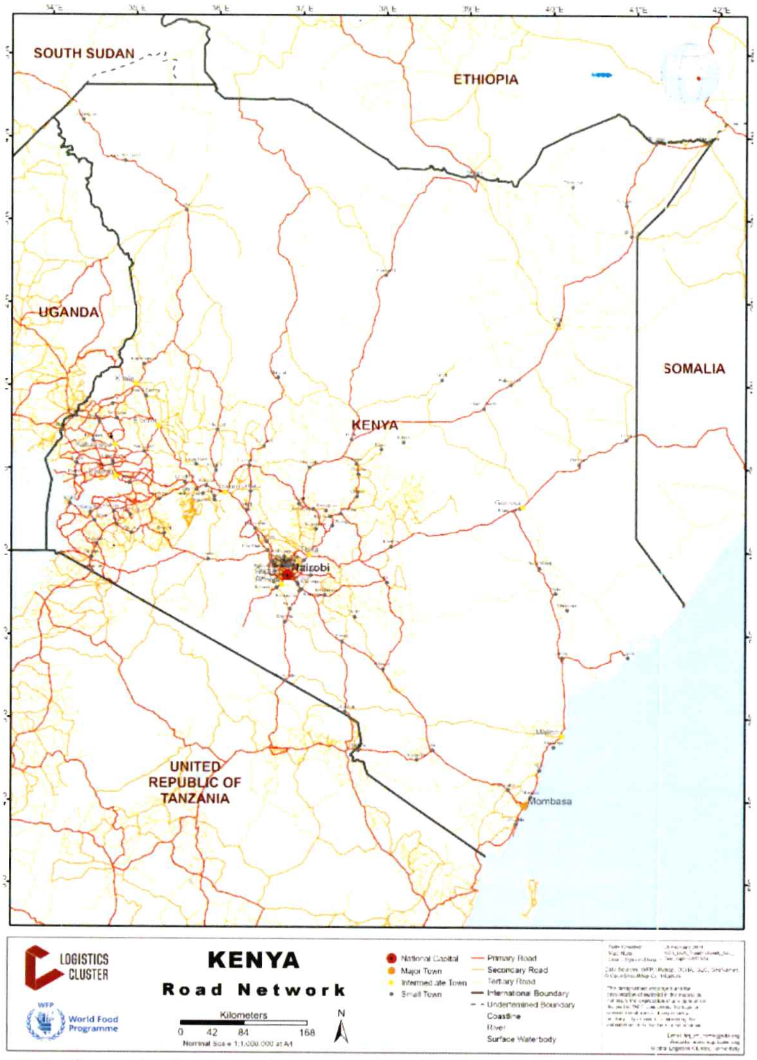


Figure 9-6: Alternative Routes to bypass bottlenecks along the current and preferred route

9.3.5 Traffic

The project will involve 600 trucks taking a six-day round trip. On any given day at any point along the route we envisage that 200 trucks will pass (100 headed to KPRL Mombasa and 100 destined for Lokichar). Table 9-4 shows the effect of the crude oil trucks at three critical weighbridges along the route. Table 9-5 gives an indication of the overall impact of the increased truck movements on the most congested parts of the route.

Table 9-4: Impact of crude oil trucking at critical weighbridges

Location	Average Daily Trucks at Weighbridge	Crude Oil Trucks	% Increase in Traffic
Gilgil	4,752	200	4.2%
Athi River	7,866	200	2.6%
Mariakani	5,483	200	3.6%

Table 9-5: Extract from Hatch traffic report showing impact of crude oil trucking along the most congested sections of the current available route

From	To	ADT (Average Daily Traffic)	Phase 1 Daily Trucks	Impact
Lokichar	Morpus	5003	200.0	4.0%
Morpus Kitale	Leseru	14298	200.0	1.4%
Mau Summit	Nakuru	16,060	200.0	1.2%
Njoro Junction	Elementaita	71,805	200.0	0.3%
Elementaita	Naivasha	25,230	200.0	0.8%
Naivasha	Rironi	31,760	200.0	0.6%
Rironi	Gitaru	36,812	200.0	0.5%

9.4 Rail Transport

To enable the project ramp up to 50,000 stb/d, an effective evacuation midstream solution is required. Using road tankers will necessitate loading and offloading 250 trucks per day and deploying a total fleet of 1500 trucks. Current usage of the Meter Gauge Railway (MGR) is suboptimal as it requires trucking of tanktainers (150 barrels) from Lokichar to Eldoret for transshipment onto the MGR. Usage of the Single gauge Railway(SGR) will require that the tanktainers are trucked to Naivasha for transshipment and further transshipment from SGR rail via truck or MGR for the last mile from SGR terminal Mombasa to KPRL Mombasa. This option is also considered to be suboptimal due to the low-capacity road haulage and the double tanktainer transshipment process.

Desktop studies have also shown that construction of a pipeline to rail heads at Kitale, Eldoret or Nakuru is not recommended as this will involve having storage facilities at rail head locations whereas Kenya Railways has a long term plan of expanding the railway network to Lokichar and beyond. The contractor's ramp up plans to 50 kstb/d are in line with Kenya Railways strategic plan and would provide much needed south bound cargo which will add to the viability of Kenya Railways plans. Subsequently, the contractor has requested GOK to extend the railway network to Lokichar by 2032. Contractor's estimates that 155 (MGR)/ 99 (SGR) crude oil insulated wagons with steaming capacity carrying 324 (MGR)/ 554 (SGR) barrels each will be loaded and off loaded daily in Lokichar and KPRL Mombasa respectively. Apart from extension of the railway line the Government or its railway agents will need to invest in sufficient rolling stock, railway line rehabilitation and construct appropriate railway siding at KPRL to enable the operation.

9.4.1 Railway Line

GOK can construct a meter gauge line from Lokichar and connect it to the main MGR line at Kitale, Eldoret, Nakuru, Nyahururu, Nanyuki or any other location. Usage of the MGR will optimize on existing facility and increase the MGR business by over 100%. Alternatively, GOK can extend the SGR line to Lokichar and connect to the proposed extension of the SGR line from Naivasha to Lokichar. Usage of the SGR will enable haulage of 561 barrels per wagon hence increase efficiency. Despite being a modern rail infrastructure, the SGR's current configuration presents significant challenges for Turkana crude oil evacuation. The challenges include lack of direct connection since the SGR line currently terminates in Naivasha and is not directly connected to the KPRL terminal in Mombasa. There are considerable elevation differences between KPRL and potential SGR connection points at Mombasa port, complicating direct integration. A new terminal may be required to handling crude oil via SGR, with potential locations at Dongo Kundu Economic Zone. Crucially, the SGR line does not currently serve Eldoret, which is the proposed railhead for Turkana crude. Planned SGR phases (Naivasha–Kisumu and Kisumu–Malaba) utilize a southern route that bypasses the Turkana corridor. Studies will need to be carried out to establish the most optimal solution.

9.4.2 Rolling Stock

The rolling stock requirements necessary for transporting 3,500 tons/day (~4,000 m^3/day) of waxy crude oil from Eldoret/Leseru to Changamwe using the MGR are shown in Table 9-6. The analysis compares the use of specialized heated tank wagons and ISO tanks mounted on flat wagons, considering both 8-day (current infrastructure) and 6-day (after upgrades) round trip cycle times.

Table 9-6: Rolling Stock Requirements

Parameter	8-Day Cycle	6-Day Cycle
Active Locomotives	31	23
Option A: Tank Wagons		
Capacity per Wagon	45 tons	45 tons
Fleet Size	758 wagons	556 wagons
Option B: ISO Tanks + Flat Wagons		
Capacity per ISO Tank	23 tons	23 tons
Capacity per Flat Wagon	46 lons	46 tons
ISO Tanks Required	1.565 tanks	1,148 tanks
Flat Wagons Required	783 flats	574 flats

9.4.3 Off Loading Railway Sidings

KPRL Changamwe is adjacent to the Kenya Railways marshalling yard in Changamwe. In conjunction with KPRL, a possible location for rail offloading facilities was identified along the boundary between the two organizations (Figure 9-7). A conceptual design for the oil handling facilities (racks, connections, piping, pumping and tanks) will need to be developed by KPRL.

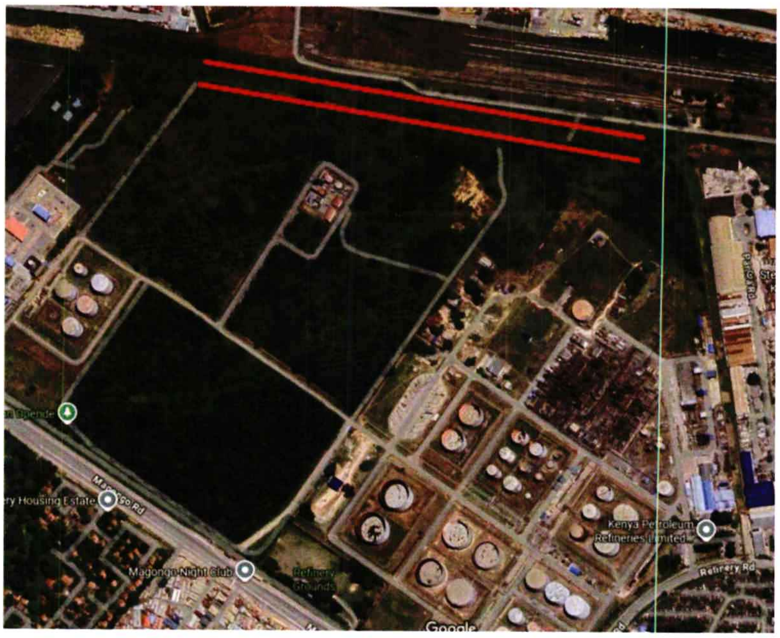


Figure 9-7: Proposed rail offloading location in Mombasa

9.5 KPRL Mombasa

It is planned to use existing storage tanks identified at the KPRL facility in Mombasa. The total required storage volume is approximately 900,000 barrels to support export parcels of approximately 600,000 barrels by Aframax tankers via KOT2 at Mombasa Port monthly. There are three broad areas that must be addressed at KPRL before export of crude can be possible:

- Crude Receiving Facilities
- Crude Storage Facilities
- Crude Export Facilities

9.5.1 Crude Receiving Facilities

Currently white oil products i.e. Liquefied Petroleum Gas (LPG), Premium Motor Spirit (PMS), Automotive Gas Oil (AGO) and Heavy Fuel Oil (HFO) are evacuated from KPRL via pipelines and trucks. Handling of crude oil shall be simultaneous to existing business. Therefore, a dedicated entry of trucks delivering crude oil shall be required and two dedicated weighbridge units shall be required. A segregated truck parking bay is required to accommodate at least 50 trucks.

There are currently five offloading gantries bays in place. Two were used for EOPS, whilst three are yet to be commissioned; two have shed, one will require a shed to be constructed. Though the five gantries can work (24/7), it is prudent to provide an additional two crude oil off-loading gantries to ensure continuous operations. A truck reheating facility shall be required to reheat the crude oil where the temperatures have dropped below the minimum for swift offloading. KPRL will need to confirm integrity of the existing EOPS crude offloading facilities and confirm the applicable coupling for efficient discharging.

At the KPRL facility, there should also be steam supply for heating up the crude in the road tanker in the case where it is found to have cooled and therefore cannot flow.

9.5.2 Crude Storage Facilities

The crude congeals and stops flowing at about 45°C (pour point) while its wax comes out of solution at about 69 °C (wax appearance temperature). Consequently, Kenyan crude oil has to be maintained at above these temperatures. Therefore, the crude tanks must have installation of coils to allow for passage of a heating medium to keep the crude temperature elevated. The medium can be steam or hot oil. In addition, the tanks should have insulation on the exterior walls and roofs of the crude oil tanks to minimize heat loss and thereby reduce the required heat input to the tanks. For receipt of 20,000 barrels of oil per day and export of one crude shipment parcel totaling 600,000 stb per month, 143,000 M3 (900,000 stb) of tank capacity is required at KPRL.

Currently there are six storage tanks converted for handling and storage of Kenya Crude Oil i.e. insulated and fitted with steam heating coils (Table 9-7).

Table 9-7: Current Storage Tank Capacity

Tank	Net Working Capacity (M^3)	Duty	Heating Coil	Insulation	Notes
T-117	15,760	AGO	Heating Coil installed and insulation present		1
T-118	15,760	AGO			
T-119	15,760	AGO			
T-101	16,857	PMS			
T-103	17,024	PMS			
T-104	17,374	PMS			
T-201	29,583	Crude Slops	Required		2 & 3
T-202	29,864				
T-109	15,057	4			
Total	**173,039**	**Cubic Meters (M3)**			
	1,088,296	**Barrels (bbls)**			

Notes

1. Current available capacity for the modified tanks (T-117,118,199, 101, 103 & 104) is 98,535 M3 of 619,717 barrels.
2. Modifications of Tanks 201, 202 & 109; Modifications required includes introduction of heating coils and insulation of the tank and provision of tank mixers, modifications of the connecting pipelines to enable receipt and evacuation to Jetty.
3. These additional three tanks will provide capacity of 74,504 M3 or 468,579 barrels.
4. T-109 is currently decommissioned, installed with heating coils, however the roof is perforated. Tank insulation shall be required.
5. Review impact of conversion of tanks 117, 118, 119, 101, 103 and 104 to CO service on security of supply.

Apart from crude oil storage tanks, other facilities such as a heating system are required. There are three boilers in place at KPRL. The boilers were previously used to maintain temperatures of the crude oil in the storage tanks, line heat tracings, and heating crude in truck which arrived in KPRL at low temperatures before offloading under the EOPS project. These boilers have been idle since September 2022 and to be operationalized. They will require inspection, maintenance and overhaul of some critical accessories. The Boiler Feed Treatment facilities shall also be required. The integrity of steam and condensate system will need to be checked and pressure testing of the steam heating coil on the storage tanks to be performed. The steam boilers are HFO fired and the integrity of the HFO system will need to be checked.

9.5.3 Crude Export Facilities

The crude export facility consists of: (1) an 18" pipeline from KPRL Changamwe to Port Reitz, (2) a 32" Pipeline from Port Reitz to the Beach Valve Station (BVS) and (3) a Subsea 32" Pipeline from BVS to the New Kipevu Oil Terminal (KOT2).

9.5.3.1 Crude Export Facilities 18" KPRL to Port Reitz

The 18" pipeline between KPRL Changamwe and Port Reitz Tank farm has been the main artery supplying crude oil to the refinery since 1974. The pipeline is buried at approximately 1.2-1.5 meters below grade, and at road crossing it is protected by concrete culverts from road traffic loads. The pipeline is designed for maximum pressure of 19 bar, with original wall thickness of 9.53 mm. The pipeline is cathodically protected by impressed current cathodic protection system which maintains the pipe at a negative voltage of below -850Mv, which is monitored on monthly basis and recorded. Records indicate that the pipeline is normally always at -1200 mV, at which level the corrosion protection is considered optimal. The pipeline has an industrial quality paint coating, and two layers of polyken bituminous insulating tape wrapped throughout its buried length. The underground pipeline sections are subject to a scheduled 10-year inspection interval program, whereas the above ground sections undergo six monthly visual inspections. The key degradation mechanisms anticipated for this pipeline are external corrosion due to failure of external coating, and internal corrosion at low points due to entrained water.

Above ground sections were inspected by visual and found to be in good condition. For underground section, bell hole inspections at selected locations in the past have shown the line to be in satisfactory condition. For further integrity assurance checks, bell hole inspections will be conducted on the above pipeline to re-establish the pipeline conditions. The line may also be subjected to a hydrotest of up to 9 bars measured at Changamwe, or 14 bar measured at KOT. There is a static head of approximately 5 bar between Changamwe and KOT due to altitude. The normal operating pressure of this pipeline is 7.1 bar. In event that the line develops a leak during hydrotest, a survey would be carried out to identify location of leak, and repairs would be carried out. Spare 18 in line pipes are held at KPRL stores specifically to facilitate replacement should such an event occur. The wall thickness of this pipeline varies from 9.5mm to 8.0mm. The pipeline is not considered piggable for intelligent pigs as the installation of elbows and the welding during installation did not have that consideration. However, it is considered that correctly sized soft pigs and brush pigs can be ran through this pipeline. Pig launcher and receivers must be installed. However, physical tests need to be carried out prior to operational commitments.

The line was last used in September 2022 and was packed with water after the crude export. The pipeline coating is not suitable for sustained duty at elevated temperatures (operating temperatures of 80°C). Scope for this section of the pipe would include excavation, inspection, making the line piggable, associated repair, insulation, heat tracing and connectivity to the 32" section [Port Reitz to BVS]. The availability of the export pipeline is among the critical success factors and is also a critical path item. Considering that the pipeline will be used for the next 25 years of the license period, the scope of proposed works for this pipeline is as follows.

- Excavate to expose pipeline in sections
- Carry out integrity inspection
- Install electric Heat trace system
- Install designed expansion joints (bellows), as per design recommendations.
- Insulate line
- Re-bury line
- Make the line piggable
- Install pig launcher and pig receiving facilities
- Another option is to replace the 18" pipeline. Therefore, the two options will be considered and costed.

9.5.3.2 Crude Export Facilities - Port Reitz to BVS 32" Pipeline

Two insulated 32" pipeline exist from Port Reitz to Beach Valve Station (BVS) one for HFO and the other for crude. The HFO line is heat traced but the CO line is not. KPC has agreed that the traced line i.e. HFO shall be dedicated for crude oil service. Therefore, tie in from 18"to 32" HFO line shall be required. The heating system of the 32" section to BVS has not been tested and will need to be tested in readiness for crude oil export.

9.5.3.3 Crude Export Facility Subsea 32" Pipeline

The subsea line from BVS to KOT II is insulated and heat traced. However, the heating system has not been tested and will also need to be tested in readiness for crude oil export. The line is piggable, however operational procedures will need to be established, reviewed and approved by KPC, GEBV and the pipeline constructors prior to export of the first cargo.

9.5.3.4 Marine Loading Arm

The Marine Loading Arm (MLA) has been designed with a flashing system that ensures no crude oil is left in the arm. The design operating temperature of the MLA is 50⁰C and the operating range is 0 to 70⁰C. Subsequently KPC, KPRL and GEBV will need to agree on the loading temperature prior to export of the first cargo.

9.6 Technical Details

9.6.1 Road Tankers

The road tankers are designed to carry 25 to 28 tons (180 to 200 barrels/ 29 to 32m3) while meeting the axle load limits. New tankers (Mono Blocks) will have the capacity to carry 30 to 33 tons payload. Pump capacity is 100m3/hr sufficient to empty 1 road tanker in less than 30 minutes.

9.6.2 Journey Management

GEBV has a Logistics and Materials Standard which provides and establishes the minimum standards required for Marine, Aviation, Land Transport, Lifting and Materials Management. GEBV will assure through inspection, review and pre-contract audit, that land transport operations and contractors comply with all safety and legal requirements applicable to the country and IOGP 365 Land Transportation Safety Recommended Practices. GEBV will produce project specific Journey Management Procedures which clearly define how the transport operations will be planned, assured and conducted. Additionally, each transporter will produce a Journey Management Plan, which will include the following:

- Geofencing of high-risk areas (including automated speed control).
- Transport contractors mandated to maintain a centralized control center monitoring individual trips (OBC and in truck cameras for fatigue management).
- Roving repair and environmental response vehicles will be stationed along route corridor.
- Roving vehicles will be mandated to conduct spot checks and road worthiness inspections.
- All vehicle journeys shall be managed through a Journey Management Form

9.6.3 Crude Receipt from Road Tankers

The road tankers will be connected to unloading pump via hoses. For some of the offloading points the Crude will be pumped from the tanktainers into a common header and directed to Intermediate storage. Crude oil receipts will be measured at point of offloading and verified per tanktainer. KPRL has factored in using receiving meters downstream the receiving pump for this purpose. Further and more robust quantification of the amount of crude received from the shipment will be by tank measurements and weigh bridge.

9.6.4 Crude Heating

The crude oil stops flowing at 45°C (its pour point) and starts forming wax deposits at 69 deg C (wax appearance temperature). Therefore, it needs to be maintained at temperatures above these thresholds. The crude tanktainers will be filled at Lokichar production site with crude at about 80°C and they will arrive at Mombasa at not less than 69°C. This indicates a temperature drop of 11°C in transit which will be assumed to be the worst-case scenario. Previously transportation through insulated tanktainers indicated that the insulated tanktainers loses just 1 °C per day. The relevant crude oil details are as follows:

- Specific Heat Capacity of the crude is approx. 2.10 kJ/kg°C.
- Crude density @72°C is 833.8 kg/m^3

9.6.5 Transfer Pumps and Boilers

The pumps will require a 2,000 m^3/hr. capacity. It is proposed that pumps operate in parallel to achieve a higher loading capacity so as to export parcel of 600,000 bbl within 32 hours against 36 hours typically allowed.

9.6.6 Jetty Metering

The crude to be exported will pass through a custody meter at BVS and KOT2 before loading onto the crude export ship. This serves as an additional verification of the exported quantity of crude beyond the exporting tank measurements (before and after export).

9.6.7 Jetty Emergency Shutdown System

An ESD that will stop the loading operation in case of an emergency is to be made operational from KPRL to KOT2. This will comprise:

- Break-away couplings at the ship/hose connection that close automatically.
- ESD valve on main pipeline close to the jetty
- Automatic shutdown of loading pump.

The jetty is fitted with firefighting facility. It is the mandate of KPA to maintain and provide firefighting services at the jetty.

9.6.8 Operating Philosophy

Crude is expected to arrive at KPRL at no less than 69°C and will be transferred from road tankers to KPRL facilities. There will be an agreed minimum crude arrival temperature at Mombasa which will determine whether the crude is unloaded as received or the tanker must first be steam-heated to the agreed minimum temperature prior to unloading. The custody transfer point shall be the coupling half of the KPRL hose connection to the tanker. Deadstock's in tanker, and material that will not flow out at delivery temperature when valves are fully open will not be considered as received at KPRL. There will be meters to establish receipt contents from each tanker, installed downstream the receipt pump. Crude receipt and export measurements will be witnessed by representatives as appropriate.

Pipelines inside KPRL will have movement on a daily basis. Under these conditions, heat tracing and insulation should suffice to keep the crude fluid.

Pipelines to KOT2 will have infrequent movements and the lines will stay idle for long periods of time. The pipeline will be heat traced and insulated but as a further countermeasure the crude content of these lines will be displaced through pigging. Every crude oil movement will be followed by displacement of the line by pigging leaving the pipeline empty.

9.7 Midstream Tariff

In line with the EPRA mandate and considering that the crude belongs to the people of Kenya, GEBV will apply for the Midstream tariff to be approved by EPRA and enable it to be reviewed as per the prevailing economic conditions. Table 9-8 shows a buildup of the midstream tariff that will be presented to EPRA for approval with the fuel pricing shown in Table 9-9.

Midstream Tarif = T1 + SH +EC + MT (for purposes of modelling the economics we have assumed $20/bbl as the midstream opex.

Table 9-8: Midstream Tariff Buildup

			MIDSTREAM TARIFF	
No	**Item**	**Symbol**	**$/bbl**	**Comment**
1	Trucking	T1	16.34	Excludes VAT.
2	Storage & Handling	SH	1.00	
3	Export Charges	EC	0.99	
4	Admin & Monitoring	AM	1.22	
5	Product Loss (0.5%)	PL	0.30	
6	Insurance (0.25%)	IN	0.15	
7	**Midstream Tariff**		**20.00**	

Table 9-9: Fuel Surcharge Calculation

	Fuel Pricing Formula		
a)	Quoted Rate Per Barrel (T0)	$/bbl	16.02
b)	Base Diesel Price (BDP): ERC Nairobi Retail Price 15 July 2025	Kes/Litre	171.58
c)	Current Diesel Price (CDP): i.e. ERC Price 15 Nov 2026 applicable for supplies in December	Kes/Litre	180.00
d)	Fuel Factor (FF): The percentage of the total transport cost that is attributable to diesel		40%
e]	Fuel Surcharge Factor (FSF): (CDP-BDP)/BDP*FF		0.020
f]	Applicable Price (TI) = TO (1+FSF)	$/bbl	16.34

9.8 Agreements

The following are the key midstream agreements that are envisaged:

- Transportation agreement – GEBV & Transporters
- Storage and handling agreement – KPC/KPRL & GEBV

10 ENVIRONMENTAL AND SOCIAL GOVERNANCE

10.1 Project Standards

The Project will comply with applicable Kenyan environmental and social regulations and standards. An environmental and social impact assessment (ESIA) report has been prepared to meet the requirements of the Environmental Management and Coordination (Impact Assessment and Audit) Regulations (2003, as amended). In addition, the Project has been designed and will manage its activities with good industry practice.

10.2 Project Compliance Framework

Chapter 9 of the Upstream ESIA includes an Environmental & Social Management Plan (ESMP) for implementation of ESIA commitments and mitigations for the upstream project component.

Following submission of the ESIA for review and approval by the National Environmental Management Authority (NEMA), the Project will prepare an Environmental and Social Management Plan which will set out how the Project (and its sub-contractors) will comply with the Kenyan regulatory requirements and internal good practice. During construction, the EPC Contractor will implement Project requirements as a contractual obligation. Implementation of these requirements will be monitored by the Project.

For each Project component, the following key compliance documents will be developed that provide auditable implementation frameworks for both construction and operations phases. These are internal performance management documents used to translate approved ESIA commitments and mitigations into specific management controls for implementation by the Project (and its sub-contractors) and are based on commitments and mitigations set out in the respective ESIAs. Table 10-1 is for information purposes only and does not require any further regulatory approvals beyond the approvals of the respective ESIAs by NEMA.

Table 10-1: Project Environmental and Social Compliance Framework

Document	Summary of Contents
Environmental and Social Management Plan	• This will capture commitments relating to: Air Emissions, Biodiversity, Climate Change, Hazardous Materials, Noise & Vibration, Soil Management, Waste Management, Water Resources. It will also capture commitments relating to: Community Development, Community Health, Safety and Security, Cultural Heritage, Influx, Infrastructure Routing, Labour and Working Conditions, Employment and Training, Resettlement, Livelihood Restoration, Transport Management (relating to community safety). Once the statutory land acquisition process has been completed by the National Land Commission, a Resettlement Action Plan will be prepared to support and document resettlement activities. • For each section, there will be a summary of key issues, applicable standards, management controls and monitoring are highlighted. • There are sections on monitoring compliance with the plan, evaluation and auditing, training, resourcing, roles and responsibilities.
Resettlement and Livelihoods Restoration Framework	• Resettlement is a function of GOK and managed and implemented by the National Lands Commission.
Stakeholder Engagement Plan (Section 9.3 and Annex II) of submitted ESIAs	• This Plan has already been prepared, and outlines processes for: informing people of: Project activities, schedule, potential impacts, local employment opportunities, community grievance resolution process. • The SEP outlines the Operator's approach to stakeholder identification, engagement with various stakeholders and includes an action plan for engagement for ongoing and planned activities. • The SEP will be updated prior to construction and will set out how the Operator will engage with stakeholders, including the ongoing management of a grievance procedure, information disclosure and consultation. It also sets out a series of engagement methods and events that are intended to maximise participation and to be appropriate for a given stakeholder group's needs and preferences. The SEP will ensure that the engagement process is credible and transparent and maintains simplicity in information comprehension, is as accessible as practically possible and maintains accuracy of information. • The SEP includes a section providing a detailed description of procedures for the resolution of complaints and grievances.
Emergency Preparedness and Response Plan	• This Plan will be prepared prior to FID and will include: ○ Procedures on how to identify and respond to potential emergency situations, potential failure of risk controls and potential for incidents that would have health and safety implications for workers and/or the community and environmental implications; ○ Provision for emergency arrangements with contractors and collaboration with other appropriate and relevant third parties; ○ Provision of equipment and resources and designation of responsibilities; and ○ A process for review and revision as necessary to reflect changing conditions.

Supporting plans and procedures will be prepared prior to FID as follows:

- Code of Conduct
- Worker Complaints and Grievance Procedure (separate to the community grievance and resolution process set out in the SEP);
- Stakeholder Engagement Plan (Section 9.3 and Annex II of the Upstream ESIA)
- Worker Health and Safety Plan which will set out the Occupational Health and Safety Management System requirements, prepared to meet the requirements of ISO 45001:2018.
- National Content Plan (as part of the Field Development Plan;)
- Local Content Development Plan (as part of the Field Development Plan);
- Contractor Management Procedure (Section 9.2.3 of the Upstream ESIA);
- Procurement Procedure (to ensure that procurement of equipment, materials, chemicals and services (including labour) meet the Operator's environmental and social requirements; and
- Environmental Incident Reporting Procedure (All non-conformances, incidents and near misses must be investigated to a level commensurate with the potential risk or outcome, to include lessons learnt and improvement recommendations).

An online version of the Upstream ESIA and the Water Supply Pipeline ESIA is hosted on the NEMA website.

10.3 ESIA Process

Environmental and Social Impact Assessment (ESIA) scoping consultations for the Project were initiated in November 2015. Relevant baseline data collection covering physical, biological, socio-economic and cultural elements was undertaken until 2021. Project disclosure to stakeholders was undertaken together with the State Department for Petroleum in mid-2021. This was closely followed by consultations and project disclosure on the impacts and mitigations set out in the ESIA. This process was undertaken to ensure that stakeholders were able to participate in the consultation process in an informed and meaningful manner.

10.4 Land Use

The National Land Commission (NLC), on behalf of the State Department for Petroleum (SDP), will acquire gazetted community lands (where registered) and "polygons" of required project land across the different oilfields in accordance with the requirements of the Land Act (2012). In addition to the oilfield polygons, land requirements will also include the Kapese Integrated Operations Base. Within these polygons, the Project has identified a defined footprint of approximately 1,500 hectares versus the predicted polygon land area of approximately 11,000 hectares.

To minimise the impacts of land acquisition, land not required by the Project within the polygons will continue to be available for community use. Some contingent well pads sit outside the gazetted areas. If contingent well pads are required, additional land will be acquired by NLC in line with statutory requirements.

Land requirements for the northern and eastern fields will be further developed during the appraisal activities and once finalised, they will be passed to SDP for gazettement and acquisition through the NLC in line with statutory requirements. The Project expects this land will be acquired through community land acquisition approach as defined under law.

The Project has developed a Resettlement and Livelihoods Restoration Framework which is included as Annex I of the Upstream ESIA.

10.5 Environmental Issues

10.5.1 General

A range of relevant environmental issues were identified for assessment in the ESIA. Key environmental issues, and Project approaches to mitigation and management are described below.

10.5.2 Water Supply

During the construction phase the estimated water demand will average 1,560 m^3/day. Existing water supply boreholes will be used to support early and enabling works, in the event prior to the availability of piped water from the Turkwel Gorge Reservoir. Current availability of ground water stands at around 2880 m^3/day. The water supply pipeline alignment has been permitted separately to the Upstream project and an Environmental License was issued by NEMA on 22nd January 2025.

The use of water is recognized by the Project to be a sensitive issue. The Project will ensure that it does not adversely affect the availability of water supplies to local communities due to water demand related to construction. Based on availability of 2880 m^3/day, project construction water demand estimated at 1,560 m^3/day and community water needs of approximately 300 m^3/day can be sustainably managed with the current resource. Ongoing monitoring of water boreholes will ensure that replacement water supplies (most likely trucked from Turkwel Gorge Reservoir) provide mitigation for the duration of any impact. Once the water supply pipeline from Turkwel Gorge Reservoir is in operation, all Project water will be provided by the water supply pipeline and the Project will reduce reliance on local water boreholes.

The water pipeline will also provide water to communities along its route further improving community access to portable water and water for irrigation. The project during the initial phase producing a peak of 20,000 b.o.p.d will require at peak 26,000 barrels of water per day for operations. Water will be abstracted from the Turkwel dam headrace and piped about 90km to the offtake point at Ngamia.

Reflecting the sensitivity of water supply for the Project, the water supply pipeline was subject to a stand-alone ESIA. This enabled stakeholder comments and concerns to be reflected in the assessment and to ensure that the final design not only met the technical requirements of the Project, but also aligned with County infrastructure planning and the expectations of local communities.

Post peak production, water demand will reduce through the Project phase, linked to the oil production rate.

10.5.3 Air Quality

Particulate matter emissions and forecast ambient concentrations were assessed as part of the ESIA for the upstream project component. Baseline (pre-existing) particulate matter concentrations in the Project Area are above the Project Air Quality Standard due to the dusty and windy environment in the Project Area.

Minor changes to existing air quality are expected during construction and operation, all of which have been assessed as being of minor significance following mitigation. During construction, the main effect will be from deposited dust, which can cause a nuisance. Dust levels will be monitored during construction and additional management actions will be taken if needed to reduce generated dust. Traffic numbers are not expected to be above levels where air quality issues are anticipated. Due to the scarce nature of water, the use of water as a dust suppressant will be avoided as far as possible, and other methods of dust suppression will be used, such as controlling vehicle speeds and ensuring that loads are covered prior to transportation.

During operations, exhausts from turbine generators at the central processing facilities may cause localised exceedances of air quality standards for particulate matter ($PM_{2.5}$). Short-term exposure is not harmful but long-term exposure can cause respiratory issues. As a result, the construction of structures in the affected areas will be prohibited although pastoralists and animals may safely graze and pass through these areas. Further air dispersion modelling will be carried out during detailed design process. The fence line will then incorporate any areas where the Process Contribution (emissions from the Project) is predicted to exceed 25% of the air quality standards to ensure that public access will be restricted.

Full details of all air quality monitoring and modelling are included in the Upstream ESIA (Chapter 7.1).

10.5.4 GHG Emissions

The Project has been designed to ensure minimal routine gas flaring. The Project will at the initial phase of 20 kstb/d production generate up to a peak of 4 MMscf/d of associated gas which shall be utilized for power generation and by fired heaters for heating. At a ramped up peak production of 50 kstb/d, the project will generate peak of 11 MMscf/d of associated gas at commencement which will decrease after seven years to around 10 MMscf/d and gradually to around 3 MMscf/d by 2052. Figure 6-4 provides an illustration of gas production over the project lifecycle. During Phase 2 of the project all produced gas is expected to be used to generate power. Projected forecasts of gas production against usage indicate a good balance with the project facing a gas deficit from around year nine. Based on the information gathered during Phase 1 updated production forecasts for Phase 2 and the associated gas balance will be reviewed and any gas storage requirements assessed. If required, gas can be stored for future use in the Z0 formation drilled by several wells in the Ngamia field. Section 6.2.1 details the available wells and high level plan.

The Project will align with Kenya's climate change objectives under its Second Nationally Determined Contributions (2031-2035) which are aligned to the Paris Agreement of which Kenya is a signatory. While Kenya's per capita GHG contributions (2.09 tCO_2e) are well below global average per capita contribution (6.76 tCO_2e), the country has all the same set aggressive objectives towards mitigating climate change. Kenya's ambitions are Article 4 of the Paris Agreement focusing on on-market based approaches.

The agricultural sector dominates the share of the total greenhouse gas emissions. Combined agriculture, land use change and forestry contribute to 73% of the total greenhouse gas emissions in Kenya. This project will seek to as far as possible minimize additional country contributions. Furthermore, climate change mitigation programmes will be integral to our operations. The project will align with Kenya's ambition to reduce emissions by 35% by the year 2035.

Greenhouse gas emissions have been reduced as far as practical with emissions efficiency of approximately 19 KgCO2/bbl for the Upstream Project component. The chart below demonstrates the project's carbon footprint over project lifecycle.

The Project will evaluate the development of an emissions offset program to reduce further net greenhouse gas emissions related to Upstream production activities with the potential for Scope 1 emissions (related to the production of oil) being fully offset (i.e. "carbon neutral").

Positive contributions of the project are expected to support Kenya's National Climate Change Action Plan 2023-2027 and specifically through;

- Reducing deforestation in the project's Area of Influence (AOI) by providing alternative livelihood.
- Adopting clean and low carbon technologies in our operations while supporting community initiatives for similar uptake especially with regards to clean cooking energy.

- Supporting community climate smart agriculture as part of GE's livelihoods restoration programme.
- Adoption of sustainable waste management for all project related wastes.
- Supporting intervention to address climate change impacts through providing just transition of livelihoods and workforce by creating employment and business opportunities in the project's AOI.

10.5.5 Biodiversity Management

The Project will avoid sensitive habitats and species wherever possible. Surveys for plants, mammals, birds, reptiles, amphibians, fish and invertebrates have been completed by expert teams.

If any potential harm or damage to habitats or species has been identified, and it is not possible to avoid it, the project has committed to a series of measures to restore habitats and species and monitor progress. Some construction activities can be timed appropriately to minimise negative effects.

A Biodiversity Action Plan will be developed to guide project activities geared towards biodiversity conservation and improvement. The BAP will include mitigative and restoration activities geared to this end. A biodiversity supervisor will be employed by the Project to ensure that all mitigation commitments are delivered. Key sensitive species will be monitored throughout the life of the project and action, in coordination with relevant government and county functions, will be taken to protect them should impacts be identified.

10.5.6 Waste Management

Drilling operations will generate solid and liquid wastes that are required to be treated and disposed of in line with legal requirements. It is expected that approximately 120 tonnes of waste will be generated per well. The initial production of 20K stb/d will require 48 wells. Five wells are already existing and hence 43 additional wells will be required generating about 5,800 tonnes of waste. The ramped-up phase will require an additional 862 wells generating a further 104,000 tonnes of waste. Waste will be classified in three categories i.e., solid waste from water-based mud cuttings, liquid waste from water-based mud and solid waste from oil-based mud cuttings.

Waste planning is compliant with jurisdictional requirements, international legislation and established industry practice. The approach is to construct an Integrated Waste Management Facility (IWMF) at the Central Facilities Area which will act as a waste reception, handling, volume minimisation, treatment and storage facility during operations.

Liquid waste from water-based mud will be dewatered and the residue mixed with the solid waste from water-based mud cuttings. This mixture will be retained in the cuttings pit for natural evaporation before it can be buried in a deep pit. No wastes will be kept on well pads. All wastes shall be transferred to the IWMF.

Solid waste from Synthetic Oil-based mud cuttings will be treated using a Thermal Desorption Unit (TDU) to eliminate the concentration of hazardous content in the cuttings. Treated cuttings shall further be used as aggregate for project construction including well pads and in-field roads for project use. All facilities will be constructed in line with Good International Industry Practice (GIIP) in order to minimise odour emissions at source and odour monitored.

An engineered landfill will be constructed which will accept construction phase waste, and some operations wastes that cannot be handled at the IMWF.

The landfill liner systems will comprise a combination of engineered clays and silts (to be confirmed by ground investigation), geosynthetic clay liner and High-Density Polyethylene (HDPE) geomembrane. The inert cell will be lined by a geological barrier of in situ or reworked site derived soils if they meet the permeability requirement, otherwise an artificial sealing layer. Non-hazardous cells will be lined with geosynthetic clay liner, HDPE welded geomembrane and provision for leachate drainage. The hazardous waste cell will be made up of a geosynthetic clay lined geological barrier, HDPE welded geomembrane sealing layer and provision for protected leachate drainage.

The IWMF will comprise the following waste processing and handling facilities:

- Recycling Facility
- Thermal Desorption Unit

- Incineration Facility
- Autoclave – for medical waste
- Anaerobic Digestion (AD) system
- Sewage treatment plant
- Effluent treatment plant (ETP)
- General and Medical waste shredder, crushers, shaker and other solids handling machinery

Water-based muds (WBM) and synthetic-based muds (SBM) and associated cuttings will be generated at each well site during the drilling phase. SBM cuttings will be collected and transported to a centrally located cuttings treatment facility where they are planned to be thermally treated to remove residual SBM and any hydrocarbons. The thermally treated waste is inert and is no longer hazardous and will be sent to disposal in the landfill. As WBM cuttings are not hazardous they will be disposed of around the perimeter of the well pads where they are generated.

The waste inventory developed for the Project indicates that there is an estimated total waste capacity requirement of 324,616 m^3. The engineered landfill will be designed to an appropriate scale to accommodate the estimated drilling, construction and operations wastes as outlined in *Table 10-2*below.

Table 10-2: Estimated Engineered Landfill Waste Quantities

Waste	Drilling (m3)		Construction (m3)	Operations (m3)	Total (m3)
Classification	Up to First Oil	After First Oil			
Inert	0	0	16,921	0	16,921
Non-hazardous	72,647	182,791	15,271	35,847	306,556
Hazardous	163	356	281	336	1,136
				Total	324,613

10.5.7 Accident, Spills / Leaks / Emergency Response

The Project will have an Emergency Response Plan and necessary equipment in place to respond to emergencies and to call for specialist support if that is required. The Operator will coordinate with the local authorities and communities to ensure that stakeholders are informed and prepared in case of an emergency.

10.6 Social Issues

A range of relevant social issues were identified for assessment in the ESIA. Key social issues, and Project approaches to mitigation and management are described below.

10.6.1 Land and Livelihoods

Land acquisition for the Project will follow the statutory process to be undertaken by the Government of Kenya to make land available for the Project. In support of the statutory land acquisition process, the Project will undertake additional livelihood support activities, on a voluntary and non-statutory basis, to ensure that the livelihoods of affected households are not adversely affected by the Project. This may include provision of additional material and logistical support to those identified during the NLC land acquisition process that are required to relocate their dwelling and will also include supporting more regionally focused pastureland management and animal husbandry initiatives to support improvements in pastoralist livelihoods.

10.6.2 Community Health Safety & Security

The Project will develop and implement appropriate procedures to support community health, safety and security in compliance with Kenyan regulatory requirements and industry best practice. To that end, The Project will work with National Government, County Administration and key stakeholders to support existing community health, community safety and livestock grazing programmes.

The Project emergency response procedures and general operating procedures will be designed to safeguard local communities and households from potential impacts related to emergency and normal state activities. This will include engagement to ensure residents are appropriately informed of Project activities and any potential community risks.

Influx of speculative migrants seeking employment will be managed through a combination of a proactive, multi-sectoral approach that begins with assessing baseline conditions and forecasting potential population movements, planning for expanded infrastructure and services, and promoting social cohesion through inclusive policies. public messaging, monitoring, preference for local workers, a clear policy of no informal (at the gate) recruitment and the management of worker integration with local communities. The Project will work with National Government, County Administration and key stakeholders to manage Project-induced influx through Economic integration, local employment and business support, environmental safeguards. Coordination with local governance structures to ensure alignment with Community development plans, while continuous monitoring and adaptive management help respond to emerging challenges effectively.

10.6.3 Occupational Health & Safety

The Project and its contractors will comply with all applicable Kenyan worker health and safety legislation during all phases of the Project. All Project employees and contractors will be given awareness training on community health, safety and security and a Code of Conduct will be in place to ensure respectful relations are maintained with local communities.

10.6.4 Cultural Heritage

The project area is home to diverse communities with rich traditions, sacred sites, and archaeological significance, including globally recognized fossil discoveries. Project planning must include thorough cultural heritage assessments, active engagement with local elders and custodians, and measures to protect tangible and intangible heritage.

Cultural heritage surveys have been undertaken and plans to manage cultural heritage issues have been developed in conformance with Kenyan cultural heritage requirements and good industry practice. The National Museum of Kenya will be involved and informed as required.

Pre-construction surveys will be undertaken prior to the commencement of any ground-disturbing construction activities and micro-alignments made to avoid previously unidentified cultural heritage sites, where that is possible. Where disturbance is unavoidable, culturally-appropriate relocation will be undertaken in consultation with affected communities.

Training for all staff and contractors will include awareness raising related to cultural practices and will include procedures for the protection of cultural heritage sites.

10.7 Local Content and Employment

10.7.1 General

Gulf Energy E&P BV (GEBV), a Kenyan-owned and operated company, is committed to delivering petroleum development in a manner that maximizes value for the Kenyan economy and its people. ~~T~~This summary accompanies the Field Development Plan (FDP) for the South Lokichar Field Development and highlights GEBV's strategic approach to local content integration.

The Local Content Plan (Appendix F, Section 19) is prepared in accordance with the requirements of the Petroleum Act (2019).

GEBV's local content philosophy is built on four strategic pillars: employment, procurement, capacity building, and stakeholder engagement, ensuring sustainable benefits and measurable impact

10.7.2 Local Content Strategy & Principles

GEBV prioritizes Kenyan participation at all stages of the project. Core principles include:

- **Employment**: Prioritize Kenyans with emphasis on local communities.
- **Procurement**: Promote Kenyan suppliers and SMEs across the supply chain.
- **Capacity Building**: Training and technical skills development for workforce and enterprises.
- **Stakeholder Engagement**: Continuous liaison to maintain social license to operate and transparency.

10.7.3 Local Content Approach

GEBV uses the "Wheel of Opportunity" to guide localization across employment, procurement, capacity building and technology transfer.

Opportunities are classified into:

- **Priority Sectors**: Existing market services able to adapt to industry standards (e.g., crane hire, catering, security).
- **Potential Transformation Sectors**: Specialist services requiring development over time to meet project needs.

- **Opportunistic Sectors**: High-investment, specialized Oil & Gas services introduced gradually (e.g., well services, drilling, seismic services).

The wheel of opportunity involves continuous assessment, adaptation, and strategic decision-making to maximize local content.

10.7.4 Key employment and Procurement Highlights

- **Employment:**
    - Unskilled positions ring-fenced for local persons.
    - Semi-skilled roles prioritized locally before extending nationally.
    - Skilled positions sourced nationally with preference to local persons where feasible.
    - Peak workforce targets: **50% Kenyan** for upstream, **100% Kenyan** for civil works and midstream.
    - Overall Project (direct and indirect) workforce is estimated to total **2,000**.
    - Clear and defined succession plan to allow for seamless transition and localisation of positions held by expatriate employees at the outset of the petroleum operations
- **Procurement:**
    - Tendering designed to maximize Kenyan supplier participation.
    - Supplier development and capacity-building programs implemented.
    - Phase 1 trucking: 600 trucks required, County content at least 200 trucks.
    - Phase 2 rail logistics: 155 wagons daily, monthly exports up to 600,000 -1,500,000 barrels.

10.7.5 Market Capabilities and Capacity

National Capabilities: Professional services (financial, legal, ITC, HSE, audits), construction, drilling equipment, mechanical and electrical services, logistics (transport, fleet management, site support, waste management, fuel, international freight).

Local Capabilities: Small-scale firms subcontracted nationally, delivering civil works, light vehicle hire, site consumables, fuel supply, and local support services.

Capacity building: Initiatives will address gaps in specialized oil & gas skills to unlock further local content.

10.7.6 Training and Capacity Building Overview

Training focuses on:

- Workforce and youth development (internships, graduate programs).
- Enterprise and supplier development (SME and county-level engagement).
- HSE standards and certification.
- On-the-job training supervised by experienced contractors.
- Long-term capability strengthening for sustainable local workforce growth.
- The Project is committed to training its workforce. GEBV will continue making contributions to the Training fund and it is assumed that the funds will be utilized for training programs targeting Kenyans who are not in the Project's workforce and will be implemented by EPRA.

10.7.7 Implementation & Monitoring Approach

- **Governance**: Management oversight with support from the Local Content Unit and contractor integration.
- **Implementation**: Embed local content obligations in contracts with defined KPIs.
- **Monitoring & Reporting**: Quarterly contractor performance reviews, independent audits, and regular reporting to EPRA.
- **Continuous Improvement**: Feedback loops to ensure objectives are achieved and enhanced over time.

10.7.8 Key Commitments and Stakeholder Engagement

- Maximize Kenyan participation across all workstreams.
- Promote knowledge transfer and technology sharing.
- Engage stakeholders: regulatory authorities, national & county governments, local communities, contractors, and the business community.
- Maintain transparency and deliver measurable local content outcomes, including quantified workforce and procurement participation targets.

10.7.9 Conclusion

The South Lokichar Field Development is a milestone for Kenya's petroleum sector. GEBV commits to:

- Maximizing Kenyan participation.
- Supporting enterprise growth.
- Delivering workforce training and development.
- Promoting technology transfer.
- Ensuring transparent reporting.

Key Quantitative Commitments:

- **600 trucks** in Phase 1 (**at least 33% Local Content**)
- **155 rail wagons** daily in Phase 2
- **Monthly exports**: up to 600,000 barrels for Phase 1 and up to 1,500,000 barrels for Phase 2
- **Workforce participation**: 50–100% Kenyan across workstreams

This LCP establishes a living framework for sustainable local content, ensuring petroleum development catalyses inclusive and long-term socio-economic benefits for Kenya, particularly Turkana communities

10.8 Social Investment

The Project will contribute to social investment in the Project area, building on existing community projects and initiatives (for example education, healthcare, road improvements, Community Health and livestock grazing programmes and maintenance of water supplies) and working with County and National governments.

Social investment and related activities related to livelihoods restoration will be set out in a Community Development Plan, to be developed in consultation with Affected Communities. This will enable Affected Communities to have the opportunity to determine how best the Project can support social investment and community development.

This is summarized in Chapter 7.9 (Social) of the Upstream ESIA.

10.9 Stakeholder Engagement & Grievance Management

The Project has engaged with stakeholders and Affected Communities throughout the exploration and appraisal period. A structured process of disclosure and consultation has been undertaken to support the scoping, baseline data gathering and impact assessment for the ESIA in line with Kenyan regulatory requirements and good industry practice.

The basic standard of consultation and engagement adopted by the Project is informed consultation and participation. This is particularly relevant to pastoralists who are recognised as potentially being vulnerable and marginalised, and therefore be engaged in a culturally appropriate manner to ensure they have full opportunities to be involved in Project consultation and engagement activities, and also to have the opportunity to share in development opportunities provided by the Project.

The Project recognizes concerns will arise as the Project advances planning, land access, clearance, construction and moves into operations.

A grievance resolution process has been developed and implemented that applies to all complaints related to the Project. However, because land acquisition for the Project is being undertaken by the Government of Kenya as part of the statutory land acquisition process, any grievances relating to statutory land acquisition and compensation will be the responsibility of the Government in line with mechanisms and rights to appeal set out in Kenyan law.

The Project's grievance resolution process has been developed to meet Kenyan legal requirements relating to grievance resolution. This is summarized in Chapter 7.9 (Social) of the Upstream ESIA and is also set out in the Project's Stakeholder Engagement Plan which is included as an Annex to the ESIA (Volume 3, Annex 2A).

10.10 Implementation, Monitoring and Reporting

The Project will implement all mitigations and other commitments set out in the ESIA and subsequent Supplemental Assessment through the Project Environmental & Social Management System.

The Environmental & Social Management System will set out the processes and organisation to be adopted and implemented by POK so that it can achieve its environmental and social performance objectives. The Project will develop specific policies for Environmental Performance, Social Performance, Human Rights and Occupational Health and Safety. Underneath this will sit a set of auditable management plans that set out the specific management controls, roles and responsibilities, for implementation of the Project's environmental and social requirements.

Project commitments (to its environmental and social performance) from the ESIA will be captured in the following internal management documents which will be prepared prior to FID (Table 10-3):

Table 10-3: ES Project Management Documentation

Environmental Performance Plan	This will include: air emissions, biodiversity, climate change, hazardous materials, noise & vibration, soil management, waste management, water resources. The plan will be prepared to meet the requirements of ISO 14001:2015
Social Performance Plan	This will include: Community Development, Community Health, Safety and Security, Cultural Heritage, Influx, Infrastructure Routing, Labour and Working Conditions, Employment and Training, Resettlement, Livelihood Restoration, Transport Management. The Plan will be prepared to meet the requirements of ISO 14001:2015.
Stakeholder Engagement Plan	This Plan will outline processes for informing people of Project activities, schedule, potential impacts, local employment opportunities, community grievance resolution process. The Stakeholder Engagement Plan outlines the approach to stakeholder identification, engagement with traditional leadership, and an action plan for engagement for ongoing and planned activities.
Workers Health And Safety Plan	This Plan will outline processes for informing people of Project activities, schedule, potential impacts, local employment opportunities, community grievance resolution process. The Stakeholder Engagement Plan outlines the approach to stakeholder identification, engagement with traditional leadership, and an action plan for engagement for ongoing and planned activities.
Emergency Preparedness And Response Plan	This will include: • Procedures to identify and how to respond to potential emergency situations, potential failure of risk controls and potential for incidents that would have health and safety implications for workers and/or the community; and environmental implications. • Provision for emergency arrangements with contractors and collaboration with other appropriate and relevant third parties.

Reporting to, and auditing by, NEMA will be undertaken in conformance with applicable requirements. Independent auditing by Project Lenders will also be undertaken on a regular basis, as agreed.

The above documents are technical implementation documents that will be developed by the Contractor and subject to consultation with the appropriate regulatory authorities in accordance with regulatory requirements. Where such documentation goes beyond Kenyan regulatory requirements, relevant authorities will be engaged on the basis of good practice. Implementation of the above does not require any special GoK involvement above and beyond existing regulatory approvals and therefore does not have an impact on approval of the FDP.

11 SCHEDULE AND COST PROFILES

11.1 Project Schedule

The provisional project schedule is presented in Figure 10-1 and commencing with FDP approval and shows the key timings of Phase 1, Phase 2 and the E&A programme.

Phase 1 first oil is planned for December 2026, facilitated by the use of existing wells, pads and rental infrastructure supported by pattern drilling across the areas of the thickest net reservoir sections in Amosing and Ngamia.

Achievement of this Phase 1 schedule requires robust project management, coordination of interfaces and timely support from the relevant Kenyan Government agencies.

The schedule makes no allowance for any future legislative or regulatory requirement which may impact the schedule as proposed.

The following activities are required to prepare to start work immediately once an FID has been taken if the project is to meet the Phase 1 schedule (Figure 11-1):-

- Land Access, Water Rights, Commercial Agreements, Contracting and Project Finance
- Water pipeline tendering, detail design, procurement and early construction
- Enabling Works comprising amongst others: temporary camp, quarry, batching plant set up, access road construction, site preparation and concrete pre-fabrication yard establishment, etc.
- Early Works comprising amongst others: infield roads, construction camp, CFA laydown area, drilling laydown area, landfill site, infrastructure surveys, flood defences, etc.
- Permitting
- FEED validation, detail design to support early ordering for Long Lead Items procurement

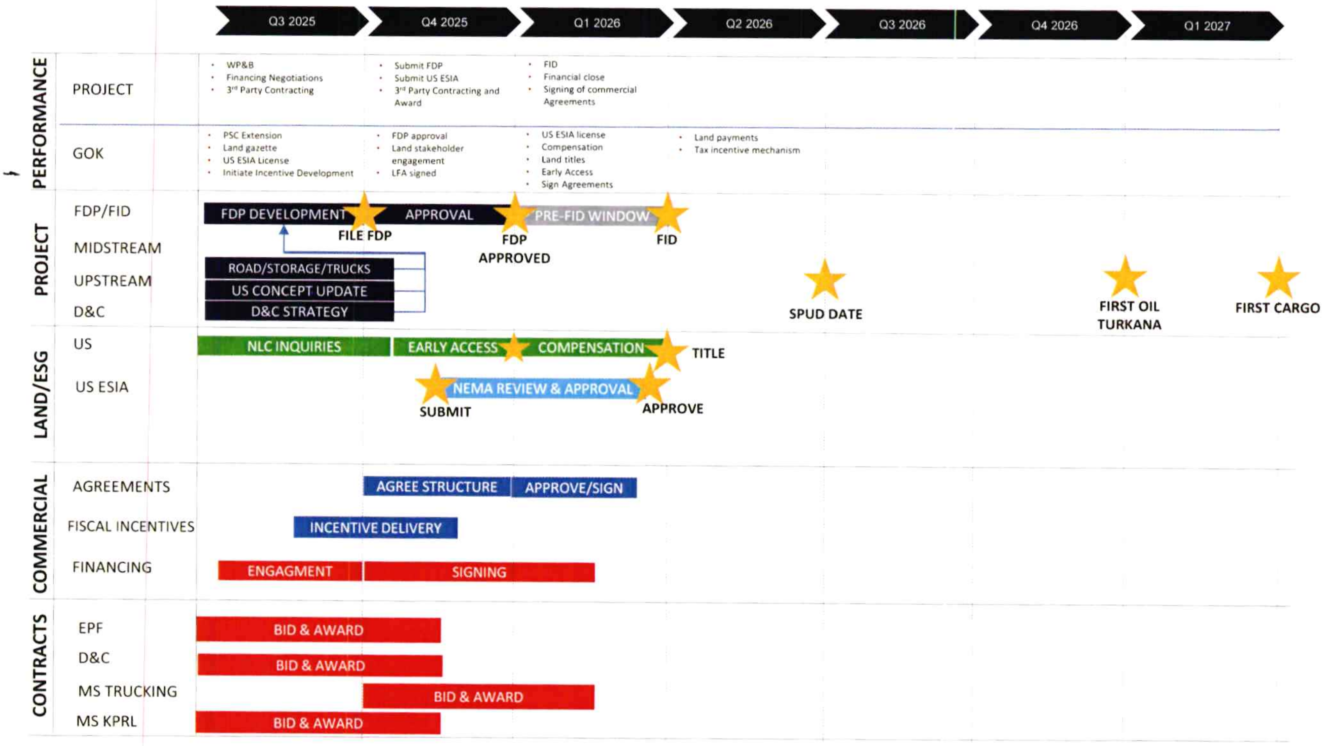
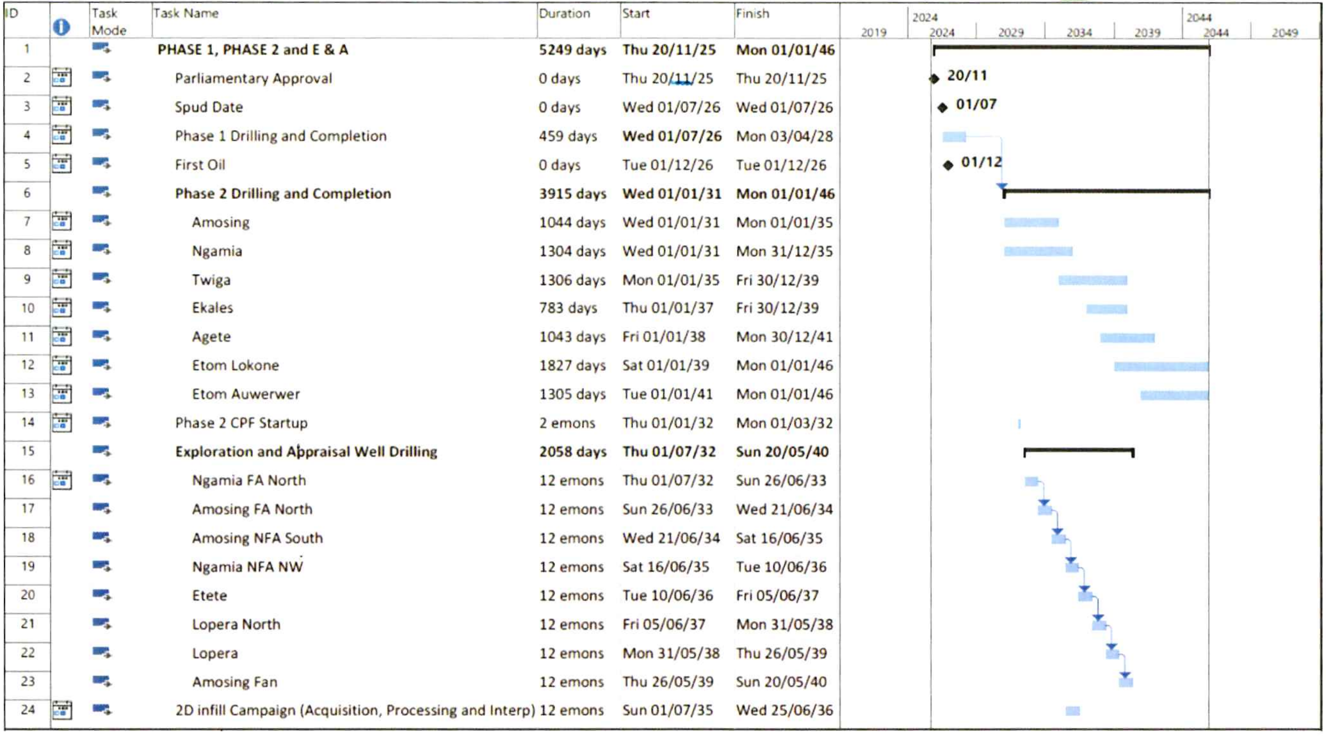


Figure 11-1: Phase 1 Schedule

Figure 11-2 shows the project schedule for Phase 1 and Phase 2 along with the proposed appraisal programme.



ID	ℹ	Task Mode	Task Name	Duration	Start	Finish
1			**PHASE 1, PHASE 2 and E & A**	**5249 days**	**Thu 20/11/25**	**Mon 01/01/46**
2	📅		Parliamentary Approval	0 days	Thu 20/11/25	Thu 20/11/25
3	📅		Spud Date	0 days	Wed 01/07/26	Wed 01/07/26
4	📅		Phase 1 Drilling and Completion	459 days	**Wed 01/07/26**	Mon 03/04/28
5	📅		First Oil	0 days	Tue 01/12/26	Tue 01/12/26
6			**Phase 2 Drilling and Completion**	**3915 days**	**Wed 01/01/31**	**Mon 01/01/46**
7	📅		Amosing	1044 days	Wed 01/01/31	Mon 01/01/35
8	📅		Ngamia	1304 days	Wed 01/01/31	Mon 31/12/35
9	📅		Twiga	1306 days	Mon 01/01/35	Fri 30/12/39
10	📅		Ekales	783 days	Thu 01/01/37	Fri 30/12/39
11	📅		Agete	1043 days	Fri 01/01/38	Mon 30/12/41
12	📅		Etom Lokone	1827 days	Sat 01/01/39	Mon 01/01/46
13	📅		Etom Auwerwer	1305 days	Tue 01/01/41	Mon 01/01/46
14	📅		Phase 2 CPF Startup	2 emons	Thu 01/01/32	Mon 01/03/32
15			**Exploration and Appraisal Well Drilling**	**2058 days**	**Thu 01/07/32**	**Sun 20/05/40**
16	📅		Ngamia FA North	12 emons	Thu 01/07/32	Sun 26/06/33
17			Amosing FA North	12 emons	Sun 26/06/33	Wed 21/06/34
18			Amosing NFA South	12 emons	Wed 21/06/34	Sat 16/06/35
19			Ngamia NFA NW	12 emons	Sat 16/06/35	Tue 10/06/36
20			Etete	12 emons	Tue 10/06/36	Fri 05/06/37
21			Lopera North	12 emons	Fri 05/06/37	Mon 31/05/38
22			Lopera	12 emons	Mon 31/05/38	Thu 26/05/39
23			Amosing Fan	12 emons	Thu 26/05/39	Sun 20/05/40
24	📅		2D infill Campaign (Acquisition, Processing and Interp)	12 emons	Sun 01/07/35	Wed 25/06/36

Figure 11-2: Provisional integrated project schedule

11.2 Drilling & Completions Schedule

The Phase 1 project envisages an initial 21 month drilling programme to construct 43 new wells and to reinstate 5 existing wells in Amosing and Ngamia.

Phase 2 is planned for a 14 -year program of continuous development drilling from 2031 (3 rigs) with additional wells in Amosing and Ngamia followed by Twiga , Ekales, Agete and Etom to maintain and extend the 50,000 stb/d plateau. This second programme involves drilling and completing 862 wells, employing a multi-well, pad-based factory drilling and completion approach.

Following initial development drilling the rigs will support an appraisal and exploration program with a view to extending the plateau further in both near field appraisal and higher risk / high potential exploration targets. Detailed planning of exact timing and the sequence of the follow-on programs will be validated following receipt of initial production data and after incorporation of learnings from the initial program.

The planned well count per year is shown in Figure 11-3.

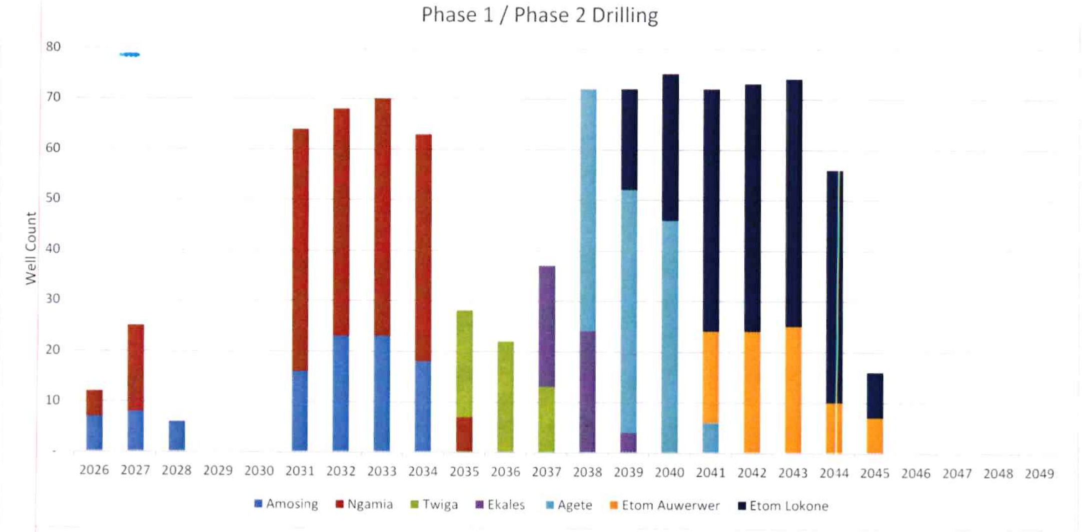


Figure 11-3: Well drilling schedule

11.3 Project Cost Summary

The overall Project Cost Summary is shown in Table 10-1.

Table 11-1: Project Cost Summary

CAPEX ($M)	Phase 1	Phase 2	Total
Surface Facilities	36.8	430.8	467.6
Drilling and Completions	215.8	5,021.8	5,237.6
Project Owners Costs	11.3	-	11.3
Project Total	263.9	5,452.6	5,716.5

11.4 Upstream CAPEX

The Upstream CAPEX estimate is shown in Table 11-2.

Table 11-2: Upstream CAPEX

CAPEX ($MM)	Phase 1	Phase 2	Total
Exploration & Appraisal	7.5	70.0	77.5
Development Drilling	215.8	4,876.5	5,092.3
Well Pads	-	145.4	145.4
CPF	22.0	197.0	219.0
Infrastructure, Water Pipes, Power & Ancillary	14.8	233.8	248.6
Owner's Costs	11.3	-	11.3
Total	271.4	5,522.6	5,794.0

11.5 Drilling & Completions CAPEX

The Drilling & Completions CAPEX in shown in Table 11-3.

Table 11-3: Drilling & Completion CAPEX

CAPEX ($M)	Phase 1	Phase 2	Total
Drilling and Completions	215.8	4,876.5	5,092.3
Well Pads	-	145.4	145.4
Total	215.8	5,021.8	5,237.6

The well count is shown in Table 11-4.

Table 11-4: Well Count

Year	Amosing	Ngamia	Twiga	Ekales	Agete	Etom Auwerwer	Etom Lokone
2026	7	5	-	-	-	-	-
2027	8	17	-	-	-	-	-
2028	6	-	-	-	-	-	-
2029	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-
2031	16	48	-	-	-	-	-
2032	23	45	-	-	-	-	-
2033	23	47	-	-	-	-	-
2034	18	45	-	-	-	-	-
2035	-	7	21	-	-	-	-
2036	-	-	22	-	-	-	-
2037	-	-	13	24	-	-	-
2038	-	-	-	24	48	-	-
2039	-	-	-	4	48	-	20
2040	-	-	-	-	46	-	29
2041	-	-	-	-	6	18	48
2042	-	-	-	-	-	24	49
2043	-	-	-	-	-	25	49
2044	-	-	-	-	-	10	46
2045	-	-	-	-	-	7	9
2046	-	-	-	-	-	-	-

The CAPEX and OPEX associated with Drilling and Completion activities for the project represents a substantial proportion of the overall project CAPEX and OPEX. Consequently, preparation of robust wells specific CAPEX and OPEX forecasts are important in the pre-development planning process.. The current estimate is based on the following:

- Tenders previously received circa 2019/ 2020 and 2024
- Detailed well engineering
- Well metrics, along hole lengths, casing depths and preliminary locations
- Drilling and Completions with no stimulation
- Well counts based on 1:1 producer to injector on a 5-spot pattern

The cost estimate production included the addressing, amongst others, the following topics:

- Drilling & Completions Timings
- Benchmarking Review
- Non-Productive Time & Contingency approach
- Learning Curve Review
- Deliverability Review

The cost estimate was also reviewed to identify any potential opportunities for cost reductions. The Rig and Associated Costs category represents an area that would benefit from further review. This would include the review of alternative choices for contracting e.g. rig purchase versus hire, initial down payments, etc. Such a review should be undertaken as part of the preparation and completion of the tendering packages.

11.6 Opportunities and Risks

Table 11-5 summarizes the Upstream Opportunities and Risks identified.

Table 11-5: Opportunities and Risk

Opportunities	Risk
• Potential to power auxiliary and industrial loads from solar to further reduce GHG emissions	•Host Government Dependency Timing
• Process simplification to challenge need for stabilization units	•Cost escalation
• Adopting a different approach for equipment sizing and training	•Water permitting and delivery
• Selecting alternative oil processing technologies for emulsion breaking and stabilization	•Timely land access
• Reducing number of crude oil storage tanks by increasing tank sizes	•Regulatory approvals
•Relaxing water injection 5-micron specification	•Security
•Using alternative design standards (e.g. Chinese)	•Political and Social
•Further engagement with international EPC contractors to challenge execution, cost and timing assumptions	•Competing projects impacting on supply chain for critical materials
•Construction of a CPF in the north to process high CO2 well fluids	•Global pandemics
•Monitor production performance and water injection performance to optimize recoveries through variation of production and/or injection rates	•Preferential water breakthrough to be monitored via reservoir management plan to enable early response if required
•Review risk of alternative options for pipeline heating (e.g. bulk heating) to determine if cost savings might be achieved	
•Review feasibility of utilizing cooler water injection temperatures to reduced heating loads	

A Project Risk and Opportunity Plan will be introduced leading up to FID. The objective of the plan is to ensure that both risks and opportunities are clearly visible to the Project Management Team to enable timely intervention. The plan will incorporate all identified items but the main focus will be on the top impact elements.

The five fundamental steps will be specifically included in the Plan, which are Risk:

- Identification
- Evaluation and Ranking
- Mitigation
- Monitoring

- Communication

11.7 Project OPEX

The breakdown of the Project OPEX is presented in Table 11-6.

Table 11-6: Project OPEX

UPSTREAM OPEX ($MM)	Phase 1	Phase 2	Total
Lease of Surface Facilities, TDU & Water	267.7	247.4	515.2
GE Personnel (G&A)	56.6	226.5	283.2
Camp Costs	11.7	63.2	74.9
Consumables (Elec & Diesel)	14.9	171.8	186.6
Chemicals	5.8	138.7	144.5
Travel	5.2	20.4	25.6
Vehicles	5.3	73.5	78.8
Support Services	72.5	288.6	361.1
Insurance	3.0	47.0	50.0
Upstream Total	**442.8**	**1,277.1**	**1,719.9**
MIDSTREAM OPEX ($MM)	**Phase 1**	**Phase 2**	**Total**
Oil Trucking / Rail Transportation	466.9	4,848.6	5,315.5
Export Charges	28.3	293.9	322.1
Storage & Handling	28.6	296.8	325.4
Admin & Monitoring	34.9	362.1	397.0
Product Loss	8.6	89.0	97.6
Trucking Insurance	4.3	44.5	48.8
Midstream Total	**571.5**	**5,934.9**	**6,506.4**

Total OPEX	**1,014.3**	**7,212.0**	**8,226.4**

The Project OPEX estimate is based on inputs from previous FEED Contractors, Well Engineering estimates, past costs incurred during the Exploration Phase and in-house databases.

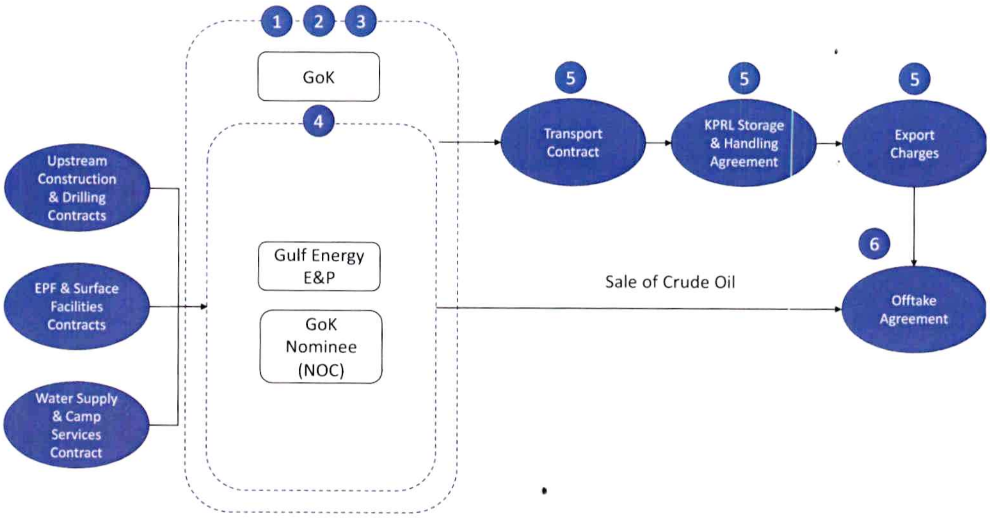
The G&A estimate is based on the minimum manpower and non-manpower G&A costs required to sustain the project in addition to the direct operational facility costs

12 COMMERCIAL AND ECONOMIC ANALYSIS

This section summarizes of the upstream and evacuation cost estimates, as well as the main economic assumptions used by the company to produce its economic analysis of the project and the key results of such analysis, including project cash flows and returns for the contractor and the State of Kenya.

12.1 Integrated Project Contractual Structure

Figure 12-1 gives an outline of the envisaged contractual framework and identifies the key enabling agreement for this project.



Key Elements & Contractual Agreements

① Production Sharing Contracts (10BB & 13T)
② FDP, Land, Water, Security Enabler, ESIA, Joint Marketing Agreement, etc...
③ Harmonization / Unitization & Fiscal Terms
④ Participation Agreement, Joint Operating Agreement
⑤ Transportation Contract(s), KPRL Crude Oil Storage & Handling Agreement
⑥ Export of Crude Oil Produced

Figure 12-1: Contractual Framework

As part of the considered development plan, crude oil will be produced from fields covering an area spread across the current acreage of both 10BB & 13T licenses. As detailed further below, Gulf will request the implementation of relevant agreements & contracts in order to have the whole development area governed by a single set of harmonized fiscal terms and accounting procedures. Other key agreement related to upstream development area will include agreements related to land access, water supply, security & logistical enablers among others.

Should the NOC decide to exercise its right to participate in the contractor group for the considered development, it will be required to implement certain contracts such as a Participation Agreement, as envisaged in the PSCs, defining the rights, roles and responsibilities of each member of the contractor group.

A Joint Marketing agreement is required to enable the Contractor, GOK Nominee and GOK pool their respective entitlements together and market jointly.

The contractor will enter into Transportation Agreement(s) to transport produced crude oil via truck and or/rail to the port of Mombasa for storage at KPRL facilities under a storage and handling agreement. Crude oil will then be sold on international markets through offtake agreement(s) to be negotiated with commodity merchants.

12.2 Upstream Economic Assumptions

12.2.1 Oil Price

Crude oil produced is expected to be intermediate, paraffinic, sweet oil with an API degree of 30.5° and will be indexed to the Dated Brent. All economic evaluations have been run using a forecasted oil price of $60/bbl which the company considers reasonably conservative given macroeconomic situation, as well as current dynamics of international commodity markets. No inflation or price escalation has been assumed on crude oil prices as part of this economic analysis. Due to the expected quality and waxy nature of the crude, a long-term constant quality differential of -$3.5/bbl is applied to the economics. This differential is consistent with discount achieved by the previous operator during the first EOPS sales and market data.

12.2.2 Key Economic Assumptions

The following economic assumptions have been made in this analysis:

- Cash flow calculation start date: 1st January 2025
- Oil price: $60/bbl, no inflation
- Crude quality differential: $-3.5/bbl
- Cost inflation: 0% p.a.
- GoK nominee (NOC) participation: 20% (up to 20% in Block 10BB license, up to 22.5% in 13T license, expected to be harmonized at 20% in the Unitized Area)

12.2.3 Upstream Fiscal Terms

As stated above, in order to facilitate accounting procedures and ensure that investment decisions are made according to what is best from a technical standpoint, as part of the considered integrated development plan, the company is requesting that competent authorities allow for the implementation of relevant agreements that will permit a de-facto unitisation of the whole development area under harmonized fiscal terms. Such unitisation mechanization may be done following the procedure foreseen in article 21 of the 10BB and 13T PSCs, or through an alternative legal and contractual scheme.

GEL is convinced that this unitisation would be both in the contractor's and the regulator's interest, as it would reduce the complexity of the tax treatments, ease the investment decision process and any future audit / due diligence works.

Moreover, given the current cost environment and in view of the investments required to achieve the considered development plan, the contractor is in the that the current fiscal terms included in the 10BB and 13T PSCs would not allow the economic viability of the project. As part of the requested unitization of the development area, the company is therefore also requesting for the support of Kenyan authorities to obtain a revision of certain aspect of the fiscal treatment of petroleum revenues, while retaining the same framework.

Changes requested are summarised in Table 12-1.

Table 12-1: Current and Adjusted Fiscal Terms

<table>
<tr><th>Item</th><th>10BB PSC (current terms)</th><th>13T PSC (current terms)</th><th>Unitised Lokichar Area (Requested)</th></tr>
<tr><td>VAT</td><td colspan="2">16.0%</td><td>Exempt</td></tr>
<tr><td>WHT</td><td colspan="2">5% Local
5.625% Imported</td><td>Exempt</td></tr>
<tr><td>RDL & IDF</td><td colspan="2">2% & 2.5% on imported goods</td><td>Exempt</td></tr>
<tr><td>Cost Recovery Ceiling</td><td>55.0%</td><td>65.0%</td><td>85.0%</td></tr>
<tr><td>Profit Oil Split</td>
<td><table>
<tr><th>Daily production (stb/d)</th><th>Government share</th><th>Contractor share</th></tr>
<tr><td>0-20,000</td><td>55%</td><td>45%</td></tr>
<tr><td>20,001-50,000</td><td>60%</td><td>40%</td></tr>
<tr><td>50,001-100,000</td><td>63%</td><td>37%</td></tr>
<tr><td>101,001-150,000</td><td>68%</td><td>32%</td></tr>
<tr><td>Over 150.000</td><td>78%</td><td>22%</td></tr>
</table></td>
<td><table>
<tr><th>Daily production (stb/d)</th><th>Government share</th><th>Contractor share</th></tr>
<tr><td>0-20,000</td><td>50%</td><td>50%</td></tr>
<tr><td>20,001-50,000</td><td>60%</td><td>40%</td></tr>
<tr><td>50,001-100,000</td><td>65%</td><td>35%</td></tr>
<tr><td>101,001-150,000</td><td>70%</td><td>30%</td></tr>
<tr><td>Over 150.000</td><td>75%</td><td>25%</td></tr>
</table></td>
<td><table>
<tr><th>Daily production (stb/d)</th><th>Government share</th><th>Contractor share</th></tr>
<tr><td>0-20.000</td><td>50%</td><td>50%</td></tr>
<tr><td>20,001-50,000</td><td>60%</td><td>40%</td></tr>
<tr><td>50,001-100,000</td><td>65%</td><td>35%</td></tr>
<tr><td>101,001-150,000</td><td>70%</td><td>30%</td></tr>
<tr><td>Over 150,000</td><td>75%</td><td>25%</td></tr>
</table></td></tr>
<tr><td>Windfall T2 Tax</td><td>26%
Trigger Price $50/bbl, indexed since 2007</td><td>20%
Trigger Price $50/bbl, indexed since 2008</td><td>26%
Trigger Price $50/bbl, indexed since 2007</td></tr>
</table>

Note, the analysis below is based on the requested fiscal terms.

12.2.4 Development Concept

As detailed in the previous sections of this document, the development concept considered consists of a two-phase approach, with the first phase being focused on implementing a fast-track development of the Ngamia & Amosing fields, achieving first oil by December 2026, before ramping up production to 20,000 stb/d from these fields. The second phase will comprise a larger-scale development of the Ngamia & Amosing fields, aiming to reach a production of 50,000 stb/d. The company will then continue investing on the asset and develop the Twiga, Agete, Etom and Ekales fields, with the objective of maintaining a production plateau of approximately 50,000 stb/d over multiple years.

12.2.5 Upstream Capex

Table 12-2 and Figure 12-2 below give a breakdown of capex program for the life of the project, as considered as part of the presented development plan.

Table 12-2: Project CAPEX

Year	Exploration & Appraisal ($MM)	Development Drilling ($MM)	Well Pads ($MM)	CPF ($MM)	Infrastructure, Water Pipes, Power & Ancillary ($MM)	Owner's Costs ($MM)	Decommissioning ($MM)	Total ($MM)
2025	-	-	-	-	-	-	-	-
2026	7.5	57.3	-	22.0	14.8	11.3	-	112.9
2027	-	119.5	-	-	-	-	-	119.5
2028	-	28.7	-	-	-	-	-	28.7
2029	-	4.8	-	-	-	-	-	4.8
2030	-	5.5	-	-	-	-	-	5.5
2031	-	307.1	11.8	197.0	19.0	-	-	534.9
2032	8.6	329.7	11.8	-	19.0	-	-	369.1
2033	8.6	340.0	11.8	-	19.0	-	-	379.3
2034	8.6	316.4	9.8	-	15.8	-	-	350.7
2035	9.6	153.6	3.9	-	6.3	-	-	173.5
2036	8.6	126.0	3.9	-	6.3	-	-	144.9
2037	8.6	206.0	5.9	-	9.5	-	12.7	230.0
2038	8.6	369.7	11.8	-	19.0	-	25.3	409.1
2039	8.6	369.5	13.8	-	22.1	-	25.2	414.0
2040	-	395.3	13.8	-	22.1	-	25.1	431.1
2041	-	384.6	13.8	-	22.1	-	24.9	420.5
2042	-	389.1	11.8	-	19.0	-	24.8	419.9
2043	-	406.0	11.8	-	19.0	-	24.7	436.8
2044	-	323.1	9.8	-	15.8	-	24.5	348.7
2045	-	131.9	-	-	-	-	24.4	131.9
2046	-	67.8	-	-	-	-	24.3	67.8
2047	-	67.1	-	-	-	-	24.2	67.1
2048	-	58.8	-	-	-	-	24.0	58.8
2049	-	67.8	-	-	-	-	23.9	67.8
2050	-	67.1	-	-	-	-	23.8	67.1
Total	77.5	5,092.3	145.4	219.0	248.6	11.3	331.8	5,794.0

Note: Decommissioning costs exclude interest of $11.2 MM which makes up the remainder of the total cost

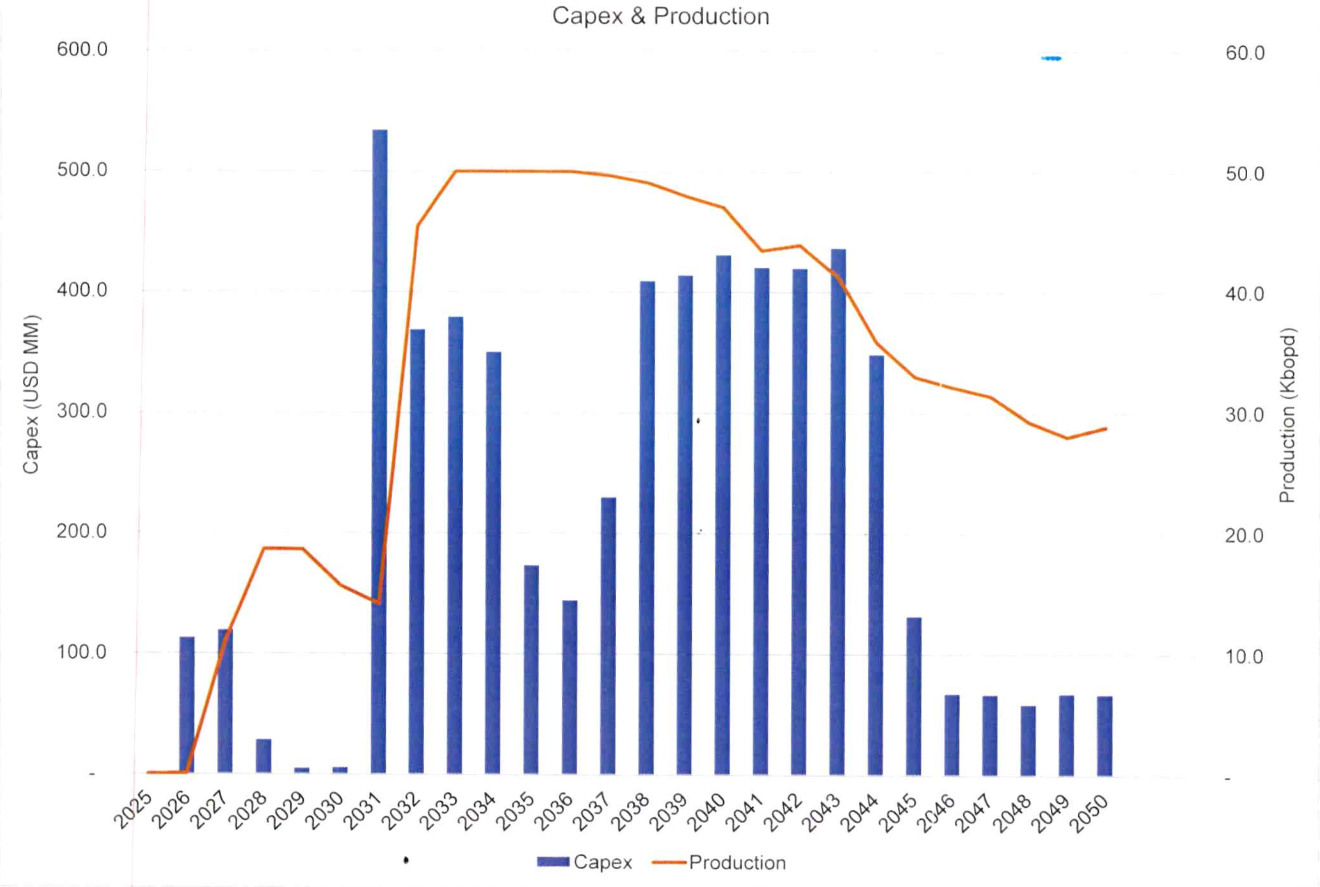


Figure 12-2: Project CAPEX phasing

12.2.6 Upstream Operating Costs

Table 12-3 gives a detailed breakdown of the operational costs budgeted for the project economic analysis.

Table 12-3: Project OPEX

OPEX MODEL		2026	2027	2028	2029	2030	2031	2032	2033
BOPD		1,575	11,061	18,660	18,635	15,632	14,186	45,469	50,000
Annual Production (BBL)		48,840	4,037,158	6,810,765	6,801,663	5,705,616	5,177,741	16,596,221	18,250,059

UPSTREAM OPEX		2026	2027	2028	2029	2030	2031	2032	2033
Lease of Surface Facilities, TDU & Water	$K	2,781	52,899	52,947	52,946	53,031	53,140	12,396	12,396
GE Personnel (G&A)	$K	-	11,327	11,327	11,327	11,327	11,327	11,327	11,327
Camp Costs	$K	33	2,338	2,338	2,338	2,338	2,338	3,161	3,161
Consumables (Elec & Diesel)	$K	244	2,926	2,926	2,926	2,926	2,926	7,316	7,316
Chemicals	$K	72	709	1,215	1,343	1,319	1,147	3,926	4,782
Travel	$K	85	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Vehicles	$K	87	1,044	1,044	1,044	1,044	1,044	3,676	3,676
Support Services	$K	366	14,429	14,429	14,429	14,429	14,429	14,429	14,429
Insurance	$K	-	456	521	521	521	1,020	1,415	1,815
TOTAL UPSTREAM	$K	**3,669**	**87,147**	**87,766**	**87,894**	**87,955**	**88,391**	**58,665**	**59,921**
UNIT COST UPSTREAM	$/bbl.	**75.11**	**21.59**	**12.89**	**12.92**	**15.42**	**17.07**	**3.53**	**3.28**

MIDSTREAM OPEX		2026	2027	2028	2029	2030	2031	2032	2033
Oil Trucking	$K	798	65,947	111,255	111,106	93,202	84,579	271,101	298,117
Export Charges	$K	48	3,997	6,743	6,734	5,649	5,126	16,430	18,068
Storage & Handling	$K	49	4,037	6,811	6,802	5,706	5,178	16,596	18,250
Admin & Monitoring	$K	60	4,925	8,309	8,298	6,961	6,317	20,247	22,265
Product Loss	$K	15	1,211	2,043	2,040	1,712	1,553	4,979	5,475
Trucking Insurance	$K	7	606	1,022	1,020	856	777	2,489	2,738
TOTAL MDSTREAM	$K	977	80,723	136,182	136,000	114,084	103,529	331,843	364,912
UNIT COST MIDSTREAM	$/bbl	**20.00**	**20.00**	**20.00**	**20.00**	**20.00**	**20.00**	**20.00**	**20.00**

OPEX MID & UPSTREAM		2026	2027	2028	2029	2030	2031	2032	2033
TOTAL OPEX	$K	**4,645**	**167,870**	**223,948**	**223,894**	**202,039**	**191,920**	**390,508**	**424,833**
TOTAL UNIT COST	$/bbl	**95.1**	**41.6**	**32.9**	**32.9**	**35.4**	**37.1**	**23.5**	**23.3**

12.2.7 Evacuation (Transport) Cost

As detailed in Section 9, the contractor is considering several options to transport crude oil produced from Lokichar to Mombasa. Initially, export will be via truck from the upstream storage facilities to KPRL facilities in the Mombasa port. A transportation cost of $20/bbl has been assumed for the economic analysis. The details cost breakdown can be found in Section 9.7 and Table 9-8.

In the second stage of the development, the company intends to transport its production to export facilities by rail, which will require an upgrade of the existing infrastructure (Section 9.4). As of the date of this FDP, this solution is not yet available and its potential cost is still uncertain, GEBV has therefore decided to use the transport cost estimates of the trucking solution for the purpose of performing this economic analysis.

This approach is considered conservative by GEBV as it is expected that the rail solution will improve the evacuation route economics, as it will likely benefit from economies of scale and be less subject to logistical disruptions. For financial modelling purposes, the company has therefore assumed a $20/bbl flat, long-term transport cost.

12.3 Economic Analysis Results

12.3.1 Key Project Economics

Table 12-4 shows the forecasted free cash flows to the contractor group over the initial 15 years of the project.

Table 12-4: Forecast Free Cashflow

Year	Revenues (USDMM)	Transport Costs (USDMM)	Revenues Net of Transport Costs (USDMM)	Opex (USDMM)	Capex (USDMM)	Fees & Levies (USDMM)	Govt Share of Profit Oil (USDMM)	Contractor Group Net CF (USDMM)
2025	-	-	-	-	-	-	-	-
2026	16.4	1.0	1.8	-3.7	-112.9	-0.6	-0.4	-115.8
2027	228.1	80.7	147.4	-87.3	-119.5	-1.1	-36.5	-96.9
2028	385.8	136.6	249.2	-88.0	-28.7	-1.1	-61.7	69.8
2029	384.3	136.0	248.3	-88.1	-4.8	-1.1	-61.4	92.8
2030	322.4	114.1	208.3	-88.2	-5.5	-1.1	-51.5	61.9
2031	292.5	103.6	189.0	-88.6	-534.9	-1.1	-46.8	-482.3
2032	940.1	332.8	607.3	-59.3	-369.1	-1.1	-151.0	26.8
2033	1,031.1	365.0	666.1	-60.7	-379.3	-1.1	-166.5	58.5
2034	1,031.1	365.0	666.1	-61.7	-350.7	-1.1	-166.5	86.1
2035	1,031.1	365.0	666.1	-62.2	-173.5	-1.3	-159.8	260.9
2036	1,034.0	366.0	668.0	-62.8	-144.9	-1.3	-155.2	295.3
2037	1,024.3	362.6	661.7	-64.6	-230.0	-1.3	-153.6	203.8
2038	1,012.0	358.2	653.8	-65.5	-409.1	-1.3	-143.8	25.7
2039	989.1	350.1	638.9	-65.7	-414.0	-1.3	-134.1	15.6
2040	972.1	344.1	628.0	-66.3	-431.1	-1.3	-128.1	-7.1
Total	10,694.4	3,780.8	6,900.0	-1,012.6	-3,707.9	-16.9	-1,616.9	495.0

Figure 12-3 shows the cashflow and key project economics over the life of the project, under the assumptions listed above.

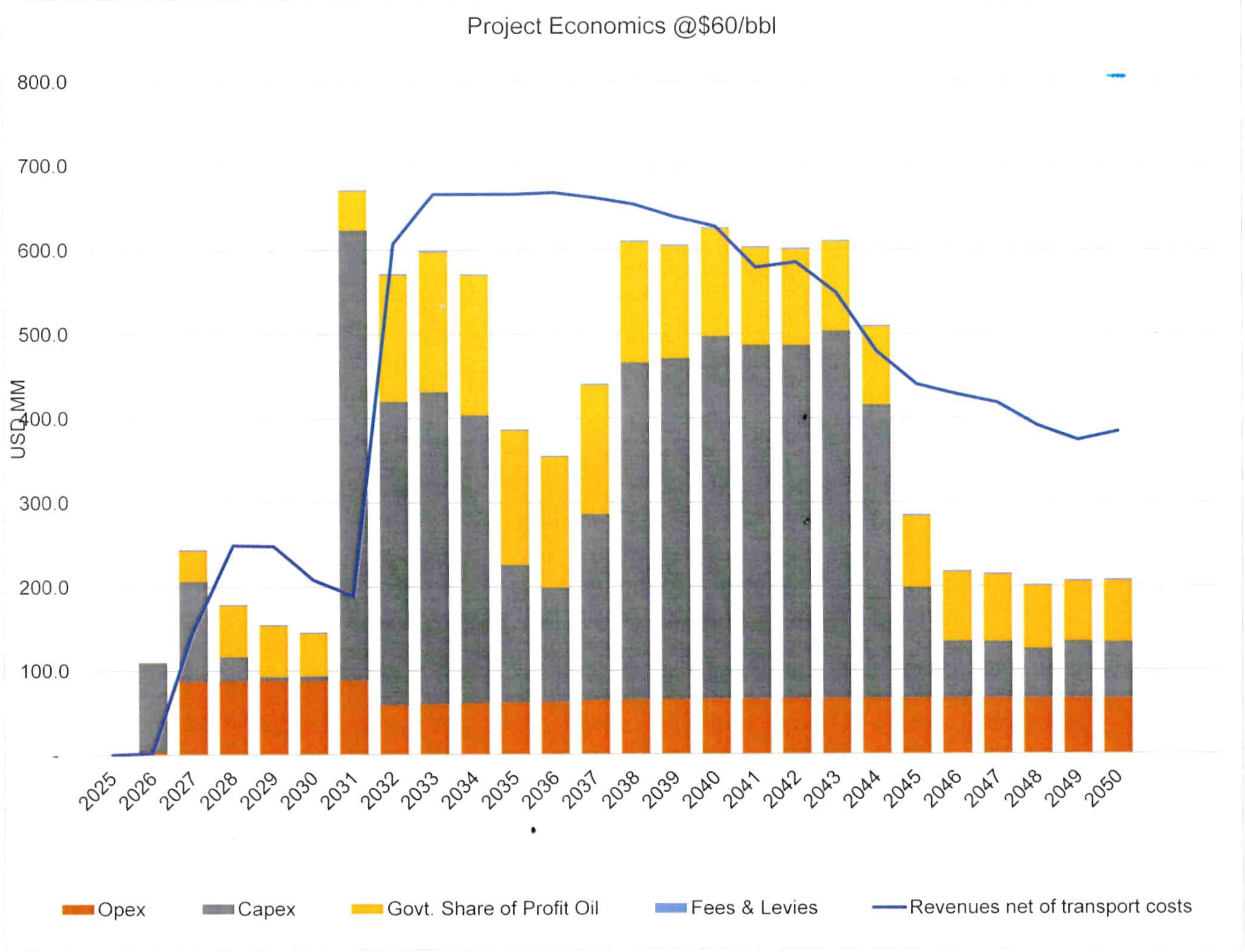


Figure 12-3: Project Cashflow

Figure 12-4 shows the contractors group's cumulated free cash flows over the life of the project, alongside the annual forecasted oil production.

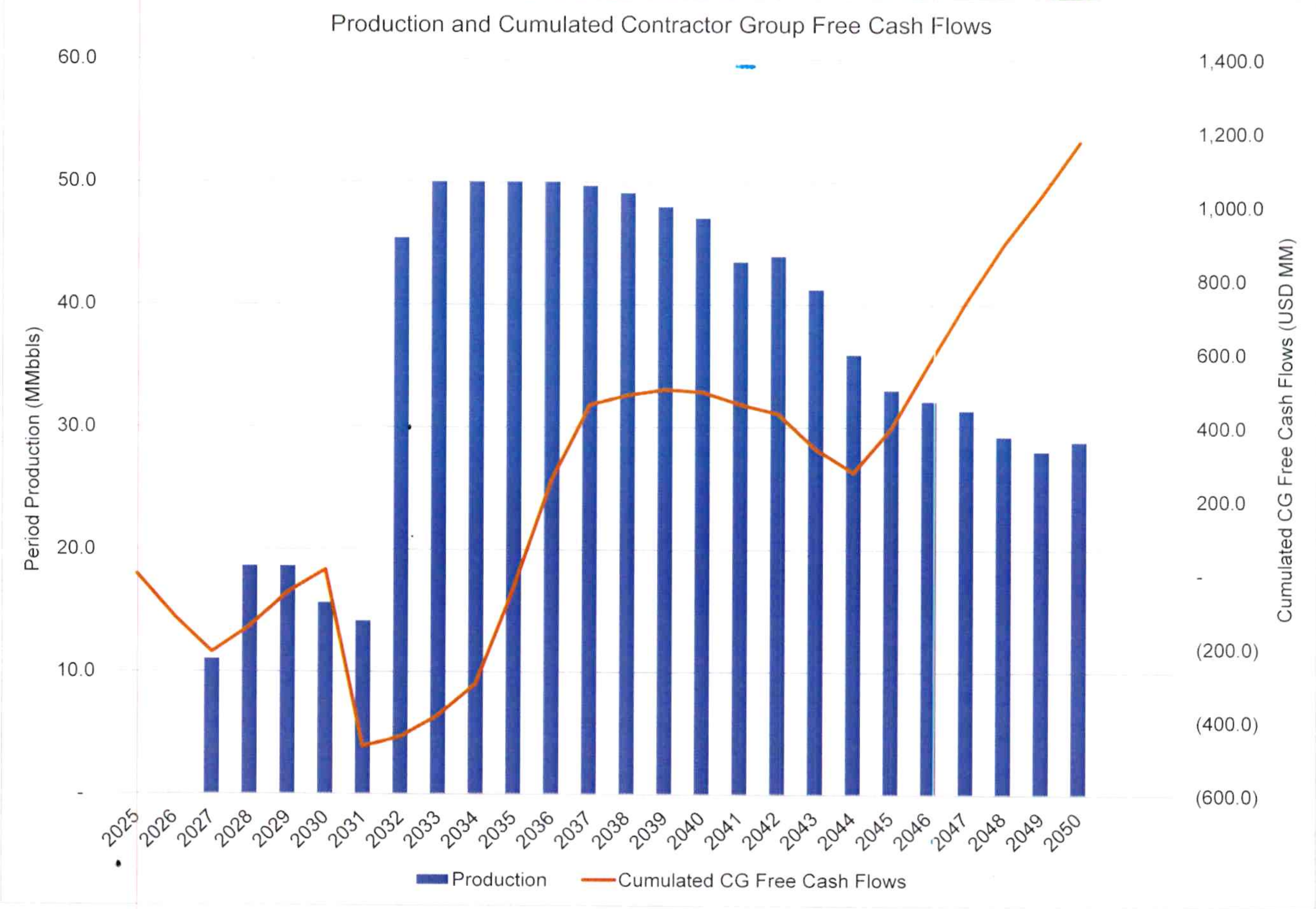


Figure 12-4: Project Free Cashflow and Gross Oil Production

12.3.2 Contractor / State Split of Revenues

Table 12-5 and Figure 12-5 illustrate the split of value added between GEBV and the State, under the technical economic and fiscal assumptions presented.

Table 12-5: Gulf Energy / Government of Kenya Split of Revenues

Year	Gulf Energy Net Cash Flow	Govt. Tax Revenues	Govt. Revenues as a Contractor	Govt. Total Revenues
2025	-	-	-	-
2026	-94.0	0.8	-21.6	-20.8
2027	-57.0	11.8	-14.2	-2.4
2028	91.0	18.9	22.7	41.6
2029	119.0	18.7	17.6	36.3
2030	92.3	15.7	6.7	22.3
2031	-362.0	18.0	-90.5	-72.5
2032	103.1	47.9	27.9	75.8
2033	138.9	52.3	34.9	87.2
2034	186.4	52.2	15.2	67.4
2035	351.4	52.3	26.8	79.2
2036	390.3	52.3	17.7	70.0
2037	292.9	52.4	9.0	61.4
2038	104.3	52.9	-3.3	49.6
2039	86.0	51.8	-3.7	48.2
2040	56.2	51.2	-1.8	49.4
2041	18.6	47.5	1.1	48.6
2042	21.8	47.9	4.3	52.2
2043	-19.6	45.3	-4.9	40.4
2044	-0.2	39.5	-0.0	39.5
2045	152.1	35.2	29.2	64.4
2046	221.6	33.9	13.4	47.2
2047	217.3	33.1	9.3	42.4
2048	204.9	31.0	5.1	36.1
2049	184.0	29.8	1.3	31.1
2050	173.8	30.6	22.1	52.6
Total	2,673.0	923.0	124.2	1,047.2

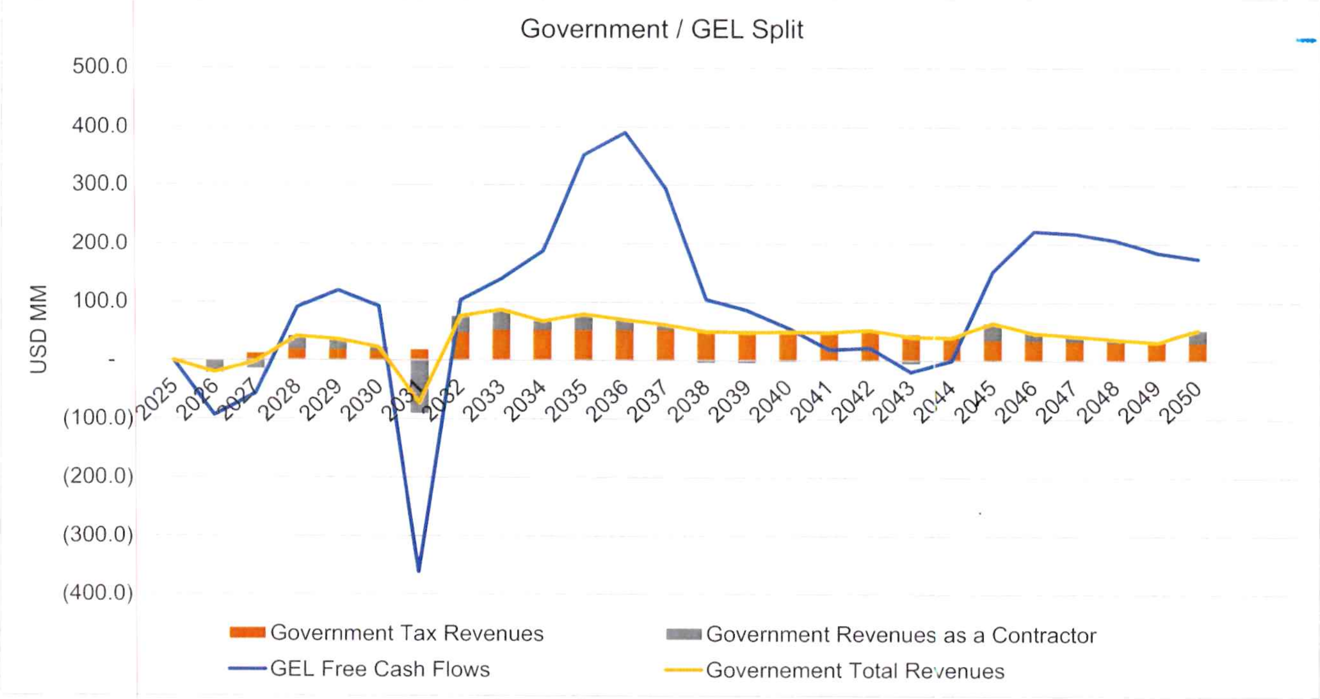


Figure 12-5: Gulf Energy / Government of Kenya Split of Revenues

As detailed in the above tables and graphs, under the considered assumptions, the project would produce sufficient free cash flows for the contractor group to be able to fund the investments required to maintain production at the targeted levels, while generating over 1.1 billion USD of revenues for the State of Kenya.

13 HOST GOVERNMENT ENABLERS

13.1 General

This Field Development Plan (FDP) outlines the strategy for fully developing six key discoveries within the Block 10BB-13T license areas, as well as the subsequent appraisal and exploration activities that will be conducted to maximise resource recovery within the Development Area. The development strategy uses a phased approach, beginning with the largest and most technically mature reservoirs. To achieve first oil and support an initial plateau of 20,000 barrels of oil per day, 48 wells in the Ngamia and Amosing fields will be used and produced through Early Production Facilities. The data gathered through this phase will be used to optimise a second phase of development, which plans to execute further drilling in Ngamia and Amosing, while adding production from the Twiga, Ekales, Agete, and Etom fields. The second phase of the development will utilise a Central Production Facility to increase the oil plateau to some 50,000 stb/d. The feasibility of the plans outlined in this document is also dependent on some key assumptions.

These key assumptions relate to regulatory approvals, fiscal stimuli, infrastructure utilities and resources, water, and land acquisition. The following sections outline the assumptions on which the Contractor has relied for the development of this Field Development Plan.

13.2 Land

13.2.1 General

The project requires unfettered access to sections of land. The said requirements are for the purposes of constructing and operating project assets. The assets include physical facilities, wells, infield pipelines, roads and other infrastructure.

Through MOEP the Project land will be acquired by the National Land Commission (NLC) under the statutory land process. The Phase-1 development envisages the production of 20 kbopd using two 10 kstb/d modular leased facilities, known as Early Production Facilities (EPF), at well pads located within the Ngamia 3 and Amosing 1 fields. Three of the four proposed well pads are existing (Ngamia-03, Amosing-01, Amosing-03), with one new well pad yet to be constructed (Ngamia-11). It will be necessary to increase the size of existing well pads and improve some access roads. The locations of the proposed Phase 1 well pads are shown in Figure 13-1. The distance between NG-03 and NG-11 is approximately 500m, and the distance between AM-01 and AM-03 well pads is approximately 750m.

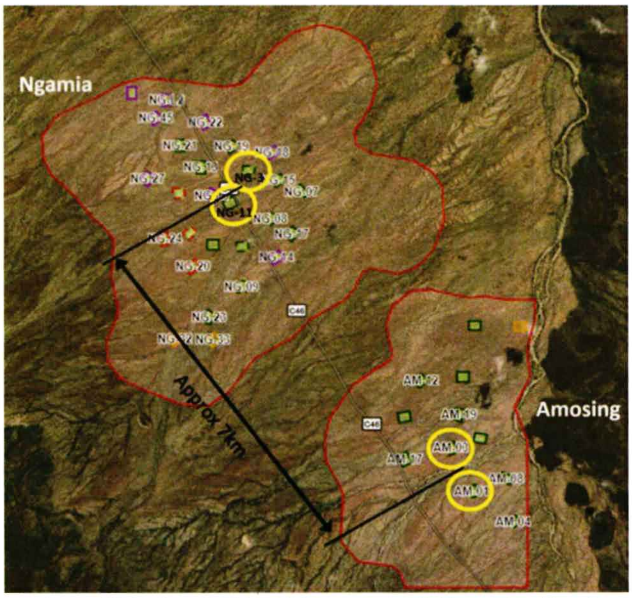


Figure 13-1: Gazetted Land Polygons, with Phase 1 well pads

MOEP, through the NLC, has gazetted an intention to acquire the land for Ngamia, Amosing and Twiga fields as well as the Kapese Integrated Operations Base in the immediate term and the other fields of Ekales, Agete and Etom in the near future as the communities secure titles for their lands. The MOEP will acquire the surrounding land in totality as polygons to provide flexibility as shown in Figure 13.2:-

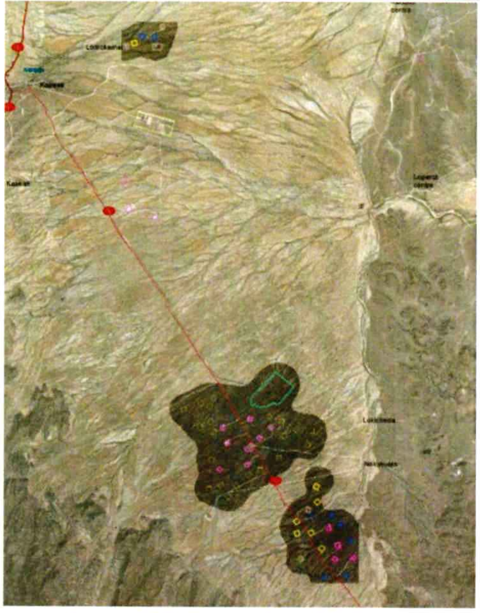


Figure 13.2: Gazetted Land Polygons

The Contractor will be provided unfettered access to the acquired project lands by MOEP (Landlord) to construct project facilities and conduct petroleum operations. Where applicable, the Contractor will be granted such way-leaves, easements, temporary occupation or other permissions as are necessary for the project and in particular for the purposes of laying, operating and maintaining pipelines, cables and passage between the Development Area. The Landlord will maintain the land in good standing with the National and County Governments, as required, to ensure access at no cost to the Contractor.

13.3 Water

The project requires access to a reliable and uninterrupted source of water to support construction activities and facilitate reservoir recovery. Peak demand is expected during the plateau production period, with an average requirement of approximately 70,000 barrels per day (bwpd) to sustain operations.

The most effective and sustainable solution is the provision of water from Turkwel Dam to the project facilities. This infrastructure will not only serve the operational needs of the project but will also benefit surrounding communities through strategically located offtake points.

In recognition of the strategic importance of the project, the Government of Kenya, through the Ministry of Water, has committed to construct the pipeline from Turkwel Dam to the upstream fields. The availability of water is a prerequisite for production and places this pipeline on the critical path of project execution.

Accordingly, the Contractor requests that the Government prioritize and implement the construction of the pipeline ahead of production commencement, and supply water to the project at a commercial tariff, in line with the agreed commitment.

13.4 Security

The National Police and other Government agencies are responsible for public security and law and order. The Contractor also requests the enhancement of the Critical Infrastructure Protection Unit complement of the National Police Service to support the increased operations by the Contractors, particularly with the trucking of crude oil along the A1 Highway.

13.5 Grid Power

The project's primary electrical power will be generated using associated gas via gas engines and in the absence of associated gas, with grid power and diesel generators serving as backup during start-up and contingency scenarios. To ensure operational safety and reliability, an Uninterruptible Power Supply (UPS) system will be installed to support emergency and controlled shutdown procedures.

Existing facilities, including Kapese camp, Kapese airstrip, and boreholes—will primarily rely on grid power, with diesel generators providing backup.

In line with this configuration, the Contractor respectfully requests that the Government of Kenya, through the relevant agencies, provide last-mile grid power connections to the project's upstream fields, camps, airstrip, and boreholes. Power will be supplied to the project on a commercial tariff basis, consistent with national infrastructure development frameworks.

13.6 Roads

For phase 1, trucking is the primary evacuation option. The following road construction and maintenance is required to enable the evacuation of 20,000 barrels of oil per day at the plateau via road tankers from Lokichar to KPRL Changamwe: Upgrading of C46 road to Class A/B, maintenance of A1 road from Lokichar to Sebit, completion of ongoing construction work of A1 Road from Sebit to Kitale and construction of a deceleration lane into KPRL Changamwe. Additionally, suppose the Government completes the road construction from Marich Pass to Chemolingot. In that case, the trucks will be able to avoid the towns of Kitale and Eldoret, saving over 50 km of distance to KPRL Changamwe. The Contractor requests that the Government provide the enabling road infrastructure. The Contractor's trucking service providers will contribute significantly to the Road Maintenance Levy through their diesel consumption.

13.7 KPRL Storage and Handling

The project requires truck offloading facilities with a capacity to offload 100 trucks per day, as well as at least 900,000 barrels (143,000 m^3) of heat-traced and insulated storage capacity at KPRL. Additionally, a heat-traced and insulated pipeline is required for evacuating crude oil from KPRL to KOT2. The Contractor requests that KPRL provide the necessary infrastructure to offload, store, and export the crude oil. This should be provided at a commercial tariff to the project, similar to the commercial arrangements with the downstream petroleum business.

13.8 Fiscal Incentives

13.8.1 General

Since the effective date of the Production Sharing Contracts (PSCs) for Blocks 10BB and 13T, the Contractor's economic position has been materially impacted by the enactment of new legislation and amendments to applicable petroleum laws and regulations. These changes have altered the fiscal and regulatory framework under which the PSCs were originally negotiated. In line with the principle of mutual economic benefit, it is both appropriate and necessary for the parties to review and adjust the PSC terms to reflect the current legal and economic environment.

Such adjustments will help preserve the original economic equilibrium, ensure project viability, and support continued investment in Kenya's petroleum sector. The request for Fiscal Incentives is based on the following key principles:

i. The Contractor undertakes exploration and production risks, while the Government retains ownership of petroleum resources. The PSC structure ensures that both parties share in the rewards once production begins, typically through cost recovery and profit-sharing mechanisms
ii. PSCs were negotiated based on prevailing legal, fiscal, and market conditions. These conditions changed materially through new legislation or regulatory amendments, hence disrupting the economy. The PSC principle of mutual economic benefit supports renegotiation or adjustment to restore fairness and viability.
iii. The review of the fiscal regime encourages continued investment by the Contractor while enabling the Government to meet its development and revenue goals. This includes provisions for local content, royalties, and government participation, etc.
iv. The Petroleum Act 2019 emphasizes transparency, accountability, and equitable sharing of benefits. The Act empowers the Cabinet Secretary and the National Upstream Petroleum Advisory Committee to negotiate PSCs that reflect mutual economic interests

To make the project viable, the following project-specific fiscal terms must be approved by the applicable government organs before ratification of the Field Development Plan by Parliament.

13.8.2 Cost Recovery

The Contractor shall recover costs incurred in relation to operations from cost recovery crude oil as detailed below.

The Parties agree the order of priority in recovery of costs as follows:-

i. Production;

ii. development costs;
iii. exploration and appraisal costs; and
iv. decommissioning costs.

The maximum percentage of cost recovery crude oil in a fiscal year that the Contractor can use to recover petroleum costs shall be 85% for Block 10BB & 13T

Harmonised Profit oil split and Windfall tax as detailed for Block 10BB & 13T as detailed below:

- **Profit Oil Split** (Table 13-1):-

Table 13-1: Profit Oil Split

Daily production (bopd)	Government share	Contractor share
0-20,000	50.0%	50.0%
20,001-50,000	60.0%	40.0%
50,001-100,000	65.0%	35.0%
101,001-150,000	70.0%	30.0%
Over 150.000	75.0%	25.0%

- **Windfall tax**: 26%, Trigger Price $50/bbl, indexed since 2007

13.8.3 Taxes

The Contractor requests that the following taxes be applied to the project.

- VAT on goods and services for the direct and exclusive use in the construction of the Project will be exempted.
- VAT on goods that will be used in the development (construction) of the infrastructure needed for the Project will be exempted.
- Goods that are used in the upstream for exploration shall be covered as originally provided for under the Production Sharing Contracts (PSCs).
- Exemption from the Railway Development Levy and Import Declaration Fee will be granted to goods that will be imported for direct and exclusive use in the construction of the Project.
- Exemption from Withholding Tax for local and imported services.

13.9 Phase 2

In line with the Government's strategic plan to extend the railway line to Northern Kenya, the Contractor requests that the Government of Kenya provide a railway line at the fields in Lokichar for evacuating 50,000 barrels (ca. seven million metric tons) of oil per day (155 wagons MGR/99 wagons SGR) by January 2032. The project will provide southbound cargo, hence improving the railway investment economics.

14 APPENDIX A – EXPLORATION AND APPRAISAL WELL INVENTORY

South Lokichar Basin Exploration and Appraisal Well Inventory

Well	Spud Date	Rig Release Data	Type	Block	Rig	Surface Location					Depth MDRT (m)	Depth TVDRT (m)	Profile	Status	Comments
						Elevation (m)	X	Y	Latitude	Longitude					
Ngamia-1/1A	24/01/2012	06/07/2012	Exploration	10BB	WFD 804	733.6	8070546.0	244266.3	02° 12' 26.50" N	35° 45' 37.40" E	2,340	2,336	Vertical	P&A	Oil Discovery
Twiga South-1	21/08/2012	22/02/2013	Exploration	13T	WFD 804	701.5	802067.2	265908.2	02° 24' 10.88" N	35° 42' 57.43' E	3,250	3,250	Vertical	Susp.	Oil Discovery
Etuko-1	11/05/2013	24/08/2013	Exploration	10BB	Sakson PRS	647.3	816280.5	265411.1	02° 23' 53.80" N	35° 50' 37.10' E	3,100	3,097	Vertical	Susp.	Oil Discovery
Ekales-1	22/07/2013	14-/10/ 2013	Exploration	13T	WFD 804	720.7	800664.2	2571243.0	02° 19' 25.201" N	35° 42' 11.50" E	2,554	2,554	Vertical	Susp.	Oil Discovery
Agete-1	17/09/2013	25/11/2013	Exploration	13T	Sakson PRS	714.9	798972.6	272706.5	02° 27' 52.26" N	35° 41' 17.78' E	1,930	1,930	Vertical	Susp.	Oil Discovery
Amosing-1	25/11/2013	22/01/2014	Exploration	10BB	WFD 804	720.2	811955.8	239097.1	02° 09' 37.99" N	35° 48' 15.57" E	2,531	2,531	Vertical	Susp.	Oil Discovery
Ewoi-1	16/12/2013	27/01/2014	Exploration	10BB	Sakson PRS	622.5	820261.2	265777.8	02° 24' 05.43" N	35° 52' 45.85' E	1,911	1,911	Vertical	Susp.	Oil Discovery
Emong- 1	05/02/2014	12/03/2014	Exploration	13T	WFD 804	777.5	8017947.0	245886.9	02° 13' 20.46" N	35° 42' 46.20' E	1,394	1,394	Vertical	P&A	Dry Hole
Etuko-2/2A	04/02/2014	24/03/2014	Appraisal	10BB	Marriot 46	647.3	816279.8	265405.1	02° 23' 53.801" N	35° 50' 37.07' E	650	649	Deviated	P&A	Oil
Twiga-2	11/02/2014	24/03/2014	Appraisal	13T	Sakson PRS	717.9	801452.9	265895.5	02° 24' 10.57" N	35° 42' 05.22" E	2,103	2,099	Vertical	P&A	Oil
Twiga-2A	24/03/2014	03/06/2014	Appraisal	13T	Sakson PRS	717.9	800452.9	265895.5	02° 24' 10.57" N	35° 42' 05.22" E	2,886	2,301	Deviated	Susp.	Oil
Ngamia-2	08/04/2014	08/06/2014	Appraisal	10BB	Marriot 46	740.9	805716.0	245387.1	02° 13' 03.05" N	35° 44' 54.16" E	1,924	1,921	Vertical	Susp.	Oil/Gas
Ekunyuk-1	11/04/2014	13/05/2014	Exploration	10BB	WFD 804	612.6	825379.2	251956.6	02° 16' 35.51" N	35° 55' 30.421" E	1,802	1,801	Vertical	P&A	Oil Discovery
Agete-2	24/05/2014	28/06/2014	Appraisal	13T	WFD 804	700.6	800381.9	271166.4	02° 27' 02.06" N	35° 42' 03.26" E	2,024	1,790	Deviated	P&A	Dry Hole
Amosing-2	11-062014	27/07/2014	Appraisal	10BB	Sakson PRS	720.4	811953.9	239107.1	02° 09' 38.38" N	35° 48' 15.50" E	2,878	1,477	Deviated	P&A	Oil
Ngamia-3	13/06/2014	22/08/2014	Appraisal	10BB	Marriot 46	722.3	8072016.0	245853.6	02° 13' 18.20" N	35° 45' 42.30" E	2,700	2,618	Deviated	Susp.	Oil
Etom-1	13/07/2014	26/08/2014	Exploration	13T	WFD 804	703.5	798636.0	279330.0	02° 31' 27.77" N	35° 41' 07.33" E	2,000	2,000	Vertical	Susp.	Oil Discovery
Amosing-2A	27/07/2024	05/09/2014	Appraisal	10BB	Sakson PR5	720.4	811953.9	239107.1	02° 09' 38.38" N	35° 48' 15.50" E	2,165	2,091	Deviated	Susp.	Oil
Ngamia-4	29/08/2014	04/10/2014	Appraisal	10BB	Marriot 46	742.8	8059444.0	244514.7	02° 12' 34.66" N	35° 45' 01.50" E	1,814	1,766	Deviated	Susp.	Oil/Gas
Ekosowan-1	14/09/2014	31/10/2014	.Exploration	10BB	Sakson PRS	769.4	818657.2	229172.9	02° 04' 14.83" N	35° 51' 51.66" E	2,029	2,025	Vertical	P&A	Dry Hole
Ngamia-5	13/10/2014	28/11/2014	Appraisal	10BB	Marriot46	732.6	807113.0	244305.2	02° 12 27.81" N	35° 45' 39.29" E	2,317	2,237	Deviated	Susp.	Oil
Ngamia-6	01/12/2014	30/12/2014	Appraisal	10BB	Marriot 46	732.6	807096.7	244303.4	02° 12 27.73" N	35° 45' 38.76" E	2,480	2,307	Deviated	Susp.	Oil
Amosing-3	03/01/2015	24/01/2015	Appraisal	10BB	Marriot 46	718.0	8114641.0	239997.1	02° 10' 09.29" N	35° 47' 59.65" E	2,403	2,377	Vertical	Susp.	Oil
Ngamia-7	27/01/2015	28/02/2015	Appraisal	10BB	Marriot 46	713.2	808345.3	245452.0	02° 13' 04.94" N	35° 46' 19.25" E	2,924	2796	Deviated	Susp.	Oil
Ekales-2	07/02/2015	11/04/2015	Appraisal	13T	WFD 804	705.4	8020516.0	256716.2	02° 19' 11.80" N	35° 42' 56.26" E	4,059	3,437	Deviated	Susp.	Oil
Amosing-4	03/03/2015	28/03/2015	Appraisal	10BB	Marriot 46	718.6	812833.1	238418.3	02° 09' 15.74" N	35° 48' 43.891" E	2,500	2499	Vertical	Susp.	Oil
Ngamia-8	31/03/2015	07/05/2015	Appraisal	10BB	Marriot 46	723.0	807692.7	244855.4	02° 12' 45.59" N	35° 45' 58.03" E	1,730	1,616	Deviated	Susp.	Oil
Ngamia-9	13/05/2015	17/07/2015	Appraisal	10BB	Marriot 46	740.2	807027.8	243418.3	02° 11' 58.92" N	35° 45' 36.46' E	2,595	2341	Deviated	Susp.	Oil
Twiga-3	22/07/2015	14/08/2015	Appraisal	13T	Marriot 46	700.7	802373.6	266971.4	02° 24' 45.441" N	35° 43' 07.39" E	2,575	2575	Vertical	Susp.	Oil
Amosing-5	19/08/2015	13/09/2015	Appraisal	10BB	Marriot 46	726.3	810357.0	241005.4	02°10'39.66" N	35° 47' 23.85" E	2,475	2,398	Deviated	P&A	Oil
Amosing-5A	13/09/2015	07/10/2015	Appraisal	10BB	Marriot 46	726.3	810357.0	241005.4	02° 10'39.66" N	35° 47' 23.85" E	1,868	1,592	Deviated	P&A	Oil
Etom-2	24/11/2015	18/12/2015	Appraisal	13T	Marriot 46	693.2	799742.5	279573.8	02° 31' 35.66" N	35° 41' 43.05" E	1,655	1606	Vertical	Susp.	Oil
Erut-1	19/12/2016	21/01/2017	Exploration	13T	Marriot 46	644.3	802795.1	290724.6	02° 37 38.19" N	35° 43' 22.65" E	1,317	1317	Vertical	Susp.	Oil Discovery
Amosing-6	28/01/2017	03/03/2017	Appraisal	10BB	Marriot 46	745.5	810016.8	238353.7	02° 09' 13.99" N	35° 47' 12.50" E	2,455	2,102	Deviated	Susp.	Oil
Ngamia-10	06/03/2017	12/04/2017	Appraisal	10BB	Marriot 46	758.4	805587.8	2431343.0	02° 11' 49.77" N	35° 44' 49.88" E	2,202	2,027	Deviated	Susp.	Oil/Gas
Emekuya-1	25/04/2017	17/05/2017	Exploration	13T	Marriot 46	685.7	800138.8	281990.2	02° 32 54.30" N	35° 41' 56.09" E	1,356	1,356	Vertical	Susp.	Oil
Etom-3	26/05/2017	21/06/2017	Appraisal	13T	Marriot 46	707.7	798079.6	280568.0	02° 32' 08.09" N	35° 40' 49.44" E	1,244	1,244	Vertical	Susp.	Oil
Etiir-1	24/06/2017	11/07/2017	Exploration	13T	Marriot 46	724.4	796667.7	279296.2	02° 31' 26.81" N	35° 40' 03. 60"E	1,250	1,250	Vertical	P&A	Dry Hole
Ekales-3	14/07/2017	25/08/2017	Appraisal	13T	Marriot 46	726.9	800399.9	258689.4	02° 20' 16.10" N	35° 42' 02.99" E	2,721	2580	Deviated	Susp.	Oil
Ngamia-11	27/08/2017	14/09/2017	Appraisal	10BB	Marriot 46	722.2	807192.3	245853.9	02° 13' 18.15" N	35° 45' 41.55" E	1,655	1,554	Deviated	Susp.	Oil
Amosing-7	16/09/2017	17-1C2017	Appraisal	10BB	Marriot 46	729.3	811767.4	238389.1	02° 09' 15.02" N	35° 48' 09.48" E	2,170	2,022	Deviated	Susp.	Oil

5 APPENDIX B – EXPLORATION AND APPRAISAL WELL LOG ACQUISITION SUMMARY

	LWD																			
Wel Name	GR	Res	Den/Neu	SGR	SP	Res	Micro LL	Cali	Star/FMI	EI/OBMI	CBIL	ECS/Flex	CMR/Mrex	Den/Neut	Sonic	MDT/R CI	VSP	STB/CBL	PSWC	RSWC
Agete-1	X	X		X	X	X	X	X	X				X	X	X	X	X	X	X	
Agete-2	X	X																		
Amosing-1	X	X		X		X	X	X	X		X		X	X	X	X	X	X	X	X
Amosing-2				X		X		X		X	X	X	X	X	X	X	X			
Amosing-2A	X	X		X		X		X		X	X	X	X	X	X	X	X	X		
Amosing-3	X	X		X		X		X		X	X		X	X	X	X	X	X		
Amosing-4	X			X		X		X					X	X	X	X	X	X		
Amosing-5	X			X		X		X		X				X	X	X	X	X		
Amosing-5A	X			X		X		X						X	X	X		X		
Amosing-6	X	X	X	X		X		X		X				X	X	X	X	X		
Amosing-7	X	X	X	X		X		X						X	X	X	X	X		
Ekales-1	X	X		X	X	X		X	X				X	X	X	X	X	X	X	X
Ekales-2	X			X		X		X		X			X	X	X	X	X	X		X
Ekales-3	X	X	X			X		X						X	X	X	X	X		
Ekosowan-1	X	X		X	X			X		X	X	X	X	X	X	X	X			X
Ekunyuk-1	X	X		X	X	X	X	X	X				X	X	X	X		X		
Eong-1	X	X		X	X	X	X	X	X				X	X	X	X	X	X	X	X
Erut-1	X			X		X		X		X				X	X	X	X	X		X
Etiir-1	X			X		X		X						X	X	X	X	X		X
Etom-1	X	X		X	X	X	X	X	X				X	X	X	X	X			X
Etom-2	X			X		X		X			X		X	X	X	X	X	X		X
Etom-3	X	X	X	X		X		X		X				X	X	X	X	X		X
Etuko-1	X	X		X	X	X		X	X				X	X	X	X	X			X
Etuko-2A	X	X		X	X	X	X	X	X				X	X	X	X				
Ewoi-1	X	X		X	X	X	X	X	X				X	X	X	X	X		X	X
Ngamia-1	X	X		X	X	X		X						X	X	X				
Ngamia-1A	X	X		X	X	X	X	X	X			X	X	X	X	X	X	X	X	
Ngamia-2	X	X		X		X	X	X		X	X	X	X	X	X	X	X	X		X
Ngamia-3	X	X		X		X		X		X	X	X	X	X	X	X	X	X		X
Ngamia-4	X	X		X		X		X		X	X	X	X	X	X	X	X	X		
Ngamia-5	X	X	X	X		X		X		X	X	X	X	X	X	X	X	X		
Ngamia-6	X	X	X	X		X		X					X	X	X	X	X	X		
Ngamia-7	X			X		X		X					X	X	X	X	X	X		
Ngamia-8	X			X		X		X					X	X	X	X	X	X		
Ngamia-9	X			X		X		X					X	X	X	X	X			
Ngamia-10	X	X	X	X		X		X		X				X	X	X	X	X		
Ngamia-11	X	X	X	X		X		X		X				X	X	X		X		
Twiga South-1	X	X		X	X	X	X	X	X			X	X	X	X	X	X	X	X	X
Twiga-2	X	X		X		X	X	X		X		X	X	X	X	X	X	X		X
Twiga-2A	X	X		X		X		X		X	X			X	X	X				
Twiga-3	X			X		X		X		X	X		X	X	X	X				

🟦 Polymer Based Mud 🟨 K2SiO3 🟩 Polymer Based Mud

GR	Gamma Ray	**SP**	Spontaneous Potentia	**ECS/Flex**	Elemental Spectroscopy
Den	Density	**Cali**	Caliper	**CMR/Mrex**	Nuclear Magnetic Resonance
Neut	Neutron	**Micro LL**	Laterolog	**MDT/RCI**	Formation Pressure/Samples
Sonic	Sonic	**STAR/FMI**	Water Base Imager	**VSP**	Vertical Seismic Profile
Res	Resistivity	**EI/OBMI**	Synthetic Base Image	**SBT/CBL**	Cement Bond Log
SGR	Spectral Gamma Ray	**CBIL**	Sonic Imager	**PSWC/RSWC**	Percussion/Rotary Sidewall Core

Technology	Example Vendor Products	Description	Pros	Cons	Recommendation
DTS (Distributed Temperature Sensor)	Schlumberger Well Watcher	Permanently installed fiber optic cable in the wellbore is used to continuously monitor the temperature profile along to lower completion. The temperature profile can be used to infer changes in oil, water and gas Inflow in each of the zones.	Permanent flow monitoring requiring no downhole intervention.	Uncertainty in interpretation of results and identifying water / gas breakthrough. Interface between lower and upper completion during workovers, artificial lift replacements etc. Cost	Not recommended
Inflow Tracers	RESMAN	Water or oil soluble tracer sticks installed in the annulus of each isolated reservoir section. Each reservoir section has a unique chemical signature. Analysis of the chemical signatures in the produced fluids during a well test can be used to infer zonal contribution and water breakthrough.	Eliminates need for interventions to conduct PLTs. (Although occasional PLTs can be useful to calibrate the response of the chemicals)	Some uncertainties in the interpretation. Initial cost plus ongoing sample analysis charges for large number of wells. Design life (up to 10 years)	To be investigated in project Execute phase
PLT (Production Logging Tools)	Various	Conventional Production Logging Tool run on wireline or coiled tubing.	Field proven and reliable technology	For ESP wells a Y-tool bypass would be required which is not possible In 7" liner with the pump sizes required. For JP and Insert PCP wells the pump would need to be removed from the well and temporary gas lift applied. For conventional PCP wells, a PLT would not be possible.	Feasible for temporary gas lift in jet pump wells and water injection wells.
Downhole Flow Metering	Halliburton SmartWell	Downhole venturi mandrels and pressure gauges are installed in the lower completion. The pressure data can be used to interpret fluid density and flowrate.	Continuous flow measurement with no need for intervention.	Multiple venturi mandrels and pressure gauges would be required to monitor flow from five zones creating high complexity and cost. Uncertainty when interpreting density data to determine GOR and watercut from each zone.	Not recommended

7 APPENDIX D – TECHNOLOGY LISTINGS (ZONAL ISOLATION OPTIONS)

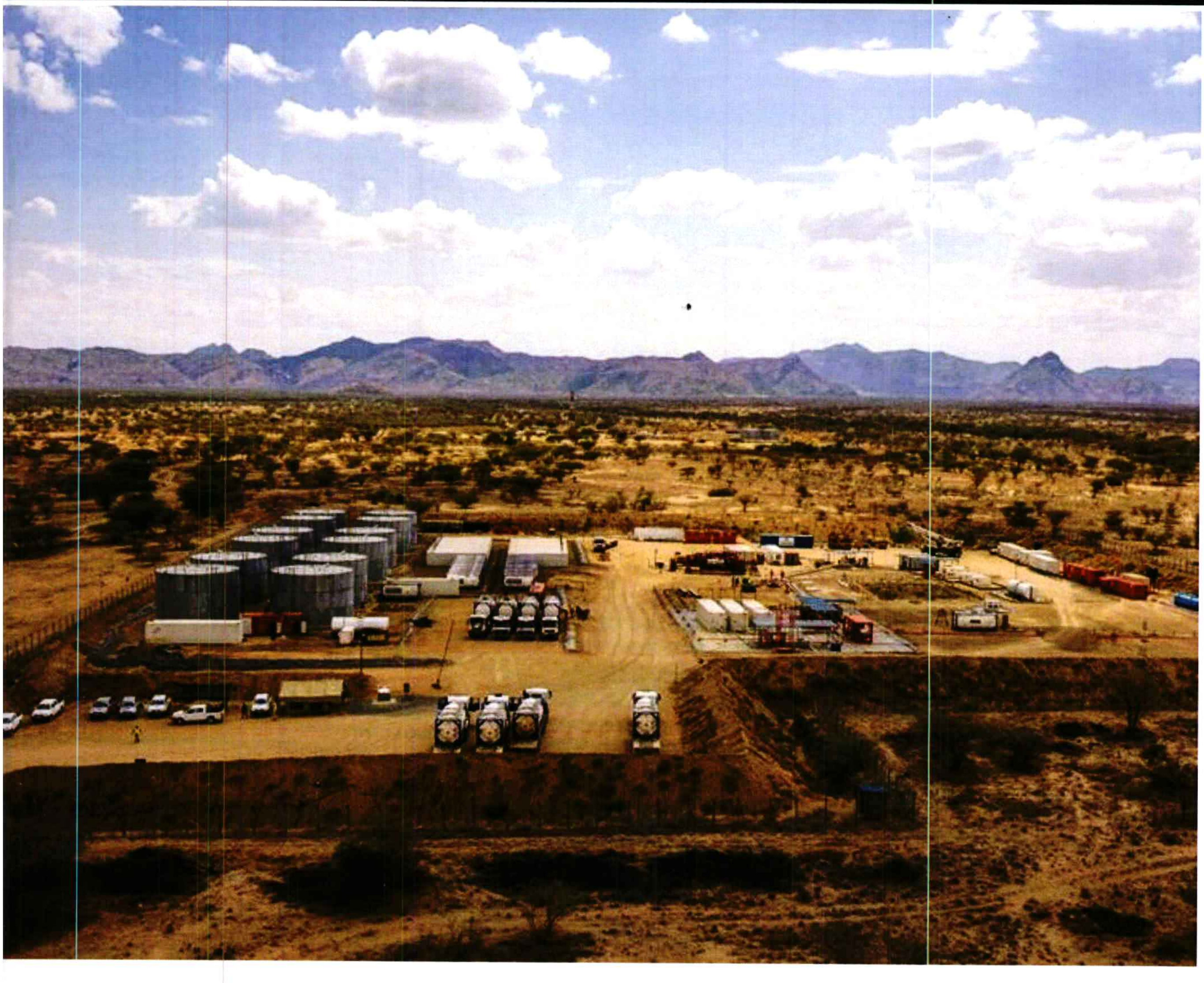
Technology	Example Vendor Products	Description	Pros	Cons	Recommendation
AICD	Tendeka FloSure Halliburton Equiflow	Autonomous Inflow Control Devices are installed in the lower completion and preferentially restrict inflow of gas and/or water from each of the isolated reservoir zones. Different technologies are available including floating disc, fluidic diode and ball type.	No interventions required for monitoring or activation	Additional drawdown required to maintain oil production leading to increased FGF and lift capacity requirement. Water producing zones are only choked back, never fully closed. Therefore, there is still a significant amount of water circulation required. Further lower completion equipment required increasing complexity and installation cost.	AICDs are not considered for the base case development plan but further work is recommended with the simulation model to Investigate their potential benefit to recovery and water utilisation.
Passive ICD	Baker Hughes Equaliser	Passive Inflow Control Devices are installed in the lower completion and provide a predefined restriction to flow for each of the inflow zones. Available technologies include nozzle and helical types. Passive ICD's can also be combined with a sliding sleeve to provide on/off capability via slickline or colled tubing.	Lower completion cost compared to MP-ICDs and ICVs. No interventions required	No ability to change nozzle / restriction sizes post installation (on/off ability only). Uncertainty in reservoir performance makes it difficult to pre-select nozzle / restriction sizes.	Not recommended due to difficulty in preselecting the nozzle / restriction sizes
Multi Position ICD	Schlumberger ResFlow	Multi-Position Inflow Control Devices are similar to Passive ICDs but contain a number of nozzle sizes which can be selected using a slickline or coiled tubing shifting tool.	Lower completion cost compared to ICVs. Provide variable drawdown control as compared to on/off control provided by SSDs	Require a CTor slickline Intervention with a shifting tool to actuate. Need to remove artificial lift to access reservoir. (Unless ESP with bypass is used). Require surveillance capability of sufficient accuracy / frequency to realise benefit of the additional control.	Could be considered as an enhancement to SSDs if we have fit-for-purpose monitoring capability and drawdown control is proven to be of significant benefit.
Single or Multi Position ICV	Halliburton SmartWell	Inflow Control Valves are installed in the lower completion to provide on/off (single position) or variable (multi-position) inflow control from individual reservoir zones. ICVs are controlled from surface via an electrical or hydraulic connection rather than a coiled tubing or slickline shifting tool.	Can be controlled from surface, no intervention needed. Could perform multi-zone well tests thereby reducing the need for surveillance interventions (i.e.. PLTs)	High cost Complexity and increased potential for failure	Expect the cost to be prohibitive for field wide implementation. Further work could be undertaken however to understand the tradeoff between the higher Initial completion cost and the lower reservoir surveillance and intervention costs.

Technology	Example Vendor Products	Description	Pros	Cons	Recommendation

SSDs	Haliburton Durasleeve Baker Hughes	Conventional Sliding Side Door technology installed in the lower completion to open or close each of the isolated reservoir zones.	Relatively low completion cost. Proven technology, relatively reliable	Require a CTor slickline intervention with a shifting tool to open or close sleeves. Need to remove artificial lift to access reservoir (unless ESP with bypass is used.) Only have on/off control. Cannot therefore slow the development of water in one zone without affecting other	Relatively low-cost option which provides good flexibility to open and close zones. Need to consider in concert with the artificial lift option, e.g., with conventional PCPs or non-bypass ESPs, a full workover would be required to remove the pumps and actuate the sleeves. Potential to use in water injection wells
Bridge Plugs /Straddles	Interwell HEX Plugs TTS	As and when water breakthrough is identified bridge plugs and/or straddles are installed to isolate specific perforation intervals. Through tubing deployment of the bridge plugs and straddles may be possible depending on the tubing and casing size.	Low upfront cost Proven technology, relatively reliable	Require a CTor slickline intervention if through tubing is possible, or a full workover if not. More difficult to reopen isolated zones compared to other options. Need to be able to reliably measure water cut to determine correct zone to isolate?	A field proven low-cost option which could be used with the 'Deferred Lower Completion' strategy discussed below.
Deferred Lower Completion	N/A	No lower completion is run into the cased & perforated section initially. When water breakthrough is identified the decision is made regarding which of the above zonal isolation options are used.	Reduces initial completion cost and short-term project risk. Maximises initial well productivity when water cut is low Allows time to develop better understand of the reservoir performance before selecting the preferred completion option.	Will likely require a full workover to isolate high watercut zones (unless through tubing plugs/ straddles are selected) Possibly not optimal for long term project economics	This is an attractive option to minimise upfront capex and defer decision on whether to install a lower completion with SSDs / ICDs or use bridge plugs/straddles when water breakthrough occurs. Combined with the phased approach proposed the data from Phase 1 can be used to refine this option.

SOUTH LOKICHAR BASIN
WELL AND RESERVOIR MANAGEMENT PLAN

SEPTEMBER 2025



Document Number: GE-FDP-APPE-D1

Document Owner: FJ

REV	DATE	DESCRIPTION	COMPILED	REVIEWED	APPROVED
1	15/9/2025	INITIAL DRAFT	RPH		

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UNITS OF MEASURE

Unit	Definition
AMSL	Above Mean Sea Level
bara	Bar absolute
BCF	Billion Cubic Feet
blpd	Barrels Liquid Per Day
stb/d	Stock tank barrels per day
bwpd	Barrels of water per day
km	Kilometres
m	Metres
MMbbls	Millions of barrels
MMscf/d	Million standard cubic feet per day
MMstb	Million stock tank barrels
MW	Mega Watts
psia	Pounds per square inch absolute
TVDSL	True vertical depth sub lake
TVDSS	True vertical depth sub sea

ABBREVIATIONS AND KEY WORDS

Abbreviation	Definition
10BB	means the new Block T6, previously Block 10BB
13T	means the new Block T7, previously Block 13T
2D	Two Dimensional Seismic
3D	Two Dimensional Seismic
BS&W	Basic Sediment & Water
C/O	Carbon / Oxygen Log
CPF	Central Processing Facility
EPF	Early Production Facility
ESP	Electrical Submersible Pump
GEBV	Gulf Energy B.V.
GVF	Gas Volume Fraction
HUD	Hold Up Depth
KPRL	Kenya Petroleum Refineries Limited
LWD	Logging While Drilling
MDT	Modular Dynamic Tester
PCP	Progressive Cavity Pump
PFO	Pressure Fall Off
PI	Productivity Index
PLT	Production Logging Tool
PVT	Pressure Volume Temperature
RCI	Reservoir Characterization Instrument
SWCT	Single Well Chemical Tracer
VSP	Vertical Seismic Profile
WHFP	Wellhead Flowing Pressure
WHFT	Wellhead Flowing Temperature
WRMP	Well & Reservoir Management Plan

EXECUTIVE SUMMARY

This document defines the Well and Reservoir Management Plan (WRMP) that will be followed to optimize the development of the South Lokichar Basin reservoirs. Specifically, it covers actions that will contribute to the surveillance of the production and injection wells, and the reservoirs, to maximise economic recovery from those reservoirs.

The WRMP applies to existing discoveries that are described in the South Lokichar Field Development Plan but should also be followed for new discoveries to be tied into the South Lokichar facilities.

The WRMP covers not simply data acquisition in the wells but all aspects of the reservoir management process. The well and reservoir management plan require the integration of many separate elements, including:

- Reservoir management team
- Data acquisition
- Data management
- Appropriate monitoring technologies and analytical tools
- Reservoir description
- Static and dynamic reservoir models
- Reservoir depletion plan and depletion plan updates
- Implementation plan
- Performance reviews
- Ranking, justification, and sanction of additional opportunities

This WRMP plan should be considered an evolving document to be updated periodically, as reservoir understanding evolves and new evaluation technologies become available.

ASSET OVERVIEW

The South Lokichar Basin is located within the Turkana Rift of the Great East African Rift System. It is approximately 70 km long and 35 km wide at its maximum extent and covers an area of approximately 1700 km2. Fifteen exploration wells have been drilled in the basin including the original discovery well, Loperot-1, drilled by Shell in 1992. The first commercial discovery was made in 2012 by the Ngamia-1/-1A exploration well. Since that time, there have been ten declared discoveries in the basin resulting from the subsequent drilling campaigns (Figure 18-1).

The South Lokichar Basin is covered by two production sharing contracts for Blocks 10BB and 13T, recently redesignated as T6 and T7 respectively. Both blocks are operated by GEBV with a 100% working interest, subject to the government's back-in rights under the PSCs. From the approval of the Field Development Plan, the Contractor's production licence duration is 25 years.

The South Lokichar Basin has a straightforward half-graben geometry with Lower to Middle Miocene syn-rift sediments thickening westwards towards the basin bounding north-south trending Lokichar Fault (Figure 18-2). Displacement along the eastward-dipping basin bounding Lokichar Fault dies out along strike to the north and south with the maximum displacement located near the centre of the fault. The syn-rift sediments thicken along this north-south trend towards the centre of the basin as shown in Figure 18-2. The depositional centre of the basin is located offsetting the Ekales field where the thickest section of syn-rift sediments is present. The basin is bounded to the east on the flexural margin by the Lokone Horst bringing Pre-Cambrian aged crystalline metamorphic rocks to surface.

The depositional environment in the South Lokichar Basin during Miocene time is interpreted as terrestrial with predominantly fluvial, lacustrine, alluvial plain, and alluvial fan deposits. The shallower Auwerwer reservoirs are primarily stacked fluvial deposits; the deeper Lokone formation is predominantly lacustrine. On the western side of the basin, adjacent to the rift bounding fault, alluvial fan deposits are encountered. These deposits tend to be very immature in nature and are non-reservoir in every location encountered to date.

Both the Auwerwer and Lokone are characterised by multiple stacked hydrocarbon pools within each reservoir. Dedicated wells will be drilled for the two separate reservoirs when they are encountered within a single field. Figure 18-3 shows a representative well log display from Ngamia-3 highlighting the relative locations of the Auwerwer, Lokone Shale and Lokone Sandstone. Pressure and elevation differences, contrasting productivities and the requirement to frack most Lokone intervals means that commingled production is impractical.

The development strategy uses a phased approach, beginning with the largest and most technically mature reservoirs. To achieve first oil and support an initial plateau of 20,000 stb/d of oil, 48 wells in the Ngamia and Amosing fields will be used and produced through Early Production Facilities (EPF). The data gathered through this phase will be used to optimise the further development which plans to execute further drilling in Ngamia and Amosing whilst adding production from the Twiga, Ekales, Agete and Etom fields. The second phase of the development will utilise a Central Production Facility to increase the oil plateau to some 50,000 stb/d.

In total, seven discovered reservoirs from the Auwerwer (primary) and Lokone (secondary) are currently planned to be exploited over the life of the development. The initial Phase 1 production performance from the Ngamia Auwerwer and Amosing will be used to optimise development of the subsequent reservoirs and maintain the planned production plateau.

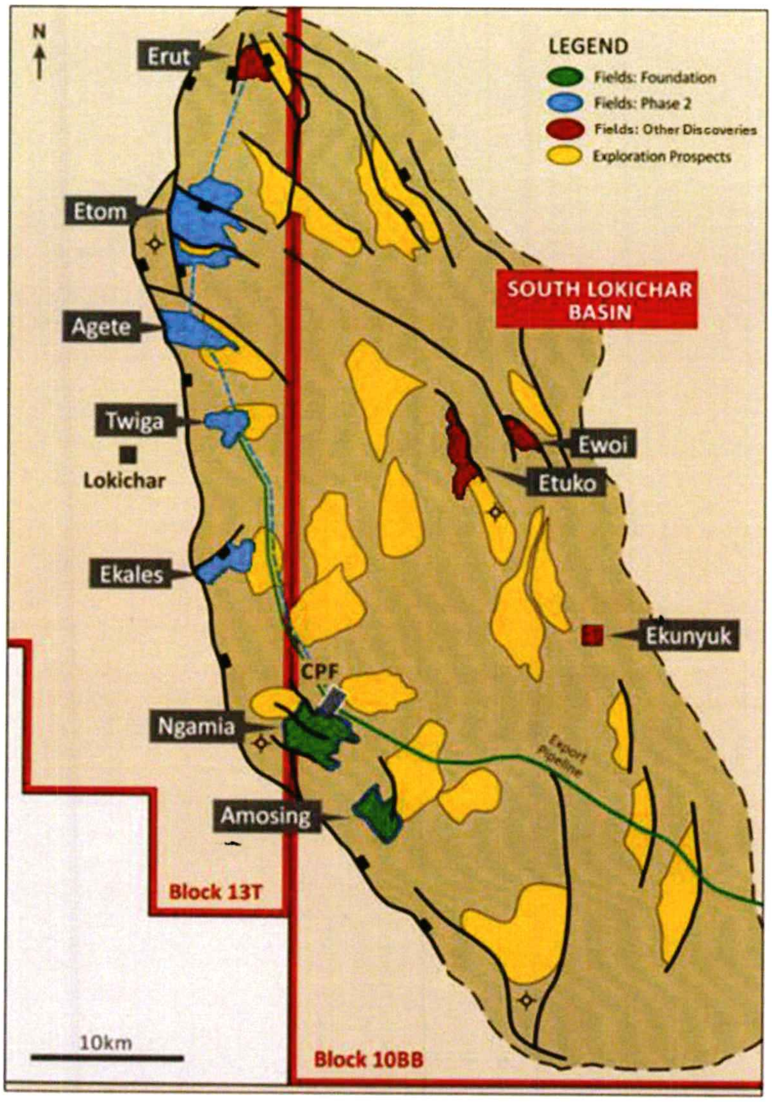


Figure 18-1: Basin Discoveries and Exploration Prospects

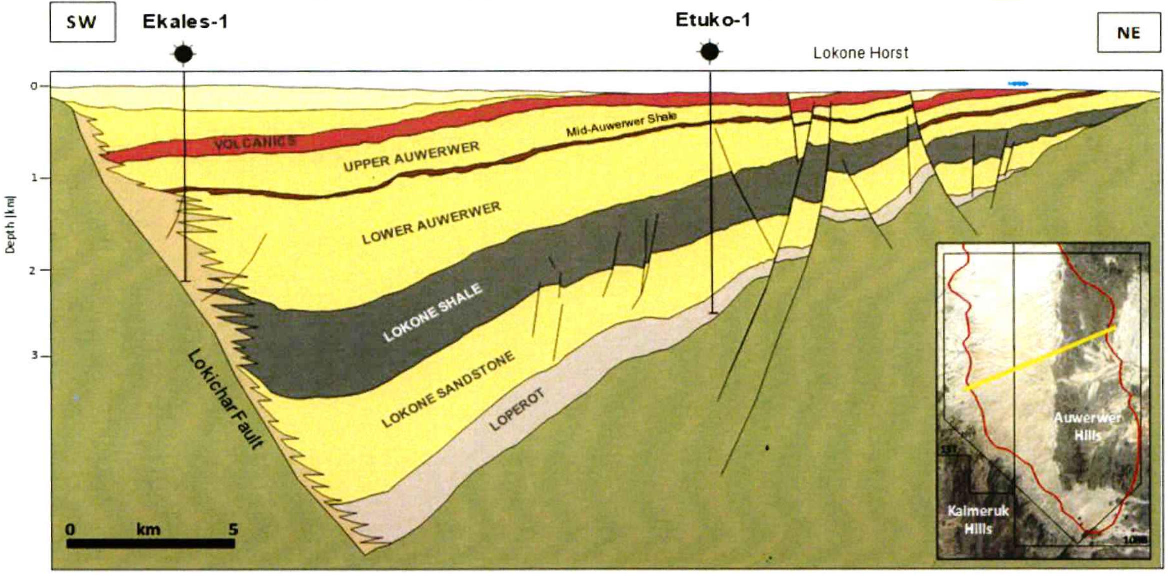
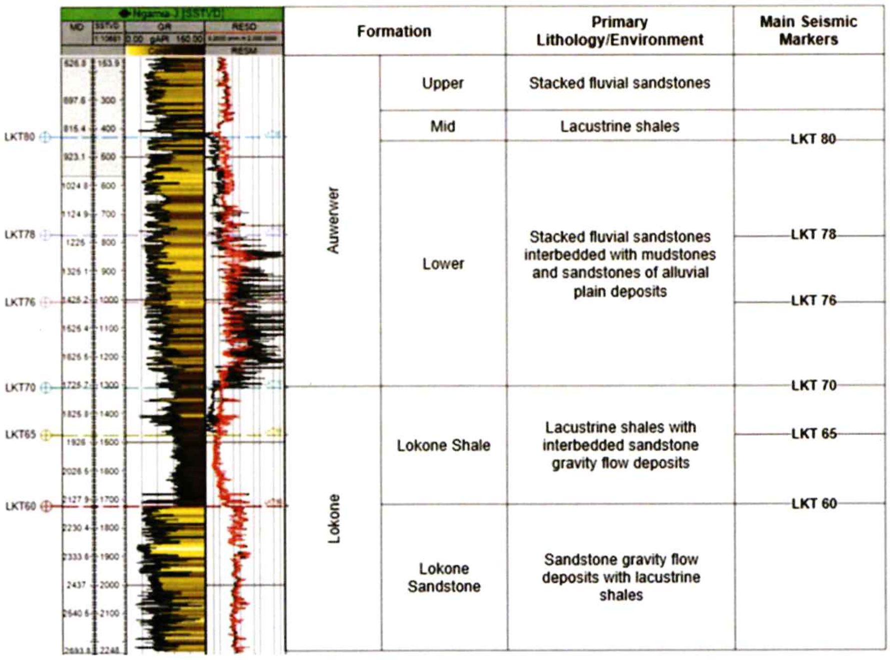


Figure 18-2: South Lokichar Basin Stratigraphic Cross-section

Figure 18-4 shows an arbitrary cross-section of the Amosing field that provides an example of the multiple reservoir pools that will be developed in the South Lokichar reservoirs; in Ngamia and Amosing, as many as eight hydraulically separate hydrocarbon intervals may be encountered in a single Auwerwer development well. To minimize drilling and completion costs, wells will be completed with a perforated, cemented liner across multiple hydrocarbon pools, produced to surface via a single production string. This maximises early production to attain the plateau and delivers early cashflow and value to stakeholders.



Formation		Primary Lithology/Environment	Main Seismic Markers
Auwerwer	Upper	Stacked fluvial sandstones	
	Mid	Lacustrine shales	LKT 80
	Lower	Stacked fluvial sandstones interbedded with mudstones and sandstones of alluvial plain deposits	LKT 78 LKT 76 LKT 70
Lokone	Lokone Shale	Lacustrine shales with interbedded sandstone gravity flow deposits	LKT 65 LKT 60
	Lokone Sandstone	Sandstone gravity flow deposits with lacustrine shales	

Figure 18-3: Well log display illustrating the key reservoirs in the Ngamia Field

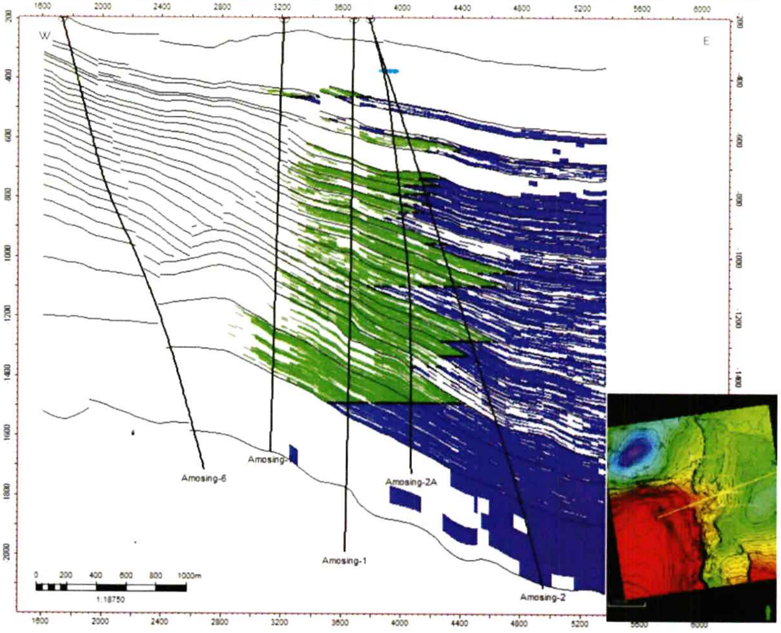
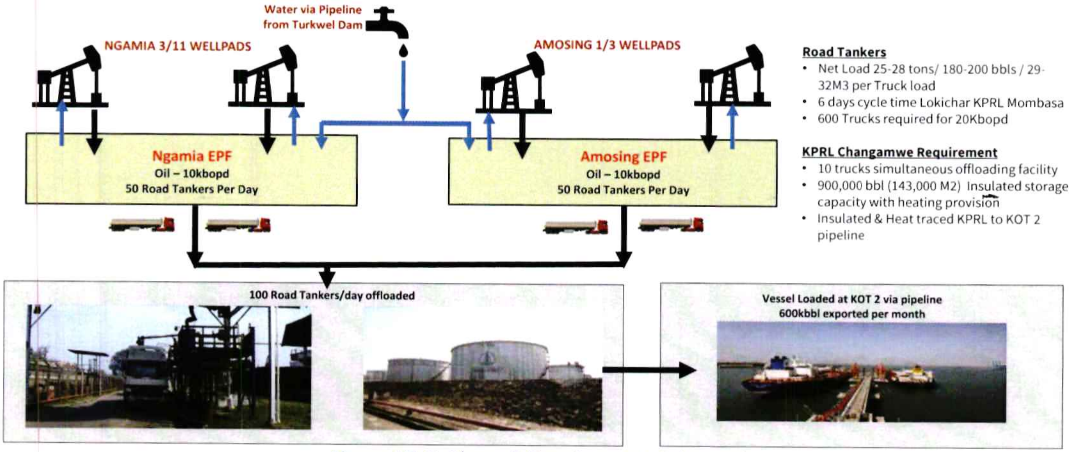


Figure 18-4: Arbitrary Cross-section Through Amosing Highlighting Hydrocarbon Pools

The phased approach to the development will initially start with the infrastructure shown in Figure 1-2. To achieve an accelerated first oil date and to allow for early data gathering to further optimise later developments in the basin production will initially be through rental EPFs. Crude will be trucked through KPRL Changamwe and exported through Mombasa port.

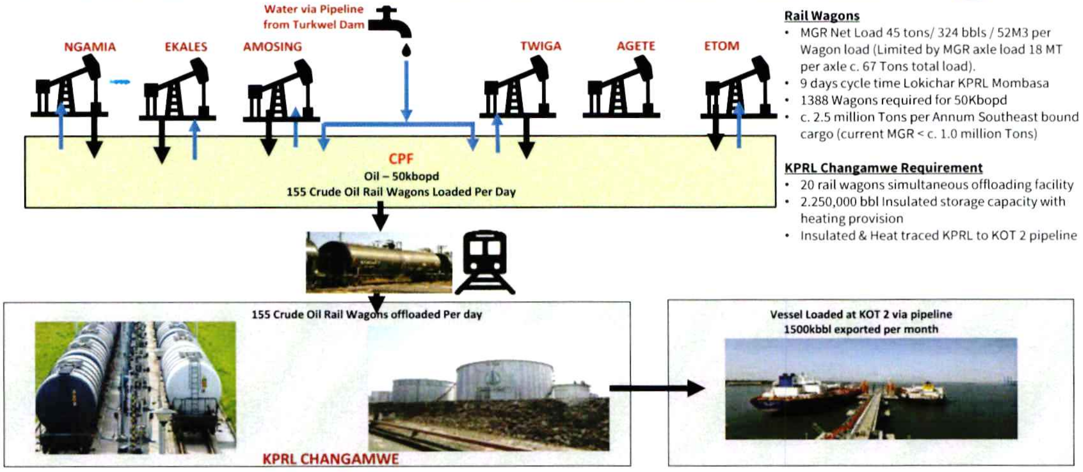


Road Tankers
- Net Load 25-28 tons/ 180-200 bbls / 29-32M3 per Truck load
- 6 days cycle time Lokichar KPRL Mombasa
- 600 Trucks required for 20Kbopd

KPRL Changamwe Requirement
- 10 trucks simultaneous offloading facility
- 900,000 bbl (143,000 M2) Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 18-5: Phase 1 Development Schematic

Phase 2 of the development will entail a larger drilling campaign across the Amosing, Ngamia, Twiga, Ekales, Agete and Etom fields (Figure 1-3). The higher production plateau of 50 kstb/d is planned to be exported through the rail network, with final export also through Mombasa.



Rail Wagons

- MGR Net Load 45 tons/ 324 bbls / 52M3 per Wagon load (Limited by MGR axle load 18 MT per axle c. 67 Tons total load).
- 9 days cycle time Lokichar KPRL Mombasa
- 1388 Wagons required for 50Kbopd
- c. 2.5 million Tons per Annum Southeast bound cargo (current MGR < c. 1.0 million Tons)

KPRL Changamwe Requirement

- 20 rail wagons simultaneous offloading facility
- 2.250,000 bbl Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Figure 18-6: Phase 2 Development Schematic

Oil will be produced through commingled production wells, supported by water injection in an inverted five-spot pattern. Wells will be vertical and S- shaped, drilled from well pads containing up to 24 wells, divided equally between producers and injectors.

A make-up water line will be commissioned from the Turkwel Dam for pressure support. Due to the waxy nature of the South Lokichar crude, injection water will be heated and produced water will be reinjected.

WELL AND RESERVOIR MANAGEMENT PRINCIPLES

The Well and Reservoir Management Plan (WRMP) philosophy for the South Lokichar development is to ensure optimum economic recovery of discovered and undiscovered prospective resources. This will be achieved through a detailed well data acquisition strategy to include static data acquisition during development well drilling and active monitoring of the wells and the reservoir from production start-up and throughout the life of the fields. Acquired data will be used to calibrate well and reservoir models and to optimize the field development plan.

KEY VALUE DRIVERS

Key value drivers in the South Lokichar Basin have been identified as the following:

- Deliver base case production forecast and mitigate low case outcome.
- Conduct operations to commercialise high case resources.
- Maximise economic oil recovery.
- Minimise greenhouse gas emissions and the environmental impact of the development.
- Manage water production to deliver highest possible oil recovery and minimise water cycling.
- Optimise development well spacing
- Maintain well operability
- Create learning in the early stages of basin development to maximise value creation in subsequent activity.

KEY RESERVOIR UNCERTAINTIES AND OPPORTUNITIES

Due to lack of previous development in Kenya or onshore East Africa, there are no valid regional producing analogues for the South Lokichar Basin. With a reliance on waterflooding in stacked oil pay, the development carries several subsurface uncertainties and performance risks.

Subsurface uncertainties

Key subsurface uncertainties and the data required to manage the associated risks are summarized in Table 18-1, below. The static geological models and dynamic simulation models will be the primary tools to investigate and resolve the subsurface uncertainties.

Table 18-1: Subsurface Uncertainties and Data Acquisition

Uncertainty	Data Required
Well drainage area and recovery, area conformance, and sweep efficiency	Production rates and water cut, injection rates, interference tracer data, well pressure data, formation tester (MDT/RCI) pressure data, C/O log
Reservoir compartmentalisation, structural and stratigraphic compartmentalization - lateral reservoir continuity	Production rates and water cut, injection rates, interference tracer data, well pressure data, formation tester (MDT/RCI) pressure data
Optimise well production	Production rates, reservoir pressure and pump inlet pressure data, pump parameters
Vertical conformance	PLTs, zonal tracer data, formation tester (MDT/RCI) pressure data, C/O log
Gas injection performance	LWD log data, gas injection rate, reservoir pressure, calculated injectivity over time
Water injection performance	LWD log data, water injection rate, reservoir pressure, calculated injectivity over time, water quality monitoring
Pump performance, reliability	Production rates, reservoir pressure and pump inlet pressure data (direct measurement, memory gauges, annulus level sounder), pump VSD parameters
Reservoir containment, seal integrity under water injection	Spectral noise log, high resolution temperature, injection rate, pressure data, pressure fall offs (PFO).
Water allocation and proration	Continuous, online water rate metering
Hydrocarbon allocation	Reliable, frequent (monthly) well tests providing oil, water, and gas rates; robust production allocation system.
Well integrity	Tubing and casing thickness measurements; well pressure monitoring
Artificial lift design	Well productivity index (PI); reservoir properties assessment (porosity, permeability, permeability-thickness); formation pressure measurements
Aquifer behaviour/strength	Pressure and rate data; material balance estimates on a reservoir/fault block basis
Scaling tendency	Water ion analysis
Producer under-performance, premature water breakthrough	MPFM test data and water cut, production allocation; pressure data; zonal tracer data
PVT and potential for PVT grading	Targeted PVT samples from MDT/RCI tool
Oil-water contacts	Reservoir formation pressures (MDT/RCI); mud gas/mud logging data; ECS log (electron capture spectroscopy).
Permeability	Cores
Residual saturation	SCAL on core samples, SWCT, C/O logs
Sand production and erosion monitoring	Surface BS&W monitoring, sand traps, well HUD measurement
Well productivity	MPFM test data and water cut, production allocation; pressure data; zonal tracer data

DATA MANAGEMENT

Data management is the organisation of both raw and interpreted data into a readily accessible form that can be accessed easily and quickly by the reservoir management team. Proper data management is vital to enable the technical team to do their job effectively and accurately. In a large reservoir basin like South Lokichar, covering multiple fields and reservoirs with hundreds of development wells to be drilled, high quality data management is essential. Its role must not be underestimated in the context of the overall management of the asset.

Data captured over the life of the field will include, but not be limited to, the following raw data:

- 2D seismic lines and 3D seismic volumes, each with different vintages of processing
- Open and cased hole well logs, including mudlogging records and cuttings samples
- Drilling performance information
- Conventional and special core analyses – full core and sidewall samples
- Fluid samples and analyses – oil, water, gas at reservoir and surface conditions, other chemicals and tracers used

during field life

- Static and flowing pressure and temperature data – downhole and surface equipment values, high frequency, and low frequency
- Periodic well production tests
- Daily/weekly/monthly measurements of produced volumes of oil, gas, and water

Processes for the timely capture and quality maintenance of data also should be established and specific personnel will be required for this purpose. While this assignment may be a drain on limited manpower, the benefits of readily available, high-quality data will save time spent in reorganizing, checking, and reinterpreting data each time a study is conducted. Before drilling mobilization is complete, the data management infrastructure and personnel must be in place to properly manage the high volumes of data that will be continuously delivered through the pre-drilling phase of the project.

Although it is expected that the static geological models and dynamic simulation models will the primary locations to maintain the reservoir understanding, these models will be supported by the development and maintenance of interim interpreted products:

- Seismic time maps within seismic interpretation software (i.e. Kingdom, Petrel)
- Seismic conversion of time-to-depth maps
- Seismic attribute maps
- Open and cased hole log analyses
- Database of formation tops
- Set of structure and isopach maps
- Geological cross-sections
- Pressure build-up and fall off analysis
- Zonal and interwell tracer measurements and interpretation
- Geological models (i.e. Petrel)
- Reservoir dynamic simulation models (i.e. Eclipse, tNavigator)

Asset data management is a formal set of processes that will collect, prepare, and distribute the field data to the asset team to enable appropriate technical analysis to support management decisions. Drilling, petrophysical, pressure, rate, process measurements and fluid analysis should be available.

A valuable standard for the management of data in the oil and gas industry is provided by the International Organization for Standardization (ISO), which has a specific technical committee for the upstream business, ISO TC67. The ISO 14224: 2006 standard provides a standard format for equipment in all facilities and operations within the oil and gas industry; this reference is expected to be used for South Lokichar Basin subsurface.

o Well Books

Electronic Well Books will be established and maintained for every well. These will comprise a comprehensive summary of all basin wells. The Well Book documentation will be compiled beginning with the initial well proposal and the well drilling program; it will be maintained as a complete record of activity on the wells, including drilling and completion activity, open and cased hole logging records, up to date well completion diagrams, and well intervention history includes programs and close-out reports. The Well Books will integrate with a Well Intervention Database to maintain the full on-line record of activity. These records will be an important resource for emergency response purposes and, most importantly provide a full well history and data continuity in the event of personnel changes during the asset life. Consistent wellbooks for historical wells will also be made, with emphasis on the wells which will be re-used during the Phase 1 production.

Quality Assurance

Processes for the timely capture and quality maintenance of data will be established and dedicated personnel will be required for this specific purpose. While this assignment may be a drain on limited manpower, the benefits of readily available, high- quality data will save time spent in reorganizing, checking, and reinterpreting data each time a study is conducted. The time savings more than returns the cost of quality data capture. Studies of work output indicate that as much as 50% of the time spent on a project can be consumed by finding and organizing data that is not maintained in a readily accessible, high-quality format.

FIELD DEVELOPMENT PLAN

The subsurface development plan is in place for the South Lokichar Basin. It has been prepared based on the results of exploration and appraisal drilling, and the well testing program that has been completed to date. The subsequent data interpretation and reservoir models have been tuned to the dynamic data to create the approved development plan for the basin. Key aspects of the subsurface development plan are:

- Production will be supported by water injection from first production. This is considered vital due to relatively low in-situ compressibility of the South Lokichar crude oil and the need to maintain reservoir pressure. The degree of support that will be available from the Auwerwer aquifer is presently uncertain.
- The reservoirs will be developed on an inverted five spot pattern at a 200m well spacing (measured as the shortest distance between adjacent producers and injectors).
- Production and injection will be dedicated to a single reservoir (i.e. Auwerwer or Lokone) but production will be commingled from multiple pools within that reservoir. All net pay within producers and net reservoir within the hydrocarbon pools of the injectors will be perforated.
- A reservoir voidage replacement ratio of 1.0 will be maintained within the fault blocks of each reservoir.
- Wells are drilled from pads with a normal pad housing 12 wells. Depending on the lateral reach required some areas may be developed with up to 24 wells on a given pad. A combination of injectors and producers will be completed on all pads.

The key risks and uncertainties in the execution of the development relate to identifying the reservoir pay zones in both injection and production wells. There is a significant risk of early water production in the producers if the water leg in those wells is incorrectly interpreted or if perforations are added in the transition zone or very close to the oil-water contact. An overly conservative approach during the initial completion will lead to a risk of undeveloped STOIIP and underperformance of production wells against expectations.

For Phase 1, 9 wells in Amosing are expected to be initially completed and on-line. Understanding the results of the initial production and how it is related to the perforation strategy selected is critical to the long-term success of the full basin development. Challenges the reservoir management team will need to address are:

- Is the prescribed perforation strategy appropriate, too conservative or too aggressive? How should the plan be modified for future wells?
- Is the well 200m well spacing of the development plan optimal? Can the well spacing be relaxed for other fields or in specific areas of some fields? i.e. Is wider well spacing appropriate for structurally less complex fault blocks where fault-related compartmentalisation is a lower risk?
- When water breakthrough occurs, can it be detected reliably? Is it possible to identify the reservoir zone water comes from using the reservoir monitoring strategy? Are the tools available to successfully and effectively complete zonal isolations? What is the operational and value benefit of such an intervention?

Data acquisition will focus on providing data to support reliable reservoir modelling. Does the data acquisition plan deliver the required information to satisfactorily model the reservoir behaviour? It will be important for the team to focus on the question whether there are new or updated technologies becoming available that will provide better quality data or fill a gap in existing data being recorded?

STATIC RESERVOIR MODELLING

Static geological models have been built for the key fields (Amosing, Ngamia, Twiga) on the western side of the South Lokichar Basin that constitute 'development pending' Contingent Resources. These are the primary repository for the reservoir management team's understanding of the field's static geophysical and geological data. The current models have been built using the Relative Amplitude (RAP) Prestack Time Migration (PreSTM) processing of the South Lokichar 3D seismic data and populated using all available well data from the 2012 to 2017 exploration and appraisal drilling program.

These static models will continue to provide the foundation of the reservoir management team's evaluation and surveillance program as the reservoir description evolves and is improved with additional data. During the Phase 1 preparation and early production, models for the other Phase 2 fields (Ekales, Agete and Etom) will be built based on the knowledge being acquired to optimise the future developments.

Even after the extensive exploration and appraisal campaign across the basin, data is still relatively sparse from a reservoir modelling point of view, and this is reflected in the relatively large 1C to 3C range of STOIIP described for the fields. The primary sources of these differences are mapping, due to seismic pick and depth conversion uncertainties; reservoir pool definitions and error bars carried for hydrocarbon contact depths; and the risk of the presence of rift edge facies encroaching into the Auwerwer and Lokone fluvial reservoir environment.

○ Development Drilling Phase

The development drilling phase, beginning at Amosing and Ngamia, will provide a substantial increase in the amount of reservoir data available to update and to substantially improve the quality of the static reservoir models. The data acquisition program from the development wells is described in the Section ▯ of this document. With up to three rigs drilling and well drilling times around twelve - fifteen days per well, there will be large volumes of data arriving continuously to be integrated into the reservoir models.

The wells will have production casing run by the drilling rig and will be suspended until the completion rig is mobilized to the well for completion operations. The well log data, in the context of the models, will primarily be used to direct decisions around completion intervals for both injectors and producers within a given area of the reservoir. Care must be taken to review well data immediately it becomes available from the wellsite as this data may affect drilling programs and decisions on subsequent wells to be drilled from the same or an adjacent well pad.

• DYNAMIC RESERVOIR MODELLING

The dynamic reservoir models of the South Lokichar reservoirs will be the key tools for production forecasting and long-term planning. The dynamic models will use the static model as their foundation but will be calibrated (or history-matched) with the historical field production data. The dynamic data specifically gathered during field production – production and injection rates, pressure and productivity/injection data, tracer samples, production logs – will provide key calibration information that will in turn be used to improve the validity of the static models.

The static and dynamic reservoir models will necessarily be complex, given the size of the reservoirs, the number of wells, hydrocarbon pools and fault blocks that may need to be modelled. It is critical that appropriate resources are dedicated to completing these models in a timely and efficient way and the task of building and maintaining these models is not underestimated by the asset team.

Base case models for most of the reservoirs are built and have been used to optimise the subsurface development and these should provide the foundation for future dynamic models.

• DRILLING PHASE DATA ACQUISITION

Vertical and deviated development wells will be drilled from multi-well pads for all reservoirs exploited in the basin. Well pads will carry as many as twenty-four wells; a combination of producers and injectors will be drilled from the pads to support the inverted five-spot subsurface grid.

Data acquisition during the drilling phase and its correct analysis is critical to correctly distinguishing reservoir net pay from non-pay zones and correlating these pay intervals between producers and supporting injectors. Mud gas data will provide preliminary evidence to identify pay, in conjunction with reservoir models that were developed during the exploration and appraisal phase of development and will be subject to continuing evolution.

Routine log data will be acquired using logging-while-drilling (LWD) tools in the drill string behind the drill bit and mud motors. A minimum depth rat hole will be required beneath the deepest reservoir objective of each well to ensure a full suite of data can be captured on the LWD tools within the reservoir section.

A limited log dataset will be acquired in all development wells, in addition to logs that may be run in the initial set of wells drilled from any given pad. The primary objectives of the open hole logging suite are:

- Acquire data with LWD wherever possible to minimize impact on well construction time.
- LWD provides real-time information available at wellsite to help drilling team manage well decisions and high-quality data from memory download, comparable with conventional wireline acquisition.

- Use formation evaluation logs to evaluate reservoir quality (porosity, Vshale, net-to-gross, formation fluid mobility, identify net pay). This information will be critical to process of updating the static geological (Petrel) models, which will be a priority during the development drilling phase.
- Evaluate the potential of the LWD electron capture spectroscopy tool as an aid to robustly identifying oil-bearing intervals.

Wireline cement evaluation logs can be run in all wells after the TD casing has been run, particularly if the cementing operations wer considered problematic. Understanding cement quality, coverage and bond strength will be vital to optimize the perforated intervals in all wells.

Additional logs will be run in exploration and appraisal wells to include capture of sidewall cores, VSP and formation pressures.

It is not currently anticipated that there will be a requirement for full bore core to be cut in the future South Lokichar drilling program.

Table 18-2: LWD and Wireline Acquisition Matrix

Running Method	Tool	Development Well	Exploration/Appraisal Well
LWD	Gyro	X	X
	Gamma Ray	X	X
	Resistivity	X	X
	Neutron-density	X	X
	Sonic	X	X
	Formation Pressures	Optional	X
	Elemental Capture Spectroscopy	To be evaluated	
	Seismic-while-drilling		To be evaluated
Wireline	VSP		X
	Sidewall cores		X
	Cement Evaluation		X

• WELL ARCHITECTURE

Well trajectories for both production and injection wells will range from vertical to S-shaped, with a maximum well deviation of ~55°. Figure 18-7 shows the Phase 1 drilling patterns planned for the Amosing field. Wells have been planned to intersect top reservoir at inclinations of 20° and dropping to vertical or near vertical through the reservoir section. This design gives flexibility in the artificial lift methods available as rod driven pumps sited near top reservoir will minimise rod wear around two "corners" in the well.

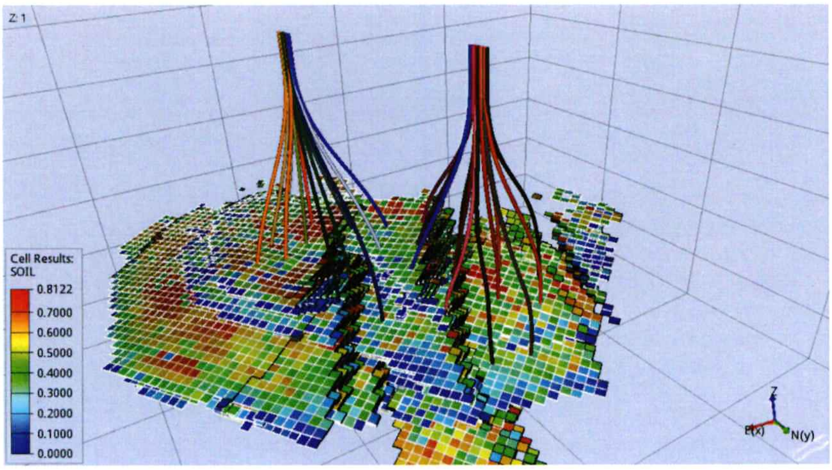


Figure 18-7: Amosing Well Trajectories

- **Oil Producers**

A key driver of the development well design is low capex to minimize capital cost while maintaining production potential. The selected well design also keeps operating cost and abandonment expenses as low as reasonably possible. All wells will be completed as commingled multizone wells within the Auwerwer or Lokone and producers will have artificial lift installed at first production. Wells will be dedicated to Auwerwer or Lokone service; there will be no commingling of production between the two reservoirs due to depth, pressure, and reservoir quality differences.

Artificial lift will be provided by a combination of ESPs, jet pumps and PCPs. For Phase 1 ESPs have been selected as the preferred artificial lift method considering expected well productivity, fluid properties / flow assurance, wellhead pressure, sanding risk and Gas Volume Fraction (GVF) at the pump intake.

At the start of Phase 2 with the CPF becoming available Jet pumps may be able to use excess capacity in the water injection system during the early field life to provide the drive fluid. Jet pumps could be deployed in selected wells in Amosing and Ngamia to assist in fluid circulation within the surface facilities is maintained above the inversion points (water cut > 60%) for flow assurance purposes. Circulating heated water will maintain flowline temperatures above the oil wax appearance temperature. ESPs will be used in the balance of the production wells.

If jet pumping is used, as the producing water cut of the wells increases, the water available water as a drive fluid will consequently decrease and the jet pumps will be replaced with ESPs to maintain field deliverability. A key activity for the reservoir management team will be artificial lift optimisation and timing of jet pump conversion to sustain production and control well intervention opex.

When ESPs are deployed in wells, they will be run with surface readout inlet and discharge pressure and temperature monitors. These data will be critical to the optimisation of pump performance and to maximise the ESP's run life, but the inlet gauges will also provide continuous read out of well drawdown and wellbore-averaged reservoir pressure. Dedicated pressure sensors for each zone will not be possible.

For lower rate wells at Amosing and Ngamia, PCPs can be deployed, where applicable. For other reservoirs, the higher flowline back pressures of the production system preclude the use of PCPs, due to the maximum pressure limits of the PCP drive head stuffing box. PCP inlet pressures, drawdown and reservoir pressure can be determined using a well sounder to monitor the annulus fluid level and permit a calculation of wellbore pressure.

The reservoir section will be cased hole and perforated, and no sand control will be installed (Figure 18-8). Sanding potential analysis has indicated limited risk of sand production during the development phase of the Auwerwer reservoir. The greatest risk will be presented after water breakthrough has occurred at the production wells.

Sand monitoring will be installed at the well pads on the production flowlines and it is expected that any sand production will be managed through surface mitigations and wellbore cleanouts, if required. During each well intervention to change out the well completion, most likely due to artificial lift replacement, a hold-up depth (HUD) measurement will be made. This will indicate whether any sediment fill is accumulating in the wellbore. This should be logged and monitored over time and, if the HUD is approaching the base of the perforated interval, a wellbore cleanout will be required. In extreme cases, where the accumulation of sand debris is impacting the productivity of the well, it may be necessary to run a dedicated lower completion with sand control screens in affected wells.

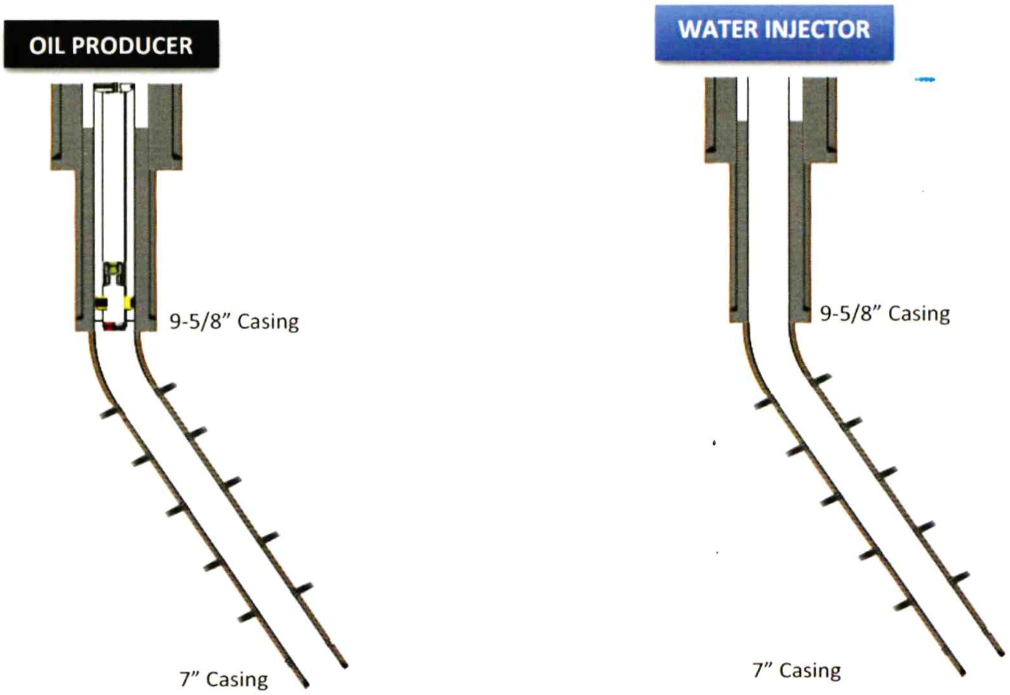


Figure 18-8: Producer and Injector Completion Schematics

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○ Water Injectors

The injectors are planned to be wells with 7" casing monobore (Figure 18-8). If the requirement for zonal flow control is subsequently considered critical in specific wells, options will be evaluated to install a 4-1/2" selective completion in a number of injection wells. There will be no tubing installed in initial injection well completions and injection will be fully commingled.

The production casing and completion material will be 13-chrome steel as identified in the Corrosion and Metallurgy study.

The implementation of an inverted five-spot pattern means that water injection rates are such that water rates required to balance reservoir voidage should be maintained under matrix conditions. The injection wells will be designed with sufficient pressure rating to accept water injection under both matrix and fracturing conditions. Injection under fracturing conditions is to be avoided – prior to initiating a fracture in an injection well, extreme care will be required to ensure fractures do not propagate beyond the targeted hydrocarbon pool.

○ Gas Injectors / Producers

The South Lokichar Basin development will use solution gas from the developed oil reservoirs for power generation in both the Phase 1 EPFs and the Phase 2 Central Processing Facility. For Phase 1 gas is planned to be used for power generation as part of the EPF systems to provide the maximum amount of electrical power possible. There is expected to be minimal flaring.

As the system becomes gas deficient the option exists to develop gas resources discovered in the Ngamia field in the Z0 / Z1 reservoirs. These gas caps will be blown down to provide an extended period of self-sufficient power generation at the CPF.

If required, these wells will be completed with a 4½" completion string and the capability to carry a memory pressure gauge in a suitable nipple profile close to the tubing wireline entry guide. The gas injectors will be completed across a single gas-bearing reservoir interval.

• ROUTINE MONITORING

Field data monitoring, providing the raw inputs required to maintain the static and dynamic models and inform business decision making will be key to optimising the South Lokichar basin fields. Selected key data required through routine monitoring are discussed below. *Table 18-3* contains a full review of the data gathering options available and the planned frequency of acquisition.

○ Wellhead Pressure and Temperature

All production and injection wellheads will be equipment with pressure and temperature sensors upstream of the production choke. The sensors will be connected to the CPF data acquisition system for remote offsite monitoring. Data will be logged with a minimum of one-minute sample interval.

○ Wellstream Sampling

A dedicated sample point will be present on each well's production flowline to allow fluid sampling to collect wellhead oil samples, monitor any tracer products or flowback of wellbore chemicals and to routinely measure BS&W over the life of well.

○ Pressure Data

All ESP completions will be run with pump monitoring equipment, including high resolution pressure and temperature gauges on the inlet and discharge side of the pump. The inlet gauge, set below the pump, will provide good quality pressure data suitable for reservoir monitoring, subject to the caveat that the pressure will be reported as an average of all open intervals.

Memory pressure gauges can be run in water injection wells to provide an instantaneous shut-in pressure or can be run for a longer period on a suitable gauge hanger in the 7" casing for longer term monitoring.

Integrating pressure data from injectors and producers within the dynamic reservoir models will be an important element for monitoring the efficacy of the pressure maintenance program.

○ Production Well Testing and Allocation

The asset operator's existing hydrocarbon allocation system will be implemented and adapted for the South Lokichar development.

Production wells will be tested at a minimum of once per month via a dedicated test manifold on each well pad using a mobile multiphase flow meter. Bulk fluids will be metered directly at each pad. A dedicated production allocation system will be used to allocate daily averaged production to the well level. There will be no allocation to zonal level within a single wellbore.

In the event of jet pumps being used for lift, drive fluid will be continuously metered to allow the drive fluid to be distinguished from formation water from the well. Care will need to be exercised in the allocation process to determine true well water cut when formation water production is low, and significantly less than drive fluid rates.

○ Water Injection Well Metering

All water injection wells will have continuous, online single-phase metering and a pad level meter. Injection rates will be reconciled monthly at the well and pad level. The proposed allocation system will not be used to allocate production to the reservoir subzone.

Production Logging

Production logs (PLTs) are routinely run in production wells to identify the inflow proportions of different zones in the well, and their water cut or gas-oil ratio. These provide key reservoir management data to direct well stimulation activities, highlight potential zonal isolations to manage injection thief zones or bypassed intervals and to optimize well injection and /production performance. Due to the nature of the production completions and the requirement for artificial lift in all producers from first production, the ability to run production logs (PLTs) is limited. ESPs may be run with a logging bypass or Y-tool, but this frequently limits ESP size, which can have a negative impact on ESP lift capacity and installed run life and is not generally recommended.

PLTs may be run in specific production wells in special circumstances at the time of a workover. After the old completion and pump or jet pump orifice has been pulled, a temporary gas-lifted production completion string will be run. Using nitrogen lift, the well will be temporarily returned to production while a suite of logging passes is acquired. Quick-look analysis of the PLT results will permit decisions to be made on zonal isolations and the well recompletion strategy before the permanent completion is re-run into the wellbore.

Production logging will be conducted routinely in water injection to characterise injection profiles. The single-phase nature of the log makes interpretation relative straightforward, provided that an appropriately sized spinner is run on the PLT string.

Interwell Tracers

Interwell tracers can be deployed to clarify communication pathways between producers that may be impacted by compartmentalization caused by structural faulting or stratigraphic/channel features. Data gathered during the exploration and appraisal testing program has highlighted that minor fault throws that are not visible on seismic can impact communication between wells.

In deployment, a specific tracer batch is injected over a short period of several hours into one water injection well. This tracer plume will be observed through periodic wellhead samples collected at offset production wells, confirming which wells are in communication but also providing a quantitative measure of the degree of connectivity. A dedicated tracer is required for each injection well and forty different tracers' formulations are currently available.

It is currently envisaged that an initial trial would be conducted in Amosing and Ngamia as part of Phase 1. In each field, injection tracers would be added to the water stream at the wellhead in the six wells at one of the pads, with twelve interwell tracers circulating in the Auwerwer reservoirs. Monitoring samples would be taken periodically in wells in the two fields. Breakthrough times and a qualitative assessment of the degree of connectivity will be used to condition the static and dynamic reservoir models.

Figure 18-9 shows a published field example[4] where injection water tracers are observed at offset producers, providing information on communication paths within the reservoir.

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[4] SPE 173760 Sanni et al; SPE Symposium of Oilfield Chemistry, TX. 2015

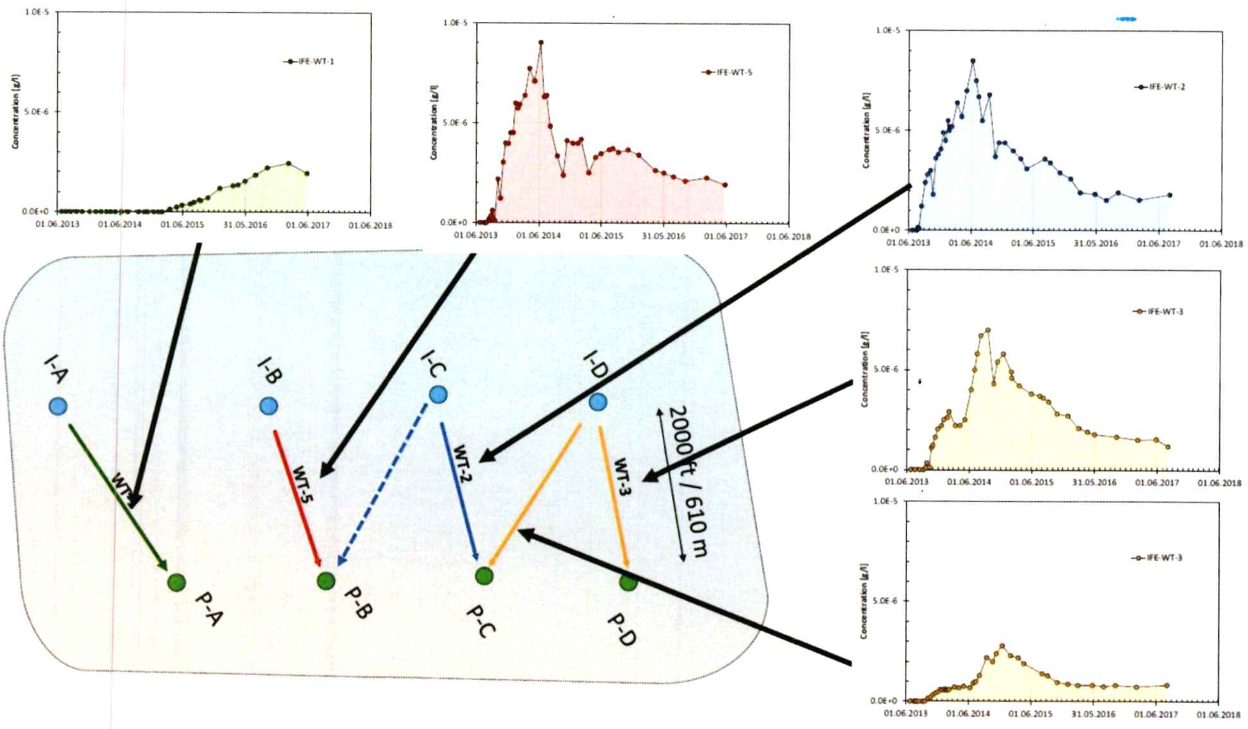

Figure 18-9: Reservoir Connectivity Determined Using Interwell Tracers

- ### Saturation Logs

Saturation logging can be used to provide information through casing on in-situ reservoir conditions. In the low salinity environment of the South Lokichar Basin, carbon-oxygen ratio measurements through inelastic neutron scattering provide the best tool to measure oil saturation. Carbon-oxygen tools can be used to measure relative concentrations of carbon and oxygen in the formation and hence calculate oil and water saturation. Thermal Decay Time logs are not effective where formation water salinities are below 35,000 mg/L.

As with PLTs, deploying a saturation log on wireline is not possible in the production wells without conducting a workover to allow access to the reservoir section. Saturation logs can, however, be run without issue in the injection wells as a method to measure residual oil saturation in injection intervals.

The pre-development reservoir simulation models include parameters for initial oil saturation, based on the saturation height function, selected relative permeability curves and residual oil saturation. There is material uncertainty on these data that is reflected in the uncertainty on resource volumes. As the development matures and water breakthrough occurs after initial oil production, the quality of the model history matches will govern when it is appropriate to update estimates of initial and residual oil saturation. The frequency and number of these measurements should be determined by the asset management team.

- ### Single Well Chemical Tracer Testing

Understanding residual oil saturation in the Auwerwer and Lokone reservoirs is an important input to the reservoir simulation models. This can be measured on core plugs in the laboratory in special core analysis (SCAL) experiments but also measured in the field. The key value of knowing the residual oil saturation to waterflood (Sorw) is that it determines the volume of mobile oil that is available for production in the reservoir, defined as the difference between initial oil saturation and residual.

A single well chemical tracer test (SWCT) is a proven way to measure in-situ water saturation following a water flood. It has previously been implemented successfully in Amosing-2A to determine residual oil saturation. SWCTs can be run in water injection wells where the perforated interval sits above the transition zone within a hydrocarbon pool. After injecting water into an interval over several days, to establish a near wellbore residual oil condition, a partitioning tracer is injected into the formation and displaced away from the wellbore by a following water slug. During a shut-in period of several days, the partitioning tracer hydrolyzes to produce a non-partitioning product tracer. Upon flowback, the non-partitioning product tracer returns to the wellbore faster than the partitioning tracer, reflecting the residual oil condition in the reservoir.

○ Well Integrity Monitoring

Routine tubing and annular pressure data acquired during production monitoring will be used to provide early identification of well integrity issues. Selective use of multi-finger calipers and wall thickness tools will be used to monitor corrosion and tubing thickness erosion and wear to build an integrity monitoring database that can be used to manage and predict potential issues within the basins injection and production wells. This is especially important in wells completed with rod driven pumps and the potential for rod wear.

Table 18-3: South Lokichar Basin Critical Well and Reservoir Management Plan Data and Uncertainties

Category	Regulatory Requirement?	Data Required	Uncertainty / Risk / Opportunity																									Comments / Asset / Frequency															Business Plan Activities			
			Areal Conformance, Sweep	Well drainage area & Recovery	Reservoir	Residual oil saturation	Vertical Conformance	Artificial lift design	Pump Performance,	Well production optimisation	Aquifer behaviour/strength	Producer under-performance	Gas injection capability	Sweep efficiency	Hydrocarbon allocation	Oil and water production	Water injection allocation	PVT and potential for PVT	Optimise Well Production	Hydrocarbon pool definition	Permeability	Reservoir containment, seal	Scaling Tendency	Water injection capability	Well productivity	Well integrity	Sand production and erosion		Every E&A well	Every Producer	Every Injector	Selected producers	Selected injectors	Continuous	One-Off	Daily	Weekly	Monthly	Quarterly	Semi-annually	Yearly	Ad Hoc, Low Frequency	Phase 1	Phase 2- Year 1	Phase 2- Year 2	Phase 2- Year 3
Drilling	X	mudlogging - mud gas																		X								All wells during drilling	X	X	X				X								x	x	x	x
Drilling	X	mudlogging - cuttings description																		X								All wells during drilling	X	X	X				X								x	x	x	x
Fluid Analyses		Zonal fluid samples			X													X		X								Fluid samples on as-needed basis, zone-specific wireline samples to improve vertical resolution of fluid models	X																x	x
Fluid Analyses		inflow tracers	X				X					X																Identified as best opportunity to monitor inflow performance and identify water cut development. To be deployed in initial Amosing and Ngamia production wells multiple wells on initial pads				X	X				X	X					x	x		
Fluid Analyses		interwell tracers	X	X	X																			X				Batch injection in selected Amosing and Ngamia injection wells				X	X		X								x			
Fluid Analyses		single well chemical tracer test				X						X		X														Opportunity exists to measure residual oil saturation in selected wells. Would need to be done with only a single injection zone open, following a				X	X		X									x	x	x
Fluid Analyses		geochemical sampling			X													X										Potential use to provide additional information on zonal production				X										X		x	x	x
Fluid Analyses		wellhead BS&W						X		X		X			X	X			X				X		X	X	X	Routine bulk sediment and water measurements - every well test		X								X					x	x	x	x
Fluid Analyses		water sample (anion/cation) analysis		X	X													X					X					Ad hoc well stream sampling. Unlikely to be used for any reservoir engineering purposes				X										X			x	x
Fluid Analyses		produced gas composition																								X		Ad hoc well stream sampling. Unlikely to be used for any reservoir engineering purposes				X										X		x	x	x
Integrity	X	Corrosion/caliper logging																								X		Corrosion logs to monitor well integrity and tubing condition. Propose to monitor selected wells and increase monitoring population in event				X									X				x	x
Integrity	X	CBl/VDL/CET					X					X														X		Cement bond evaluation run after casing has been run. Critical to select perforation intervals, especially producers, to limit risk of unwanted	X	X	X				X								x	x	x	x
Integrity		casing pressure test																								X		Casing integrity test. Annual test?		X	X												x	x	x	x
Petrophysical	X	LWD open hole log data			X		X	X			X	X	X							X	X	X		X	X			Complete set of formation evaluation data on every well. Necessary to build and update static reservoir models.	X	X													x	x	x	x
Petrophysical		injector PLT	X				X						X				X				X			X				PLTs in injector wells to assess distribution of injection water in commingled wells. Can be used to determine stimulation candidate zones.				X	X												x	x
Petrophysical		injector corrosion logs																								X		Corrosion logs to monitor well integrity, especially important without tubing. Propose to monitor selected wells and increase monitoring				X	X								X					x
Petrophysical		producer PLT	X				X					X							X	X	X					X		Can only be run during workover with temporary gas-lifted string				X										X			x	x
Petrophysical		saturation (C/O) log					X					X							X	X		X						Opportunistic saturation measurement in producers or to confirm residual oil saturation in injectors.				X	X									X	x		x	
Petrophysical		Spectral noise logging					X			X		X												X		X		Valuable slickline tool to assess cement / casing integrity and identify zones with injection behind casing. Can only be run in producers with				X	X								X				x	x
Petrophysical		side wall cores																			X							Sidewall cores to determine rock type, reservoir quality and properties.	X						X									x	x	x
Petrophysical		SCAL		X			X							X														Lack of good quality RESCAl data remains. Will additional core acquisition and lab work be required to reduce uncertainty in this area?				X	X									X			x	x
Petrophysical		full bore core											X	X							X	X			X			If required, most likely in exploration wells, to help define reservoir quality. Potentially also to improve representative nature of core database				X	X									X				
Petrophysical		high precision thermometer log					X																			X		Likely run as supplement to spectral noise logging (SNL). High precision thermometer is useful to identify inflow intervals or flow behind casing				X	X									X			x	x
Petrophysical		observation well saturation	X	X	X									X														Delay production of a development well to provide a logging opportunity for C/O saturation logs				X	X									X			x	x
Pressure		Formation pressure data		X	X		X				X	X	X							X	X			X				Assessed as critical to determine hydrocarbon pools for each pad location. Expect to log in first ten wells on each pad. Frequency of logging will				X	X										x	x	x	x
Pressure		producer memory gauge downhole pressure (flowing/shut-in)		X	X			X	X	X	X								X			X			X			Could be set below jet pump orifice on producer tail pipe; to be retrieved when orifice valve is changed out				X									X				x	x
Pressure		injector downhole pressure (flowing/shut-in)	X	X	X						X		X									X		X		X		Bottom hole pressure can be estimated from surface pressures and wellbore models. Can run occasional memory gauges for calibration					X									X		x	x	x
Pressure		ESP multisensor (P, T, I)		X	X			X	X	X	X	X							X						X			Pressure/temperature/current/vibration sensor to be run on all ESPs for pump optimisation and reservoir monitoring				X		X									x	x	x	x
Pressure		flowing bhp - annulus level measurement		X	X			X	X	X	X	X							X						X			Pressure estimate on PCP wells with open annulus. Can provide data on flowing and shut-in pressures. Run annulus surveys during well tests.				X						X								x
Pressure		observation well pressure		X	X						X			X														Use development wells after production has begun to measure formation pressures.				X	X									X	x	x	x	x
Process Measurement		Tubing head pressure, temperature						X	X			X														X		Routine surface pressure and temperature measurements	X	X	X			X									x	x	x	x
Process Measurement		annulus pressure monitoring/casing head pressure																								X		Routine surface pressure and temperature measurements	X	X	X			X									x	x	x	x
Process Measurement		Distributed temperature sensor					X																					Possible use of DTS in producers to monitor well temperature profile under flowing				X		X								X				x
Process Measurement		Flowline inlet pressures						X		X																		Will be measured to help manage flowline performance and flow assurance.						X										x	x	x
Process Measurement		oil export rates								X																		Continuous measurement at CPF.						X									x	x	x	x
Process Measurement		Make-up water temperature																										Continuous measurement at CPF.						X									x	x	x	x
Process Measurement		injection water temperature																				X		X				Continuous measurement of wellhead injection temperature and water injection stream temperature at CPF.						X									x	x	x	x
Process Measurement		Separator pressure, temperature																										Will be part of CPF monitoring						X									x	x	x	x
Process Measurement		Water injector pressure																				X		X		X		Continuous measurement at wellhead and at CPF.			X			X									x	x	x	x
Process Measurement		Gas injector pressure											X															Continuous measurement at wellhead and at CPF.					X	X												x
Production rates	X	Make-up water rate measurement													X	X			X						X			Measurement of make-up water rate into CPF, single phase meter. May be critical for water charges.						X									x	x	x	x
Production rates		water injection metering																						X				Essential rate measurement			X			X									x	x	x	x
Rate Measurement	X	routine well testing (MPFM)						X	X	X	X	X			X	X			X		X				X			Minimum of monthly well testing using MPFM located at test manifold on each pad. Development will require multiple MPFMs deployed in the	X	X								X					x	x	x	x
Rate Measurement	X	water injection metering															X				X			X				Single phase on-line meter for each injection well.			X			X									x	x	x	x
Rate Measurement	X	oil, water, gas rates						X	X	X	X	X			X	X			X		X				X			Via allocation system based on periodic MPFM tests.	X	X	X							X					x	x	x	x
Rate Measurement	X	jet pump drive fluid rate						X	X	X		X			X	X			X									Single phase on-line required meter for each jet pumped well.				X		X										x	x	x
Rate Measurement		GOR													X													Measured during routine well testing, will be valuable indicator of any wells producing below saturation pressure			X							X					x	x	x	x
Rate Measurement		Water cut									X	X		X		X			X						X			Critical measure under waterflood. Will provide indication of water breakthrough (on a total well level)			X							X					x	x	x	x
Rate Measurement		gas injection rate																										Continuous measurement of gas rate for each gas injector.					X	X											x	x
Rock Mechanics		mini frac test																				X		X		X		In water injectors to test to determine matrix-injection conditions.				X										X		x	x	x
Rock Mechanics		core strength measurements																				X					X	Additional core measurements, as required, to assess core strength for fracking properties in Lokone. Also potentially to update sanding risk in				X	X									X			x	x
Seismic		VSP			X																							Ad hoc VSPs to improve time-depth calibration, possible use of offset source geometries to image faults and alluvial fan occurrence.				X	X		X							X				
Process Measurement		inline sand monitors																									X	Monitor sand production to detect early indications.															x	x	x	x
Wireline		slickline HUD										X															X	Will be needed for each well prior to running completion and perforating well. Will be measured during each well intervention to determine changes associated with wellbore fill		X	X											X	x	x	x	x

- RESERVOIR MANAGEMENT OPERATIONS REVIEWS

Periodic and systematic reviews of asset performance, once the fields have been brought into production, should be practiced (Table 18-4). It may be necessary to break out into separate asset groups (e.g. Amosing, Ngamia etc.) to ensure sufficient focus on specific field issues for higher frequency meetings (i.e. weekly) but overall basin reviews will also be necessary to ensure best practice and learnings can be shared between asset teams. Multidisciplinary reviews will be required with the following frequency and topics. Retaining engagement across all technical disciplines is essential to maximise value from asset reviews.

These reviews should primarily be conducted as in-house exercises, however the addition of external subject matter experts who are not involved in the routine field operations may be included as valuable advisors to the asset teams.

Daily Production Review

- Small, focused group to review daily production highlights and lowlights.
- identify significant changes of well characteristics, identified through well testing, WHFP/WHFT, pump parameters.
- Highlight and discuss changes in well production behaviour, with an emphasis on artificial lift performance.
- Highlight upcoming well drilling, completion, and intervention work.
- Identify well integrity issues and direct further investigation.

Monthly Asset Performance Review

- Roll up key issues identified during Daily Production Reviews.
- Review upcoming well completion, recompletion, and other well interventions.
- Assess monthly production performance against plan by reservoir.
- Significant deviations from forecast at a well level (injector or producer) should trigger an investigation. The investigation objective should be to determine the cause of variance from plan and, if appropriate, identify the appropriate remedial operation to restore production or injection performance.

Annual Field Performance Review

- The Annual Field Performance Review should include specific attention to well, reservoir and facility performance.
- The Annual Field Performance Review should investigate the asset performance against plan.
- A detailed review of the behaviour of each producing and injecting well will be required, including the outcome of any well interventions during the period, such as workovers, production logs, well stimulations and pressure gauges.
- Development of the static and dynamic models should be reviewed with a focus on the validity of the dynamic models in the context of observed well behaviour.
- Material deviations in the asset from forecasted reservoir behaviour should trigger an update to the field depletion or development plan that reflects the new information available.
- The impact on facility performance including well and facility uptime, production and injection capacity, system operating pressures etc. should be considered in the review.
- Additional data requirements and work programs should be identified during the annual review, specifically if there are ambiguities or uncertainties in the data presently available to the reservoir management team. The cost to acquire and the expected reliability and value of additional data should be described, and a recommendation made to management.

Table 18-4: WRMP Meeting Frequency

Event	Daily	Monthly	Quarterly	Annually
Daily Performance Review	X			
Reservoir Management Team Monthly Planning Meeting		X		
Production System Optimization			X	
Injection System Optimization			X	
Annual Well Review				X
Annual Reservoir Review				X
Annual Facility Review				X
Annual Field Performance Review				X

WELL STIMULATION OPPORTUNITIES

One of the deliverables of the periodic asset reviews will be to identify changes in the injectivity or the performance of water injection wells. Sustaining injection rates is critical to balancing voidage in the reservoirs, maintaining reservoir pressure and meeting production forecasts. During the 2019 Ngamia water injection pilot, significant progress was made to identify and develop a range of key stimulation chemicals to sustain and recover well injectivity over an extended period. This learning will be captured in a separate document describing the water injection well completion and well stimulation plan. Continuous water injection rate and wellhead injection pressure measurement will be used to monitor well injectivity index. Well lift curve models will be maintained to allow accurate estimates of bottom hole pressures to be made. Periodic direct measurements in injection wells with pressure gauges will allow well models to be calibrated.

DEPLETION PLAN UPDATES

With time, cumulative production and the array of new data that will be gathered, organized, and interpreted by the reservoir management team, opportunities should be identified to update the reservoir depletion plans for the reservoirs under development and for those which are yet to be developed.

These changes should focus on improving the value proposition to the Kenyan government and GEBV. Areas of focus should include changes to development well spacing as the understanding of reservoir compartmentalization risk may change; completion and artificial lift implementation; modification to the well perforation strategy; opportunities to enhance well productivity and injectivity through well stimulation; and modifications to data acquisition opportunities to improve reservoir model calibration.

Updates to the field development plan may include justifications to optimise field and facility production rates and should be justified and supported based on acquired data and updated reservoir modelling.

19 APPENDIX F – LOCAL CONTENT PLAN

2025

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LOCAL CONTENT PLAN

SOUTH LOKICHAR FIELD DEVELOPMENT

TABLE OF CONTENTS

- ACRONYMS/ABBREVIATONS

Energy and Petroleum Regulatory Authority	**- EPRA**
Gulf Energy E&P BV	**- GEBV**
Internal Container Depot	**- ICD**
Invitation To Tender	**- ITT**
Kenya Association of Manufacturers	**- KAM**
Kenya National Chamber of Commerce and Industry	**- KNCCI**
Kenya Private Sector Alliance	**- KEPSA**
Kenya Petroleum Refineries Ltd	**- KPRL**
Local Content Plan	**- LCP**
Ministry of Energy and Petroleum	**- MOEP**
Monitoring, Evaluation, and Reporting	**- MER**
On-The-Job	**- OTJ**
Oil Country Tubular Goods	**- OCTG**
Society of Petroleum Engineers	**- SPE**
Small and Medium Sized Enterprises	**- SMEs**

- DEFINITIONS

Kenyan National	Means a Citizen of Kenya.
Local Content	Means the added value brought to the Kenyan economy through systematic development of national capacity and capabilities and investment in developing and procuring locally available work force, services and supplies, for the sharing of accruing benefits.[5]
	Local Content is referred at two levels: county and national level. Local Content refers to the whole of Kenya, whilst County Content refers to Turkana.
Local	Means a National who is from the community living near to or within reasonable or comparative proximity to COMPANY's area of operation as to be impacted by the operations; or a business wholly owned by Nationals who are from the communities which business operates near to or within reasonable or comparative proximity to COMPANY's area of operation.
National	Means a Kenyan citizen from COMPANY's area of operation and/or business operating and/or registered in the County of operation; and
	Means a business registered in Kenya with >51% Kenyan ownership or a Joint Venture with a Kenyan company and effect transfer of skills and technology; and
	Means the commitment to recruit Kenyan Nationals and train and develop them to international standards; and
	Means the commitment to procure goods and services locally and/or nationally in Kenya and/or to develop local and/or national Kenyan businesses to be able to deliver goods and services to the required standard.
County	Means Turkana County as established under the First Schedule of the Constitution of Kenya, 2010.
County Content	Means the use of locally available goods, services, labour, and financing in Turkana County to promote economic growth and social development of Turkana County and encourage local investments, ownership and participation.
County Government	County Government of Turkana provided for under Article 176 of the Constitution.
Local Community	a people living in a sub-county within which a petroleum resource under the Petroleum Act is situated and are affected by the exploitation of that petroleum resource. Means communities living within Turkana County.
Project	South Lokichar Field Development
Local Enterprise	means a business, firm or entity operating within Turkana County, whether as a supplier, contractor, consulting firm, subcontractor or otherwise, whose business enterprise is incorporated under the Laws of Kenya and whose principal place of business is in Turkana County and whose shareholding is held in majority by local persons in the Turkana County.

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[5] Adopted from the Petroleum Act, 2019

EXECUTIVE SUMMARY

Gulf Energy E&P BV (GEBV), a Kenyan-owned and operated company, is committed to delivering petroleum development in a manner that maximizes value for the Kenyan economy and its people. In line with the requirements of the **Petroleum Act, 2019**, this Local Content Plan (LCP) has been prepared for submission alongside the Field Development Plan (FDP) for the South Lokichar Field Development.

This LCP sets out the **principles, framework, and implementation mechanisms** that will guide the integration of local content throughout the life cycle of the Project. It outlines GEBV's approach to creating opportunities for Kenyan participation while ensuring alignment with national legislation, draft Local Content Regulations (2025), and international industry standards.

GEBV's Local Content philosophy is built on four strategic pillars:

1. **Employment of Kenyans** – Prioritizing recruitment from host communities, Turkana County, and across Kenya, with transparent processes that promote fairness, diversity, and skills progression.
2. **Procurement of Goods and Services** – Optimizing supply chain opportunities for Kenyan businesses, with a focus on capacity, competitiveness, and quality standards.
3. **Capacity Building** – Investing in workforce training, supplier development, and institutional partnerships to enhance long-term national capabilities.
4. **Stakeholder Engagement** – Sustaining open dialogue with communities, government, regulators, and industry partners to maintain a social license to operate.

The Project is expected to commence **Phase 1 production in December 2026**, with an initial output of 20,000 barrels per day, scaling to 50,000 barrels per day in subsequent phases. This development presents a transformative opportunity for Kenya's economy, with potential benefits including:

- Direct and indirect job creation estimated to total **2,000,**
- Growth of local enterprises across priority and transformational sectors,
- Knowledge and technology transfer, and
- Strengthened community and government partnerships.

To ensure delivery, GEBV has embedded local content obligations within its **contracting and procurement strategy**, requiring contractors and subcontractors to submit and implement local content plans. Performance will be tracked through quarterly reviews and reported to the Energy and Petroleum Regulatory Authority (EPRA) across five key dimensions: employment, training, local sourcing, supplier development, and technology transfer.

This Local Content Plan reflects GEBV's long-term commitment as a Kenyan operator to ensure that petroleum development becomes a catalyst for inclusive and sustainable growth. By aligning economic opportunity with community development and national priorities, GEBV seeks to establish a lasting legacy that benefits present and future generations.

GEBV will adopt a stratification approach to further identify opportunities within the Local Content considerations for participation of women, youth and people living with disabilities to the extent that it will be feasible.

1. INTRODUCTION

The **Petroleum Act, 2019** requires submission of a Local Content Plan (LCP) prior to the commencement of petroleum operations. In compliance with this requirement, **Gulf Energy E&P BV (GEBV)** has prepared the present LCP for submission alongside the Field Development Plan (FDP) for the South Lokichar Field Development.

This document defines the guiding principles, strategic framework, and implementation mechanisms for local content across both **Phase 1 project delivery** and subsequent development phases. It outlines GEBV's strategy to ensure that Kenyan participation and benefits are embedded as a central component of project execution.

Beyond the initial development phase, the LCP provides a **comprehensive long-term framework** that will guide the integration of local content throughout the life cycle of the Project. The momentum gained in Phase 1 will establish sustainable practices to ensure that employment, enterprise participation, and capacity building remain integral to future operations.

The oil and gas sector represents a transformative opportunity for Kenya's economy. As a **Kenyan company**, GEBV is committed to advancing local content through four strategic pillars:

- **Employment of Kenyans**
- **Procurement of goods and services from Kenyan businesses**
- **Capacity building of individuals and businesses**
- **Stakeholder engagement**

By applying a sustainable and incremental approach, GEBV seeks to maximize opportunities for Kenyans, foster long-term capacity development, and align with both national aspirations and international industry standards.

The Petroleum Act, 2019 defines Local Content as "***the added value brought to the Kenyan economy through systematic development of national capacity and capabilities and investment in developing and procuring locally available work force, services and supplies, for the sharing of accruing benefits***". The end-to-end operations portend significant local content opportunities which will be made available to Kenyans and Kenyan businesses where capacity, quality, competitive costs and timeliness in delivery are optimal.

Local content requirements will be carried out throughout the supply chain, thereby ensuring that contractors' commitments are tracked during the service delivery period. The opportunities will be considered firstly for the communities in close proximity to the Project, and then to the rest of the country. Capacity Building is key to unlocking local content in the country. GEBV undertakes to invest in the development of Kenyans and Kenyan businesses. The training will focus on upskilling Kenyans in areas that are not readily available, as well as the workforce that will be engaged. Training areas that underpin successful operations such as Health, Safety and Environment (HSE) will be offered for all employees. A sustainable approach will be applied when identifying the areas of training to consistently ensure that expectations are managed.

The Project is committed to training its workforce and will cascade the same commitment to its Supply Chain. GEBV continues to make contributions towards the Training Fund to the MOEP as prescribed in the respective Block 10BB(**T6**) and Block 13T(**T7**) PSCs, with the assumption that the funds are being used for Kenyans that are not a part of the Project workforce, a responsibility that resides with Government.

Local content is beneficial to many parties when implemented in a strategic manner. It can enable the social license to operate by community members, promote goodwill by Government, catalyse growth in the macro and micro economy while driving success in the Project.

2. PROJECT OVERVIEW

On July 21, 2025, Tullow Overseas Holding BV, a wholly owned subsidiary of Tullow Oil plc (Tullow) and Auron Energy E&P Limited, an affiliate of Gulf Energy Limited (GEL), signed a sale and purchase agreement, between Tullow and Auron Energy Limited, an affiliate of GEL. Upon completion, Tullow Kenya B.V. (TKBV)will be rebranded as Gulf Energy BV (GEBV). GEBV aims to submit a revised Field Development Plan (FDP) by September 30, 2025. The Local Content Plan is a crucial document for South Lokichar Field Development as it provides key information on how Local Content will be considered throughout the life of the Project.

The Petroleum Act, 2019 requires that during the submission of a **Field Development Plan (FDP)**, a long-term Local Content Plan is also submitted covering a **5-year period**. The Field Development Concept indicates that production in Phase 1 will start with Ngamia and Amosing fields by December 1, 2026, with an initial output of **20,000 barrels per day** over the first five years. Thereafter there will be gradual increase of production which will reach an eventual **50,000 barrels per day**.

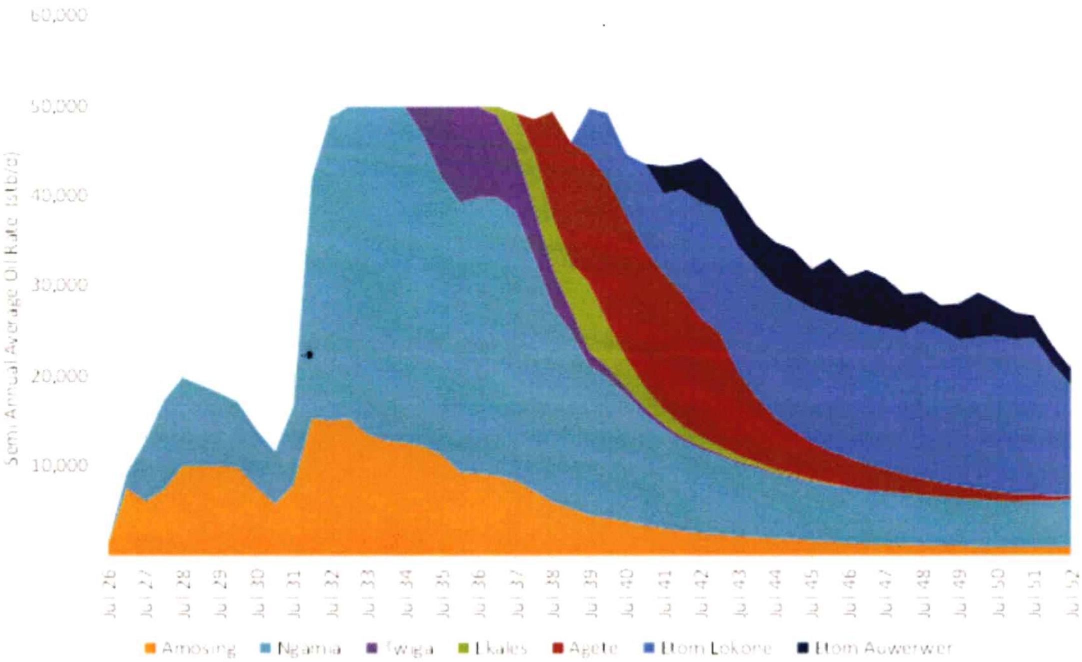
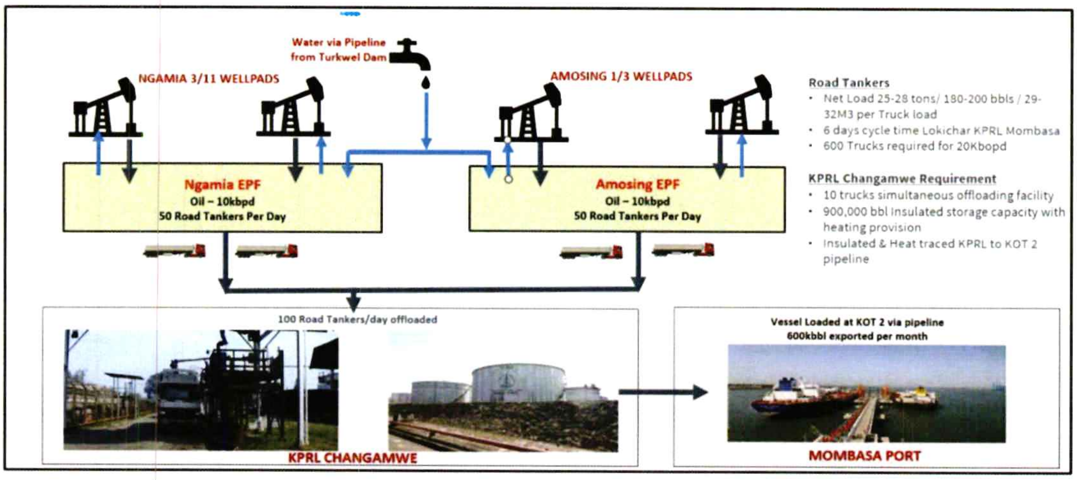


Illustration of South Lokichar Oil Project Production

Phase 1 will utilize existing upstream facilities, including well pads, supplemented by the drilling of an additional **43 wells**. For midstream operations, the initial 20,000 barrels per day will be transported by road using insulated crude oil tankers from Lokichar to KPRL Changamwe. Each tanker will carry 25–32 tons, operating on a six-day cycle. Approximately **600 trucks** will be required daily to meet Phase 1 production volumes.

Initial 20Kbopd



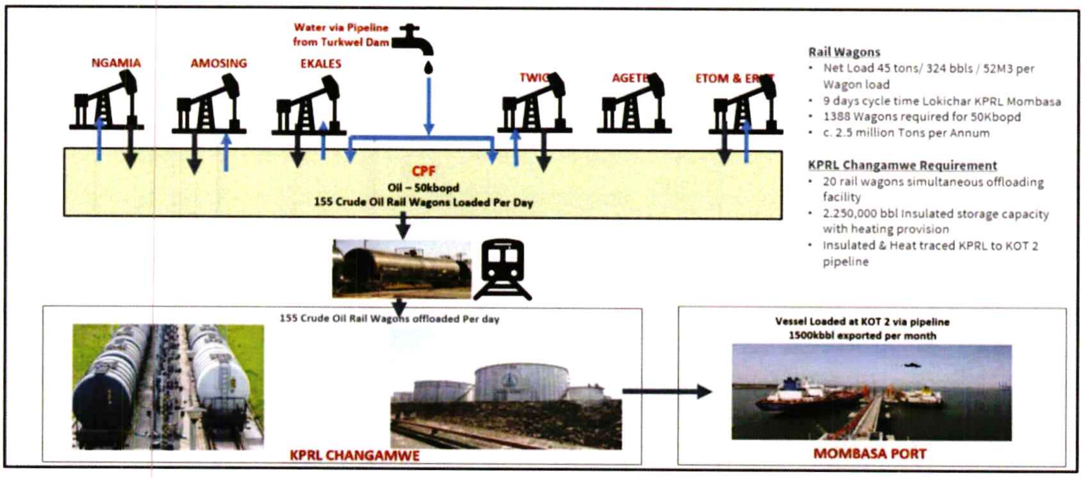
Road Tankers
- Net Load 25-28 tons/ 180-200 bbls / 29-32M3 per Truck load
- 6 days cycle time Lokichar KPRL Mombasa
- 600 Trucks required for 20Kbopd

KPRL Changamwe Requirement
- 10 trucks simultaneous offloading facility
- 900,000 bbl Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Illustration of midstream in phase 1

Phase 1 runs for a period of 5 years following which the Phase 2 rump up described below kicks in. The railway line will be extended to Lokichar.

Ramp Up 50Kbopd Jan 2031 Onwards



Rail Wagons
- Net Load 45 tons/ 324 bbls / 52M3 per Wagon load
- 9 days cycle time Lokichar KPRL Mombasa
- 1388 Wagons required for 50Kbopd
- c. 2.5 million Tons per Annum

KPRL Changamwe Requirement
- 20 rail wagons simultaneous offloading facility
- 2.250,000 bbl Insulated storage capacity with heating provision
- Insulated & Heat traced KPRL to KOT 2 pipeline

Illustration of midstream in phase 2

In **Phase 2**, crude oil will be transported by rail wagons from Lokichar to KPRL Changamwe. Local content trucking and associated support opportunities in this phase will be limited, primarily within workforce roles related to loading and offloading processes.

3. LEGAL AND REGULATORY FRAMEWORK

The Local Content Plan (LCP) is anchored in Kenya's evolving petroleum sector legal and regulatory environment. While the framework is still under development, the following instruments provide the primary basis for local content implementation in the South Lokichar Field Development:

3.1 Petroleum Act, 2019

The Act requires operators to comply with local content provisions in all petroleum operations. It emphasizes:

- **Prioritization of locally manufactured goods and services** where standards are acceptable,
- **Employment of qualified Kenyans** across all levels of the value chain, and

- Recognition that the cost of local content shall reflect **prevailing market rates**.

3.2 Production Sharing Contract

The Production Sharing Contract (PSC) embeds specific local content obligations to ensure that petroleum development contributes meaningfully to Kenya's economy and workforce. These provisions are designed to prioritize Kenyan participation while maintaining efficiency and competitiveness in project delivery.

Key requirements include:

- **Preference for Kenyan Materials and Supplies** – Contractors must give preference to Kenyan goods and supplies where prices, quality, quantities, and delivery timelines are comparable.
- **Establishment of Project Offices in Kenya** – Contractors are required, where practicable, to set up project offices in Kenya to facilitate participation.
- **Training Fund Contributions** – Contractors must contribute stipulated amounts to the Ministry of Energy training fund at each project phase to support national skills development.

3.3 The Turkana County Local Content Act, 2024

At the County level, local content efforts are guided by the following objectives:

- **Promotion of Local Goods and Services** – Encourage and enforce the use of locally available goods, services, and manufactured products within the County.
- **Maximization of Value Addition** – Enhance value creation by leveraging local expertise, goods, services, and financing. This approach supports human resource capacity building and generates employment opportunities across the value chain.
- **Strategic Framework Development** – Establish a structured framework for identifying, planning, and implementing local content development initiatives within the County.
- **Stakeholder Engagement and Coordination** – Foster effective collaboration and coordination among stakeholders to ensure the successful realization of local content strategies.

3.3 Draft Petroleum (Local Content) Regulations, 2025

The Draft Regulations, once enacted, will provide operational detail for local content implementation across upstream, midstream, and downstream activities. Key features include:

- Progressive **minimum local content thresholds** for employment, goods, works, and services,
- Definitions of local content and local participation, and
- Reporting and monitoring obligations for operators and contractors.

In summary, GEBV acknowledges that the regulatory framework may continue to evolve during the execution of the Project and commits to complying with all applicable laws and regulations to the extent possible.

4. LOCAL CONTENT STRATEGY & PRINCIPLES

As a Kenyan company, GEBV is well placed to deliver local content and is committed to embedding local participation across all stages of the South Lokichar Field Development. The LCP provides the structured approach for achieving this objective, balancing local benefits with project efficiency, safety, and cost considerations.

4.1 Strategic Commitments

GEBV's Local Content Strategy is anchored on the following commitments:

- **Sustainable Benefits** – Local content initiatives will be designed to create a lasting legacy through skills development, enterprise growth, and knowledge transfer.

- **Life-Cycle Approach** – Opportunities will be identified and implemented progressively across all phases of the Project.
- **Balanced Delivery** – Success requires alignment between cost, schedule, quality, and local participation.
- **Shared Responsibility** – Contractors and subcontractors will be required to adopt and deliver the Project's local content principles.

4.2 Local Content Drivers

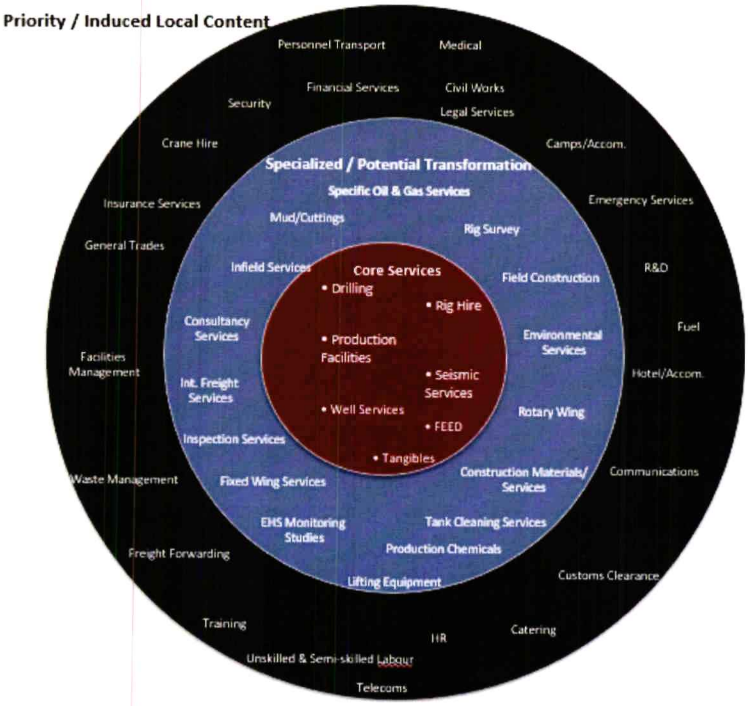
Local content implementation will focus on four key drivers:

1. **Employment of Kenyans**
   Transparent, fair, and structured recruitment processes will ensure Kenyan citizens are prioritized for available opportunities. Special focus will be placed on host communities in Turkana.
2. **Procurement of Goods and Services**
   The Project will optimize opportunities for Kenyan enterprises by providing visibility of requirements, engaging with local suppliers, and enabling competitive participation in the supply chain.
3. **Capacity Building**
   GEBV will invest in upskilling the workforce, developing supplier capabilities, and enhancing awareness of industry standards. Training programs will address both technical competencies and compliance requirements such as health, safety, and environment (HSE).
4. **Stakeholder Engagement**
   Continuous engagement with national and county governments, regulator, communities, and industry associations such as KNCCI (Turkana chapter included), KAM, KEPSA, etc. will support transparency, manage expectations, and reinforce GEBV's social license to operate.

5. LOCAL CONTENT APPROACH

The South Lokichar Field Development presents opportunities for Kenyan participation across multiple dimensions. To ensure a structured and transparent approach, GEBV has adopted the **"Wheel of Opportunity"** framework, which aligns local content opportunities with the life cycle of the Project.

The 'Wheel of Opportunity' - Localization of Supply Chain and Employment Opportunities:



🟩 **Priority Sectors**

- Readily available in local market
- Offered to other industries
- Easier for providers to meet standards/specs
- Can be capital intensive

🟨 **Potential Transformation Sectors**

- Not easily found locally
- Require medium–long term skill development
- Partnerships help build expertise
- Often capital intensive

🟥 **Opportunistic Sectors**

- Complex services used in offshore/advanced ops
- Require large investment and have high barriers
- Can deliver durable competitive advantage
- Skills can be developed over time

1. **Priority sectors:** It is expected that the goods and services that will be readily available will be those in these sectors which are already in existence in the market. Tweaks in processes would enable players to meet industry standards. Services that fall under this category include; crane hire, security, catering, customs clearance, general waste management, amongst others.
2. **Potential Transformation sectors:** The feasibility of local content from these sectors will be less likely compared to the priority sectors due to the fact that the services are more specialist in nature and are also not readily available in the market. Players in this sector would need to enhance their capacity and capability in response to Project needs.
3. **Opportunistic sectors:** The least local content is found in these sectors which fall in the specialist Oil and Gas services and naturally require a significant high investment. These services include well services, drilling services, seismic services, etc. It is necessary to point out that there could be a transferability of some expertise from the Geothermal projects, and this will be explored during the project implementation.

6. MARKET CAPABILITIES AND CAPACITY

Kenya has a diverse economic base that provides a foundation for local content delivery. However, varying levels of readiness exist across sectors and regions. GEBV recognizes both the **strengths** and **gaps** in market capacity and has tailored its strategy accordingly. It is worth noting that since the downturn that took place in 2020, there has been a lull in the upstream O&G industry and as such there is an expectation that the market will be different compared to how it was 5 years ago. It will be worth refreshing the market assessment after the Project has commenced. While the Act requires the Operator to include the list of areas to be procured locally, a market survey conducted 7 years ago indicated the following as areas with capability.

6.1 National Context

At the national level, Kenya possesses a strong pool of skilled professionals in engineering, finance, legal, logistics, and ICT. Key opportunities for national participation include:

- Civil works and infrastructure development,
- Engineering and project management services,
- Logistics and transportation,
- Catering, accommodation, and general support services, and
- Training and consultancy services.

Kenyan firms are increasingly able to compete in high-value service segments when given visibility of requirements and adequate preparation time.

6.2 Turkana County Context

Turkana County, as the host community, holds a unique position in the delivery of local content. Opportunities will be created in line with local capacity while ensuring safety, quality, and efficiency are not compromised. Key focus areas include:

- Unskilled and semi-skilled labour recruitment,
- Catering, cleaning, and hospitality services,
- Civil works and construction support,
- Transportation and security services, and
- Supply of locally available materials (sand, gravel, and aggregates).

To maximize impact, GEBV will implement **community sensitization programs**, supplier forums, and training initiatives to prepare Turkana-based enterprises and individuals for participation in the Project.

7. CONTRACTUAL FRAMEWORK

As is typical in Oil and Gas projects globally, the operations will be delivered through several service contractors. The commitments to deliver local content are therefore contained in all the contracts to ensure that local content is maximized in all possible opportunities in the Project. For phase 1, the Upstream workstream consists of i) the Drilling and Completions package will contain the scopes for Rigs, Integrated Drilling and Well Services, OCTG, Wellhead, EPF and Production. ii) Civils package that will include Roads, Well pads, Cellars, etc. The Midstream package will contain the Crude Oil trucking and inspection services.

The LCP document will be structured along these two key workstreams namely:

1) Upstream
2) Midstream

7.1 Contracting & Procurement of Goods and Services

All Invitations to Tender (ITTs) will include a Local Content Exhibit requiring bidders to submit Local Content Plans addressing the following key aspects:

i) Employment and progression of Kenyans;
ii) Training and skills development of Kenyans;
iii) Sourcing of goods and services from Kenyan suppliers;
iv) Supplier development;
v) Technology transfer.

These Local Content Proposals will be evaluated, and the scores will form part of the overall selection criteria for award. The commitments made by successful bidders will be embedded into contracts and tracked throughout the contract duration.

GEBV's contracting and procurement approach will be guided by the following measures:

- **Local Supplier Participation:** Kenyan enterprises will be afforded full and fair access to tendering opportunities.
- **Supplier Forums:** GEBV, together with its contractors, will convene regular supplier engagement forums to communicate project requirements, share upcoming opportunities, and strengthen supplier awareness.
- **Prequalification Support:** Local suppliers will receive targeted support to meet international standards in health, safety, environment, and quality (HSEQ).
- **Unbundling of Opportunities:** Procurement packages will be structured to facilitate participation of small and medium enterprises (SMEs), especially those based in Turkana County, including subcontracting opportunities within larger contracts.

7.1.1 Upstream Facilities

i) Drilling and Completions

A total of 48 wells will be required for Phase 1 of the Development, of which 43 new wells will be drilled. Three bidders have been identified to submit proposals for key work packages including rigs, integrated drilling and well services, OCTG, wellheads, EPF, and production facilities.

This scope is highly specialized and categorized as **opportunistic**, meaning that local content opportunities will be limited in both goods and services procurement, as well as workforce involvement. Nonetheless, certain services will be sourced locally, including:

- Legal and insurance services
- Logistics and transport services
- Medical and financial services
- Supply of PPEs, spares, and handling equipment
- Waste management

- Mobile and internet services
- Forklift rental
- Accommodation and catering

ii) Civil Works

Civil works will cover roads, well pads, and cellars. This scope is expected to provide considerable local content opportunities in terms of equipment supply, services, and workforce. Key areas anticipated for local participation include:

- Road construction and maintenance
- Civil works and earthworks
- General construction support

7.1.2 Midstream

The midstream phase of the Project presents significant opportunities for Kenyan enterprises and workforce participation, particularly in transportation, logistics, and associated services.

Phase 1: Road Transportation to KPRL Changamwe

During Phase 1, crude oil will be transported by road tankers from Lokichar to the Kenya Petroleum Refineries Limited (KPRL) facility in Changamwe for storage.

- **Fleet Requirements:** Approximately 600 trucks will be required, all of which can be sourced from Kenyan suppliers.
- **County Participation:** Of the total fleet, **at least 200 trucks** (equivalent to 33%) will be allocated to County-based suppliers. These suppliers will be organized through a cooperative structure that incorporates stakeholders from Turkana East, Turkana West, and Turkana North.
- **Workforce Opportunities:** Local employment opportunities will include drivers, traffic marshals, and gantry operations staff.
- **Ancillary Services:** Additional opportunities will arise for Kenyan service providers in areas such as metering, fuel testing, and product clearance, with a particular focus on local testing and certification companies.

Phase 2: Integrated Truck and Rail Transportation

During Phase 2, the transportation model will evolve to a combined truck-and-rail system:

- Crude oil will be transported from Eldoret, daily in **155 rail wagons** to the KPRL facility in Changamwe for storage.
- Export logistics will enable shipment volumes of up to **600,000 barrels per month for Phase 1** and up to **1,500,000 barrels per month for Phase 2**, strengthening Kenya's position as an emerging crude exporter.

7.1.3 Highlights of Midstream Opportunities:

- 600 trucks required, fully sourced from Kenyan suppliers
- At least 200 trucks (equivalent to 33%) will be ring-fenced for County-based enterprises through cooperatives
- Direct employment in driving, marshalling, auto mechanics and gantry operations
- Ancillary services in testing, metering, and certification reserved for Kenyan providers
- Transition to truck-and-rail system in Phase 2, with daily rail operations and monthly exports of up to 1,500,000 barrels

- The extension of the railway network to Lokichar has the potential for economic growth as transportation for goods and services to and from Turkana County is enhanced

8. RECRUITMENT STRATEGY

8.1 Recruitment Strategy

GEBV is committed to maximizing Kenyan participation in the workforce at all levels where competencies and experience exist. This principle will also be cascaded to all contractors. Recruitment processes will be guided by transparency, fairness, and inclusivity, ensuring open access to available opportunities.

Key elements of the recruitment strategy include:

- **Community-first prioritization:** Recruitment will prioritize individuals from communities in close proximity to the project, followed by Turkana County residents, and thereafter the wider Kenyan labor market.
- **Job categories:** Recruitment will be managed across management, skilled, semi-skilled, and unskilled categories to ensure equitable distribution of opportunities.
- **Employer Guidelines:** Contractors will be issued with Employer Implementation Guidelines to ensure alignment with GEBV's labor and local content policies.
- **Local outreach:** Open job opportunities will be advertised in community offices, with the option of engaging local labor recruitment firms to support outreach and fairness.

8.2 Opportunity Sharing

- **Unskilled positions** will be fully ring-fenced for Turkana nationals. Of this, 40% will be drawn from Turkana South and Turkana East, and 20% from Turkana North—ensuring 100% County content for unskilled roles.
- **Semi-skilled positions** will be sourced from Turkana where candidates with the requisite skills are available, before considering applicants from other parts of Kenya.
- **Skilled positions** will be open to all Kenyans, with preference given to qualified Turkana candidates where available.

8.3 Upstream Workstream Opportunities

- **Drilling and Completions:** Kenyan graduates in oil and gas disciplines will be prioritized for field engineering, operations, HSE, legal, compliance, tax, finance, logistics, and supply chain roles. Turkana nationals will be engaged in base operations support, security, driving, and casual labor. At peak operations, **50% of the workforce is expected to be Kenyan.**
- **Civil Works:** Roles will include civil engineers, equipment operators, and construction workforce. Civil works are projected to achieve **100% Kenyan workforce participation.**

8.4 Midstream Workstream Opportunities

The midstream phase will draw extensively from Kenya's established transport and logistics sector. Drivers, traffic marshals, and administrative staff are expected to be sourced entirely from Kenya, with significant inclusion of Turkana nationals where skills are available. Overall, the midstream workstream anticipates **100% Kenyan workforce participation.**

8.5 Highlights of Recruitment Strategy:

- Transparent, structured recruitment processes guided by fairness and inclusivity
- 100% of unskilled positions reserved for Turkana nationals
- Strong opportunities for Kenyan graduates in oil and gas-related fields

- Expected workforce participation: 50% Kenyan in Drilling & Completions, 100% Kenyan in Civil Works and Midstream operations
- Clear and defined succession plan to allow for seamless transition and localisation of positions held by expatriate employees at the outset of the petroleum operations

9. TRAINING AND PROGRESSION STRATEGY

Training is a central component of GEBV's Local Content philosophy. It aims to sustainably develop the Kenyan workforce and businesses, ensuring continuous improvement in local participation and capacity building. GEBV's training programs will focus on the development of its workforce. The PSCs require that a specific annual amount is paid towards a training fund. GEBV will continue disbursing the stated amounts with the expectation that MOEP will coordinate training programs that are outside the Project's workforce.

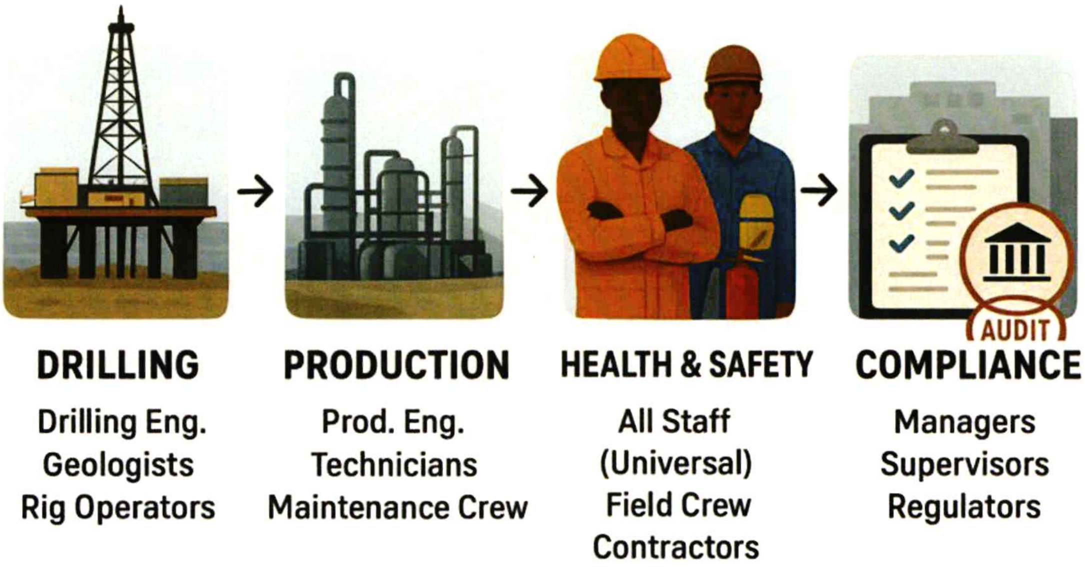
Focus areas include:

- **Youth Development:** Sponsorships for Kenyans in universities and technical institutions, alongside internships and apprenticeship programs.
- **Workforce Development:** Competency-based training tailored to specific job roles across upstream and midstream operations.
- **Market Development:** Supplier workshops to raise awareness of technical requirements and industry standards.
- **Supplier Development:** Continuous evaluation of local suppliers against service standards, followed by action plans to address identified gaps.
- **HSE Training:** Mandatory health, safety, and environment training across the supply chain, with role-specific certifications as required.

9.1 Workforce Development

9.1.1 Upstream Training Opportunities

- **Drilling and Completions:**



Illustrative training process for Drilling and Completions

Training programs will cover all staff categories, ensuring safe and competent operations. Kenyan graduates will undergo on-the-job (OTJ) training under expatriate supervision, complemented by overseas training placements where necessary. Internship and graduate trainee programs will be rolled out to further build technical capacity.

- **Civil Works:** Training will focus on safety standards, site-specific practices, and certification. Local contractors with prior experience in similar scopes will be supported with refresher HSE and technical training.

9.1.2 Midstream Training Opportunities

- **Truck Drivers:** All drivers will be required to hold EPRA certification for fuel tanker operations, supported by defensive driving courses and on-road experience-building programs.
- **Administrative Staff:** Administrative and logistics roles will include systems training and OTJ exposure.
- **Inclusive Programs:** Initiatives to support women drivers and Turkana youth will be emphasized, building on previous successful efforts.

9.1.3 Localization

Contractors will be required to implement localization strategies, including understudy programs and transition plans for expatriate roles. This ensures that over time, Kenyan staff assume leadership and technical roles without compromising safety, quality, or operational timelines.

9.1.4 Highlights of Training & Progression Strategy:

- Comprehensive focus on workforce, youth, supplier, and market development
- Internship, apprenticeship, and graduate trainee programs for Kenyan youth
- Overseas and OTJ training for drilling and technical disciplines
- Defensive driving and EPRA certification for midstream drivers
- Localization plans to transition expatriate-held roles to Kenyan professionals

9.2 Supplier Development

Supplier development is a cornerstone of GEBV's Local Content Plan. The objective is to create a competitive, resilient, and sustainable local supply chain that supports the oil and gas sector during the project lifecycle and beyond. GEBV will work closely with contractors, government agencies, and local enterprises to progressively build supplier capability, compliance, and performance.

9.2.1 Supplier Engagement Framework

- **Supplier Forums:** Regular engagement sessions will be hosted to communicate project requirements, explain tendering processes, and share global best practices with Kenyan suppliers.
- **Supplier Databases:** GEBV will maintain and continuously update a supplier register, capturing both national and county-based enterprises to ensure inclusivity.
- **Transparency in Procurement:** Open and fair access will be guaranteed for all qualified suppliers, with opportunities advertised at county and national levels.

9.2.2 Capacity Building Initiatives

- **Training Programs:** Targeted workshops will be organized to address gaps in health, safety, environment, and quality (HSEQ), financial management, and international certification standards.

- **Mentorship and Partnerships:** Local suppliers will be encouraged to form joint ventures or subcontracting arrangements with experienced international firms to accelerate skills and knowledge transfer.
- **Access to Finance:** In collaboration with financial institutions, GEBV will explore mechanisms to improve supplier access to affordable credit and working capital, enabling timely delivery of goods and services.

9.2.3 Procurement Structuring

- **Unbundling of Contracts:** Where possible, large contracts will be broken down into smaller, more accessible packages, enabling participation by SMEs and county-based enterprises.
- **Ring-Fenced Scopes:** Certain categories—such as catering, transport, accommodation, waste management, and basic supplies—will be exclusively reserved for Kenyan suppliers, with priority given to county-based enterprises.
- **Performance Monitoring:** Suppliers will be evaluated periodically against contractual KPIs, with feedback provided to drive continuous improvement.

9.2.4 Long-Term Supplier Sustainability

GEBV is committed to ensuring that supplier development has a lasting impact beyond this project. To this end:

- **Certification Programs:** Kenyan suppliers will be supported to obtain internationally recognized certifications (e.g., ISO standards).
- **Knowledge Transfer:** Systems and processes will be embedded within local enterprises to ensure competitiveness in future oil and gas opportunities, both locally and globally.
- **Legacy Impact:** By strengthening the supply chain, GEBV will contribute to Kenya's industrialization agenda and position local enterprises as regional energy sector players.

9.2.5 Highlights of Supplier Development Strategy:

- Regular supplier forums and transparent tendering processes
- Supplier training in HSEQ, financial management, and certification
- Joint ventures and mentorship programs to accelerate growth
- Unbundling of large contracts and ring-fenced scopes for SMEs
- Long-term sustainability through certification and legacy impact

10. TECHNOLOGY TRANSFER

GEBV recognizes that sustainable development of the Kenyan oil and gas sector requires not only immediate participation but also long-term capability building. Technology transfer is therefore positioned as a central pillar of the Local Content Plan, enabling Kenyan enterprises and professionals to acquire knowledge, systems, and practices that will strengthen national competitiveness in the energy sector.

10.1 Approach to Technology Transfer

- **Partnerships with Contractors:** Key contractors will be required to implement structured technology transfer programs as part of their Local Content commitments where feasible.
- **Skills Development:** Knowledge transfer will be achieved through on-the-job training, formal classroom sessions, workshops, and mentoring programs delivered jointly by expatriate and Kenyan professionals.

- **Knowledge Retention:** Training documentation, procedures, and operational manuals will be retained locally to ensure institutional memory and reuse across future projects.
- **Long-Term Capacity:** By embedding knowledge-sharing mechanisms into contracts, GEBV will ensure that technology transfer continues beyond the initial project lifecycle.

10.2 Upstream Focus Areas

- **Drilling and Completions:** Transfer of advanced well engineering and reservoir management technologies through structured understudy programs.
- **Civil Works:** Capacity building on modern construction technologies, safety monitoring systems, and environmentally sustainable construction methods.
- **Digitalization:** Introduction of real-time data monitoring platforms for drilling and production, with training provided to Kenyan engineers and technicians.

10.3 Midstream Focus Areas

- **Transportation and Logistics:** Implementation of fleet management systems, automated scheduling, and digital tracking platforms for truck and rail operations, with Kenyan operators trained in system administration.
- **Quality Assurance:** Technology transfer in crude metering, testing, and certification processes to ensure compliance with global industry standards.
- **Maintenance Systems:** Training of local technicians in predictive and preventive maintenance technologies to extend asset life cycles and enhance operational efficiency.

10.4 Institutional Partnerships

GEBV will work closely with Kenyan universities, technical institutes, and training centers to establish partnerships that enhance technology transfer. Programs will include:

- Joint curriculum development in petroleum engineering, logistics, and HSE disciplines.
- Scholarships and exchange programs with global O&G institutions.
- Collaboration on research and innovation projects relevant to Kenya's emerging O&G sector.

10.5 Highlights of Technology Transfer Strategy:

- Contractor-led technology transfer embedded in Local Content commitments
- On-the-job, classroom, and mentoring programs to ensure knowledge retention
- Focus on predictive maintenance, quality assurance, and safety technologies
- Strong partnerships with universities and technical institutions for sustainable impact

11. STAKEHOLDER ENGAGEMENT

GEBV recognizes that proactive stakeholder engagement is essential for maintaining a social license to operate and ensuring the successful implementation of Local Content initiatives.

11.1 Stakeholder Identification and Mapping

An in-depth stakeholder mapping exercise has been conducted to identify and categorize all relevant parties. For Local Content, key stakeholders include:

- **Business Community:** National and county-level enterprises with potential supply chain and service roles.
- **Regulatory Authorities:** Energy and Petroleum Regulatory Authority (EPRA) and relevant Government Ministries at both national and county levels.

- **Contractors and Service Providers:** All project contractors, sub-contractors, and suppliers engaged in project delivery.
- **Development Partners and Civil Society:** Multilateral Development Organizations, NGOs, and other civil society actors.

11.2 Engagement Mechanisms

GEBV will implement a structured engagement approach to ensure that stakeholders are consistently informed on Local Content matters:

- **Regular Updates:** Key stakeholders will receive timely updates on Local Content progress, achievements, and upcoming opportunities.
- **Workshops and Forums:** Stakeholder forums will be held to facilitate knowledge sharing, address concerns, and foster collaboration.
- **Feedback Channels:** Mechanisms will be in place to capture stakeholder feedback, enabling responsive actions and continuous improvement.
- **Transparency and Reporting:** Engagement will be underpinned by clear and transparent communication of Local Content policies, commitments, and outcomes.

11.3 Strategic Benefits

Effective stakeholder engagement will:

- Strengthen the social license to operate at local, county, and national levels.
- Facilitate alignment between GEBV, contractors, and local communities.
- Enable proactive identification of opportunities and challenges in Local Content delivery.
- Enhance trust and collaboration, supporting sustainable project outcomes.

12. MONITORING, EVALUATION AND REPORTING

Effective monitoring, evaluation, and reporting (MER) are critical to ensuring that Local Content objectives are achieved, measured, and continuously improved. GEBV will adopt a structured MER framework to track commitments, assess performance, and provide transparent reporting to regulators, partners, and stakeholders.

12.1 Monitoring Framework

- **Commitment Tracking:** Local Content commitments made by contractors during the tender process will be captured in contractual obligations and monitored throughout the project lifecycle.
- **Performance Indicators:** A set of Key Performance Indicators (KPIs) will be applied across employment, training, supplier participation, technology transfer, and community engagement.
- **Data Collection:** Contractors will be required to provide regular reports on Local Content performance, supported by audits and site inspections.
- **Digital Tools:** Monitoring will be supported by digital platforms to enable real-time data collection and analysis, ensuring timely decision-making.

12.2 Evaluation Approach

- **Quarterly Reviews:** Performance against Local Content KPIs will be evaluated quarterly, identifying gaps and opportunities for corrective action.
- **Annual Assessments:** Comprehensive annual evaluations will measure overall progress against Local Content objectives and long-term sustainability.

- **Independent Audits:** Third-party audits may be commissioned to validate reported performance, ensuring objectivity and transparency.
- **Benchmarking:** Performance will be benchmarked against global best practices and lessons from comparable O&G jurisdictions.

12.3 Reporting Mechanism

- **Internal Reporting:** Local Content performance reports will be submitted to GEBV management for oversight.
- **Regulatory Reporting:** Reports will be prepared and submitted to EPRA and other relevant government agencies in line with statutory requirements.
- **Stakeholder Updates:** Periodic updates will be shared with county governments, community representatives, and other stakeholders to promote transparency and accountability.
- **Public Disclosure:** Where appropriate, summary reports will be published to demonstrate compliance and progress on Local Content delivery.

12.4 Continuous Improvement

GEBV will treat monitoring and evaluation as a dynamic process aimed at driving continuous improvement. Corrective action plans will be developed where performance falls short, and best practices will be replicated across project phases.

12.5 Highlights of Monitoring, Evaluation & Reporting:

- KPIs tracked across employment, training, suppliers, and technology transfer
- Digital platforms for real-time monitoring and data analysis
- Quarterly reviews, annual assessments, and independent audits
- Transparent reporting to regulators, stakeholders, and the public
- Continuous improvement framework to ensure long-term impact

13. KEY RISKS

S/No.	Risk	Risk type	Proposed Mitigation
1.	**Multiplicity of legislation** e.g. Petroleum Act, 2019 and the Turkana County Local Content Act, 2024	Legal	Follow the **hierarchy of law**, in which the **National law** takes precedence
2.	Assumption that the **training of wider Kenyans** (non-workforce) will be implemented through the **Training funds** that are remitted to the Ministry on an annual basis as per the PSC	Financial	**Align** this principle with **EPRA**
3.	**High capital investment** for 600 trucks required over a short five-year period. **Limited long-term benefits** relative to the scale of investment. **Potential stakeholder dissatisfaction** arising from constrained opportunities or unmet expectations. **Idle assets post-trucking phase,** creating financial and operational challenges for entrepreneurs	Operational	Adopt a **phased investment approach** to reduce upfront financial exposure. Identify **alternative uses for trucking assets** beyond the initial five-year period. Explore **government and industry support mechanisms** to safeguard County-based enterprises. Encourage **entrepreneurial diversification** to minimize dependency on trucking as a single revenue stream.

14. CONCLUSION

The South Lokichar Field Development represents a milestone for Kenya's petroleum sector and an opportunity to create meaningful, lasting benefits for the nation. As a Kenyan operator, **Gulf Energy E&P BV** recognizes the responsibility to ensure that petroleum resources act as a catalyst for inclusive growth, capacity development, and socio-economic transformation.

This Local Content Plan demonstrates GEBV's commitment to:

- Prioritizing **employment of Kenyan citizens**, particularly from host communities;
- **Creating access for Kenyan enterprises** within the Project's supply chain;
- **Investing in training, skills development**, and **knowledge transfer** to build long-term capacity;
- **Embedding local content obligations in all contracts**, ensuring shared accountability with contractors; and
- **Maintaining transparency** through **structured monitoring, reporting,** and **stakeholder engagement.**

By adopting a structured framework, backed by measurable commitments and continuous improvement mechanisms, GEBV seeks to set a new benchmark for local content implementation in Kenya's oil and gas industry.

The Local Content Plan is not only a statutory requirement but also a reflection of GEBV's corporate philosophy as a Kenyan company. It is designed to ensure that petroleum development in South Lokichar contributes to:

- Economic empowerment of Kenyans,
- Growth of local businesses and industries,
- Sustainable community development in Turkana County, and
- Strengthened partnerships between the private sector, government, and citizens.

GEBV affirms that this Local Content Plan will remain a living framework, adaptable to evolving regulatory requirements, market conditions, and stakeholder expectations. In doing so, it ensures that Kenya's oil and gas resources deliver benefits that extend well beyond the life of the Project.