decisions with confidence

Prospective Resources report of independent qualified evaluator for Block 3B/4B, South Africa

on behalf of Africa Oil Corp.

7 March 2023

Private and Confidential

1. Executive Summary

Block 3B/4B covers an area of 17,581 km^2 within the Orange Basin offshore of the Republic of South Africa. Africa Oil Corp ("AOC") is the Operator with a 20% participating interest, Ricocure Pty. Limited holds a 53.75% interest and Azinam South Africa Limited, a subsidiary of Eco Atlantic Oil & Gas Plc has a 26.25% interest (Table 1-1). RISC has reviewed the prospective resources and probability of geological success of 24 exploration prospects contained within Block 3B/4B in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System 2018 (SPE-PRMS).

Table 1-1: Asset Summary

Asset		Operator	Participating Interest	Status	Exploration Right expiry date	Block area (km^2)	Comments
Country	Block						
South Africa	Block 3B/4B	Africa Oil	20%	2^{nd} Exploration Phase	26 October 2024	17,581[1]	Late Cretaceous prospects with AVO support.

Table 1-2: Summary of Gross and Net (20%) Unrisked Prospective Resources for Oil

Summary of Oil Gross/Net	Gross	Net
	Unrisked Prospective Resources Oil (MMstb)	Unrisked Prospective Resources Oil (MMstb)
1U (P90)	1,721	344
2U (P50)	3,055	611
3U (P10)	5,437	1,087
Note: Net values are Africa Oil Corp.'s 20% participating interest share of gross prospective resources attributable to the Exploration Right, and are not entitlement volumes.		

Table 1-3: Summary of Gross and Net (20%) Unrisked Prospective Resources for Associated Gas

Summary of Associated Gas Gross/Net	Gross	Net
	Unrisked Prospective Resources Associated Gas (Bcf)	Unrisked Prospective Resources Associated Gas (Bcf)
1U (P90)	3,039	608
2U (P50)	5,508	1,102
3U (P10)	10,011	2,002
Note: Net values are Africa Oil Corp.'s 20% participating interest share of gross prospective resources attributable to the Exploration Right, and are not entitlement volumes.		

[1] Net 3,516 km^2

The initial three year Exploration Right phase for 3B/4B expired on 26 March 2022. Relinquishment of 20% is required at the end of the initial phase, an area of 3,516 km^2, and is waiting on a decision from the Ministry of Mines classification of Marine Protected Areas.

The exploration right was renewed as part of the ‘First Renewal’ period for a duration of two years, expiring on 26 October 2024. The minimum work programme for this extension includes, reprocessing of 1,500 km^2 of Pre-Stack Depth Migration (PreSDM) 3D seismic and subsurface studies.

A large opportunity set of exploration prospects has been identified in deepwater Block 3B/4B and the ability to stack targets in early wells on the license combined with an extensive data acquisition campaign will help to significantly understand the prospectivity and presents opportunities for ‘cluster’ developments to optimize value from any possible developments.

Recent exploration in South Africa has opened a new deepwater play. TotalEnergies made the Brulpadda gas-condensate discovery on Block 11B/12B in 2019. Prior to this discovery, South Africa's deepwater plays had seen minimal exploration. Only four deepwater exploration wells had been drilled, in the late 1980s and early 1990s, in the Southwest coastal basin. TotalEnergies followed the Brulpadda discovery with the Luiperd discovery in 2020.

Shell Exploration & Production’s (“Shell”) recent Graff well discovery and TotalEnergies Venus well discovery in deep water Namibia contain seismic amplitude anomalies and are on trend with AOC’s South African 3B/4B license. The discoveries prove the existence of a working petroleum system for light oil, gas condensate and gas in the geological play fairway. The proven reservoirs in Graff and Venus discoveries are similar to Cretaceous reservoirs and geological plays that would be targeted in the AOC 3B/4B Exploration Right.

Block 3B/4B is in water depths ranging between 500 m and 2,500 m with the majority of the prospects lying in approximately 1,500 m of water. AOC has approximately 14,000 km^2 of 2D seismic and 10,800 km^2 of 3D seismic over Block 3B/4B. RISC has reviewed 10,210 km^2 of 3D seismic for this report alongside the accompanying quantitative interpretation (“QI”). Within Block 3B/4B well control is limited to the K-H1 well located on the northeast boundary of the block, drilled by Soekor in 1989 but does not help with calibration of seismic amplitudes. Seismic Amplitude Versus Offset (“AVO”) was part of the QI, as was analysis of a fluid factor and seismic amplitude fit to structure since many of the stratigraphic prospects are defined by the seismic anomalies. The seismic amplitude modelling is poorly calibrated by well data so there is a reliance on global and west African analogues at the present time.

Reservoir presence and quality is the primary geological risk in the prospects mapped in Block 3B/4B. This is determined by the absence of well penetrations in the 3B/4B block area, shale prone equivalent sections in shelf edge wells (although these wells are probably in sand bypass zones), and limited direct evidence of reworking of shelf sands into the deepwater setting of the 3B/4B block.

The reservoir targets within the Exploration Right exist at several stratigraphic levels: Santonian, or Upper Cretaceous age sandstones deposited in turbidite channel and fan systems at the slope margin, Cenomanian-Turonian age sandstones deposited in turbidite channel and fan systems at the slope margin and on the outer slope, and Albian sandstones deposited as turbidites as basin floor fans. An additional Albian carbonate play exists on the Outer Margin high but absence of well penetrations makes this play difficult to quantify.

Cretaceous Aptian to Albian and Barremian shales have been identified as source rocks in the Orange Basin. Wells located inboard and adjacent to Block 3B/4B provide key evidence for source rock quality and maturity.

To the west of the Outer High[2], source rocks are expected to be more oil prone due both to their lower maturity and less terrigenous clastic input. This interpretation is based not only on the recent light oil and wet gas discoveries by Shell and TotalEnergies, but by data provided by DSDP[3]-361 located southwest of Block 3B/4B which encountered Aptian organic-rich black shales with TOC[4] up to 25% with a thermal maturity capable of oil and wet gas generation.

The prospect traps are predominantly stratigraphic in nature with lateral extent defined by facies changes from sands to mudstones. Up-dip trap geometries vary between structural fault closures, stratigraphic onlap and unconformity truncations. The majority of the traps are supported by shut off of the AVO seismic anomaly and used as an indicator of both reservoir presence and quality, and hydrocarbon charge and trapping. Seismic anomalies seen in the shallower section exhibit broader extent and some structural conformance. RISC considers these could contain a higher gas content than the deeper reservoir targets. Hydrocarbon containment is considered to be formed by intraformational marine shales.

Resource summary and classification, and the gross oil and gas unrisked prospective resources attributable to the 24 prospects reviewed on the 3B/4B block are summarised in Table 1 2 & Table 1-5. All undiscovered petroleum initially in place (UPIIP) and prospective resources (1U, 2U, 3U) are quoted as gross unrisked on block volumes. The UPIIP and Prospective resources quoted describe the P90 to P10 range of potential outcomes given absence lack of well penetrations on the block and draw heavily on analogue knowledge and regional experience combined with seismic AVO analysis.

The P90/P10 resource ranges are not as wide as might normally be expected for an uncalibrated exploration play. However, the prospects in Block 3B/4B consist of stratigraphic, amplitude controlled, channel features with several West African discoveries used as analogues, which by definition narrows the range of gross rock volume that can be mapped as part of a prospect. The lower end of the lognormal distribution (P99 to P91) is considered to adequately encompass the downside scenarios with volumes below P99 resulting in Pg failure, and the upper end of the lognormal distribution (P9 to P1) is considered to adequately encompass upside scenarios and the probabilities of outcome.

This is currently an exploration license and detailed work on reservoir engineering, facilities and development concepts has not yet been carried out. It should be noted that although there may eventually be some potential operational synergies with possible developments at Venus and Graff, these recent discoveries are approximately 300 km from the prospects in Block 3B/4B and are located in a different country with a different fiscal regime. Export of any discovered resources in Block 3B/4B are therefore likely to be through stand-alone floating facilities.

[2] Referred to as the 'Marginal High' in some texts
[3] Deep Sea Drilling Project
[4] Total Organic Carbon

Table 1-4: Fourteen Northern Area Prospects Gross Unrisked UPIIP and Prospective Resources

Prospect	UPIIP[5] (STOIIP) (MMstb)			Prospective Resource Oil (MMstb)			Prospective Resource Assoc. Gas (Bcf)		
Classification	P90	P50	P10	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)
Mongoose	373	589	912	108	176	281	189	313	513
Assenkehr	88	212	502	26	63	153	46	113	276
Meerkat	182	296	479	53	88	147	92	158	269
Caracal	101	207	419	30	62	128	52	111	231
Bushbaby	315	509	816	91	152	251	159	272	458
Sjambok	237	385	624	68	115	191	120	206	350
Noordoewer	243	405	670	70	121	205	123	216	375
Seekoei	174	279	434	50	83	134	88	148	245
Halfmens	255	714	1,685	50	139	342	89	258	637
Halfmens Upper	109	345	1,080	21	68	221	39	126	409
Fan-SA	1,118	2,066	3,777	277	518	951	504	953	1,767
Fan-SB	423	781	1,429	79	154	296	144	284	550
Fan-SC	153	338	737	29	67	151	51	119	275
Aardwolf	903	1,313	1,884	222	327	475	384	586	882
TOTAL	**4,674**	**8,439**	**15,448**	**1,174**	**2,133**	**3,926**	**2,080**	**3,863**	**7,237**

1. Gross are 100% of resources attributable to Exploration Right .
2. Arithmetic aggregation: RISC cautions that the 1U aggregate quantities may be conservative estimates and the 3U aggregate quantities may be optimistic due to portfolio effects.

[5] Undiscovered Petroleum Initially-In-Place (UPIIP)

Table 1-5: Ten Central Area Prospects Gross Unrisked UPIIP and Prospective Resources.

Prospect	UPIIP (STOIIP) (MMstb)			Prospective Resource Oil (MMstb)			Prospective Resource Assoc. Gas (Bcf)		
Classification	P90	P50	P10	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)
Sickle Bush	132	236	418	39	70	128	67	126	233
Tambotie	103	169	269	30	50	83	52	90	152
Mopane	138	232	378	40	69	116	70	123	212
Quiver-E	229	372	591	66	111	181	116	198	333
Quiver-W	167	276	445	48	82	136	85	147	250
Maroela-Upper	264	409	615	76	122	190	133	217	349
Maroela-Lower	159	253	390	46	76	120	81	135	221
Maroela-W	213	352	561	62	105	172	108	187	317
Acacia	344	567	910	99	169	279	174	301	512
Acacia down-dip	145	227	344	41	68	106	73	121	195
TOTAL	**1,894**	**3,093**	**4,921**	**547**	**922**	**1,511**	**959**	**1,645**	**2,774**

1. Gross are 100% of resources attributable to Exploration Right .
2. Arithmetic aggregation: RISC cautions that the 1U aggregate quantities may be conservative estimates and the 3U aggregate quantities may be optimistic due to portfolio effects.

Prospective Resources are defined as "*….those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.*"

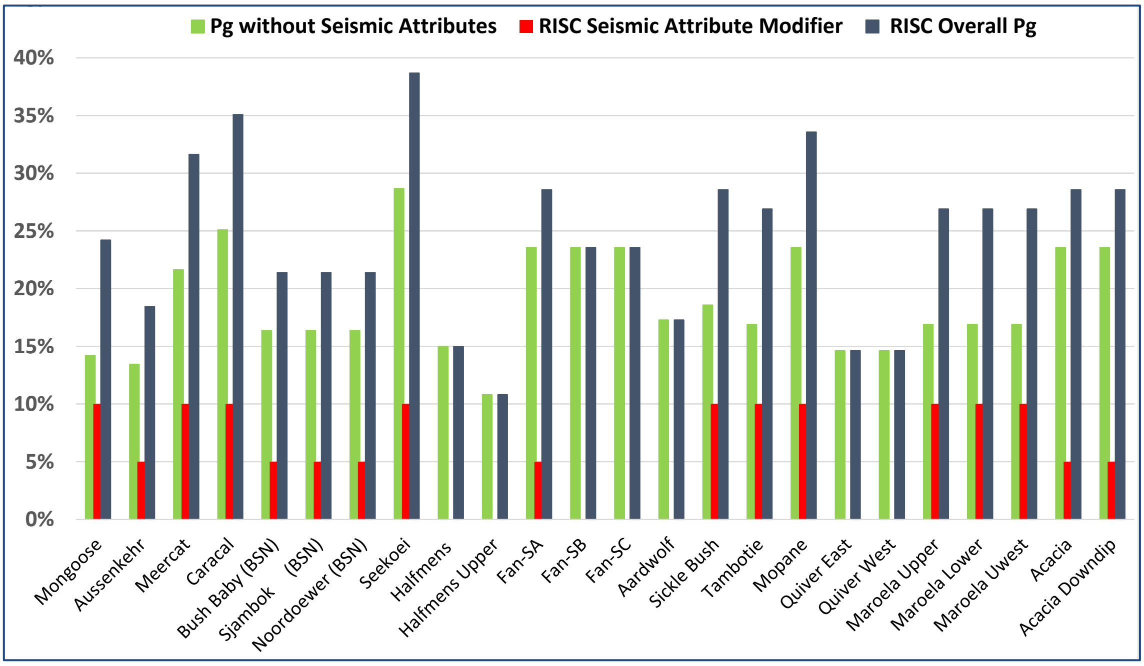

Figure 1-1: Probability of geological success (Pg) with and without Seismic Attribute modifier.

There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the P90 values from the probabilistic analysis (in other words, the value is greater than or equal to the P90 value 90% of the time), while the Mid Estimate represents the P50 and the High Estimate represents the P10. The totals given are simple arithmetic summations of values and are not themselves P90, P50, or P10 probabilistic values of the portfolio of opportunities.

With the proof of a working petroleum system and analogue reservoirs and some good seismic attribute responses RISC considers the prospects in Block 3B/4B to be of moderate probability of geological success, with average Pg of 24%, or approximately 1 in 4 (Figure 1-1, Table 1-6 & Table 1-7).

Currently the probability of geological success and volumes rely entirely on analogue data drawn from the West African and South African margins due to the lack of well penetrations in the 3B/4B acreage. The initial deep water well in the licence has the ability to test stacked targets and collect important reservoir quality, pressure, fluid, core and sonic data that, in a success case, will considerably de-risk the remaining prospectivity. However, all prospects are immature due to the lack of well calibration points in Block 3B/4B. Chance of development is therefore low and generally less than 10% to 20%. Chance of development will likely increase with drilling and development of other deepwater discoveries in the Orange Basin.

Table 1-6: Central Area Prospects Probability of Geological Success & Seismic Amplitude Modifier

Prospect Name	Source Rock	Timing / Mig.	Source RISC	Reservoir*	Trap	Seal	RISC Pg w/o Seis AVO Attrib	RISC Seis Attrib Mod	RISC overall Pg
Sickle Bush	0.8	0.6	0.5	0.7	0.7	0.9	19%	10%	29%
Tambotie	0.8	0.8	0.6	0.6	0.8	0.6	17%	10%	27%
Mopane	0.8	0.9	0.7	0.7	0.6	0.9	24%	10%	34%
Quiver East	0.8	0.7	0.5	0.5	0.8	0.8	15%	0%	15%
Quiver West	0.8	0.7	0.5	0.5	0.8	0.8	15%	0%	15%
Maroela Upper	0.8	0.8	0.6	0.6	0.8	0.6	17%	10%	27%
Maroela Lower	0.8	0.8	0.6	0.6	0.8	0.6	17%	10%	27%
Maroela Uwest	0.8	0.8	0.6	0.6	0.8	0.6	17%	10%	27%
Acacia	0.8	0.9	0.7	0.7	0.6	0.9	24%	5%	29%
Acacia Downdip	0.8	0.9	0.7	0.7	0.6	0.9	24%	5%	29%

Table 1-7: Northern Area Prospects Probability of Geological Success & Seismic Amplitude Modifier

Prospect Name	Source Rock	Timing / Mig.	Source RISC	Reserv oir*	Trap	Seal	RISC Pg w/o Seis AVO Attrib	RISC Seis Attrib Mod	RISC overall Pg
Mongoose	0.8	0.7	0.5	0.7	0.7	0.6	14%	10%	24%
Aussenkehr	0.8	0.5	0.4	0.7	0.8	0.6	13%	5%	18%
Meercat	0.8	0.8	0.6	0.7	0.8	0.7	22%	10%	32%
Caracal	0.8	0.7	0.6	0.7	0.8	0.8	25%	10%	35%
Bush Baby (BSN)	0.8	0.7	0.5	0.7	0.6	0.8	16%	5%	21%
Sjambok (BSN)	0.8	0.7	0.5	0.7	0.6	0.8	16%	5%	21%
Noordoewer (BSN)	0.8	0.7	0.5	0.7	0.6	0.8	16%	5%	21%
Seekoei	0.8	0.8	0.6	0.7	0.8	0.8	29%	10%	39%
Halfmens	0.8	0.8	0.6	0.7	0.6	0.6	15%	0%	15%
Halfmens Upper	0.8	0.8	0.6	0.6	0.5	0.6	11%	0%	11%
Fan-SA	0.8	0.9	0.7	0.7	0.9	0.6	24%	5%	29%
Fan-SB	0.8	0.9	0.7	0.7	0.9	0.6	24%	0%	24%
Fan-SC	0.8	0.9	0.7	0.7	0.9	0.6	24%	0%	24%
Aardwolf	0.8	0.9	0.7	0.5	0.8	0.6	17%	0%	17%

*Note: Risking of Reservoir considers probabilities of achieving the P90 net reservoir thickness. The volumetric input distributions have excluded the lower end of porosity, net to gross and hydrocarbon saturation since this was not considered to contribute to the volume of moveable hydrocarbons.

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2. Basis of assessment

2.1. Terms of reference

RISC was commissioned by Africa Oil Corp. ("AOC") to conduct an independent review of the hydrocarbon reserves and resources in Blocks 3B and 4B in the Orange Basin offshore South Africa.

2.2. Basis of assessment

The data and information used in the preparation of this report were provided by AOC supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied making adjustments that in our judgment were necessary. Details of the findings of our review and the resource estimation process are presented in this report.

RISC has reviewed AOC's technical interpretations and assessment of prospective resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System 2018 (PRMS).

Unless otherwise stated, all resources presented in this report are gross (100%) quantities with an effective date of 1 March 2023.

2.3. Applicable Standards

This report has been prepared in accordance with Canadian National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook, or COGEH[6]. The National Instrument requires disclosure of specific information concerning prospects, as are provided in this Report. The Prospective Resource estimates prepared by RISC are compliant with both Canadian National Instrument 51-101 and COGEH, and the Petroleum Resources Management System 2018 (PRMS). The resource definitions from both these standards are fundamentally the same.

[6] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook Third Edition, August 2018, updated October 2019*

3. Introduction

3.1. Asset/ portfolio description

Block 3B/4B covers 17,581 km^2 and is located within the Orange Basin offshore of the Republic of South Africa (Figure 3-1). Africa Oil Corp ("AOC") is the Operator with a 20% participating interest, Ricocure Pty. Limited holds a 53.75% interest, and Eco Atlantic Oil & Gas Plc has a 26.25% interest (Table 3-1).

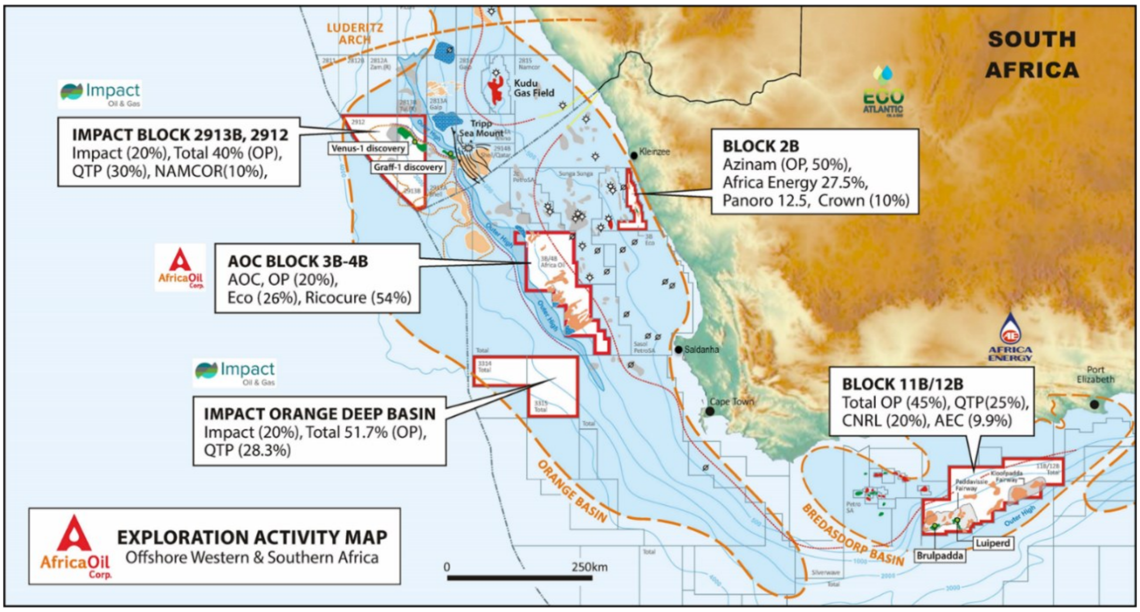


Figure 3-1: Location Map for Block 3B/4B and Africa Oil Assets

Block 3B/4B is located in water depths ranging from 500 m to 2,500 m. The majority of the exploration prospects are in average water depths of 1,500 m and are comfortably within the technical capabilities of drilling contractors specializing in deep water drilling operations. Expected total drilling depths from sea level are between 3,500 m to 4,500 m for the majority of the prospect inventory. The nearest ports to service operations in the block are Cape Town and Saldanha Bay. The town of Kleinzee provides an option that is within helicopter range.

The nearest potentially commercial oil or gas developments are likely to be the recent Shell Exploration & Production ("Shell") Graff and TotalEnergies Venus discoveries in Namibia and possibly the Kudu and Ibhuhesi discoveries also in Namibia. In Block 3B/4B in South Africa, the expected fluid type is light oil with associated gas condensate and gas, in line with the discoveries announced by Shell and TotalEnergies.

Table 3-1: Asset Summary

Asset		Operator	Participating Interest	Status	Exploration Right expiry	Block area (km^2)	Comments
Country	Block						
South Africa	Block 3B/4B	Africa Oil	20%	2nd Exploration Phase	26 October 2024	17,581	Late Cretaceous prospects with AVO support.

4. Regional information

Exploration in the Orange Basin has historically targeted Cretaceous sequences in shallow water areas, inboard of Block 3B/4B. Before the Graff and Venus discoveries in 2022, few discoveries had been made. Prior drilling had focused mainly on targets in relatively shallow water, the most notable being the Kudu gas discovery in southern Namibia (in aeolian, shallow-marine Barremian reservoirs), the Ibhubesi gas discovery (in Aptian-Albian shallow-marine fluvio-deltaics) and the small A-J1 oil field (in Hauterivian syn-rift and lacustrine clastics).

In 2009, Shell were granted an Exploration Right to explore the deepwater area to the west in deep and ultra-deep water. Shell expanded their exploration activity into Namibia which has led to their recent light oil and gas discoveries in Cretaceous age turbidite reservoirs as encountered in the Graff-1, La Rana-1 and Jonkers-1 discovery wells in 2022 and 2023. Similarly TotalEnergies have joined this activity and maintain a large position in the deep water and ultra-deepwater licenses of the Orange Basin. In Namibia, TotalEnergies and partners announced a significant light oil discovery in Cretaceous turbidite fans. These along with Luiperd and Brulpadda discoveries reportedly benefit from strong seismic amplitude, or AVO seismic signatures.

Prospects in Block 3B/4B will target turbidite fan deposits of similar age and seismic response to the discoveries made by TotalEnergies and Shell. Traps are generally combination structural-stratigraphic traps, with siliciclastic reservoirs confined within channels, or deposited as turbidite fans fully encased in shales.

4.1. Regional Geology

Block 3B/4B lies within the Orange Basin which extends from South Africa as far north as the Luderitz Arch in Namibia. The basin formed from the breakup of the African and South American continents starting in Jurassic time. The early synrift basin fill consists of both siliciclastics, and carbonates deposited during the Late Jurassic and Early Cretaceous eras (Figure 4-1: Note multiple unconformities through the Upper Cretaceous transporting sands into the deepwater basin. This was followed by deposition of Aptian-Albian aged organic-rich shales deposited in a marine restricted environment. These regionally extensive marine shales are the primary source rock for the Orange Basin.

Following deposition of the Aptian-Albian marine source rocks, separation of the continents continued during what is referred to the ‘drift’ stage, where sediments from major proto rivers deposited large quantities of clastic sediments as fluvial-deltaic deposits in the nearshore areas. Further offshore, where Block 3B/4B is located, Cretaceous clastic sediments were deposited at the paleo shelf edge and slope as turbidites. Two ancient river systems provided sediments to the nearshore and offshore areas of Block 3B/4B during the Upper Cretaceous, the Orange River to the north, and the Olifants River located immediately east of Block 3B/4B.

The shelf areas of the Orange Basin east of Block 3B/4B have been explored with more than 38 wells, most of which were drilled in water depths of 500 m or less. While these wells did not target the same depositional environments that are being targeted in Block 3B/4B, the wells do provide information about the stratigraphy of the Upper Cretaceous sediments east of Block 3B/4B. For example, wells located on the shelf confirm the presence of sandstone input into the area, and also confirm the presence of Cretaceous source rocks that are key to a working petroleum system.

Sediments of Albian age were deposited in the shelfal areas by distributary meandering channels on the lower to middle shoreface of a delta front. Proportions of sand up to 63% are noted and a general trend of decreasing sand proportions across the shelf is observed, with approximately 60% sand in proximal wells such as A-K1 and P-Fl, and very low proportions sand (4% to 5%) deposited in distal wells such as A-C3 and K-A2. Where tested, these Albian sandstones have good porosity and permeability and good flow rates.

In Ibhuhesi field, located east of Block 3B/4B, Albian deltaic sandstone reservoirs achieved rates greater than 30 MMscf/d from individual zones.

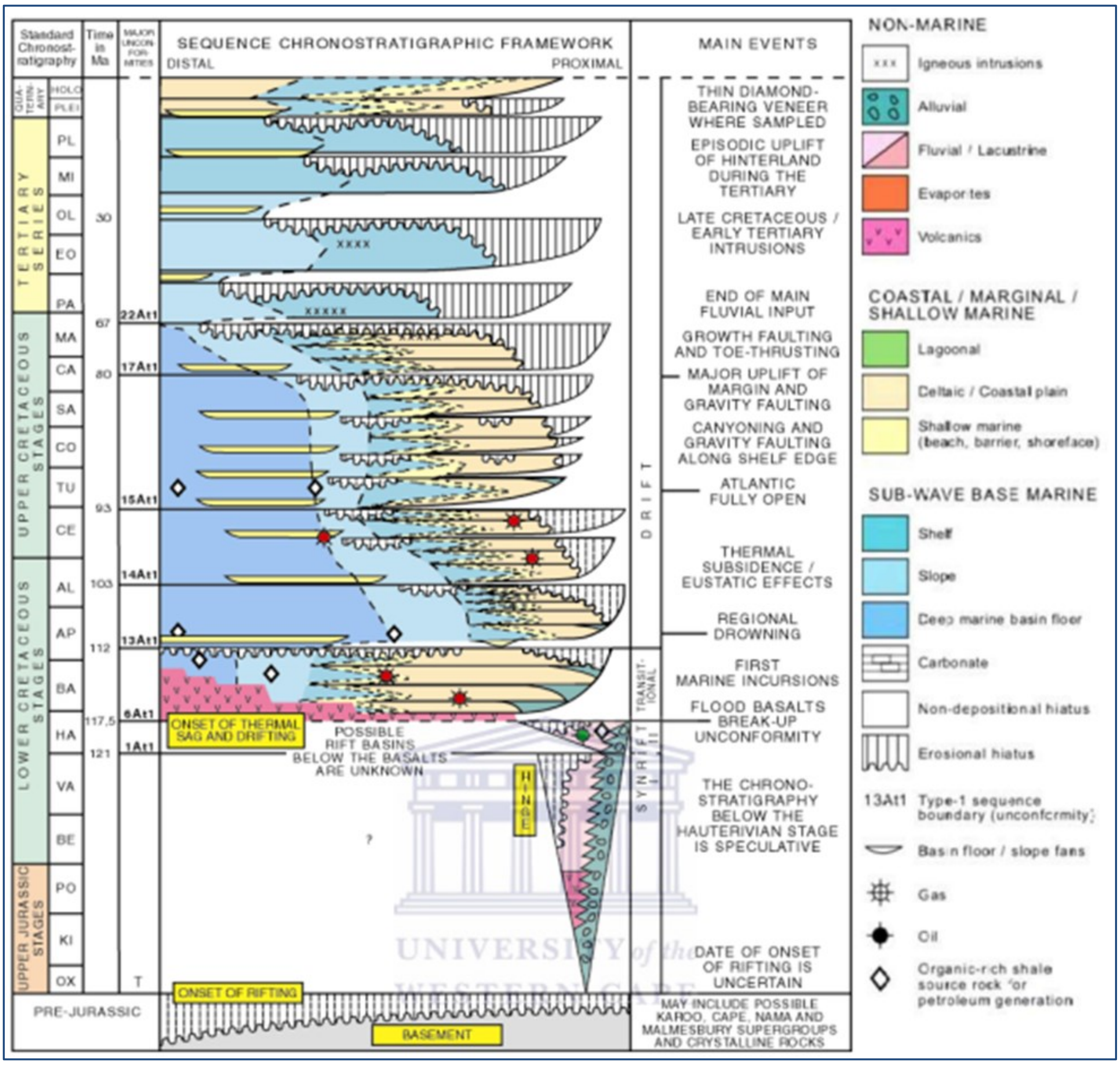


Figure 4-1: Chronostratigraphy for the Orange Basin (after PetroSA Report, 2003).

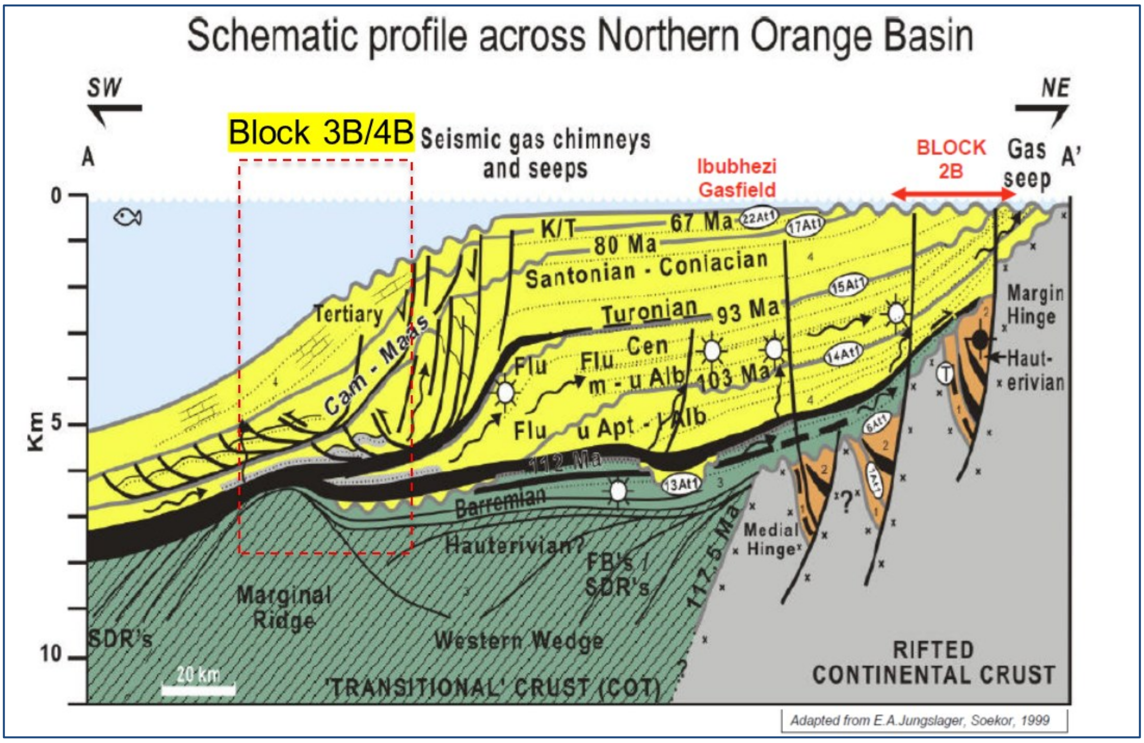


Figure 4-2: Schematic seismic profile showing location of Block 3B/4B within continental slope deposits.

Structural deformation, or faulting is not prominent in Cretaceous sediments of Block 3B/4B although some minor faulting and soft-sediment deformation has occurred in some rather limited intervals within the Cretaceous or Tertiary sections. However, a prominent topographic high referred to as the 'Outer Ridge' or 'Outer High' provides an important structural element for Block 3B/4B. This feature was a topographic high during deposition of the Aptian-Albian time and in some areas the key source rock interval is thin or absent over this Outer High[7] (Figure 4-2 & Figure 4-3).

Similarly, the Outer High affected deposition of Albian turbidite fans which in some areas ponded, thinned, or pinched-out against this topographic feature. Lower areas or 'gaps' in the Outer High allowed turbidite sediments to more easily reach deepwater areas. The Venus and Graff discoveries in Namibia are located seaward of one these 'gaps' in the Outer Ridge where sediments could more easily funnel through to more distant slope and deepwater areas. In Block 3B/4B one of the larger prospects in the inventory, 'Fan-S', is a turbidite fan that thins and truncates against the Outer High, forming a combination structural-stratigraphic trap. Further offshore, and in the area of Block 3B/4B, these Albian sandstones were deposited as turbidite channels and fans and form one of the principal reservoir targets.

Following deposition of Cretaceous sediments, Tertiary deposition continued with the development of an aggrading shelf margin with little or no deformation. Later phases of deposition during the Tertiary are characterized in some areas by instability resulting in development of a coupled growth fault and toe thrust system but these are not prominent in Block 3B/4B and have not been a focus for developing the prospect inventory. The current prospect inventory does not include any prospects of Tertiary age, but this shallow section could contain thermogenic gas generated deeper in the Cretaceous section. Tertiary deposition is

[7] Referred to as the 'Marginal High' in some texts

most significant from the prospective of source maturation in Block 3B/4B, as it is the timing and thickness of Tertiary deposition that drives the maturation of Cretaceous source rocks in Block 3B/4B.

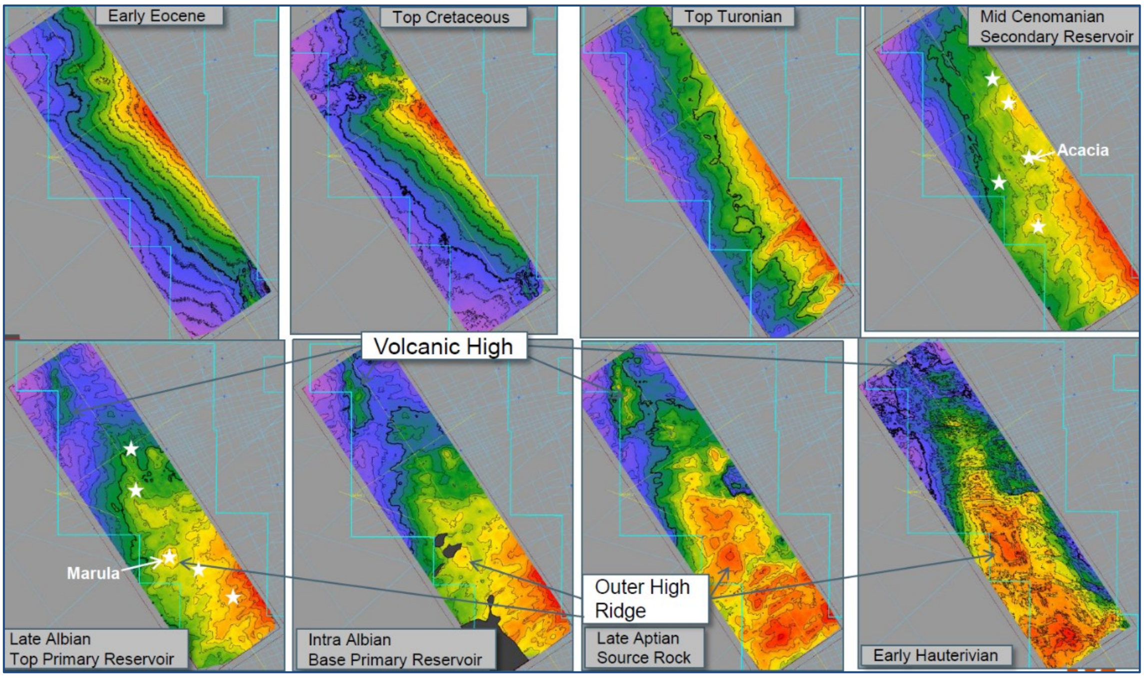


Figure 4-3: Blockwide structure maps from Early Cretaceous through Eocene time, Block 3B/4B.

Shelfal well K-D1, was used as a key well for well-ties into Block 3B/4B seismic because of the total depth of penetration (Figure 4-4). Unfortunately, well K-D1 did not penetrate the Late Cretaceous turbidite feeder channels that would have helped the correlation of sands in the deepwater section.

4.1.1. Source Rocks

Cretaceous Aptian-Albian and Barremian shales have been identified as source rocks in the Orange basin. Wells located inboard and adjacent to Block 3B/4B provide key evidence for source rock quality and maturity. Potential source rocks of Aptian and or Albian age are penetrated in wells A-F1, A-E1, K-A2, A-C2, PA-1, 0-A1, and DSDP-360 (Table 4-1). These source rocks are generally characterized by modest TOC's (2% to 3%) with kerogen types that are indicative of mixed oil and gas-prone source rocks. To the west of the Outer High, source rocks are expected to be more oil prone due both to their lower maturity and less terrigenous clastic input. This interpretation is based not only on the recent light oil and west gas discoveries by Shell and TotalEnergies, but by data provided by DSDP[8]-361 located southwest of Block 3B/4B which encountered Aptian organic-rich black shales with TOC[9] content up to 25% with a thermal maturity capable of oil and wet gas generation.

[8] Deep Sea Drilling Project
[9] Total Organic Carbon

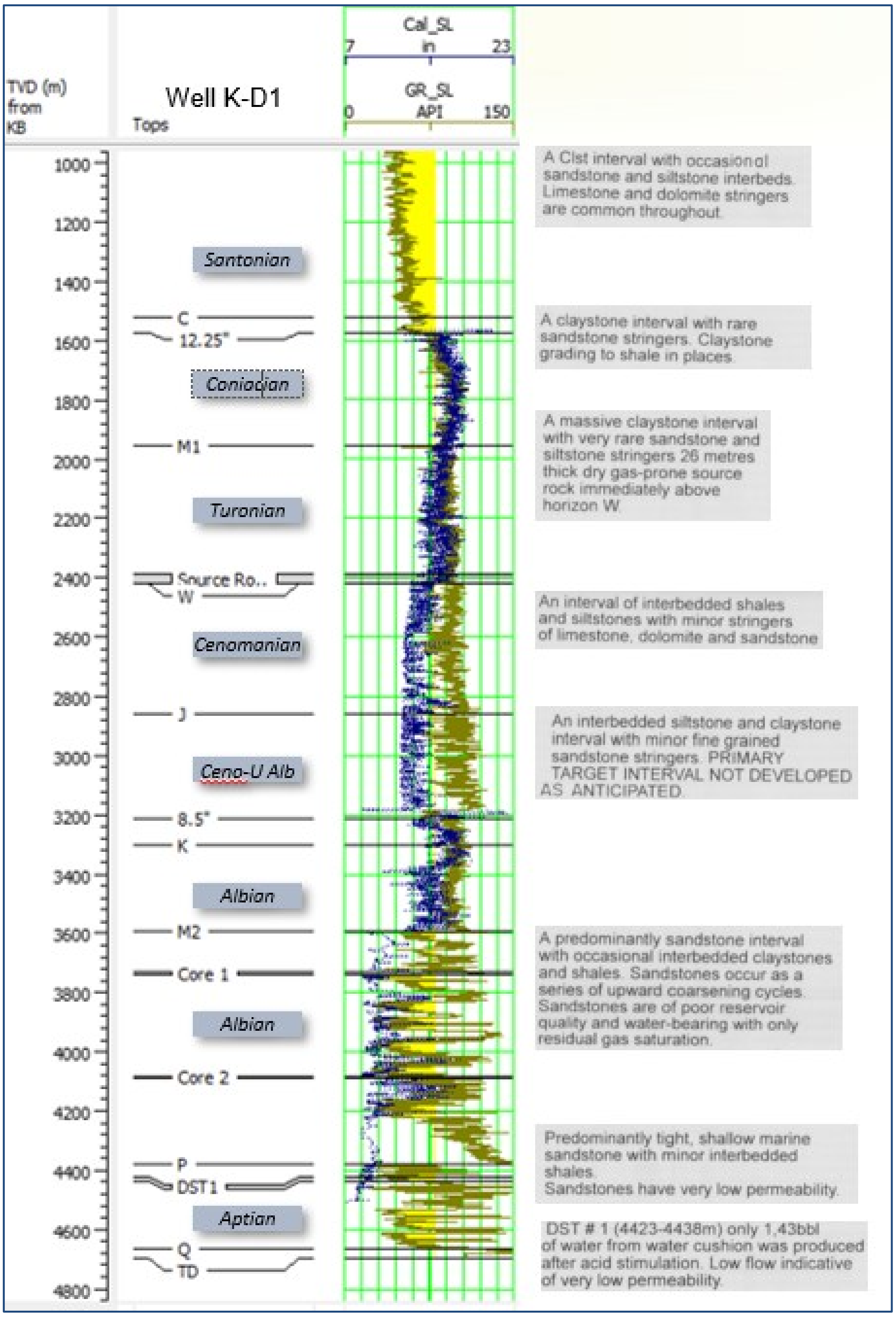


Figure 4-4: Type log from shelfal well K-D1, used as a key well for well-tie into Block 3B/4B seismic.

Table 4-1: Source rock data from selected Orange Basin wells

Sample Well	Barremian	Aptian	Albian
Kudu	90 m, TOC 1.6%, gas prone	150 m, TOC 2%, wet gas to oil prone initially,. Vitrinite Ro>1.3, yield up to 11 KgHC/T	
A-F1		HI>500g/Kg	
A-E1		2-3% TOC (4,100 – 4,774 m)	
K-A2 (Apto-Albian)		>4% TOC (4,500 – 4,760 m) 1-3% TOC (4,800 – 5,100 m)	
A-C2	Present	2% TOC (2,900 – 3,250 m)	2 TOC (2,650 – 2,700 m)
P-A1		2% TOC (1,900 – 2,300 m)	
O-A1 (Apto-Albian)		2.5% to 3% TOC (3,740 – 3,780 m). HI 110-200, yield of 3-6 kgHC/T, wet gas to oil prone	
DSDP-361		300 m interval, TOC up to 25%, yield > 2kgHC/T (upto 150 kgHC/T) with HI reaching 800 mgHC/g. Oil to wet gas prone, marine and terrigenous influence.	

Inboard of Block 3B/4B basin these source rocks are in the gas window as evidenced by the discoveries to date. However, Tertiary and Late Cretaceous overburden thins towards Block 3B/4B, and basin models suggest that source rocks are less mature and in the oil window (Figure 4-5: Note absence of source rocks on Outer High). This modeling prediction is supported by the recent light oil and wet gas discoveries by Shell and TotalEnergies along trend in Namibia.

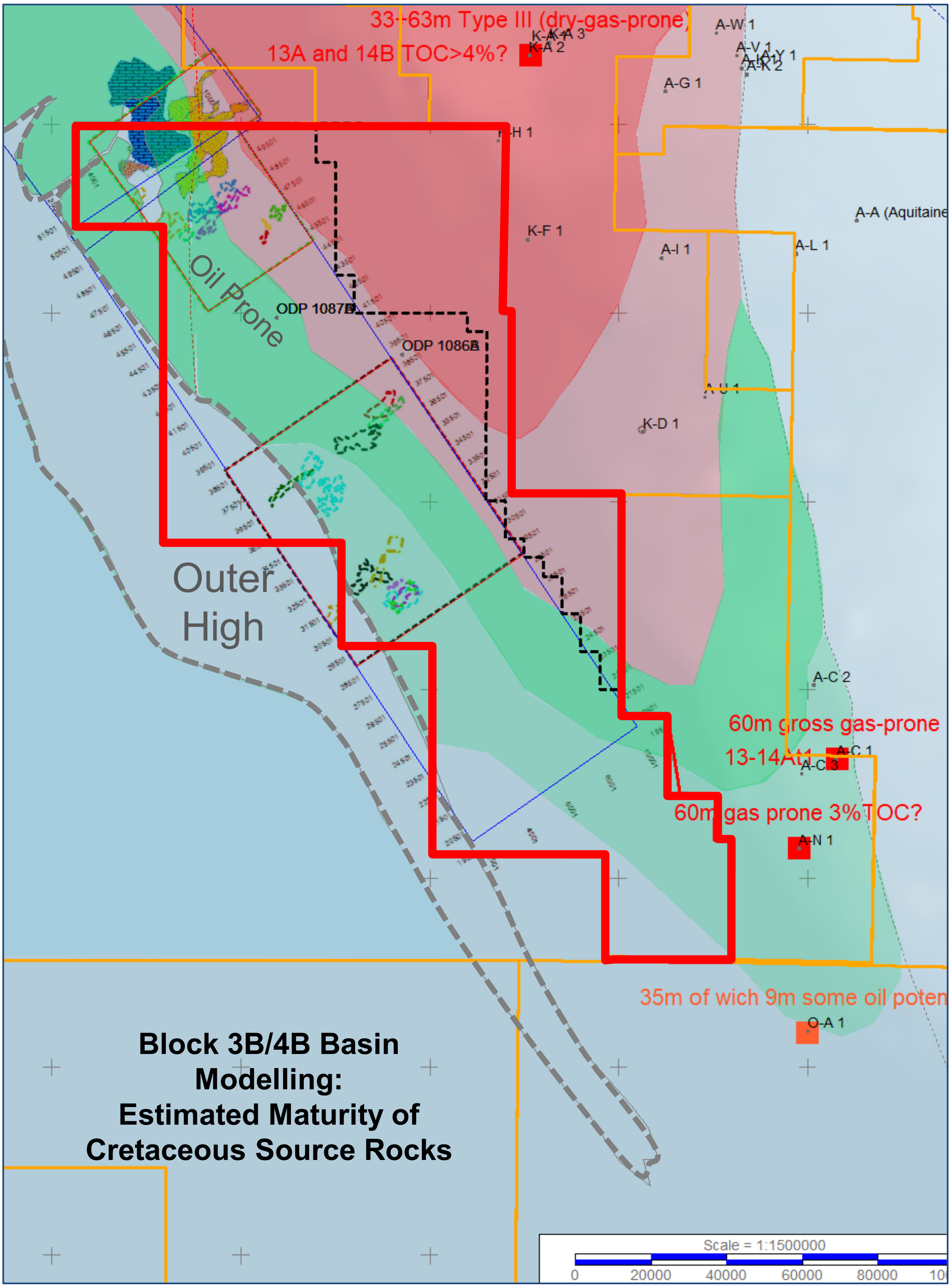


Figure 4-5: Source Rock maturity map for Aptian-Albian source rocks.

4.1.2. Reservoirs

Expected porosity and permeability ranges for potential Cretaceous reservoirs in Block 3B/4B have been derived from depth versus porosity cross plots based on available well control, most of which are located to the east of Block 3B/4B. Since prospects in Block 3B/4B are targeting different facies (turbidite sandstones versus fluvial-deltaics), analog data from other deepwater discoveries has also been incorporated into estimates for reservoirs parameters. The work of Bjorkum et al. (1998) for example provides a useful reference for estimating porosity of Upper Cretaceous sandstones deposited in a turbidite setting and buried to depths of 3 km to 4 km with a temperature gradient of circa 30°C/ km.

Primary reservoir targets in Block 3B/4B are as follows:

- Santonian or 'Upper Cretaceous' age sandstones deposited in turbidite channel and fan systems at the slope margin.
- Cenomanian-Turonian age sandstones deposited in turbidite channel and fan systems at the slope margin and outer slope.
- Albian sandstones deposited as turbidites as basin floor fans.

Studies of analog reservoirs in the Orange Basin have shown that diagenetic alteration can reduce porosity and permeability by quartz overgrowth and authigenic chlorite precipitation. In some cases, the presence of chlorite has proven to inhibit quartz overgrowths, thereby preserving porosity. However, an abundance of chlorite can reduce permeability, which can also be improved or degraded by other factors such as sorting. For prospects in Block 3B/4B porosities are generally considered to have a P50 of 20%, increasing to 25% where reservoirs are shallower and thickest.

Permeabilities are expected to be in the 10's to 100's of millidarcies based on limited well penetrations and analog data. The expectation for low viscosity light oil is expected to offset lower permeabilities and flow rates above 10,000 bopd can be achieved based on analog data from similar reservoirs, pressures, and fluid characteristics.

Seismic attributes and particularly AVO analysis has been a particularly good tool for identifying potential reservoir targets in the upper Cretaceous sequences of the Orange Basin. While calibration to well control is required for porosity and fluid prediction, in the absence of nearby well control and as a qualitive indicator, AVO analysis forms the most robust exploration tool for identifying sandstone turbidites in Block 3B/4B. Although seismic amplitude responses are non-unique, when AVO anomalies conform to depth this may be indicative of fluid contacts, which greatly increases the chance of encountering hydrocarbons. Several prospects within the Block 3B/4B prospect inventory exhibit some conformance to depth contours.

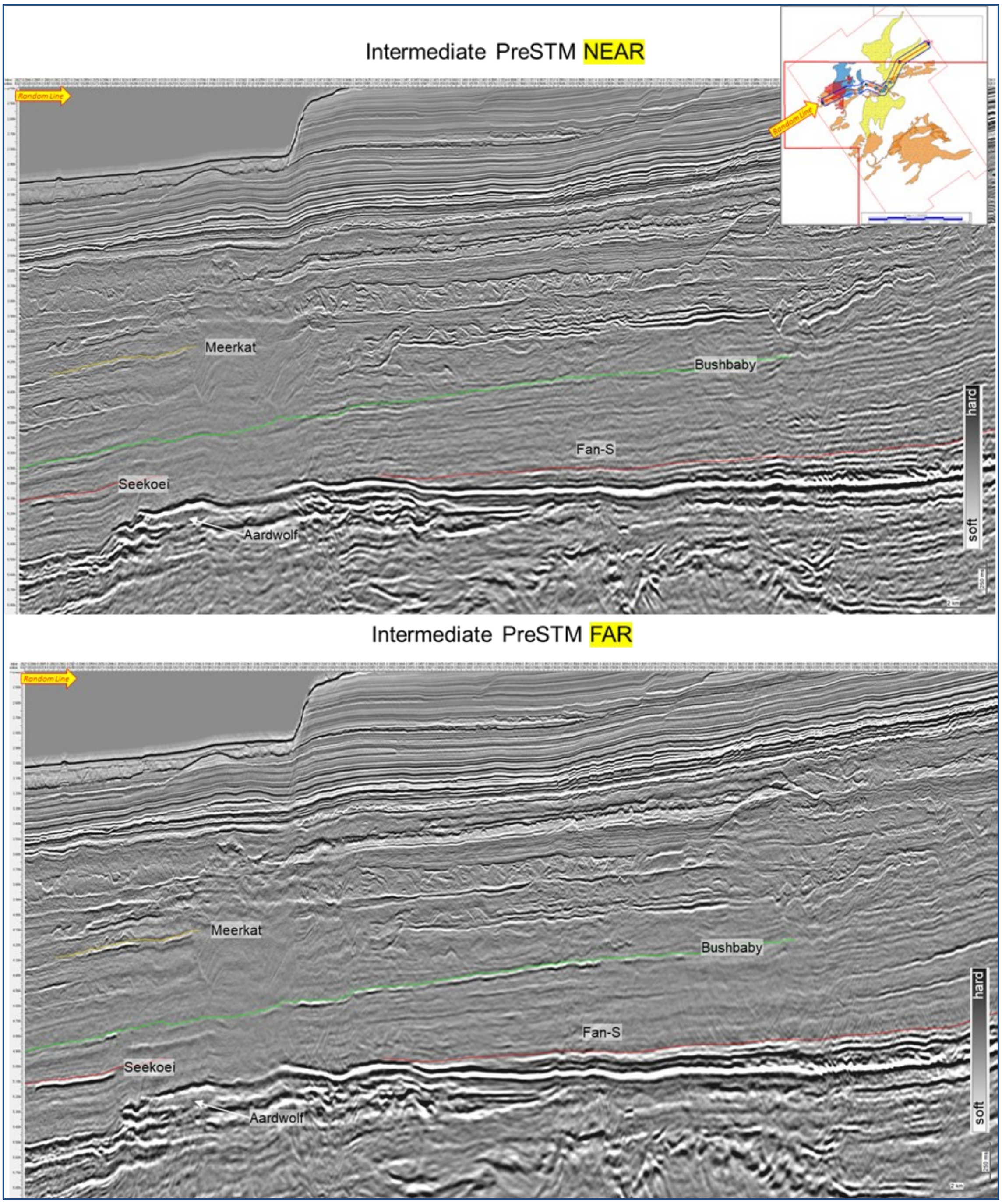


Figure 4-6: Examples of Near- and Far offset seismic data showing prospective reservoir targets in the Northern Area.

4.1.3. Play Types

Prospects within the Block 3B/4B inventory all target Cretaceous reservoirs which are sourced from Aptian-Albian source rocks, and therefore all part of a single proven petroleum system. Inboard of Block 3B/4B, source rocks have more overburden and deeper burial has pushed source rocks into the gas window. Within Block 3B/4B and source rocks are generally in the oil, or wet gas window, becoming more oil prone to the west as overburden is thinner.

Within this proven petroleum system there are at least four general play types (Figure 4-7 & Figure 4-8). The first three are similar in that they all rely on stratigraphic trapping and the key tools for identifying prospects rely on seismic attributes. Sand bodies are identified based on amplitude, relative impedance, AVO characteristics, shear modulus, and cross plots of these various attributes to produce relationships such as 'Fluid Factor' that can provide insight to fluid composition within reservoir targets.

Prospects are high graded if they show evidence of an up-dip pinchout for trapping. AVO anomalies with strong increase in FAR angle gathers are ranked higher, and AVO anomalies that have conformance to depth, indicative of a possible fluid contact are ranked with the highest chance of success.

1. **Santonian or 'Upper Cretaceous' Turbidite Play** - target reservoirs are turbidite sandstones deposited in an outer slope environment.

- Reservoir: turbidite sandstones 10 m to 30 m thick, often stacked;
- Reservoir Geometry: channelized, overbank, splays, and basin-floor fans;
- Traps: stratigraphic or combination traps relying on up-dip truncation of feeder channels;
- De-risking Elements: clear imaging of updip pinchout, strong AVO anomalies (Class II or III), conformance of AVO anomaly with depth contours.

2. **Cenomanian-Turonian Turbidite Play** - turbidite sandstones deposited in an outer slope environment; with the same prospecting characteristics as above.

3. **Albian Basin Floor Fan** - similar characteristics to Plays 1 and 2, except that sand bodies tend to be more widespread and fan-shaped due to their deposition on the basin floor. In these low gradient areas sand deposition is heavily influenced by subtle changes in topography, such as the Outer High.

4. **Barremian-Aptian Carbonate Ramp Play** - characterized by positive features of Albian age located in close association with the Outer High and interpreted as isolated carbonate platforms or ramps. Prospects often exhibit internal seismic reflections with clinoform geometry. Similar leads have been recognized along the Outer High and into Namibia. No carbonates have been encountered at this stratigraphic level in any of the inboard wells. The closest penetration of carbonates in the deepwater trend is Moosehead-1 and reservoir risk is deemed high as a result.

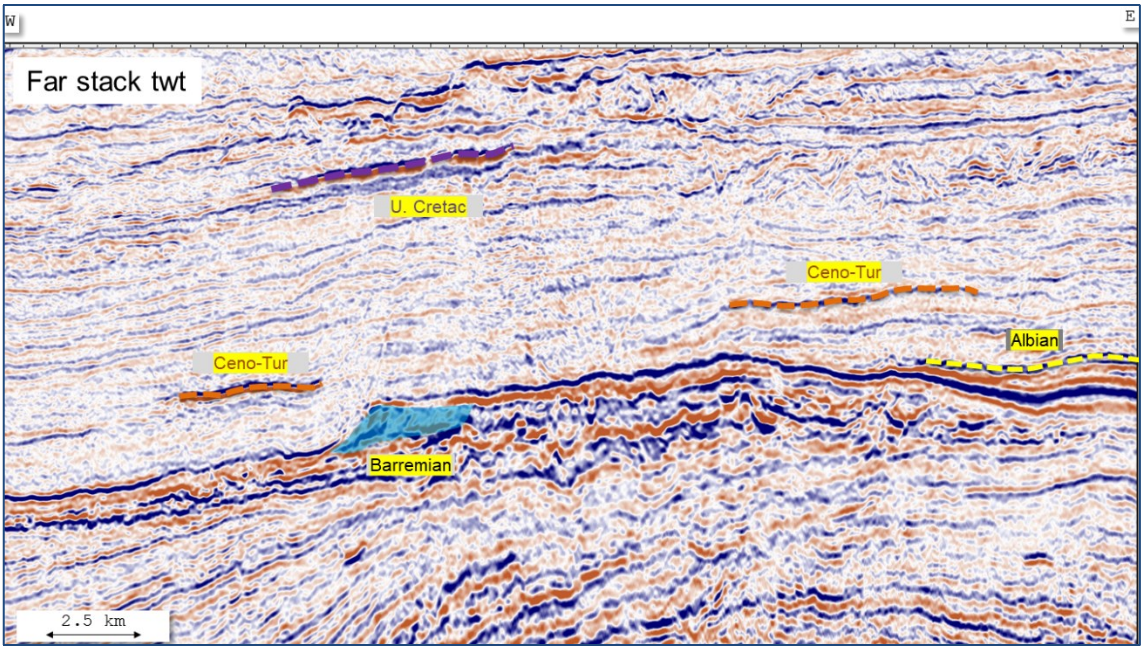


Figure 4-7: Examples of the 4 primary play types in Block 3B/4B.

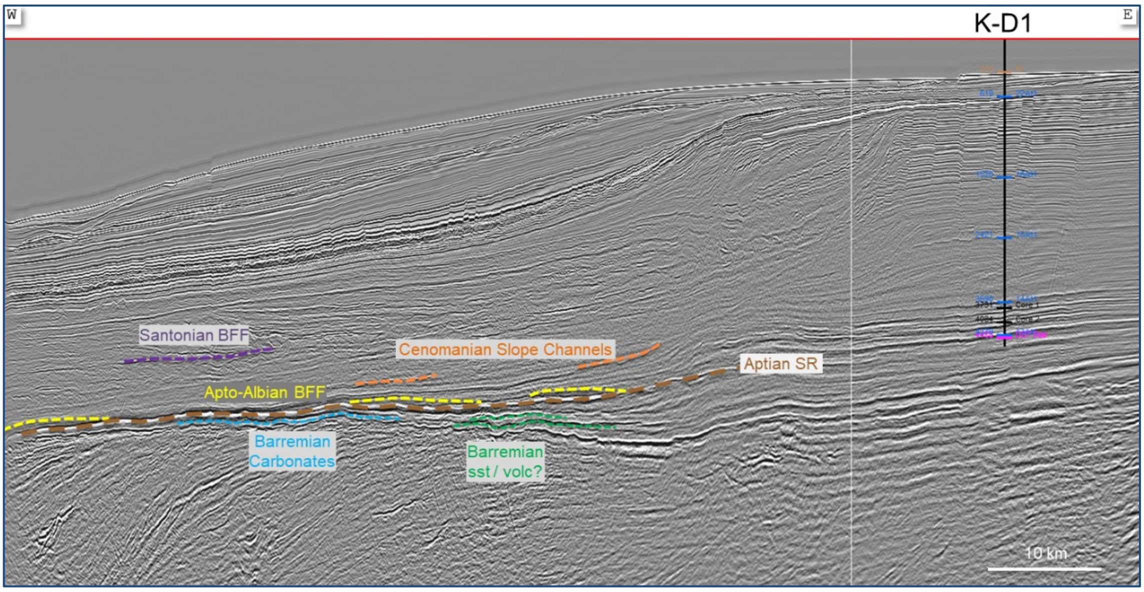


Figure 4-8: Examples of the four primary play types in Block 3B/4B, showing tie to well K-D1.

4.2. Regional RE & Analogue Data

There are no well penetrations outboard of the K-D1 well in the deepwater setting that characterises the 3B/4B block area. The closest and likely the best analogues for the exploration potential on the blocks are the Venus -1 well and Graff -1 well drilled by TotalEnergies and Shell respectively to the north west, and the Luiperd and Brulpadda wells drilled in Block 11B/12B to the east (Figure 3-1). However, public data is limited so analogue data from other fields that produce from deep water turbidites has been used to define the volumetric input parameters for this evaluation and to support the reservoir fluid and gas assumptions.

Knowledge and experience of similar plays in Equatorial Guinea, Cameroon and Ghana has been used to help describe the plays and risks for the prospectivity on the Exploration Right .

The Outer High plays an important role in controlling reservoir and source rock distribution. It also acts as a focus for migration and is partially responsible for generating many of the trap configurations seen in the Block 3B/4B prospect and lead portfolio.

Similar plays seen in the TotalEnergies and Shell acreage offshore Namibia are expected in Exploration Right 3B/4B.

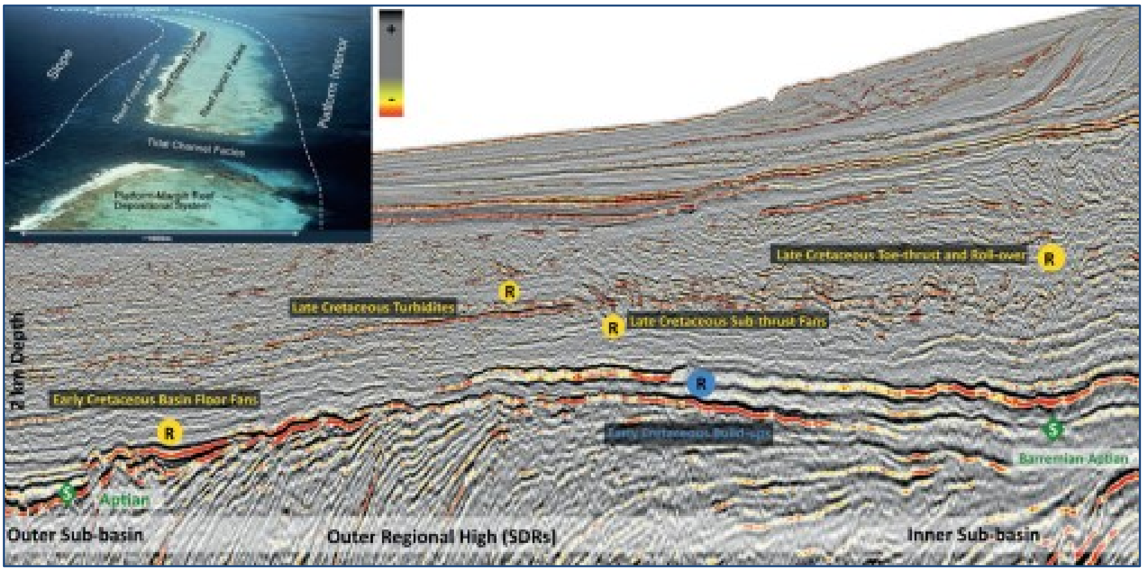


Figure 4-9: Hydrocarbon play concepts inboard and outboard of the Outer High in the Orange Basin, Namibia. Yellow R – Clastic Reservoir. Blue R – Carbonate Reservoir, Green S – Source Rock. Inset showing carbonate bank with clastic influx routes (Loucks et al., 2003) TGS.

The TotalEnergies operated Venus discovery is part of a basin floor fan fairway sitting on Aptian source rock in the outer sub basin, west of the Seaward Dipping Reflectors (SDR) basin high and located outboard of the Outer High (Figure 4-9, Figure 4-10 & Figure 4-11). The Early Cretaceous reservoir sands are probably sourced from the East and transported across the carbonate platform that sat on top of the Outer High. The Venus basin floor fan sands are onlapping the Outer High. The discovery is reported to have 84 m net pay with reported light oil.

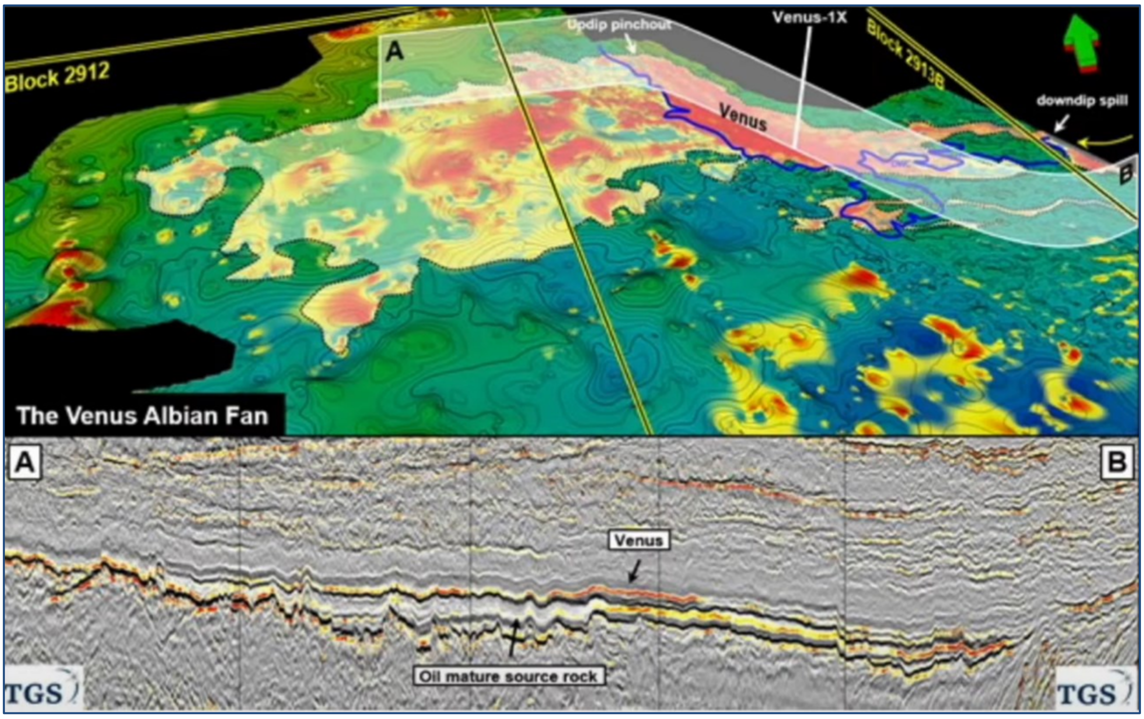


Figure 4-10: North to south strike line across Venus and structure map showing seismic amplitudes.

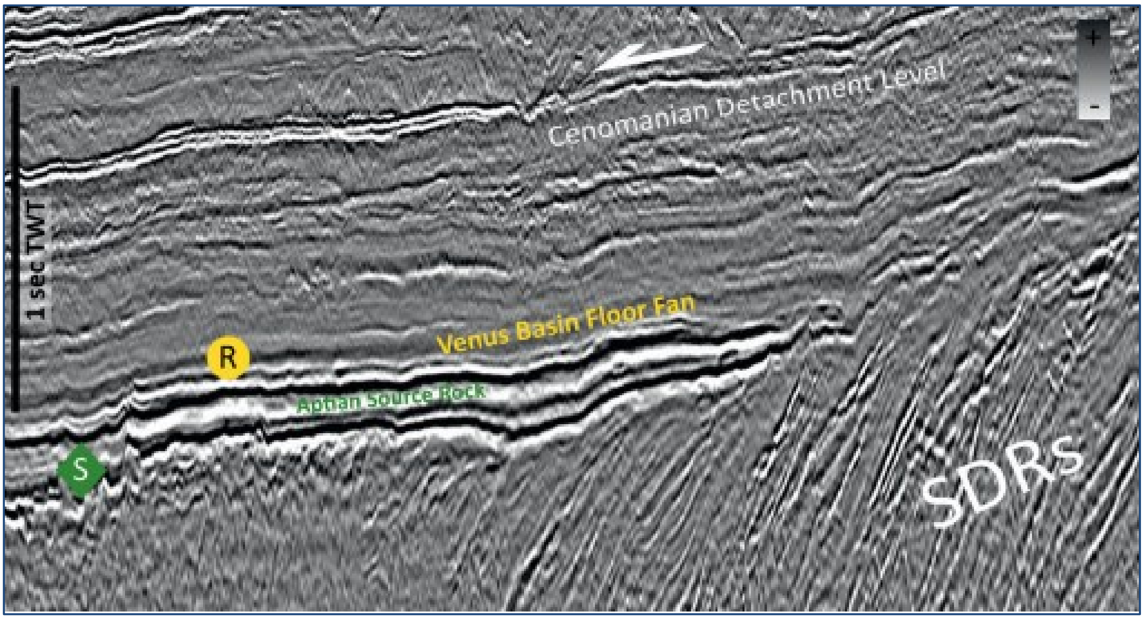


Figure 4-11: SW – NE dip line through the Venus – 1 structure (TGS)

The Late Cretaceous evolution of the Orange Basin is strongly characterised by episodic gravitational collapse of the margin. The main gravitational collapse structure is found inboard of the Outer High and soles out on a potentially over pressured Cenomanian-Turonian source rock. The Cretaceous section above the Cenomanian detachment has suffered structural collapse to the west creating multiple toe thrust and imbricate structures.

The Shell operated Graff–1 well discovered light oil in two different reservoir intervals in 2022. The reservoir is Late Cretaceous in age (possibly Campanian to Santonian) and is located at the western end of the toe thrust system and the base of collapsed structures (Figure 4-12) approximately 2.5 km below mudline.

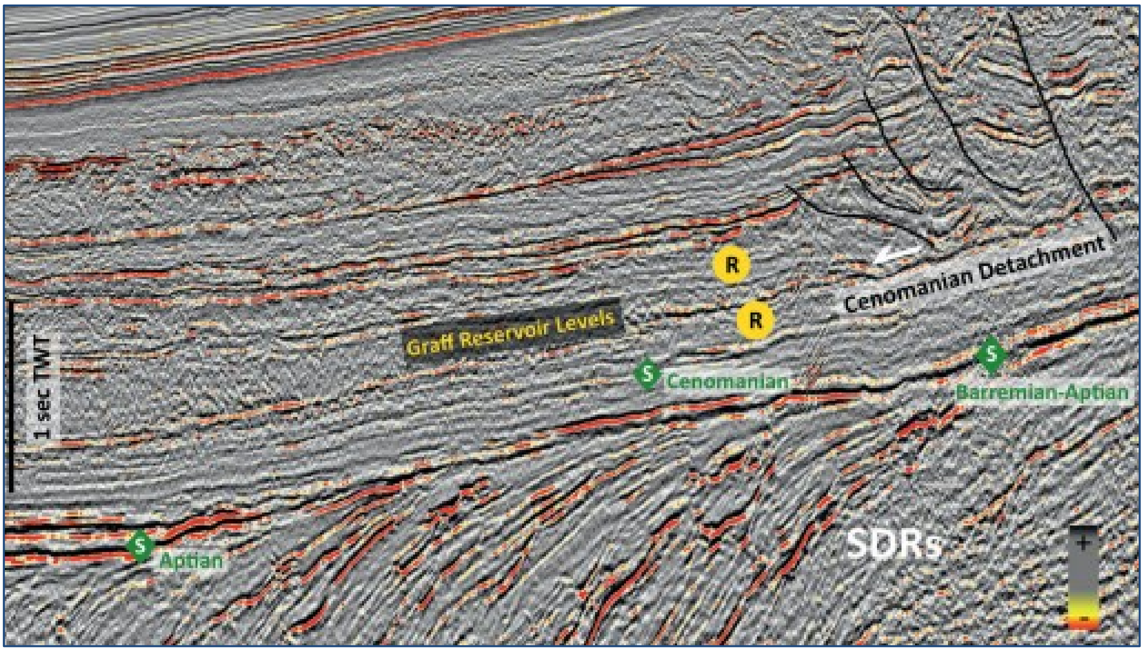


Figure 4-12: NE dip line through the Graff light oil discovery (TGS).

The trap appears to be a sub-thrust trap developed at the end of the main Late Cretaceous toe thrust structure. The Outer High probably played an important role controlling distribution of the Graff-1 Late Cretaceous reservoirs causing turbidites to pond to the east of the Outer High.

The carbonates in the Outer High are another unexplored play. The Early Cretaceous carbonate platform is mainly restricted to the inner sub basin and crest of the outer high.

4.3. Exploration/appraisal/ Permit history

Recent exploration has opened a new deepwater play. TotalEnergies made the Brulpadda gas-condensate discovery on Block 11B/12B in 2019. Prior to the discovery, South Africa's deepwater plays had seen minimal exploration. Only four deepwater exploration wells had been drilled in the late 1980’s and early 1990’s, in the Southwest coastal basin. TotalEnergies followed Brulpadda discovery well with the Luiperd discovery in 2020.

4.4. License Activity to Date

During the Initial Exploration Period joint venture partners purchased and acquired digital copies of 2D and 3D seismic data, well data, and regional reports from the Petroleum Agency of South Africa (PASA). As part of the minimum work programme the joint venture partners performed regional mapping, basin modelling studies, well log interpretation, and quantitative rock physics and AVO seismic attribute analysis on legacy

2D and 3D seismic data. In 2022, the 3B/4B partners completed reprocessing 2,020 km^2 of legacy 3D seismic survey, exceeding the minimum work commitment for the current exploration period.

The remaining work programme for the current exploration period includes the interpretation of recently reprocessed 3D seismic, geologic studies to rank prospects, and recommendations for exploratory drilling candidates. The reprocessing effort was successful in terms of providing improved seismic imaging and further de-risking the existing prospect inventory and has helped AOC identify new prospects. The current audit assesses the prospective resources of this updated prospect inventory.

The current two-year license period does not include an exploratory well as part of the minimum work programme.

5. Block 3B & 4B

Block 3B/4B lies within the Orange Basin, formed from the breakup of the African and South American continents starting in Jurassic time. Primary reservoir targets are;

- Santonian or 'Upper Cretaceous' age sandstones deposited in turbidite channel and fan systems at the slope margin.
- Cenomanian – Turonian age sandstones deposited in turbidite channel and fan systems at the slope margin and outer slope.
- Albian sandstones deposited as turbidite basin floor fans onlapping the inboard and outboard margins of the Outer High.

A Barremian carbonate play is also present in the basin and presents an additional exploration target.

The seismic database is extensive consisting of approximately 14,000 km of 2D data and 10,800 km^2 of 3D. However, there are no wells in the 3B/4B license area. AOC have attempted to tie regional seismic surfaces to the K-D1 well which is the most seaward and deepest of the shelfal wells. These well to seismic ties have proved difficult because of the complexity of the geology with large gravitational slumps, scars and thrusts effecting the Late Cretaceous sedimentary section at the shelf edge and in the deepwater setting. Public data from the adjacent Venus and Graff discoveries has also been used to characterize and tie the stratigraphic section in the 3B/4B license (Figure 4-10 & Figure 4-11).

Given the absence of well penetration and any discoveries on the license, all volumes quoted in this report are considered as Undiscovered Petroleum Initially in Place and Prospective Resources as defined by the SPE Petroleum Resources Management System 2018 (PRMS) and COGEH.

The AOC evaluation of the Exploration Right was found to be extensive and of high quality utilizing the best data available and regional expertise to inform their evaluation of the prospective resources on the block. RISC audited the AOC work, modifying it where appropriate and added the following:

- Created a probabilistic range of prospective resource volumes as distinct from deterministic volumes centered around a P50 hydrocarbon body.
- Broadened the P90 to P10 range for the prospects. Reducing the P90 prospective resource to reflect the size of the individual anomaly to be tested.
- RISC also reviewed and modified the probability of geological success (Pg) and quality of seismic attributes, such as AVO, which might increase (or decrease) Pg for the individual prospects.

5.1. Introduction

The prospect inventory for Block 3B/4B has been divided into 'Northern Area Prospects' that includes 14 prospects that are within the newly reprocessed 3D seismic area, and the 'Central Area Prospects' that includes 10 prospects located in the central portion of the block (Figure 5-1 & Figure 5-2).

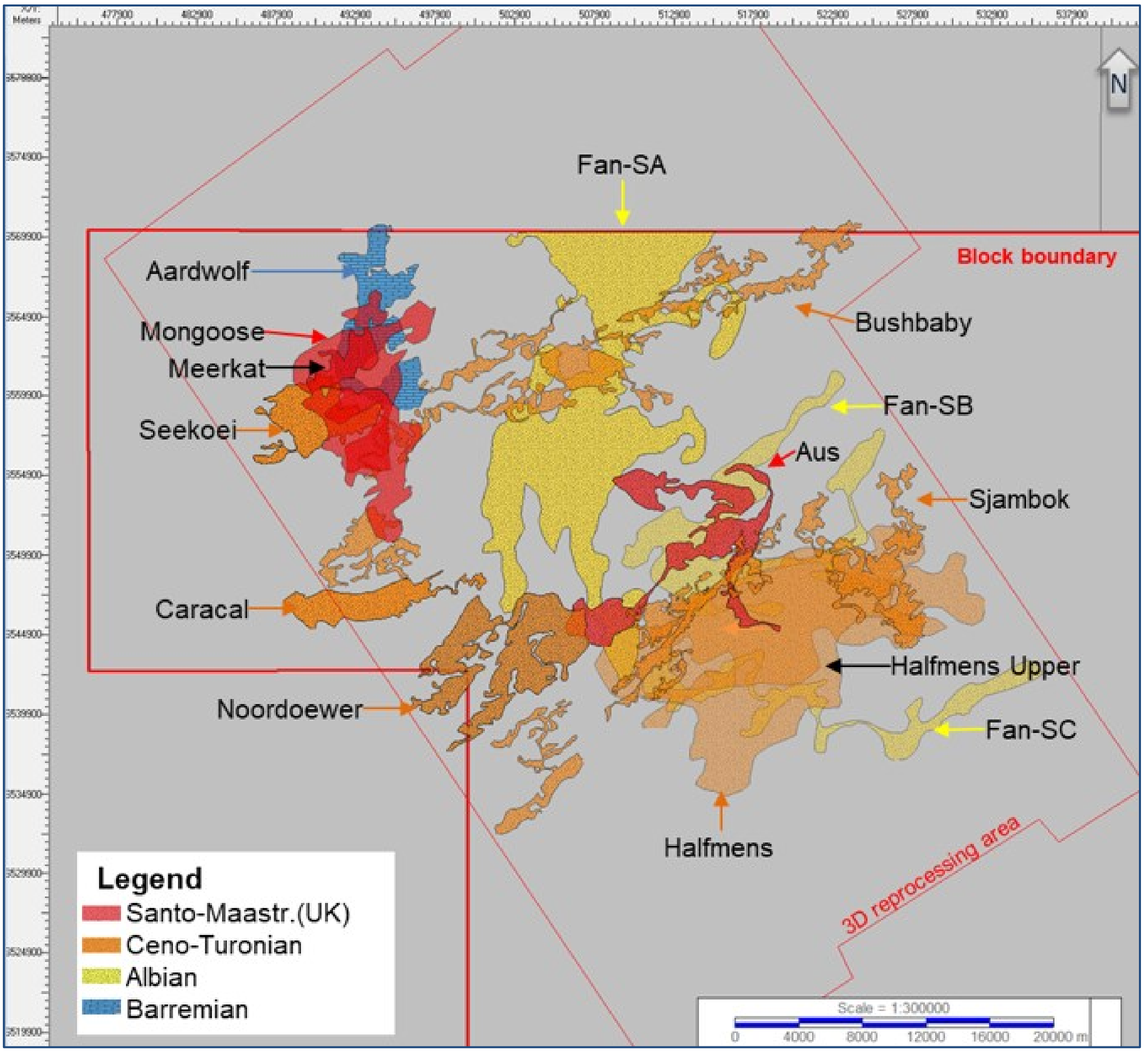


Figure 5-1: Location map showing the Northern Prospect Area and Prospects.

The audit process has included a review of the following interpretational products for each prospect:

- Seismic structure maps in depth;
- Maps of Full-Stack or relative Impedance amplitude;
- Maps showing Near-, and Far- trace amplitudes;
- Seismic sections of Near- and Far- trace amplitudes, in both strike and dip directions;
- Maps showing mid-estimate (P50) areas for volumetric estimates;
- Comparison of reservoir input parameters with known analogue and shelfal well data;
- Generation of probabilistic Undiscovered Petroleum Initially in Place and probabilistic Prospective Resources;
- An independent review of the Pg and uplift to Pg due to quality of seismic attributes applied to each of the prospects.

Summaries for each of the prospects and leads are shown in Appendix 1: Prospect Summaries.

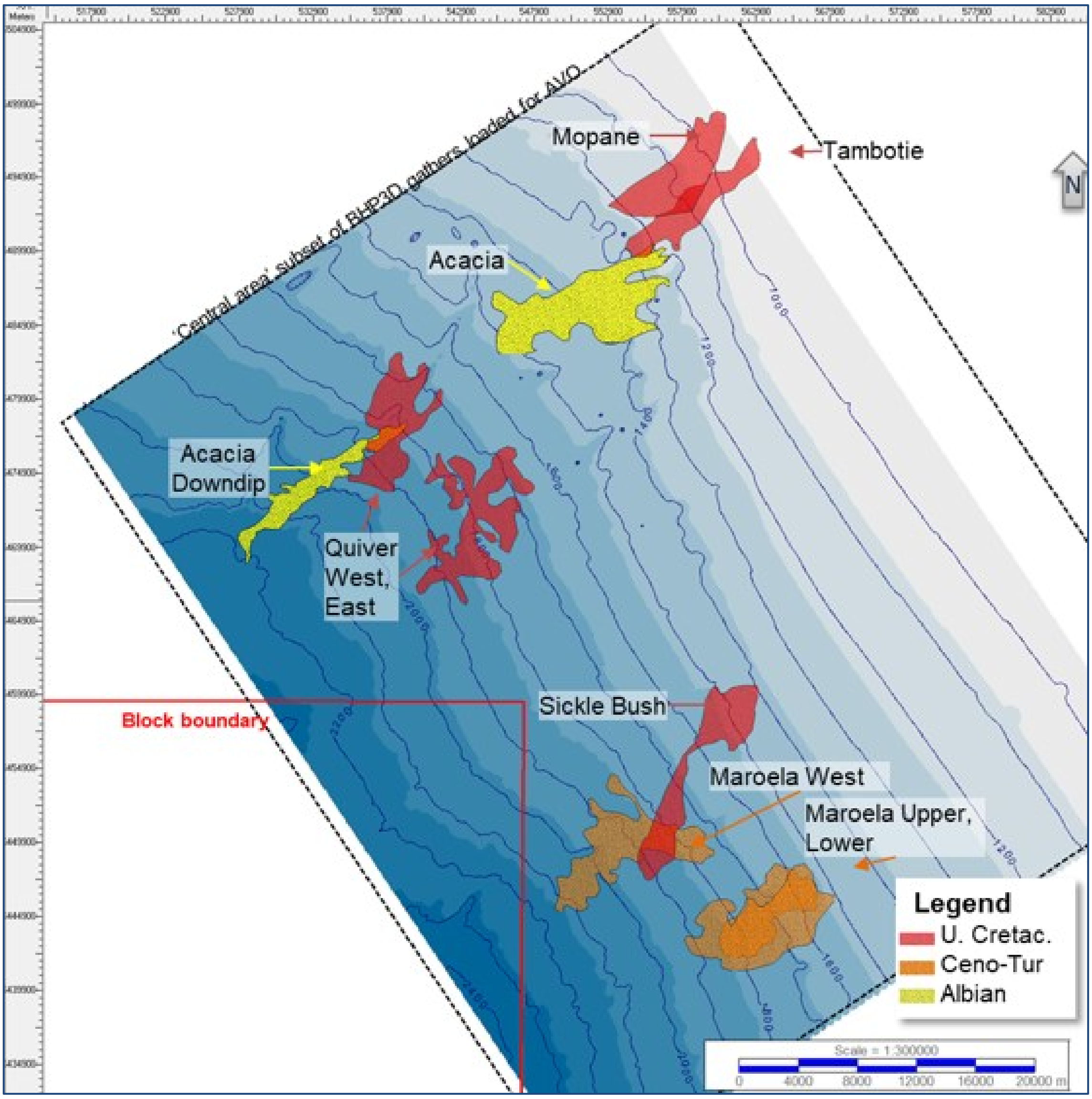


Figure 5-2: Location map showing the Central Prospect Area and Prospects.

5.2. Subsurface interpretation

5.2.1. Well Data:

Within Block 3B/4B well control is limited to the K-H1 well located on the northeast boundary of the block, drilled by Soekor in 1989. Another 12 wells are located east and outside of Block 3/4B. These wells were drilled by Soekor and Forest Oil in the 1980's to early 2000's to test shallower water shelf areas of the Orange Basin. None of these older wells encountered commercial hydrocarbons, nor did they target the prospective stratigraphic intervals that comprise the reservoir targets in the current prospect inventory, so their use is limited to confirming stratigraphic correlation with mapping seismic horizons. The current well database consists both of digital curve data and/or scanned well reports for the following wells: A-C1, A-C3, A-H1, A-I1, A-L1, A-N1, A-U1, K-A1, K-A2, K-A3, K-D1, K-F1, and K-H1 (Figure 5-3).

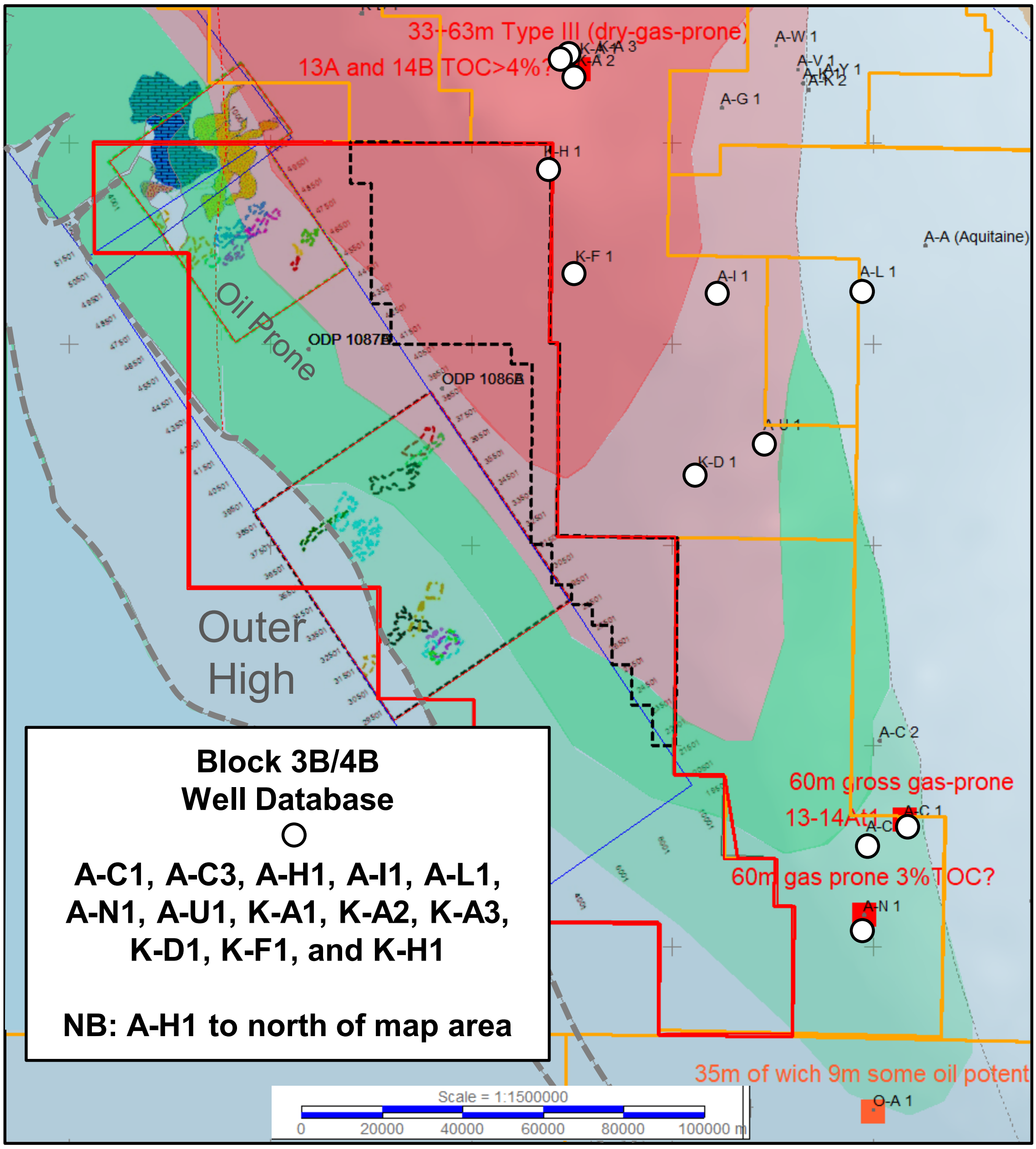


Figure 5-3: Exploration activity and play map.

5.2.2. Seismic interpretation

5.2.2.1. Seismic Database

Approximately 14,000 kms of 2D seismic and 10,800 km^2 of 3D seismic data exists over Block 3B/4B (Figure 5-4).

While a number of key 2D seismic lines have been acquired, the subsurface evaluation has largely utilized the extensive 3D seismic data that was acquired by PGS in 2013 for BHP Petroleum. This single 3D survey covers approximately 65% of the block and is joined in the northern part of the block by an overlapping 3D seismic survey acquired by Dolphin in 2013 for Shell. In 2022, a subset of the BHP survey was reprocessed by Down Under Geophysical (DUG) through Pre-Stack Depth Migration.

The seismic data accessible for this report includes the following:

- BHP 3D Survey (10,210 km²)
  - Acquisition (2013): PGS
  - Processing (2014)): Western
- Africa Oil Corp 3D Re-processing (2,200 km²)- DUG (2022)

The seismic data that were not accessible for this report includes the following:

- Shell 3D Survey (approx. 8,000 km²)
  - Acquisition (2013): Dolphin
  - Processing (2014): Shell
- Various 2D seismic surveys, particularly the more recent 'K2002' survey, of which two lines were reprocessed to serve as tie lines to well K-D1

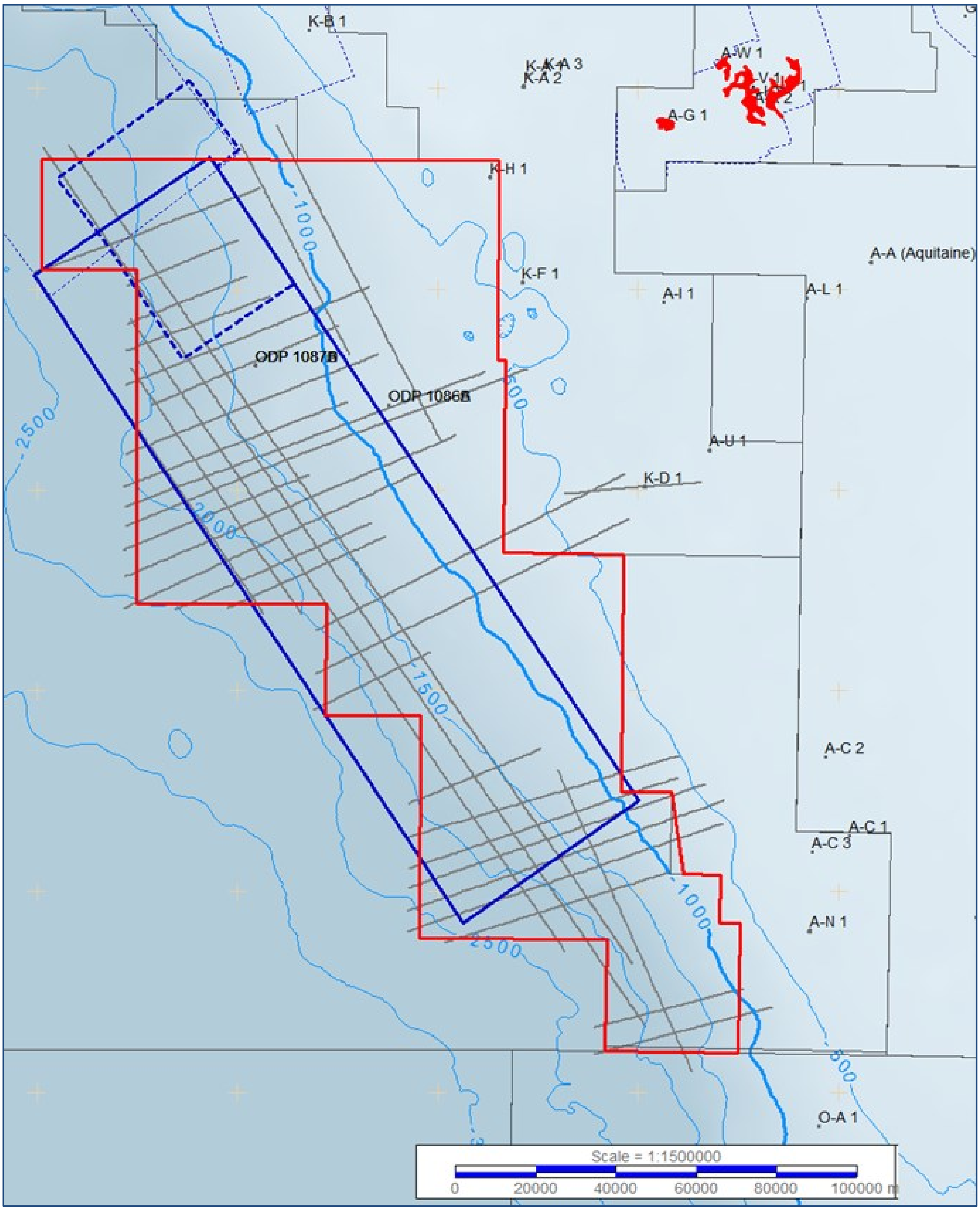


Figure 5-4: Map of 2D and 3D seismic data and well data within AOC database.

The 2022 dataset reprocessed by DUG is generally very good quality throughout the Cretaceous to Tertiary section and there is a consistent balance of amplitudes between the full and offset stack. The data do not suffer from noise contamination except for one relatively small area in the northwestern part of the survey where the Cretaceous amplitudes appear to be somewhat washed out. It is suspected that this area may have suffered from boat/seismic interference during data acquisition resulting in a poorer signal to noise ratio. The DUG processing report was not available for review and so no further detailed comment can be made on the processing and quality of the data. Full and partial offset stacks stretched back to time were available for the report. However, the depth and velocity datasets were not accessible.

The original BHP dataset, used to evaluate the Central Area is of reasonable quality. In general, the dataset is slightly noisier and so imaging is not as crisp and amplitudes less defined. Nevertheless, it is deemed suitable for this prospectivity evaluation. Full and partial offset stacks stretched back to time were available for this survey, but the depth and velocity datasets and processing report were not included in the review.

Pre-stack seismic data, common depth point (CDP) gathers, and other seismic project files have not been included in this review.

5.2.2.2. Seismic Interpretation and Depth Conversion

3D seismic interpretation was undertaken on time stretched 3D PreSDM stacks. These time horizons were subsequently depth converted using the final 3D velocity field. There are some differences between the BHP and the DUG 3D velocity fields, mainly related to a more detailed velocity model building being undertaken for the recent DUG reprocessing. During the DUG reprocessing, an attempt was made to tie the velocity field to well K-D1, using 2D lines from 2002 (included in the re-processing). Unfortunately, DUG concluded that the lithology at K-D1 is not representative of the lithologies and structures seen in the deep water reprocessing area. K-D1 mainly drilled shelf sediments. As such, the velocity fields used for the T-D conversions are uncalibrated. The anisotropy parameters are entirely data driven, rather than calibrated to a well. The absolute depths will therefore be uncertain until a well is drilled on the 3D. The absolute depth error is expected to be at least +/-5%.

Time horizon depth interpretation surfaces are sufficient to map out the extent of amplitude anomalies and define prospect areas. Many of the prospects are comprised of a strong amplitude a in single cycle seismic reflector making a base reservoir pick difficult. In such circumstances, the depth dataset has been used to estimate a range of reservoir thickness, to encompass a reasonable uncertainty, from the difference between the centre of the trough and the centre of the following peak.

Interpretation of seismic amplitudes has been a key part of AOC's work (Figure 5-5). RISC has reviewed the prospects and performed checks of the amplitude extractions on the far stack data. The areas associated with the high amplitude anomalies have been checked, calculated and used as an input to the in-place resource estimates. If the reduction in strong seismic amplitude is coincident and consistent with a structural contour in depth, then this conformance was noted as a possible fluid indicator rather than reservoir presence or quality indicator and RISC used this information as a factor for considering an uplift in prospect Pg.

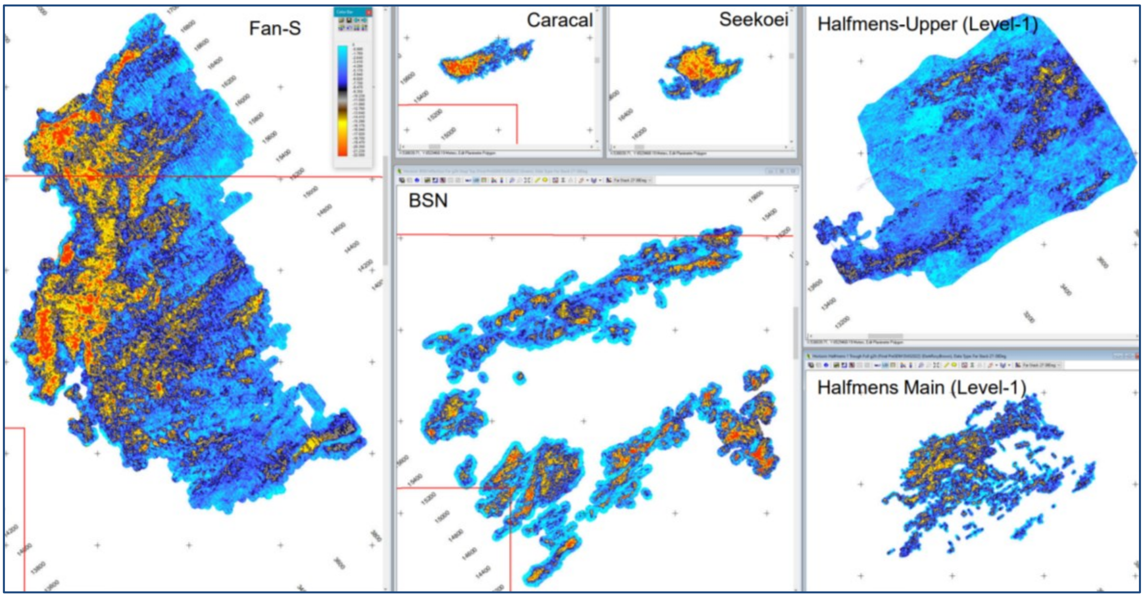


Figure 5-5: Examples of Far Stack Amplitude Maps, Northern Area (horizon based amplitude on top trough, far stack)

The second approach to QI and seismic data interpretation has been the analysis of pre-stack data. Intercept versus Gradient plots were used to characterise the class of the observed AVO anomalies, based on the industry standard approach of identifying the quadrant in which the anomalous data plots outside of the background trend. The pre-stack seismic data and interpretation project files were not accessible for review in this audit.

Strong seismic anomalies are observed at the Seekoie, Caracal, BSN and Sickle Bush prospects where there is a distinct cluster of points away from the background trend (Figure 5-6). The anomalies are not as strongly defined at Fan-SA and at Halfmens.

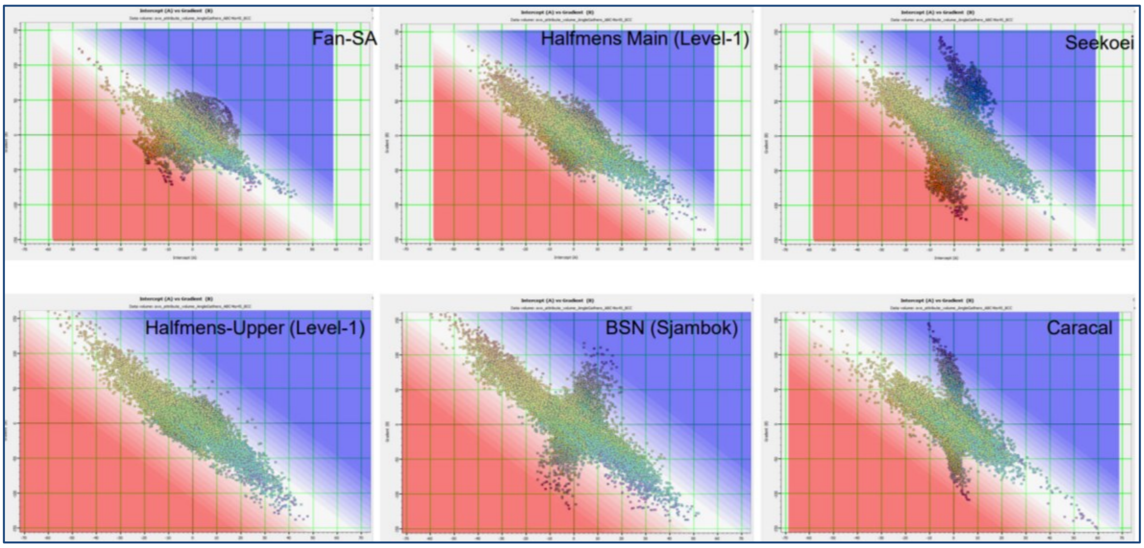


Figure 5-6: Example Prospect Intercept vs Gradient Plots, Northern Area (Northern area, Mid Cretaceous AVO prospects)

5.2.3. Reservoir description

Primary reservoir targets are:

- Santonian or 'Upper Cretaceous' age sandstones deposited in turbidite channel and fan systems at the slope margin.
- Cenomanian to Turonian age sandstones deposited in turbidite channel and fan systems at the slope margin and outer slope.
- Albian sandstones deposited as turbidite basin floor fans onlapping the inboard and outboard margins of the Outer High.
- A Barremian carbonate play is also present in the basin and presents an additional exploration target.

Palaeogeography shows the paleo Karoo river draining the South African hinterland transporting sands out into the Orange Basin adjacent to Block 3B/4B where the sands were reworked across the shelf and deposited as slope channels and turbidite basin floor fans. The headwaters of the paleo Karoo river were subsequently captured by the present day Orange River sourcing sands to the Namibian continental shelf. Kounov et al 2008 suggest that major incision from the paleo Karoo river began approximately 120 to 110 Ma and started to wane from 90 Ma till the end of the Cretaceous (65 Ma). This is from AFTA[10] data in the onshore area. The capture was therefore sometime in the Upper Cretaceous between 90 Ma and 65 Ma.

RISC hasn't seen evidence of shelfal incision points co-incident with the targeted reservoir intervals in the 3B/4B Exploration Right . However, recent deep water discoveries suggests sands are being reworked into the slope and basinal depositional environments adjacent to the present day Orange river that could support sand deposition across the shelf into the Northern area prospects. Public data suggests companies have seen sands and incision features in the A-I1 well that suggests sand mobilisation from the shelf into the deepwater setting adjacent to the Central Area prospects.

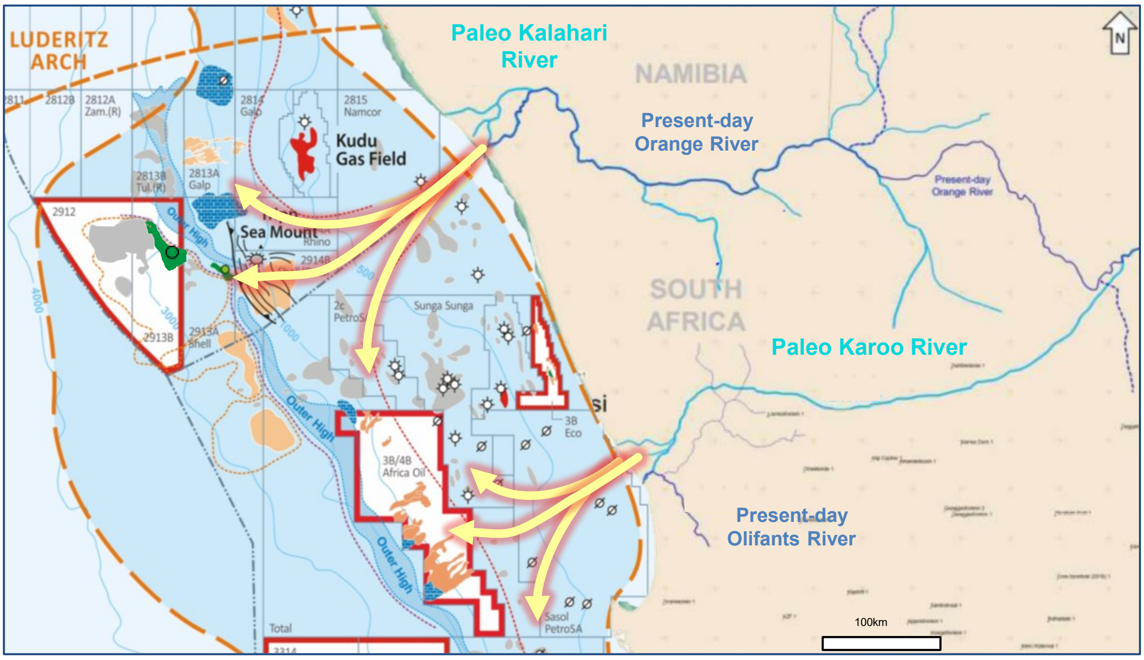
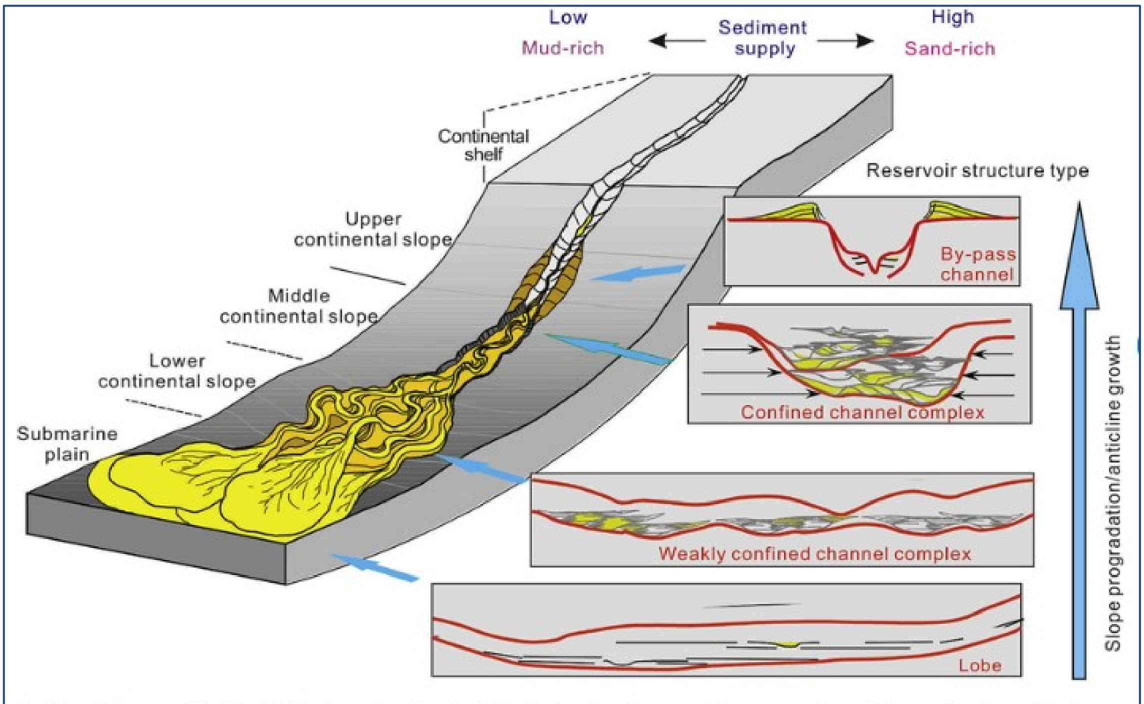


Figure 5-7: Paleo drainage patterns sourcing sands into the Orange Basin

[10] Apatite Fission Track Analysis

Whilst there are no well penetrations in the 3B/4B Exploration Right , gross sand isopach maps of the key reservoir intervals (Base Tertiary to Top Turonian, Late Cenomanian to Turonian, Late Albian to Early Cenomanian, and Late Aptian to Early Albian) on the shelf show between 40 and 300 m of sand deposited for each interval and retained on the shelf. It is likely these sands were also reworked by submarine slope channels into the deepwater environment.



Sedimentary model of turbidite fan showing that the incised valleys and by-pass channels are developed in the continental slope and the upper slope; the confined channel complexes and weakly confined channel complexes are developed in the middle slope and the lower slope; and the lobes are developed in the submarine plain (according to ENI with slightly modification).

Figure 5-8: Classic turbidite sand shelf to slope depositional model showing different channel complexes (Huang, Y. 2018).

Reservoir is seen as the primary risk for the 3B/4B Exploration Right . Whilst sediment mass transport sections are seen through Cretaceous times and proven in the shelf/proximal setting the risk remains that the outboard deepwater section of the Orange Basin may be sediment starved with only thin, fine grained, potentially low net to gross distal channel and fan lobes preserved (Figure 5-8). The compositional sorting (maturity) and associated reservoir properties of any coarser clastics present remain poorly constrained. This may be supported by the Cenomanian to Turonian channel and fan lobes prospects identified being 'single loop' (one seismic wavelet) events with no clear evidence of depositional architecture suggesting large mass transport complexes. Being single wavelet events it is also difficult to identify flat spots and strong depth conformance which may be interpreted as direct hydrocarbon indicators (DHI).

For the carbonate Aardwolf play, the type of carbonate reservoir and the influence of nearby volcanics on diagenesis and reservoir producibility are difficult to quantify due to the strong seismic amplitudes generated by lithological effects in carbonates regardless of fluid type.

The following tables show the typical reservoir input parameters used to calculate prospective resource volumes for Blocks 3B/4B. Given the absence of well penetrations the majority of this input data is drawn from direct analogues in Namibia and other West African deepwater turbidite sand sequences that have similar depositional settings. The net reservoir is calculated using analogue net to gross values applied to the interpreted seismic thicknesses of the gross sand interval predicted from the seismic. The net reservoir thicknesses are conservative when compared with publicly quoted thicknesses and pay seen in the Brulpadda and Luiperd analogue wells.

5.2.4. Petrophysical interpretation

RISC was unable to carry out any direct petrophysical analysis since there are no deep wells in the license area, or in this outboard Orange Basin setting in the South African sector. The interpretation of reservoir properties is drawn from analogue data from the shelf and the adjacent analogue public data from the Graff and Venus discoveries along strike from the 3B/4B license. However, RISC was able to draw on knowledge of relevant West African and global analogues of deepwater turbidite channel and fan lobe systems.

There is a normal compactional trend to 2,500 m below surface of shelfal wells drawn from the database of Soekor shelf wells (Figure 5-7) but between 2,700 and 3,000 m anomalous porosities of approximately 20 % begin occurring at temperatures of 90 to 110ºC. Development of this secondary porosity could potentially explain the seismic AVO responses seen on the 3B/4B Exploration Right , however this response is non-unique and an alternate porosity measure that could also create the observed AVO responses is overpressure.

5.2.5. Rock Physics Interpretation

There is a good database on Ibhubesi field on the shelf area to the northeast of Block 3B/4B. Four wells are particularly important for the geophysical rock physics analysis as they have dipole sonic logs (for shear velocity data) across water wet and gas bearing reservoirs and modelling suggests that AVO analysis should be able to identify fluid fill in the target intervals in Block 3B4B. Data from Ibhubesi wells and the modelling project were not accessible for review for this audit.

The Ibhubesi field is in a very proximal setting for reservoir deposition and the compaction and bi-modal porosity distribution in the Ibhubesi wells is consistent with that seen in other shelf wells. Initial wells on Ibhubesi drilled bright, full stack (acoustic impedance) anomalies that were unsuccessful, and the anomalies proved to be porosity related rather than fluid fill. Standard Poisson’s ratio vs acoustic impedance cross-plotting is required to distinguish wet and gas-bearing sandstone. Intercept and gradient plots have been used on Block 3B/4B in conjunction with amplitude extractions from near and far trace stacks to analyze the data and highlight anomalies, interpreted to be a hydrocarbon fluid fill.

Sands with primary porosity (down to 2,500 m burial) encased in shale are ‘hard’ on the near stack but dim to a soft on the far stack in case of hydrocarbon fill (Class II /IIp AVO). Sands with secondary porosity (buried 2,300 m -3,300 m) encased in shale show a weak trough on the near stack and a strong trough on the far stack in case of hydrocarbon fill (Class II / III AVO). Lower net-to-gross reservoir is expected to diminish the AVO response (weaker intercept and gradient).

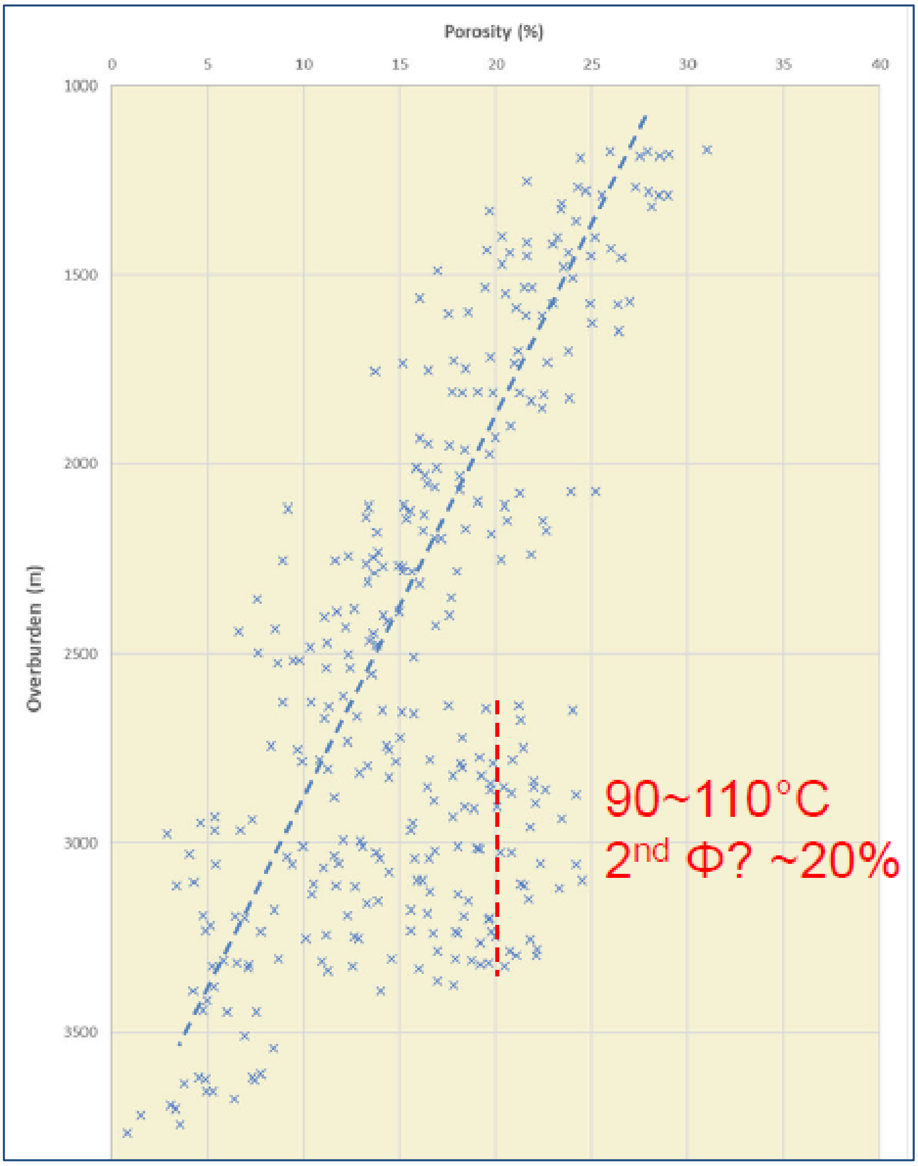


Figure 5-9: Compaction trends & secondary porosity development seen in Cretaceous sediments of shelfal wells, Orange Basin.

5.2.6. Fluid contacts

Many of the seismic AVO responses are in single cycle seismic reflectors with insufficient thickness to examine many seismic attributes which build evidence for a direct hydrocarbon indicator, such as amplitude conformance to structure, flat spots or seismic polarity changes indicative of fluid contacts. Where prosects have demonstrated amplitude conformance to structure RISC has increased the AVO uplift added to their probability of geological success.

Discoveries at Venus and Graff are reported to be light oil discoveries but RISC has not seen any references to gas caps, or separate fluid phases and specific contacts being encountered in either of these wells. By contrast, condensate, gas and oil phases have been reported in the Brulpadda and Luiperd discoveries of Block 11B/12B.

5.2.7. Fluid properties

All fluid properties have been drawn from public scout information and analogue data drawn from wells in the Orange basin (Table 5-1). The fluid data includes pressure and temperature trends plotted from the Orange basin wells and these were used to condition the reservoir input parameters for the specific prospect reservoir targets given their depth and observed seismic AVO response.

Table 5-1: Average Reservoir fluid properties for shallow Santonian and Maastrichtian prospects

Property	Unit	Oil column		
		Minimum	Most Likely	Maximum
Oil Gravity	Deg API	35	37	45[1]
Pressure	Psi/ft	0.44	0.47	0.49
Temperature	deg C	35	90 – 110	130
Formation volume factor (Boi)	rb/stb	1.5	1.8	2.1
Gas oil ratio (Rsi)	scf/stb	1,200	1,800	2,400
[1]NOTE: Could potentially be as high as 48 deg API with a GOR >3,800 scf/bbl				

5.2.8. Well testing

No flow tests have been carried out in the Block 3B/4B plays, or direct analogues in the Orange Basin. Modelling based on the expected reservoir characteristics and fluid properties for Block 3B/4B prospects suggests that oil rates of approximately 5,000 to 10,000 bopd are potentially achievable. A DST of the Middle Cretaceous reservoir penetrated in the Luiperd-1X well in the Outeniqua Basin, South Africa which has a similar depositional setting produced 33 MMscf/d of natural gas and 4,320 bpd on a 58/64” choke from 73 m of net gas condensate pay. Reservoir continuity was reported as better than expected and absolute open flow rates are expected to be significantly higher than the restricted DST flow rate.

6. Resources

6.1. In-place resource volumes

RISC carried out resource volume analysis using a Monte Carlo probabilistic approach and software. Volumes provided to RISC from AOC were deterministic in approach and prospect area ranges were determined by varying the well-defined, most likely AVO anomaly extent by +/- 35% to define the minimum and maximum areas. AOC ensured that the maximum prospect areas defined didn't exceed the mapped maximum extent of the top reservoir AVO anomaly, which is a sensible approach, as the absence of amplitude support suggests either thinning of the reservoir below seismic resolution, or loss of porosity most likely associated with facies changes away from the channel and fan lobes into more mud prone sections.

RISC applied a log normal distribution approach to the gross rock volume and widened the range of the volumes to better capture the uncertainty around the prospects given the lack of well control. RISC fixed the P90 area to the largest individual seismic AVO anomaly that could be tested by a single well, estimated the P50 area by utilizing the extent of AOC's mapped 'best' anomaly and clipped the P10 area to ensure the area remained within the limit of the mapped seismic anomaly. For prospects with consistent, aerially extensive AVO anomalies, a P90 and P50 input was used to define the lognormal distribution for the gross rock volume calculation. For prospects with highly dispersed AVO anomalies, P90 and P10 inputs were used for the log normal distribution and the P90 area was quality controlled against the individually mapped separate anomalies.

The P90/P10 resource ranges are not as wide as might normally be expected for an uncalibrated exploration play. However, the prospects in Block 3B/4B consist of stratigraphic, amplitude controlled, channel features with several West African discoveries used as analogues, which by definition narrows the range of gross rock volume that can be mapped as part of a prospect. The lower end of the lognormal distribution (P99 to P91) is considered to adequately encompass the downside scenarios with volumes below P99 resulting in Pg failure, and the upper end of the lognormal distribution (P9 to P1) is considered to adequately encompass upside scenarios and the probabilities of outcome.

Twenty-four prospects were evaluated and split into two geographical areas: 'Northern Area' cluster and 'Central Area' cluster. The same plays are present in both clusters but proximity of the Northern Area to recent discoveries at Graff and Venus potentially de-risking the plays and the higher prospect density has resulted in the Northern Area being the primary focus for the review and evaluation in this report.

Reservoir input parameters are drawn from shelf wells and analogues within the Orange Basin and West African margin where appropriate. These are seismic amplitude anomaly driven prospects but many are single loop events which limits the ability to see direct hydrocarbon indicators such as flat spots, amplitude conformance to structure and potential phase change fluid contacts. As single loop reflectors, it is also hard to see depositional architecture or differential compaction, suggestive of large sand accumulations. This has been captured in the reservoir thicknesses used in the evaluation that vary between 10 and 40 m net thickness in the turbidite channel and lobe facies in the Cenomanian to Turonian section, and the 16 to 52 m net thickness in the Albian fan lobes where stacked and laterally accreted geobodies are evident. A shape factor of 0.9 was used in the volume calculation to capture the flat topped and elongated natures of the identified anomalies/prospects.

The volumetric input distributions have excluded the lower end of porosity, net to gross and hydrocarbon saturation since this was not considered to contribute to the volume of moveable hydrocarbons.

Porosity and hydrocarbon saturation were drawn from analogue wells on the margin. The porosities do reflect the secondary porosity enhancement seen in rocks below 2,700 m with reservoir temperatures in excess of 90°C. The resulting in place volumes for each prospect are shown in Table 6-1 & Table 6-2.

Table 6-1: Northern Area Undiscovered Petroleum Initially in Place (UPIIP)

Prospect	UPIIP[11] (STOIIP) (MMstb)		
Classification	**P90**	**P50**	**P10**
Mongoose	373	589	912
Assenkehr	88	212	502
Meerkat	182	296	479
Caracal	101	207	419
Bushbaby	315	509	816
Sjambok	237	385	624
Noordoewer	243	405	670
Seekoei	174	279	434
Halfmens	255	714	1,685
Halfmens Upper	109	345	1,080
Fan-SA	1,118	2,066	3,777
Fan-SB	423	781	1,429
Fan-SC	153	338	737
Aardwolf	903	1,313	1,884
TOTAL	**4,674**	**8,439**	**15,448**

Table 6-2: Central Area Undiscovered Petroleum Initially in Place (UPIIP)

Prospect	UPIIP (STOIIP) (MMstb)		
Classification	**P90**	**P50**	**P10**
Sickle Bush	132	236	418
Tambotie	103	169	269
Mopane	138	232	378
Quiver-E	229	372	591
Quiver-W	167	276	445
Maroela-Upper	264	409	615
Maroela-Lower	159	253	390
Maroela-W	213	352	561
Acacia	344	567	910
Acacia down-dip	145	227	344
TOTAL	**1,894**	**3,093**	**4,921**

[11] Undiscovered Petroleum Initially-In-Place (UPIIP)

Prospect definition, reservoir presence, quality, thickness and hydrocarbon charge are heavily reliant on AVO attribute analysis. Although the AVO modelling was carried out using well data from outside of the 3B/4B Exploration Right , the results are considered to be appropriate for an assessment of prospects on block and includes standard approaches to classifying the quality of seismic anomalies. Where seismic anomalies are weaker, or are used to support multiple aspects of the interpretation, RISC has used a smaller uplift in the Pg risking.

6.2. Reservoir Development Concept

The notional development plan for a deep water development in Block 3B/4B would be based on a light oil discovery similar to those developed elsewhere in deep water employing a Floating Production Storage and Offloading (FPSO) vessel for condensate stripping and gas production or reinjection. Clusters of smaller fields would be developed with a single FPSO, or tied into a larger FPSO hub. A key assumption impacting project economics will be the feasibility of gas reinjection, as pipeline infrastructure is lacking. This development mirrors those being considered in the development of the Graff and Venus light oil discoveries to the north in Namibia according to public sources.

All prospects are immature due to the lack of well calibration points in Block 3B/4B. Chance of development is therefore low and generally less than 10% to 20%. Chance of development will likely increase with drilling and development of other deepwater discoveries in the Orange Basin.

6.3. Resource summary

All the following resources presented are Prospective Resources since there are no wells, or discoveries in the 3B/4B license features covered in this report (Table 6-4 & Table 6-5). Given the limited data on the license, lack of data in the outboard play and heavy use of analogue data, two sets of standardized recovery factors were used for this evaluation (Table 6-3):

1. Standard, simplistic P90, P50, P10 recovery factor distribution of 20%, 30% and 40% respectively for lobate fan geometries with good AVO support;
2. A reduced probabilistic P90, P50, P10, recovery factor distribution of 10%, 20% and 30% respectively for channelized prospects that exhibit weak, discontinuous, or highly tortuous seismic AVO anomalies which may present development challenges.

The Aardwolf carbonate play utilized the same recovery factors as the tortuous channels to reflect uncertainty on the type of carbonate expected and likely porosity model.

Table 6-3: Recovery factors used for the different play types.

Property	Unit	Input range		
		P10	P50	P90
Fan lobe and simple AVO recovery factors	%	20	30	40
Tortuous complex channels & carbonate recovery factors	%	10	20	30

Table 6-4: Prospective Resources Summary for the Northern Area

Prospect	Recoverable Oil (MMstb)			Associated Gas (bcf)		
	P90	P50	P10	P90	P50	P10
Mongoose	108	176	281	189	313	513
Assenkehr	26	63	153	46	113	276
Meerkat	53	88	147	92	158	269
Caracal	30	62	128	52	111	231
Bushbaby	91	152	251	159	272	458
Sjambok	68	115	191	120	206	350
Noordoewer	70	121	205	123	216	375
Seekoei	50	83	134	88	148	245
Halfmens	50	139	342	89	258	637
Halfmens Upper	21	68	221	39	126	409
Fan-SA	277	518	951	504	953	1,767
Fan-SB	79	154	296	144	284	550
Fan-SC	29	67	151	51	119	275
Aardwolf	222	327	475	384	586	882
TOTAL	**1,174**	**2,133**	**3,926**	**2,080**	**3,863**	**7,237**

Table 6-5: Prospective Resources Summary for the Central Area

Prospect	Recoverable Oil (MMstb)			Associated Gas (bcf)		
	P90	P50	P10	P90	P50	P10
Sickle Bush	39	70	128	67	126	233
Tambotie	30	50	83	52	90	152
Mopane	40	69	116	70	123	212
Quiver-E	66	111	181	116	198	333
Quiver-W	48	82	136	85	147	250
Maroela-Upper	76	122	190	133	217	349
Maroela-Lower	46	76	120	81	135	221
Maroela-W	62	105	172	108	187	317
Acacia	99	169	279	174	301	512
Acacia down-dip	41	68	106	73	121	195
TOTAL	**547**	**922**	**1,511**	**959**	**1,645**	**2,774**

6.4. Probability of geological success

Probability of geological success in this report is defined as discovering hydrocarbons that will flow on test. RISC reviewed and quality controlled the probability of geological success (Pg) derived by AOC for each prospect by using a five component base analysis consisting of Source, Migration, Reservoir, Trap and Containment. Overall, RISC considers that AOC's geological risking was a fair representation of the individual prospect risks and this was adopted by RISC (Figure 6-1). However, RISC then modified the Pg uplift applied by AOC to each prospect following analysis of the quality of seismic attributes.

Reservoir and seal are the key risks for the majority of the prospectivity mapped in Block 3B/4B. Presence of source rock is held constant at 80% based on the mapped Aptian to Albian interval, analogue discoveries at Venus and Graff along strike, and penetrated source rock intervals in shelfal wells and in the deepwater ODP-361 well.

Migration risk is varied between 50% and 90% to reflect vertical distance from the mapped Aptian to Albian source interval. Shallower prospects are deemed higher risk for migration due to poorly resolved and complex migration paths complicated by the large scale shelf slump and mass transport complexes in the Cenomanian to Maastrichtian intervals.

Where stacked seismic anomalies are present with depositional architecture indicative of stacked turbidite channel or lobe features, containment is seen as the critical risk due to the risk of potential thief sands in the overlying section. Where the prospects are single cycle seismic events with no evidence of depositional architecture, reservoir is seen as the critical risk as the seismic anomaly could be caused by other lithologies such as calciturbidites, or tuffs, or possible thin bed sands.

Trap risk varied and was seen as lowest risk where structural trap elements were evident on the seismic.

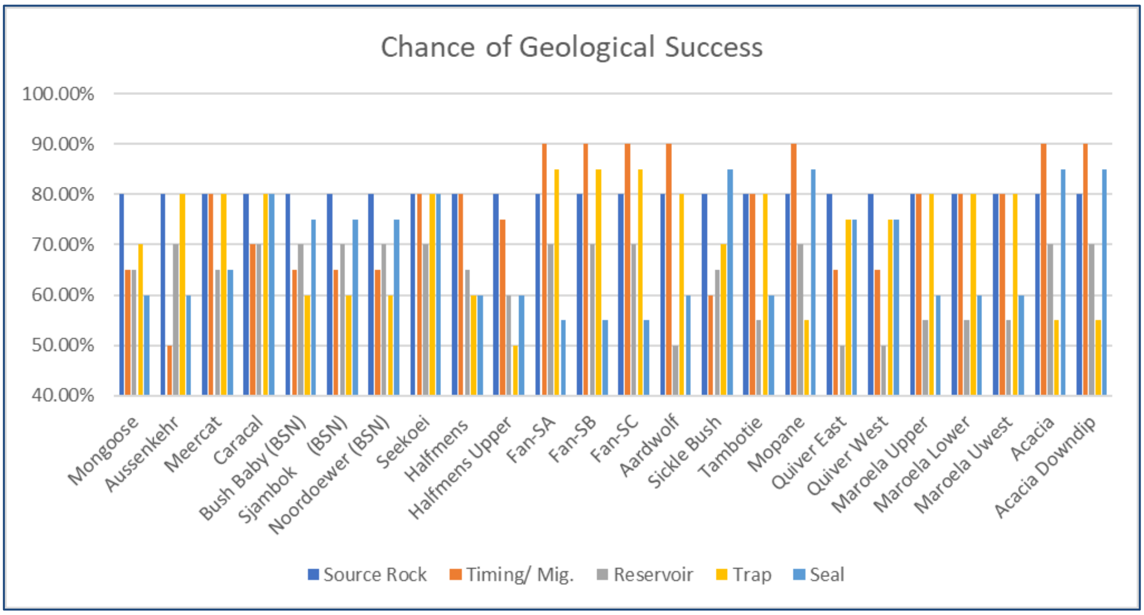


Figure 6-1: Chance of geological success by prospect (without seismic attribute uplift).

Well calibrated seismic attributes can significantly enhance the probability of geological success. However, seismic attributes are non-unique so the lack of data to calibrate the attributes significantly reduces the uplift that can be applied to Pg in Block 3B/4B. RISC have reviewed the seismic attributes available for this review and formed its own opinion on quality of seismic attribute and corresponding uplift to Pg for each of the prospects (Table 6-6 & Table 6-7 & Figure 6-2).

Table 6-6: Northern Area Geological Risk and AVO Uplift.

Prospect/Lead	Trap	AVO Type	AVO Conformance	Reservoir Type	Single Loop (Seismic Character)	RISC		
						Pg w/o AVO	AVO Mod	Pg Overall
Mongoose	Fault	Strong Class 3	Conformance to structure	Channel Lobe	No. (Thick channel geometries observed in X-section)	14	10	24
Aussenkehr	Strat	Med - Strong Class 3	None observed	Slope channels & lobes	No. (Part of large eroded stratigraphic complex)	13	5	18
Meerkat	Fault	Strong Class 3	Tentative conformance to structure	Slope channels	Yes, but indications of laterally stacked units	22	10	32
Caracal	Fault	Strong Class 2	Conformance to structure	Channel	No. (Suggestion of X-section channel geometry with thinning at the margins)	25	10	35
BushBaby	Strat	Strong Class 2	None observed	Slope channels	Yes	16	5	21
Sjambok	Strat	Strong Class 2	None observed	Slope channels	Yes	16	5	21
Noordoewer	Strat	Strong Class 3 ?	None observed	Slope channels	Yes	16	5	21
Seekoei	Struct/Strat	Strong Class 3	Conformance to structure	Ponded lobe	Yes	29	10	39
Halfmens	Strat	Patchy Class 2	None observed	Slope channels & lobes	Part (top?) of large stratigraphic complex	15	0	15
Halfmens Upper	Strat	Patchy Class 2	None observed	Slope channels & lobes	Part (top?) of large stratigraphic complex	11	0	11
Fan - SA	Struct/Strat	Medium Class 2/3	Possible pinchout on outer ridge. No conformance to structure.	Fan	No. (Possible sedimentary geometry seen in X-section)	24	5	29
Fan - SB	Struct/Strat	Weak Class 2/3	Possible pinchout on outer ridge. Weak & patchy with no conformance to structure.	Fan	No. (Possible sedimentary geometry seen in X-section)	24	0	24
Fan - SC	Struct/Strat	Weak Class 2/3	Possible pinchout on outer ridge. Weak & patchy with no conformance to structure.	Fan	No. (Possible sedimentary geometry seen in X-section)	24	0	24
Aardwolf	Structural	None	n/a	Aptian Shoal	not applicable	17	0	17

Table 6-7: Central Area Geological Risk and AVO Uplift.

Prospect/Lead	Trap	AVO Type	AVO Conformance	Reservoir Type	Single Loop (Seismic Character)	RISC		
						Pg w/o AVO	AVO Mod	Pg Overall
Sickle Bush	Strat	Class 3	Dip conformance	Turbidite	Yes, but indications of sedimentary geometry beneath seen in X-section	19	10	29
Tambotie	Strat	Class 2	Dip conformance	Channel	Yes	17	10	27
Mopane	Strat	Class 2	Dip conformance	Channel	No. (Some lens geometry in X-section)	24	10	34
Quiver East	Strat	Patchy Class 2	None observed	Fan	No. (Possible sedimentary geometry seen in X-section, noisy data)	15	0	15
Quiver West	Strat	Class 2	None observed	Fan	No. (Possible sedimentary geometry seen in X-section, noisy data)	15	0	15
Maroela Upper	Structural	Class 3	4 way conformance	Fan/splay	Yes	17	10	27
Maroela Lower	Strat	Class 3	Weak conformance	Fan/splay	Yes	17	10	27
Maroela Uwest	Strat	Class 3	Dip conformance	Fan/splay	Yes	17	10	27
Acacia	Strat	Class 3	None observed	Ponded lobe	Possibly slightly more than single loop; noisy data	24	5	29
Acacia Downdip	Strat	Class 2	None observed	Lobe and channel	Yes	24	5	29

KEY: Green = Good, Amber = Moderate, Red = Poor

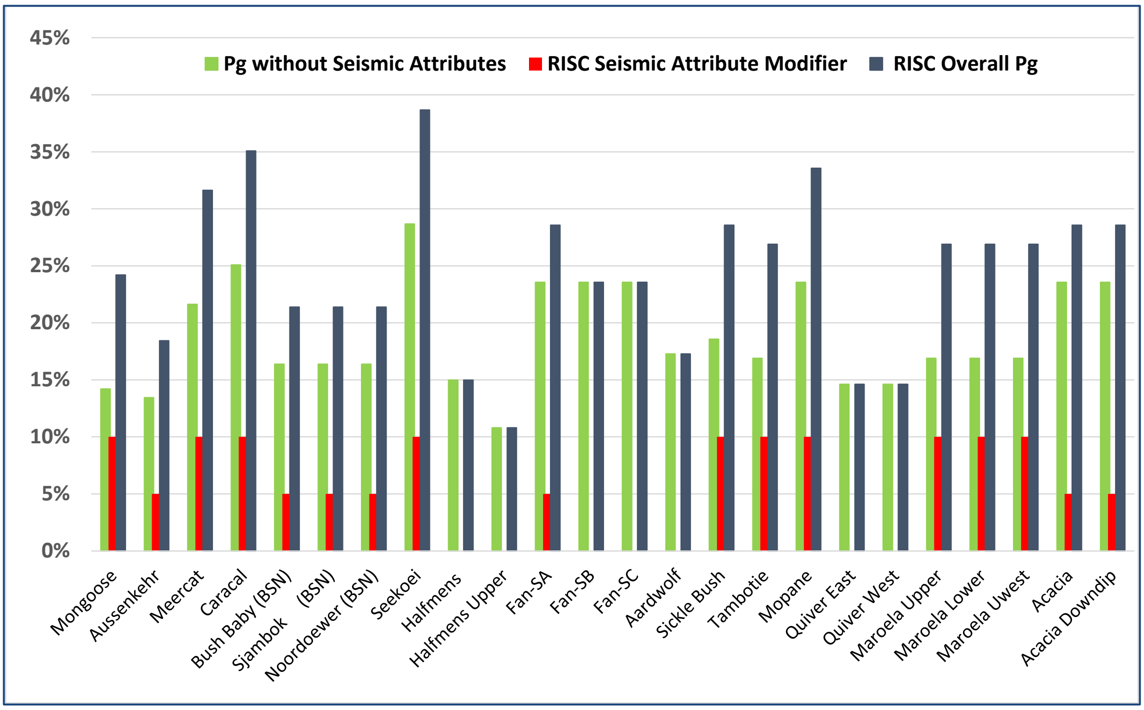


Figure 6-2: Probability of geological success (Pg) with and without Seismic Attribute modifier.

7. Commercial

South Africa's entire oil and gas production comes from the PetroSA-operated Block 9 (E-M, F-A and F-O) and South Coast Gas, located off the southern coast in the Outeniqua Basin. Oil production began in 1997 and ceased in 2013. Offshore gas production began in 1992, supplying the 45,000 boe/d synfuels gas-to-liquids plant at Mossel Bay.

South Africa imports close to 400 MMscf/d gas from neighbouring Mozambique. Gas imports are via the 865 km Republic of Mozambique (ROMPCO) pipeline. Piped gas supply is steady. However, decline from the Pande-Temane fields is expected to begin in the mid-2020s. Future sources of supply could be via LNG imports via the ROMPCO pipeline.

TotalEnergies and South Africa's Gigajoule Group were awarded an LNG import concession via a permanently moored floating storage and regasification unit (FSRU) at the Matola harbour in Maputo in second half of 2019. LNG imports via South Africa's ports at Coega in Port Elizabeth and Richards Bay have also been proposed.

7.1. Fiscal regime

South Africa’s concession regime is based on royalty and income tax. The Minerals and Petroleum Resources Development Act (MPRDA) of 2002 and the 2008 amendment act, modified the royalty calculation and income tax rate separately. The government is developing new petroleum legislation that will separate the petroleum sector and the country's legacy mining sector. The government published draft legislation, the Upstream Petroleum Resources Development Bill in 2019 and an updated bill was made public in 2021. The new legislation proposes a 20% state participating interest in upstream projects during exploration and development. Fiscal elements proposed a petroleum resource rent tax (PRRT) and production bonuses were removed in the 2021 update. The new legislation has yet to be passed by national and provincial assemblies.

7.2. Exploration Right

The Exploration Right (ER) for Block 3B/4B was granted to Ricocure (Proprietary) Ltd (“Ricocure“) by the South African Agency for Promotion of Petroleum Exploration and Exploitation in terms of Section 80 of the Mineral and Petroleum Resources Development Act, 2002.

The ER was signed on 9 May 2019 with an effective start date of the Initial Period of 27 March 2019 and recorded as file reference number 12/3/339. The ER allows for two additional renewal periods, each with a two-year duration. The work programme for each renewal period is negotiable.

The Block 3B/4B ER requires a 20% relinquishment upon completion of the Initial Exploration Period which equates to approximately 3,516 km^2 (Table 7-1). However, The Ministry of Mines approved a deferral of this relinquishment pending resolution and clarification on areas that have been proposed as Marine Protected Areas (MPA’s).

Table 7-1: Relinquishment Schedule (Block 3B/4B).

Period	Percentage of original extent of the Exploration Area
End of Initial Period	Not less than 20%
End of First Renewal Period	Not less than 15%
End of Second Renewal Period	Not less than 15%

Africa Oil's wholly owned subsidiary, Africa Oil SA Corp. acquired a participating interest and operatorship in the Exploration Right for Block 3B/4B in 2019 from Azinam South Africa Limited, a subsidiary of Eco Atlantic Oil & Gas Plc. Africa Oil Corp is the Operator with a 20% participating interest, Ricocure Pty. Limited holds a 53.75% interest and Eco Atlantic Oil & Gas Plc has a 26.25% interest.

7.3. Work Programme

The Initial three-year exploration period expired on 26 March 2022. The Initial work programme included the following:

- Regional interpretation and mapping of key horizons and faults;
- Detailed petrophysical analysis tying to neighbouring wells;
- Quantitative interpretation work of the physical properties;
- Basin model update Integrating the regional studies;
- Prospect maturation;
- Prospect ranking and final report compilation.

The Exploration Right was renewed as part of the First Renewal Period for an additional two year term from 27 October 2022 to 26 October 2024 with a minimum work commitment that includes the following:

- Reprocess 1,500 km^2 of 3D Seismic applying Pre-stack Depth Migration;
- Seismic Interpretation of the newly reprocessed seismic data in the Northern Area;
- Seismic Amplitude Versus Offset analysis of prospects identified on the newly re-processed seismic data;
- Update regional source rock and reservoir models developed during the Initial Exploration Phase with results from the recent wells in the Deepwater Orange Basin;
- Update Prospect Inventory (Volumes and Ranking);
- Conduct commercial evaluation of high-graded prospects to determine the risked value, or the risk versus reward of the best prospects.

8. Declarations

8.1. Terms of Engagement

This report, any advice, opinions, or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by AOC and RISC.

8.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and all have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry.. RISC have completed over 2,000 assignments in more than 90 countries for over 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr. Gavin Ward who is an employee of RISC. Mr. Ward is a member of the Society of Petroleum Evaluation Engineers (SPEE), the Society of Petroleum Engineers (SPE), the Petroleum Exploration Society of Great Britain (PESGB) and is a Fellow of the Association of Chartered Certified Accountants. Mr. Ward holds a B.Sc. (Hons) (Geology & Physics), Aston University, 1988, and an MBA, Cranfield University, 2007. Mr Ward has over 30 years' experience in the sector and is a qualified reserves auditor who is independent of the reporting issuer for the purposes of the TSX.

8.3. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

8.4. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to these assets.

RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

8.5. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Africa Oil Corporation and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Africa Oil Corporation, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Africa Oil Corporation or in any of the properties described herein.

8.6. Copyright

This document is protected by copyright laws. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

8.7. Authorization for release

This Report is authorised for release by Mr. Gavin Ward, RISC Director dated 7 March 2023.

Gavin Ward

9. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (10^9) cubic feet
BCM	Billion (10^9) cubic metres
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
DEG	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
EIA	US Energy Information Administration

Term	Definition
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf/d	Million standard cubic feet (per day)

Term	Definition
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration

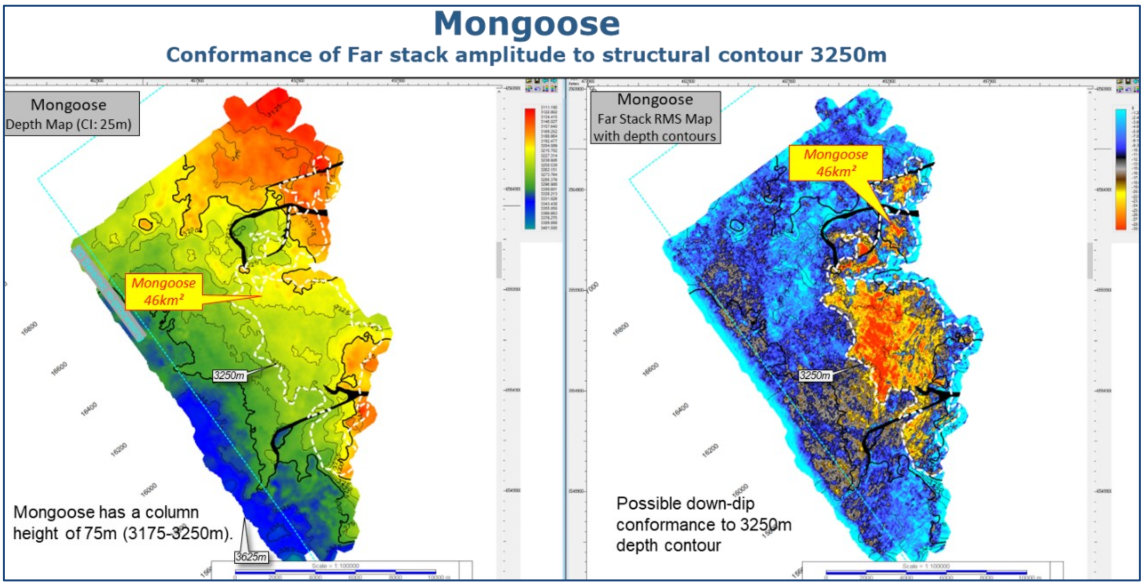
Term	Definition
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil

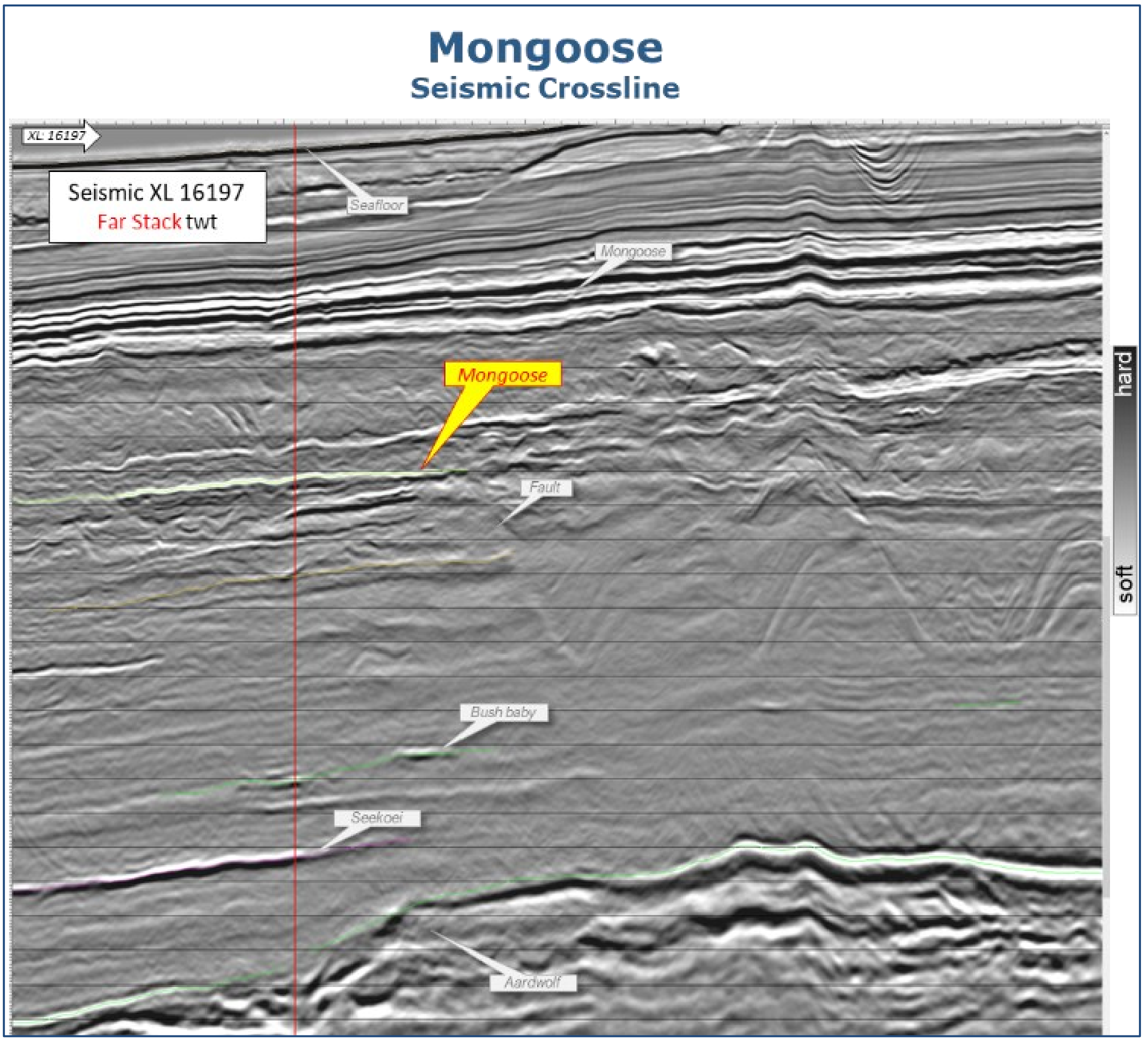
10. Appendix 1: Prospect Summaries

10.1. Mongoose Prospect

Water Depth	2,125 to 2,240 m
Overburden thickness	945 to 1,045 m
Reservoir Temperature	35-40°C
Zone	Santonian
Reservoir Type	Channel lobe
Trap	Structural - fault
Seal	Deepwater mudstone for top, lateral and base seal
AVO Type	Strong Class 3 with conformance to structure.

The Mongoose fan sits in front of a leading thrust front of Santonian age, and trapping is formed by either truncation of the fan by the thrust front, or fault offset. This prospect is similar to the trap types that Shell is targeting in Namibia, where turbidite fans are trapped against thrust faults within the Santonian section. While Mongoose is at relatively shallow depths, shallow discoveries in similar stratigraphic intervals are being reported. The prospect would be charged from the Aptian-Albian kitchen below with migration though faulting evidenced in seismic. Notably Mongoose is situated above a several deeper prospects including Bush Baby, Seekoei, Meerkat, and Aardwolf, possibly indicating an area with multiple paths for vertical migration. A well located to test Mongoose could also test five potential objectives.

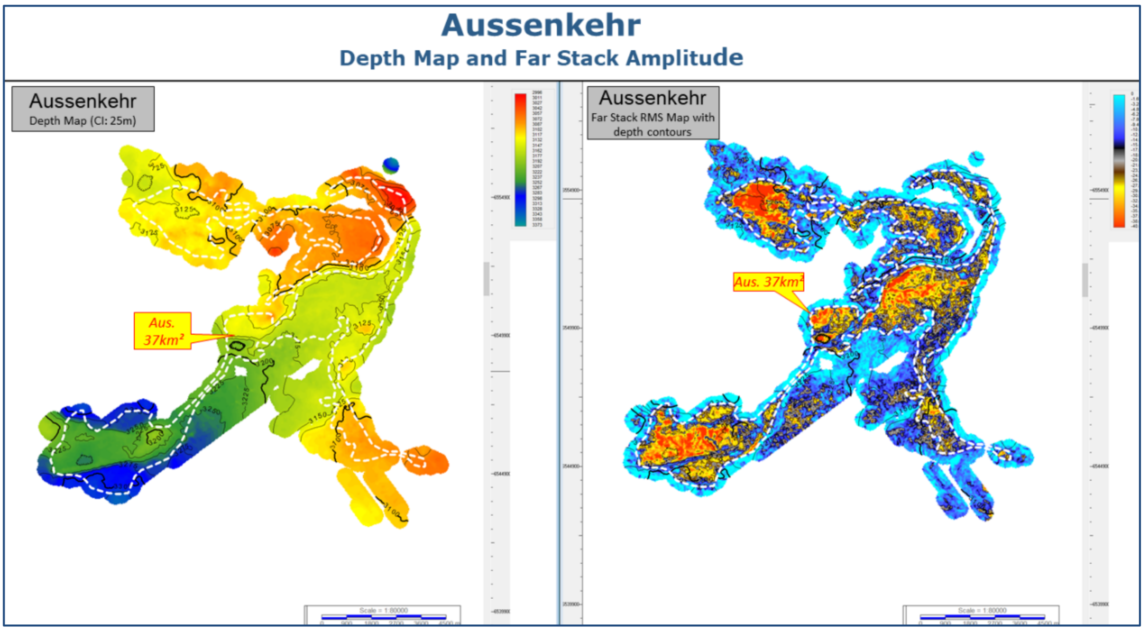


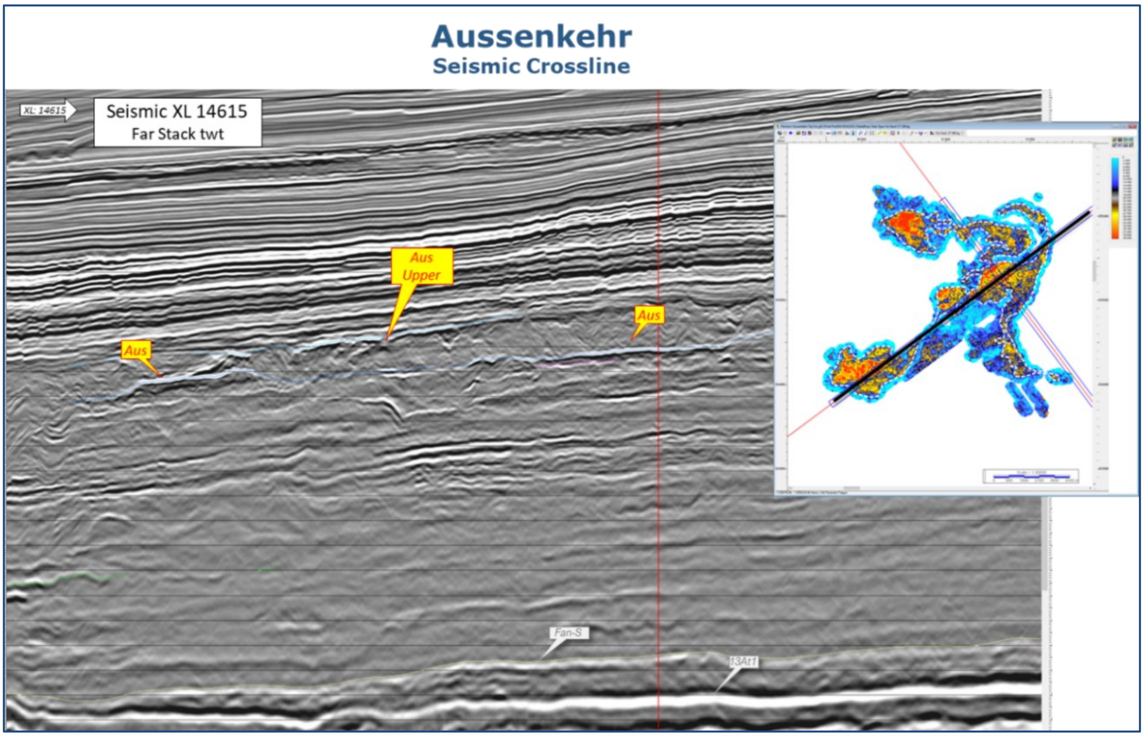

Mongoose
Seismic Crossline
XL 16197
Seismic XL 16197
Far Stack twt
Seafloor
Mongoose
Mongoose
Fault
Bush baby
Seekoei
Aardwolf
hard
soft

10.2. Aussenkehr Prospect

▪ Water Depth	1,500 to 1,800 m
▪ Overburden thickness	1,400 to 1,700 m
▪ Reservoir Temperature	55-65°C
▪ Zone	Maastrichtian
▪ Reservoir Type	Channel and fans
▪ Trap	Stratigraphic
▪ Seal	Deepwater mudstone for top and base seal
▪ AVO Type	Med-Strong Class 3, no conformance to structure observed.

Based on mapping Aussenkehr FAR stack amplitude response the flow unit is both channelized and also includes overbank or fan lobe deposits. The flow unit is overlain by deformed and thrusted Santonian age clastics that interrupt the flow unit in some areas, and possibly contributing to formation of traps. Aussenkehr overlies prospect Fan SB, Sjambok, and Halfmens, and affords an opportunity to test multiple AVO-supported prospects.

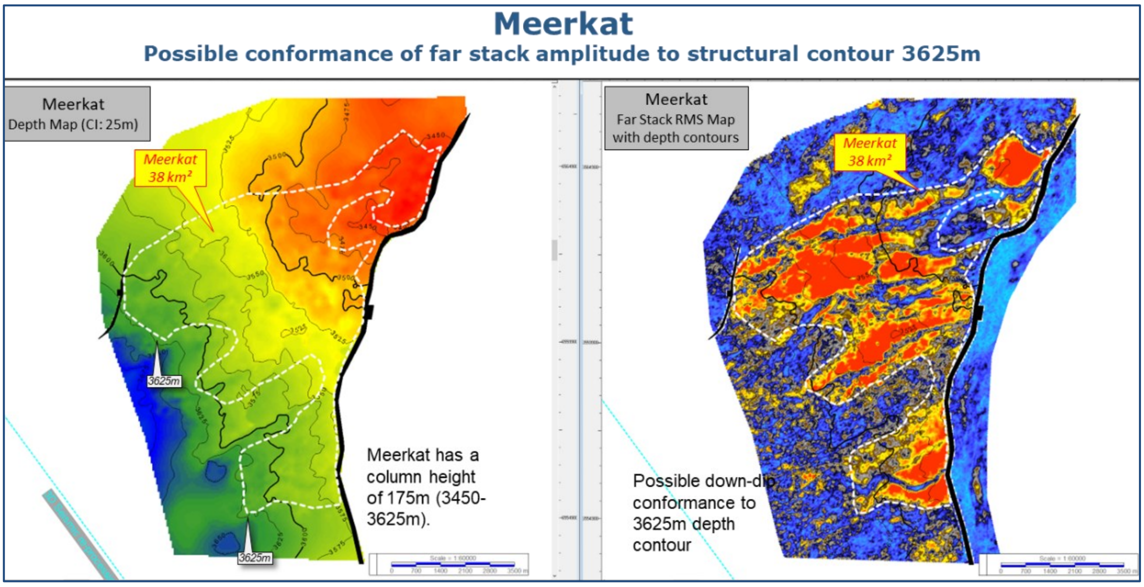


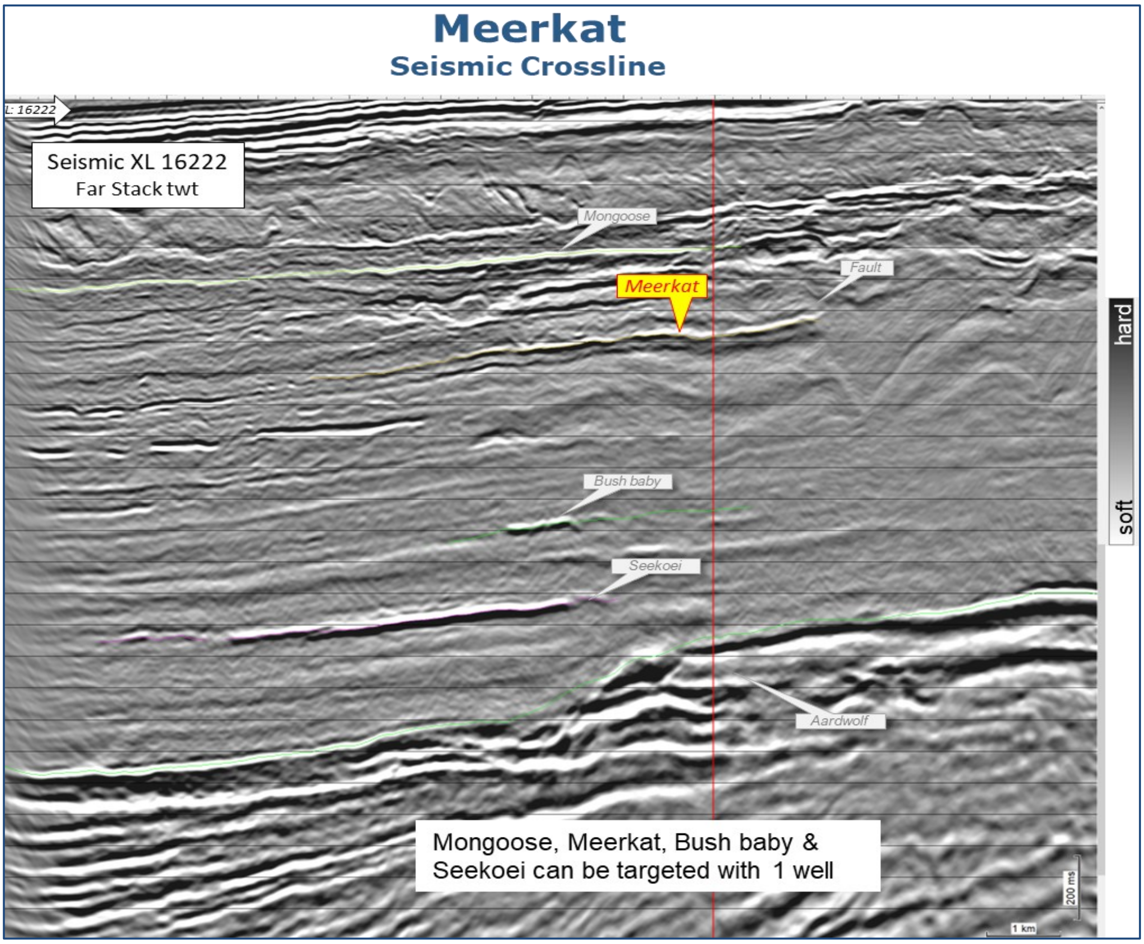

Aussenkehr
Seismic Crossline
XL: 14615
Seismic XL 14615
Far Stack twt
Aus
Upper
Aus
Aus
Fan-S
13At1

10.3. Meerkat Prospect

▪ Water Depth	2,100 to 2,225 m
▪ Overburden thickness	1,300 to 1,400 m
▪ Reservoir Temperature	55°C
▪ Zone	Santonian
▪ Reservoir Type	Slope channels
▪ Trap	Structural - fault
▪ Seal	Deepwater mudstone for top, lateral and base seal
▪ AVO Type	Strong Class 3 with conformance to structure.

Like Mongoose, the Meerkat prospect is a Santonian age turbidite fan that exhibits a strong Class II AVO anomaly with a possible conformance to structure. Meerkat is located in front of leading thrust front of Santonian age, and trapping is formed by either truncation of the fan by the thrust front, or fault offset. This prospect is similar to the trap types that Shell is targeting in Namibia, where turbidite fans are trapped against thrust faults within the Santonian section. The Far stack amplitude response of Meerkat is one the most pronounced in the inventory. Depositional features such as meandering channels are well imaged by seismic in these shallower intervals. Like Mongoose, a well located to test Meerkat could also test Bush Baby, Seekoei, and Aardwolf.

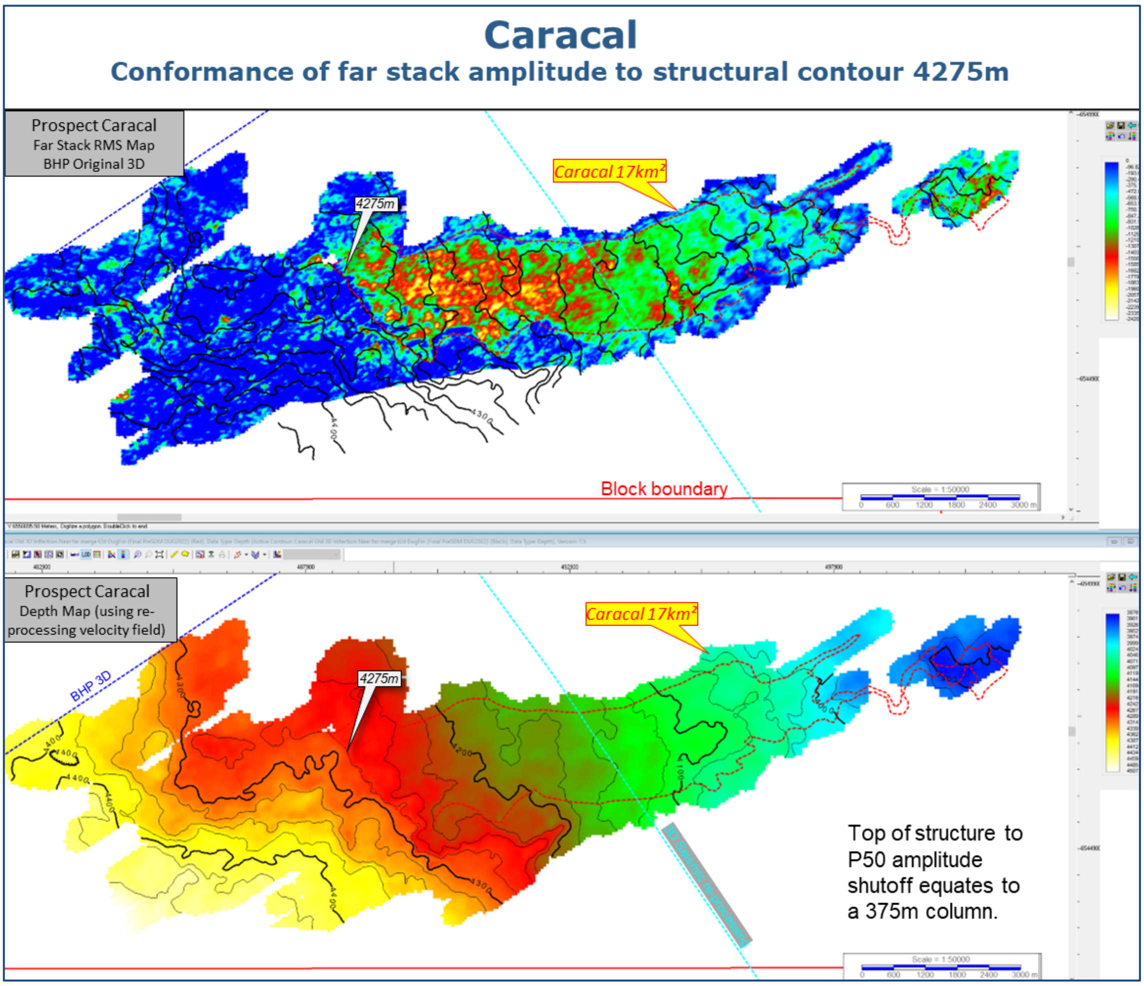


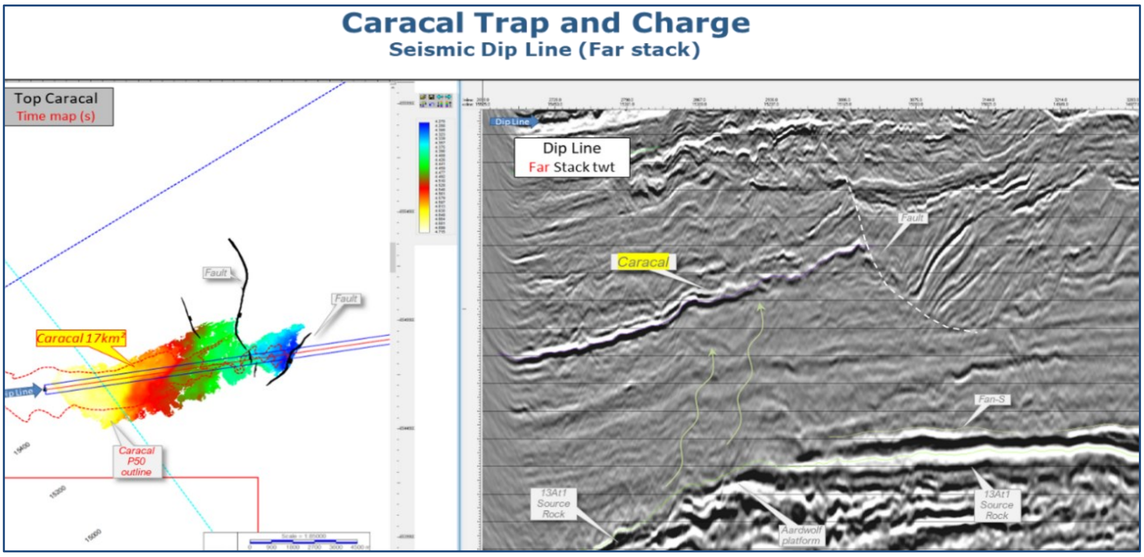

Meerkat
Seismic Crossline
L: 16222
Seismic XL 16222
Far Stack twt
Mongoose
Meerkat
Fault
hard
soft
Bush baby
Seekoei
Aardwolf
Mongoose, Meerkat, Bush baby & Seekoei can be targeted with 1 well
200 ms
1 km

10.4. Caracal Prospect

- Water Depth 1,850 to 2,400 m
- Overburden thickness 1,850 to 2,050 m
- Reservoir Temperature 70°C
- Zone Cenomanian
- Reservoir Type Channel
- Trap Structural - fault
- Seal Deepwater mudstone for top, lateral and base seal
- AVO Type Strong Class 2 with conformance to structure.

Caracal is a Cenomanian age turbidite fan that exhibits a strong Class II AVO anomaly with apparent conformance to the 4,275 m contour level. Based on amplitude mapping the fan itself is strongly elongate with a narrow feeder channel that is truncated updip by a prominent listric fault having significant displacement. Additional faulting in the section below is imaged seismically and could provide migration pathways for charging.



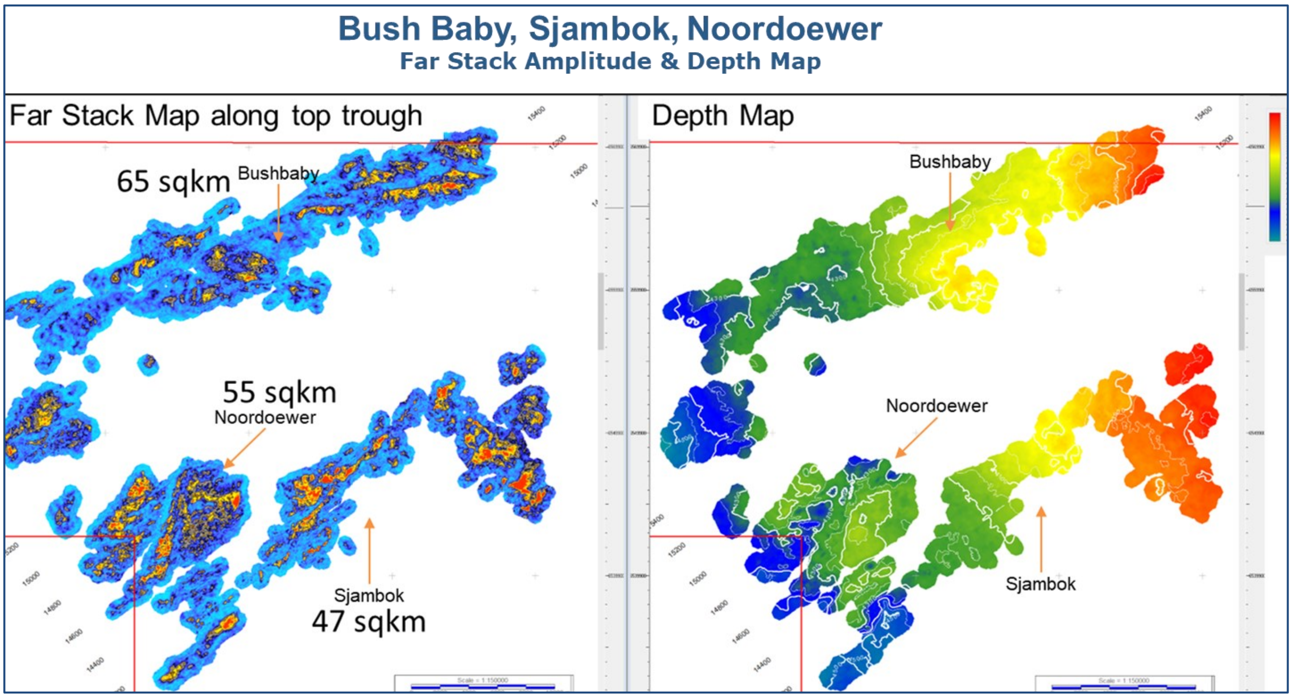


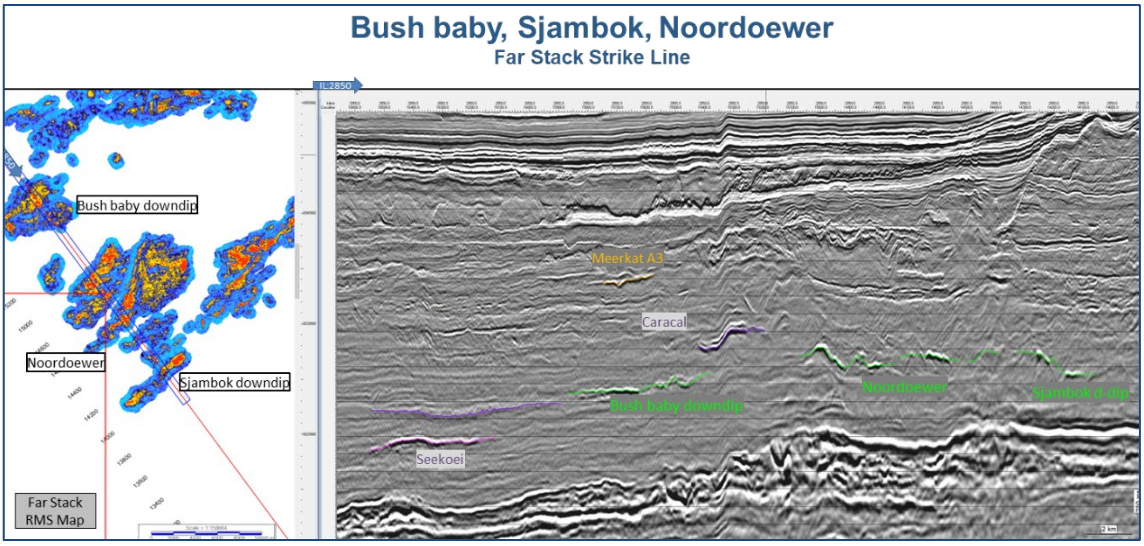
Caracal Trap and Charge
Seismic Dip Line (Far stack)
Top Caracal
Time map (s)
Fault
Fault
Caracal 17km²
Caracal
P50
outline
Dip Line
Far Stack twt
Caracal
Fault
Fan-S
13At1
Source
Rock
Aardwolf
platform
13At1
Source
Rock

10.5. Bush Baby, Sjambok, & Noordoewer Prospects

▪ Water Depth	1,200 to 2,200 m
▪ Overburden thickness	2,000 to 2,700 m
▪ Reservoir Temperature	76-99°C
▪ Zone	Cenomanian-Turonian
▪ Reservoir Type	Slope channels
▪ Trap	Stratigraphic
▪ Seal	Deepwater mudstone for top and base seal
▪ AVO Type	Strong Class 2, no conformance to structure observed.

Bush Baby, Sjambok, and Noordoewer are Cenomanian-Turonian age turbidites that are highly channelized and are grouped together as being part of a similar depositional system. Based on amplitude mapping the depositional pattern is highly channelized with some fan or lobe-shaped deposition that exhibit strong but patchy Class II or Class III AVO anomalies within what appear to be the thickest areas. Some of the discontinuity in the Far Amplitude response may be due to structural deformation in units immediately overlying these channelized systems and could in part be contributing to trap formation. Given the discontinuous nature of amplitude response and channelized geomorphology, these prospects could be good secondary targets. Bush baby for example can be tested with wells that target Fan SA, Meerkat, or Mongoose. Similarly Sjambok and Noordoewer overlay deeper prospects like Aussenkehr and Halfmens.

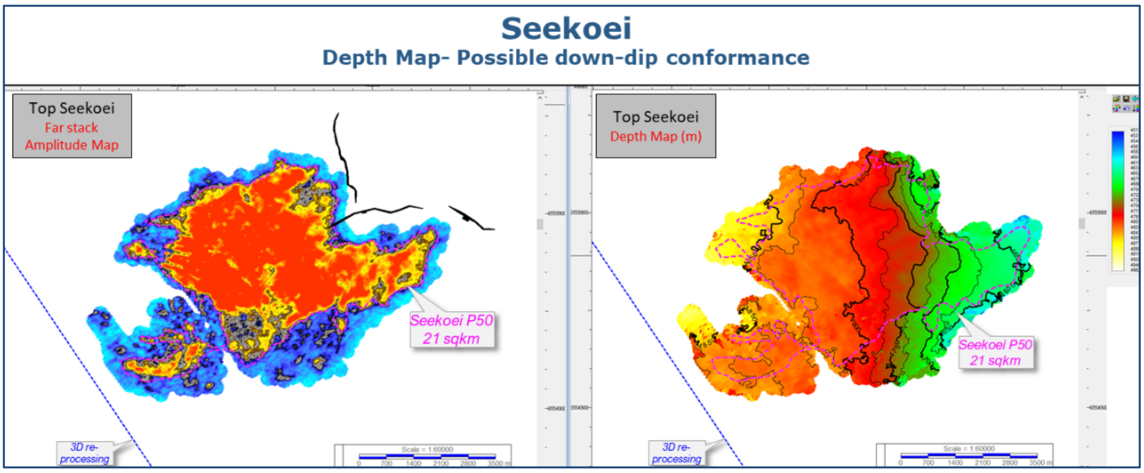


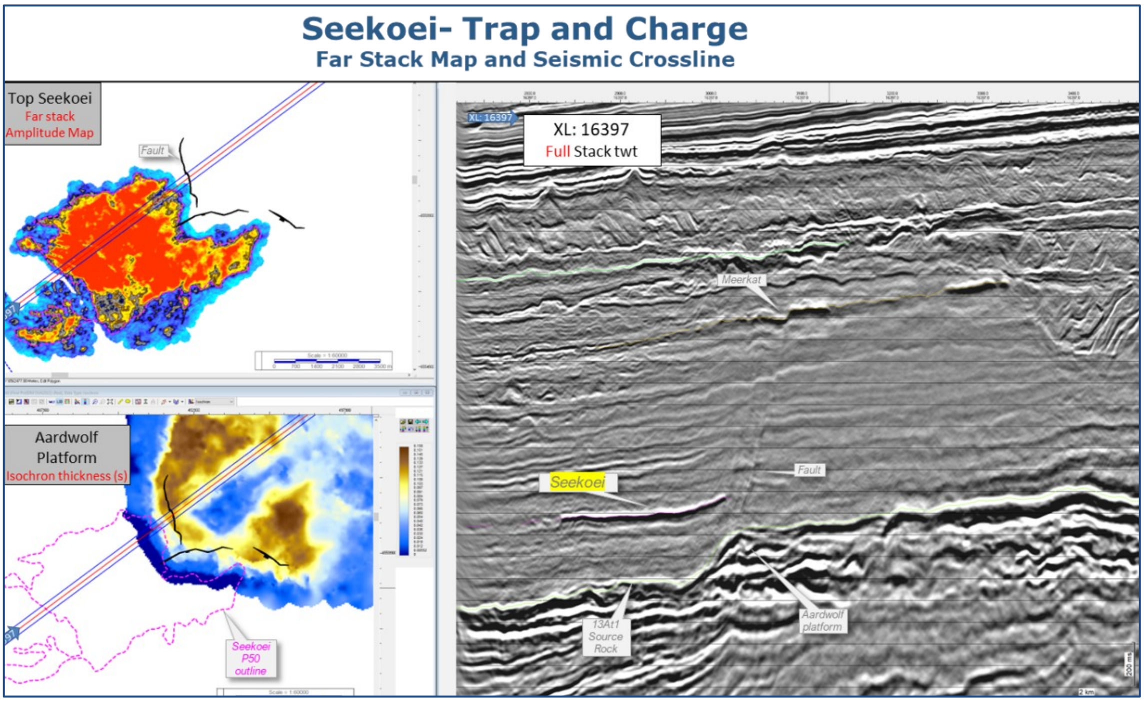

Bush baby, Sjambok, Noordoewer
Far Stack Strike Line
Bush baby downdip
Noordoewer
Sjambok downdip
Far Stack
RMS Map
Meerkat A3
Caracal
Noordoewer
Sjambok d-dip
Bush baby downdip
Seekoei

10.6. Seekoei Prospect

▪ Water Depth	2,200 to 2,250 m
▪ Overburden thickness	2,440 to 2,600 m
▪ Reservoir Temperature	90-95°C
▪ Zone	Cenomanian
▪ Reservoir Type	Ponded lobe
▪ Trap	Structural/Stratigraphic
▪ Seal	Deepwater mudstone for top and base seal
▪ AVO Type	Strong Class 3, with conformance to structure.

Seekoei is an isolated Cenomanian turbidite fan lobe with a very strong Class 3 AVO anomaly that appears to have a relatively strong amplitude shut-off with depth or corresponding to a small fault. It is within the cluster of prospects of Mongoose, Meerkat, Bush Baby and Aardwolf and could be targeted with multiple objectives.

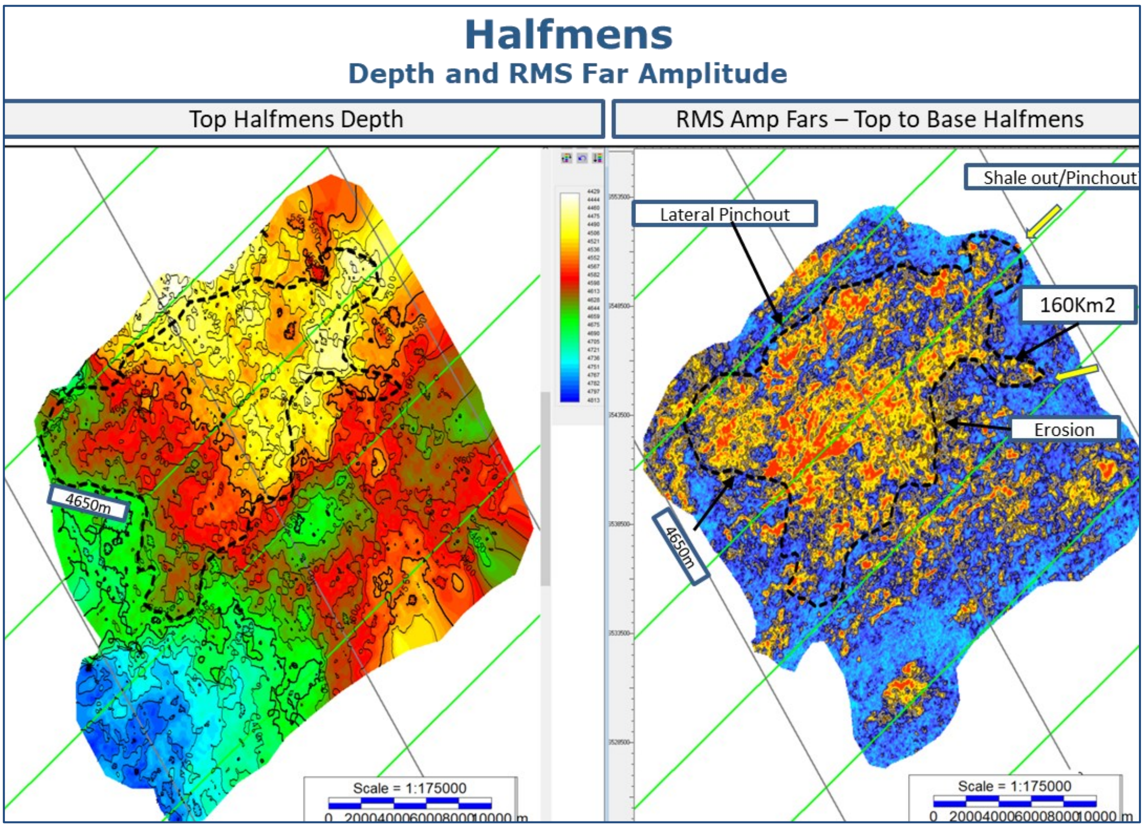


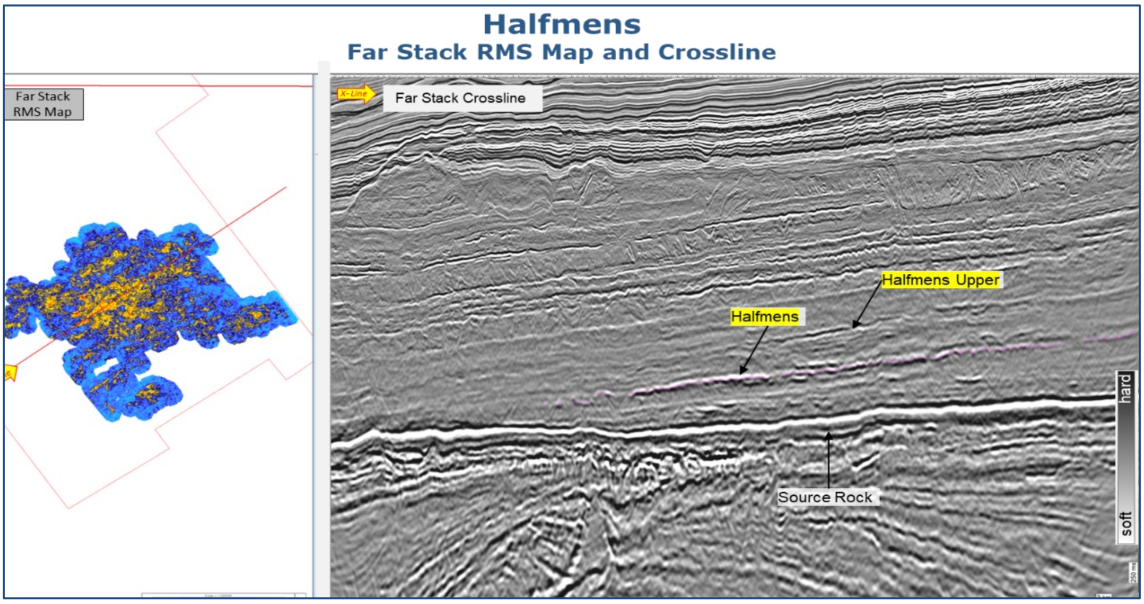

Seekoei- Trap and Charge
Far Stack Map and Seismic Crossline
Top Seekoei
Far stack
Amplitude Map
Fault
Aardwolf
Platform
Isochron thickness (s)
Seekoei
P50
outline
XL: 16397
Full Stack twt
Meerkat
Seekoei
Fault
13At1
Source
Rock
Aardwolf
platform

10.7. Halfmens Prospect

- Water Depth — 1,600 to 1,700 m
- Overburden thickness — approximately 3,000 m
- Reservoir Temperature — 100-110°C
- Zone — Cenomanian
- Reservoir Type — Slope channels
- Trap — Stratigraphic
- Seal — Deepwater mudstone for top and base seal
- AVO Type — Weak and patchy Class 2, with possible conformance to structure.

Halfmens is a relatively large Cenomanian aged turbidite fan that exhibits an extensive yet 'patchy' Class II AVO anomaly. Within the overall feature there are places with strong AVO signature and there is possible/ weak conformance of FAR amplitudes to structure at the 4,650 m contour level. Far amplitudes disappear updip allowing for an updip truncation or pinchout to be interpreted. Some apparent channelization based on mapping of RMS and Far amplitudes support the interpretation of a large turbidite far.

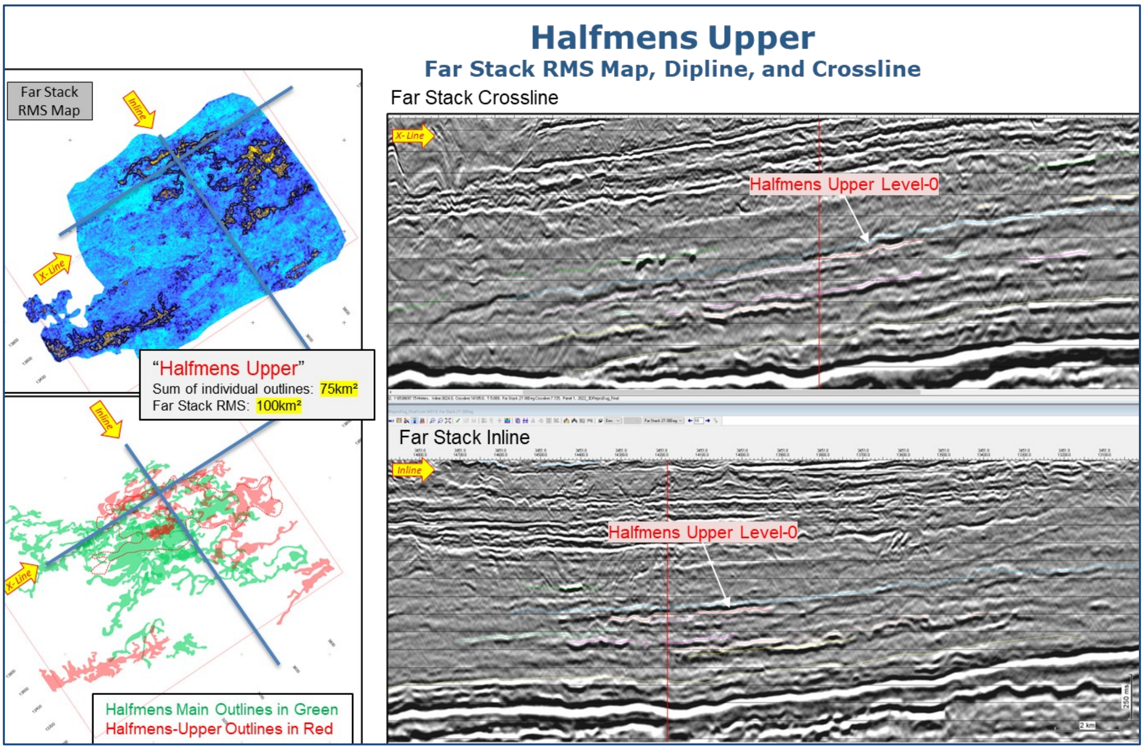



Halfmens
Far Stack RMS Map and Crossline
Far Stack
RMS Map
Far Stack Crossline
Halfmens Upper
Halfmens
Source Rock
hard
soft

10.8. Halfmens Upper Prospect

- Water Depth approximately 1,600 m
- Overburden thickness approximately 2,600 m
- Reservoir Temperature 96°C
- Zone Cenomanian-Turonian
- Reservoir Type Channel lobe
- Trap Stratigraphic
- Seal Deepwater mudstone for top and base seal
- AVO Type Weak and patchy Class 2.

Directly above Halfmens is Halfmens Upper, which has a near identical dip-oriented flow direction. Based on mapping of Far amplitudes Halfmens Upper has a less pronounced and more discontinuous Far response, suggesting thinner and more channelized flow units. Halfmens upper is viewed as a secondary objective within the Halfmens prospect area.



10.9. Fan S Prospects (Fan SA, SB, SC)

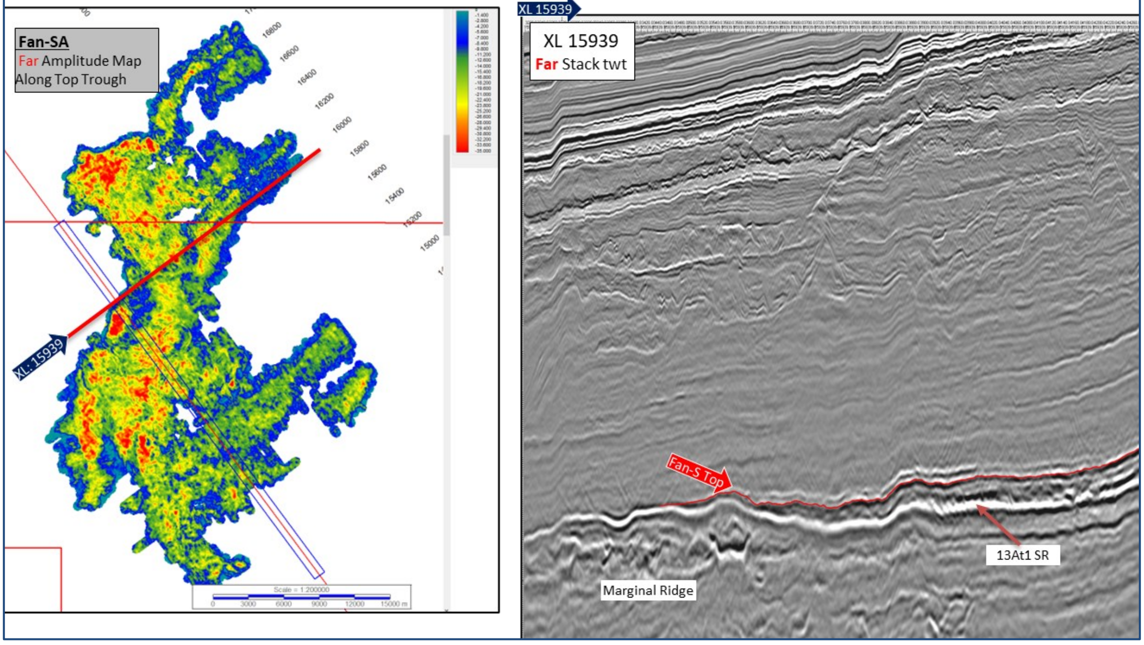
Water Depth	1,500 1,600 m
Overburden thickness	3,150 – 3,300 m
Reservoir Temperature	110-112°C
Zone	Albian
Reservoir Type	Basin floor turbidite fans
Trap	Structural/Stratigraphic
Seal	Deepwater mudstone for top and base seal
AVO Type	Class 2/3, no conformance to structure observed.

Fans SA, SB, and SC are Albian age basin floor turbidite fans that are of similar age, stratigraphic sequence, and depositional environment as the Lower Cretaceous age sandstones of the Venus discovery in Namibia. In Block 3B these large Albian turbidites have both channel and fan geometries and in the case of Fan SA, are ponding on the eastern side of the Outer Ridge, which is a regionally high salient during Albian time that parallels the African plate and extends from offshore South Africa to Namibia. In the case of Fan SA, which is the largest of the group, the Outer High provides a component of stratigraphic trapping as the Fan SA truncates or pinches out against the positive topographic feature.

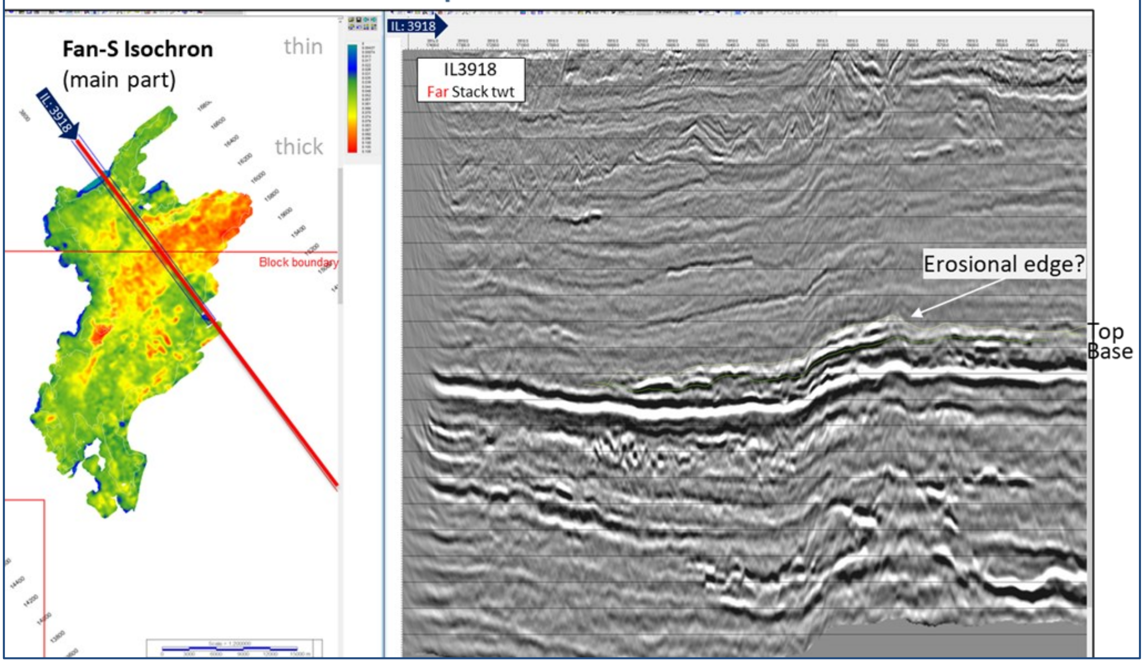
Fans SA, SB, and SC all exhibit Class II and Class III AVO responses that range from week to strong within various fans or area within the fans. Differences in fluid phase in terms of GOR may have some affect on the AVO responses observed and may cause some of the differences observed between Class II and Class III anomalies for example.

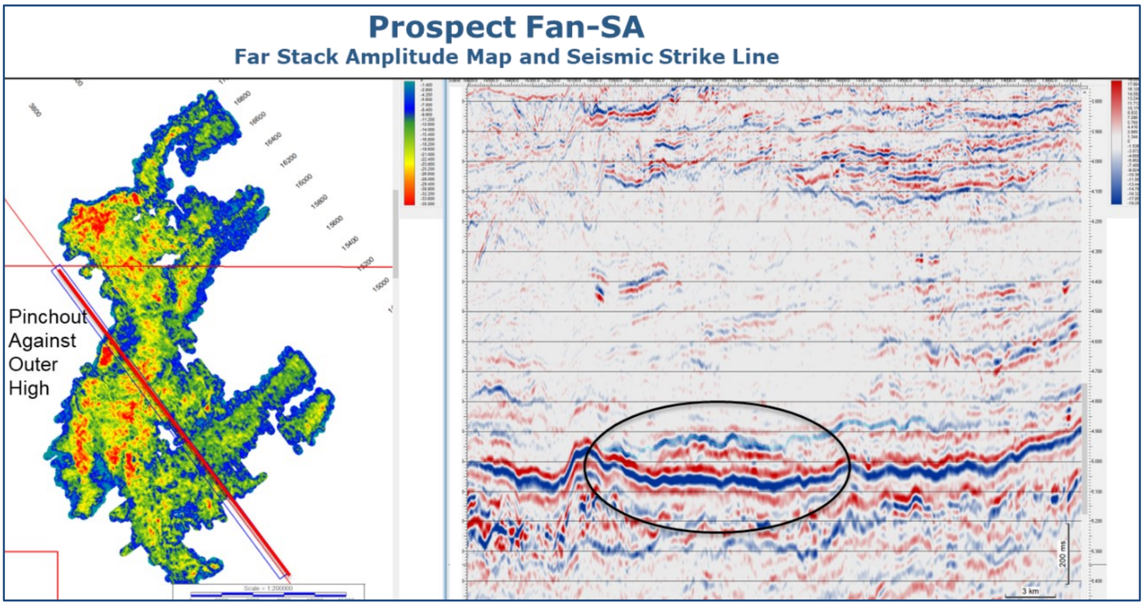
Fan SA is at-present the largest prospect in the inventory. Detailed mapping of its internal structure indicated that it is comprised of at least three interfingering or shingle-like lobes. A prospect location has been selected within Fan SA that would test a structurally high AVO-supported position within the fan that would also be an advantageous position to test Bush Baby.

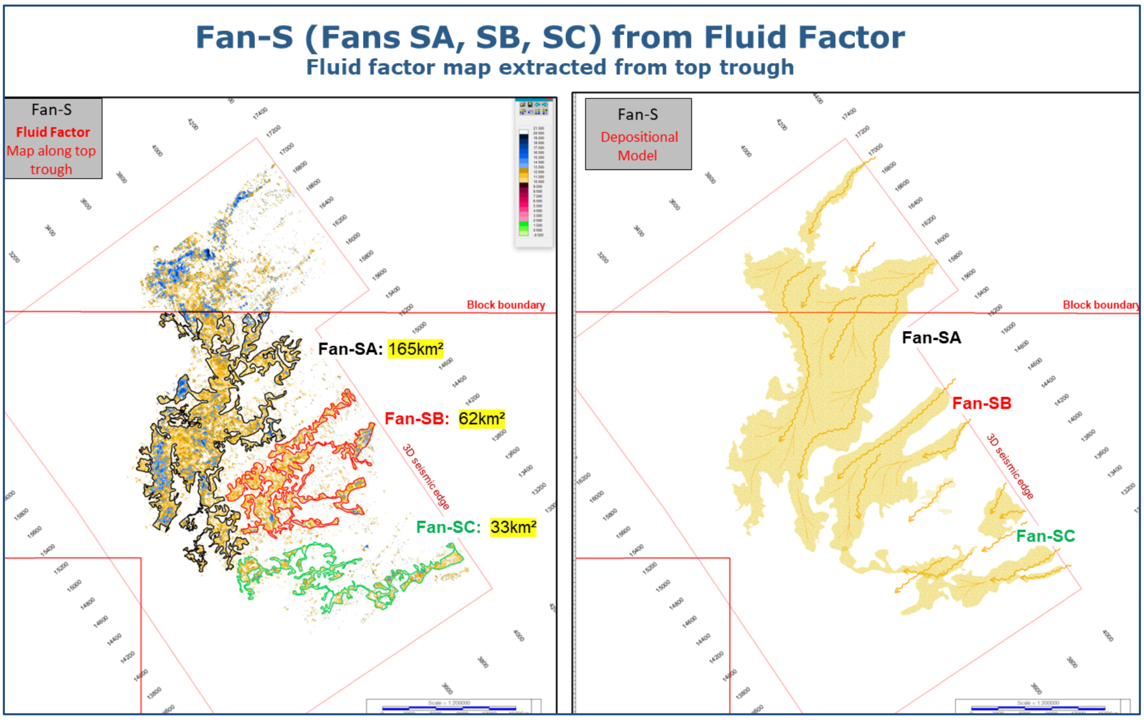
Prospect Fan-SA
Far Stack Amplitude Map and Seismic Dip Line

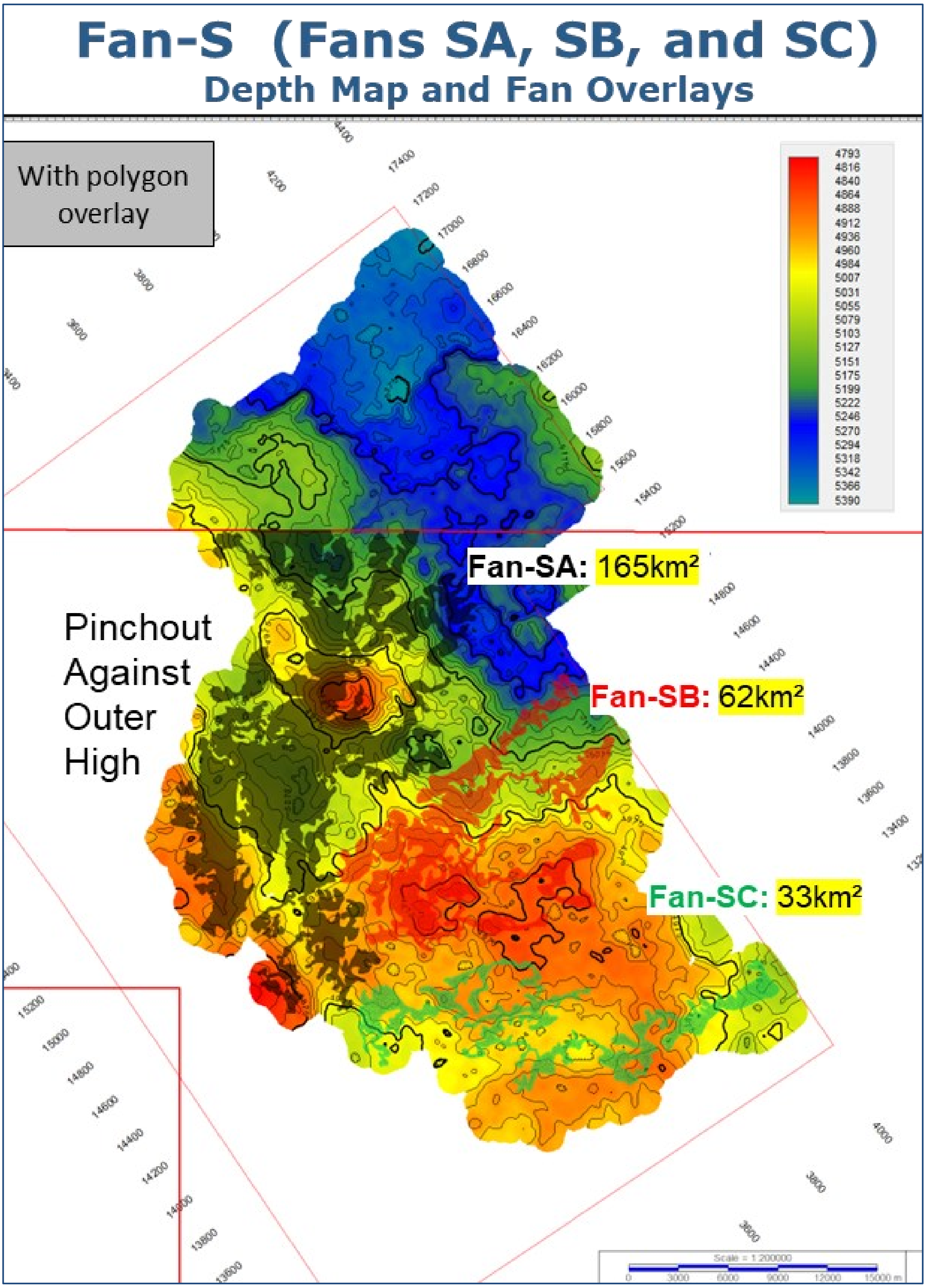


Prospect Fan-SA
Isochron Map and Seismic Strike Line

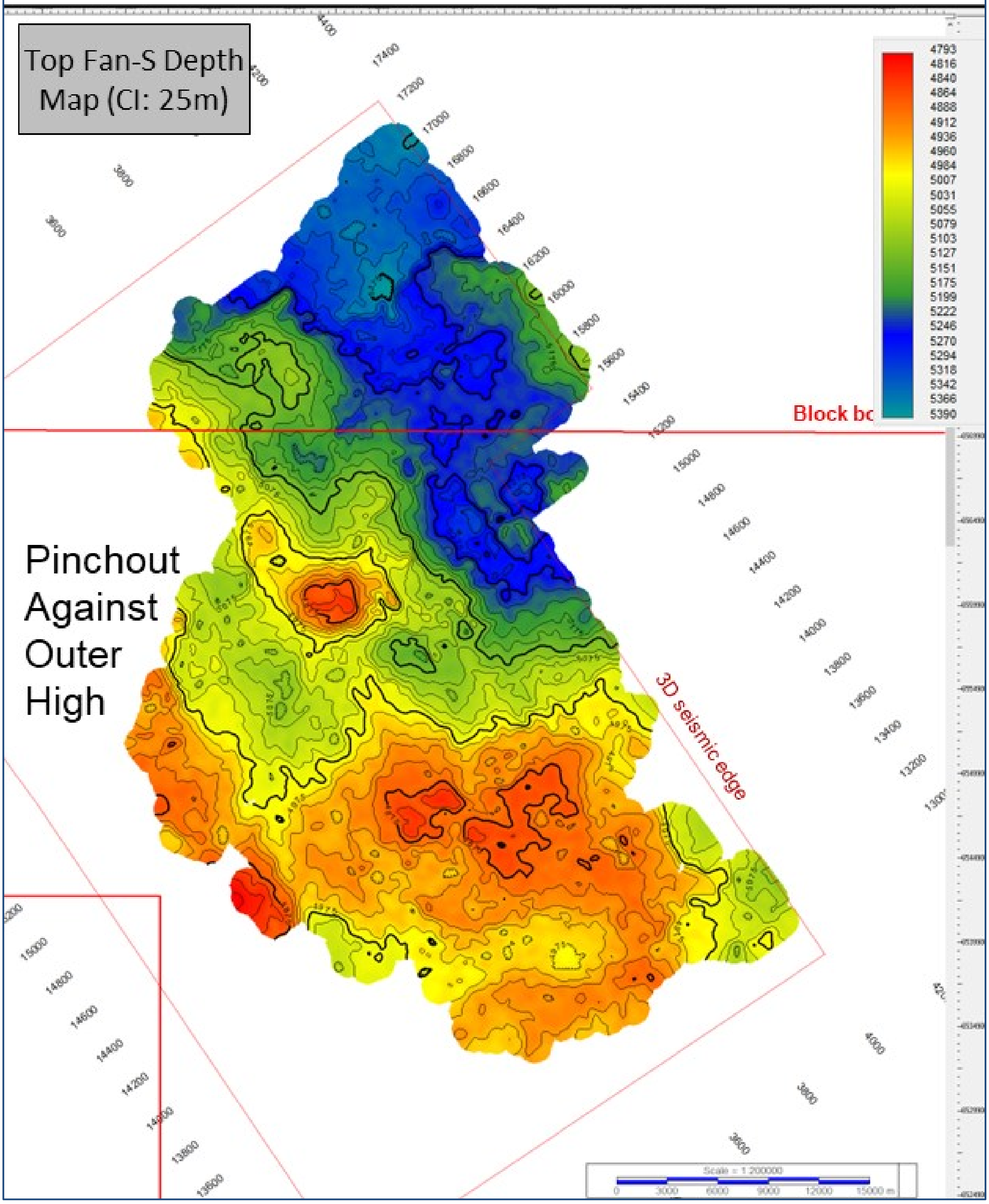


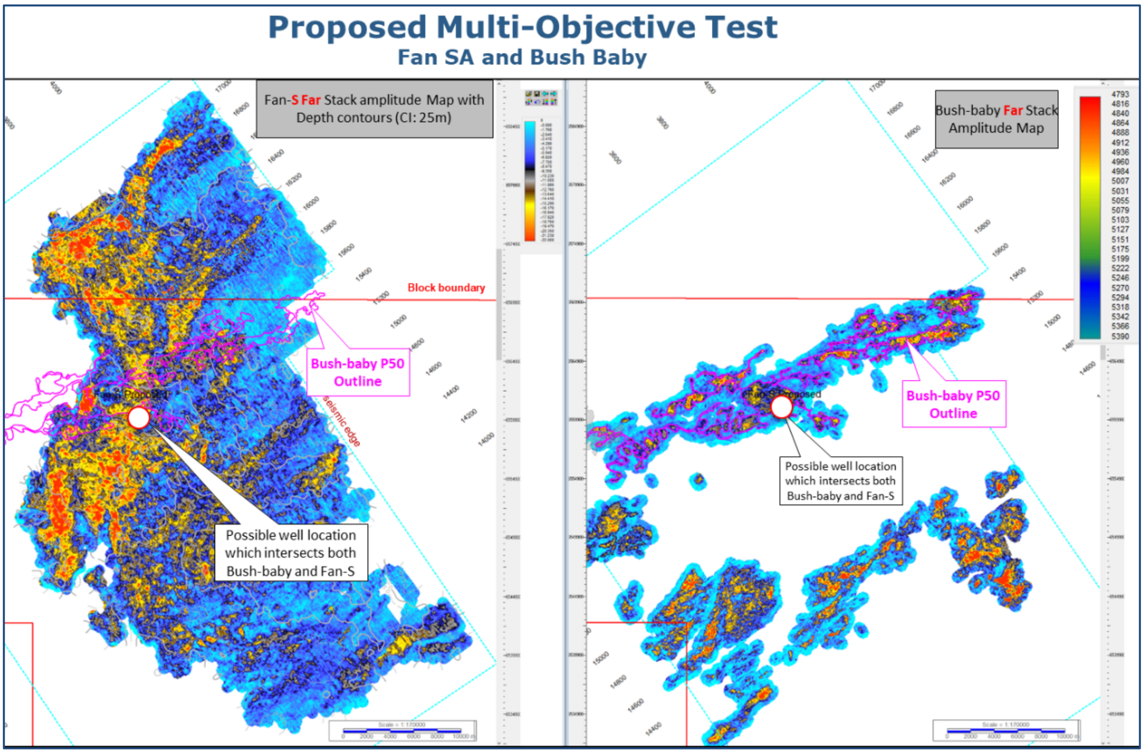

Prospect Fan-SA
Far Stack Amplitude Map and Seismic Strike Line
Pinchout
Against
Outer
High
3 km
200 ms


Fan-S (Fans SA, SB, SC) from Fluid Factor
Fluid factor map extracted from top trough
Fan-S
Fluid Factor
Map along top trough
Block boundary
Fan-SA: 165km²
Fan-SB: 62km²
Fan-SC: 33km²
3D seismic edge
Fan-S
Depositional
Model
Block boundary
Fan-SA
Fan-SB
Fan-SC
3D seismic edge


Fan-S (Fans SA, SB, and SC)
Depth Map and Fan Overlays
With polygon overlay
Pinchout Against Outer High
Fan-SA: 165km²
Fan-SB: 62km²
Fan-SC: 33km²
4793
4816
4840
4864
4888
4912
4936
4960
4984
5007
5031
5055
5079
5103
5127
5151
5175
5199
5222
5246
5270
5294
5318
5342
5366
5390

Fan-S Area- Depth Structure Map

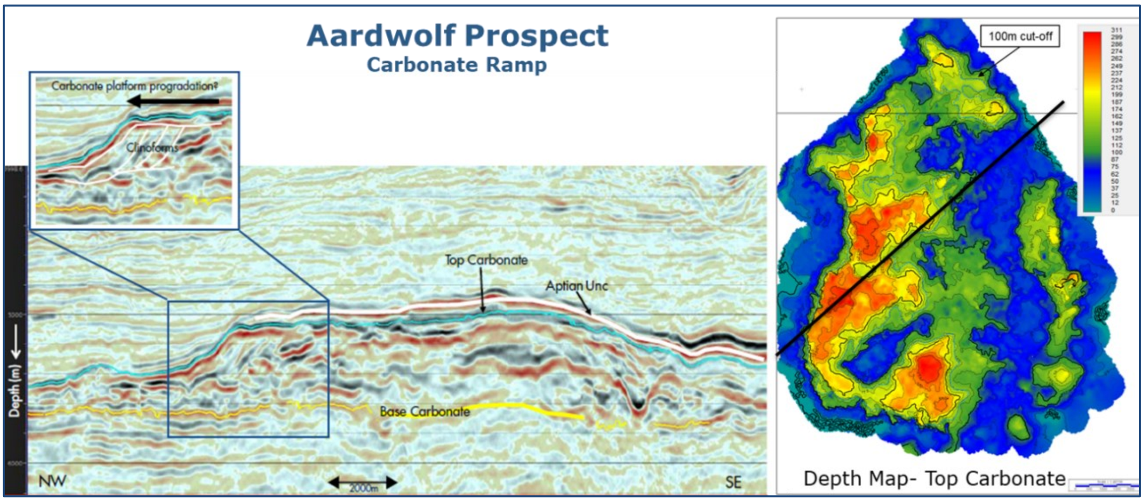



Proposed Multi-Objective Test
Fan SA and Bush Baby
Fan-S Far Stack amplitude Map with Depth contours (CI: 25m)
Block boundary
Bush-baby P50 Outline
seismic edge
Possible well location which intersects both Bush-baby and Fan-S
Bush-baby Far Stack Amplitude Map
Bush-baby P50 Outline
Possible well location which intersects both Bush-baby and Fan-S

10.10. Aardwolf Prospect

▪ Water Depth	2,200 m
▪ Overburden thickness	3,500 m
▪ Reservoir Temperature	130°C
▪ Zone	Barremian
▪ Reservoir Type	Prograding carbonate ramp/ carbonate buildup
▪ Trap	Structural, 4-way closure
▪ Seal	Deepwater mudstone for top and lateral seal
▪ AVO Type	None.

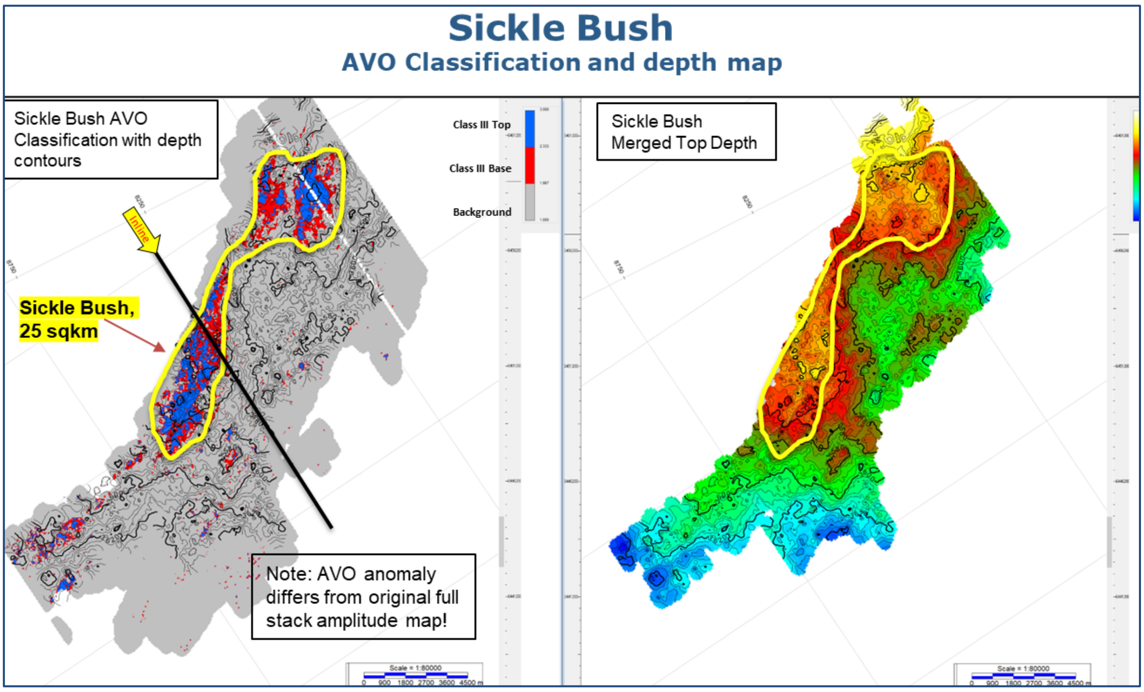
Aardwolf is a Barremian age carbonate whose internal geometry appears include prograding (clinoform) bedding indicative of prograding carbonate ramp or a carbonate buildup with local aggradation. It's location along the Outer High makes it one of several carbonate features that have been identified as prospects by other operators along this trend. The nearest penetration of similar age formations is in the Moosehead well in Namibia, several hundred kilometres north in Namibia, so analogues must come from a larger database. This has been considered in the risking elements for the prospect where reservoir is the highest risk given the wide range of porosity types in carbonate reservoirs. While the Aardwolf feature has no AVO signature, it is well described structurally, has four-way closure, and is overlain the primary Aptian-Albian source rock. Seal risk was considered as the feature is a topographic high and the overlying regional source rock could be thin or absent at the crest, although the overlying Albian system is a deep marine system. Prior to the discoveries made in the siliciclastic Cretaceous play it is notable that Shell had prioritized a similar carbonate buildup for drilling among their inventory of deepwater prospects offshore Namibia and South Africa.



10.11. Sickle Bush Prospect

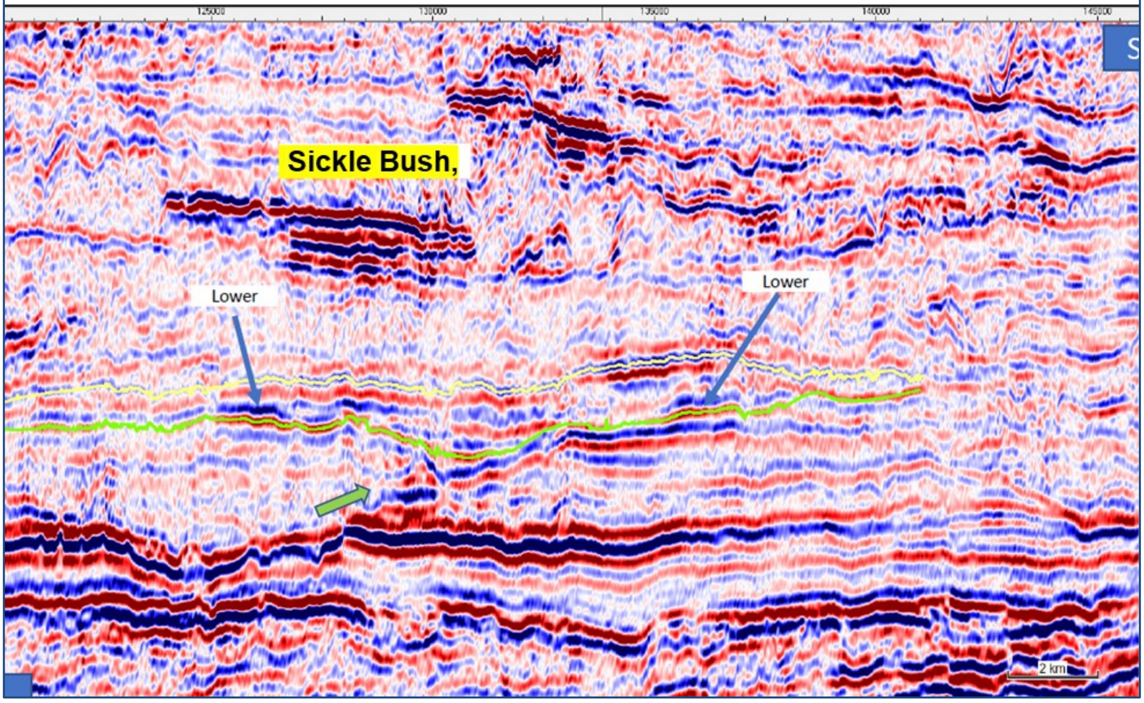
- Water Depth 1,840 m
- Overburden thickness 1,710 m
- Reservoir Temperature 65°C
- Zone Santonian
- Reservoir Type Turbidite fan
- Trap Stratigraphic
- Seal Deepwater mudstone for top and base seal
- AVO Type Strong Class 2 with conformance to structure.

Sickle Bush is a Santonian turbidite with a strong Class II AVO anomaly. The sequence appears to be composed of stacked channels in areas where it is thickest. Sickle Bush is located above the Maroela West prospect and in an area that is a topographic high at Aptian and deeper stratigraphic levels, making the area a possible regional focus for hydrocarbons. Both the Fluid Effect and FAR Amplitude AVO signatures have a possible conformance with depth.



Sickle Bush

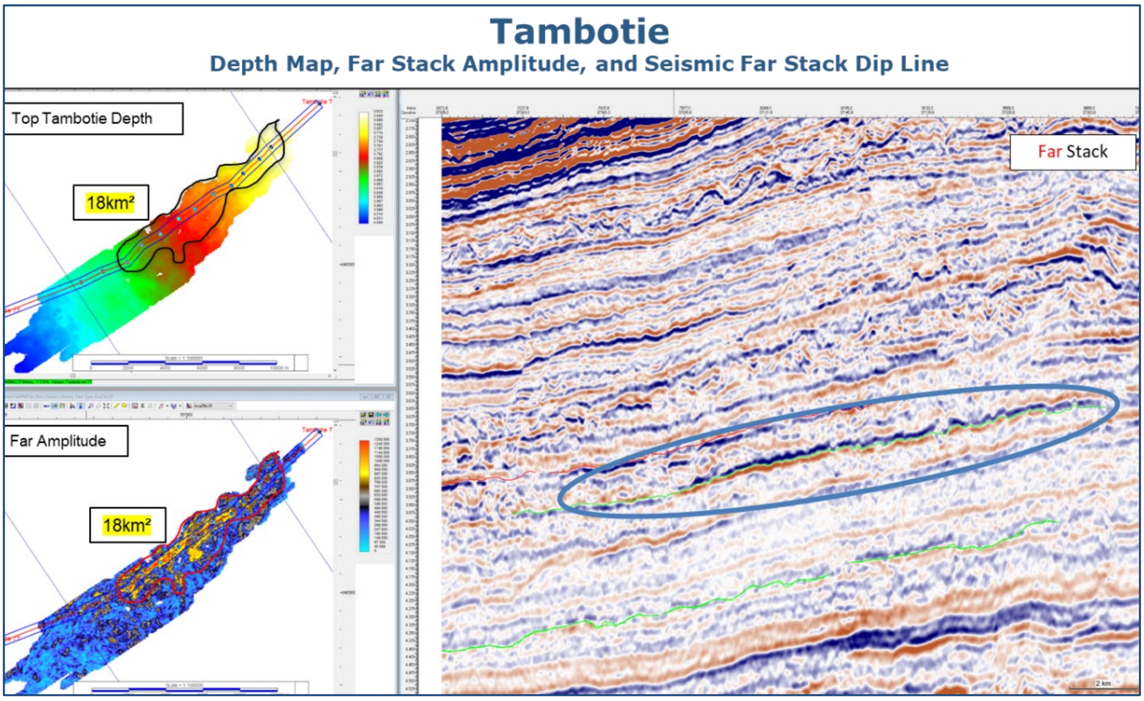
AVO Classification and Seismic Cross line



10.12. Tambotie Prospect

Water Depth	1,050 m
Overburden thickness	2,650 m
Reservoir Temperature	101°C
Zone	U. Cret
Reservoir Type	Channel
Trap	Stratigraphic
Seal	Deepwater mudstone for top and base seal
AVO Type	Strong Class 2 with conformance to structure.

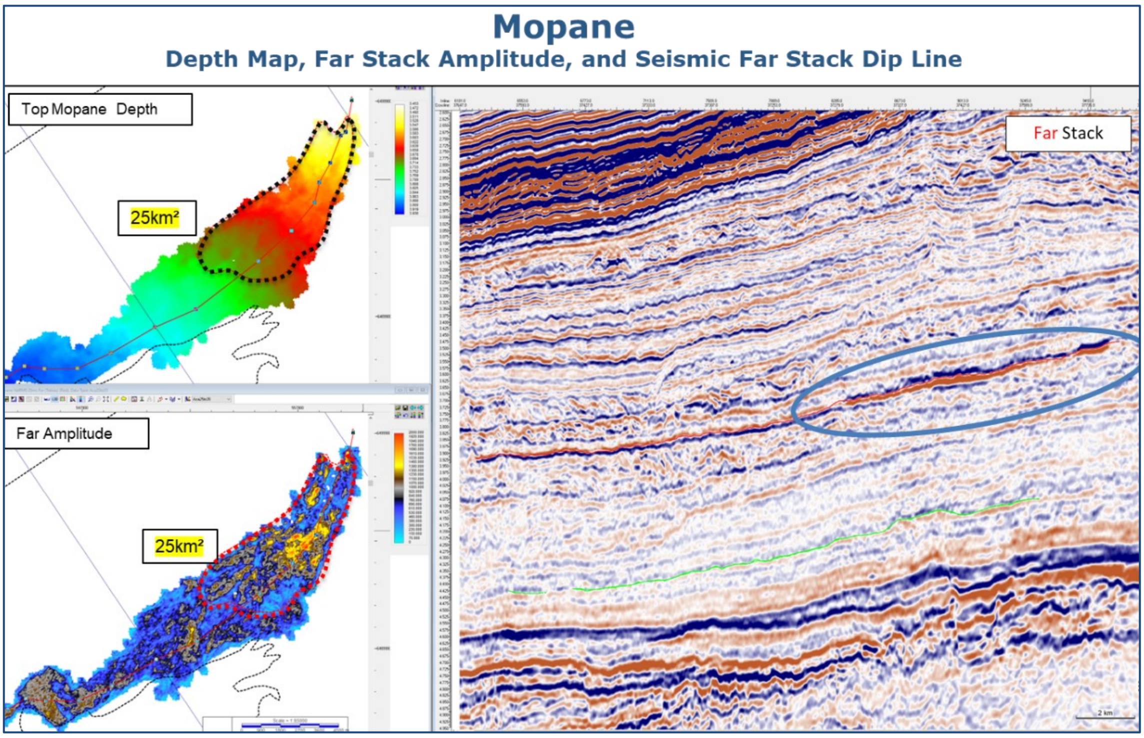
Tambotie is an Upper Cretaceous (likely Cenomanian) turbidite with a strongly linear, channel like morphology based on mapping of FAR amplitudes. It has a strong Class II AVO anomaly in the Far stack amplitudes within the thicker portions of the mapped interval. The updip trap is formed by a truncation of the channel feeder which is imaged seismically by a disappearance of RMS and Far amplitude response.



10.13. Mopane Prospect

- Water Depth — 1,050 m
- Overburden thickness — 2,300 m
- Reservoir Temperature — 90°C
- Zone — U. Cret
- Reservoir Type — Channel
- Trap — Stratigraphic
- Seal — Deepwater mudstone for top and base seal
- AVO Type — Strong Class 2 with conformance to structure.

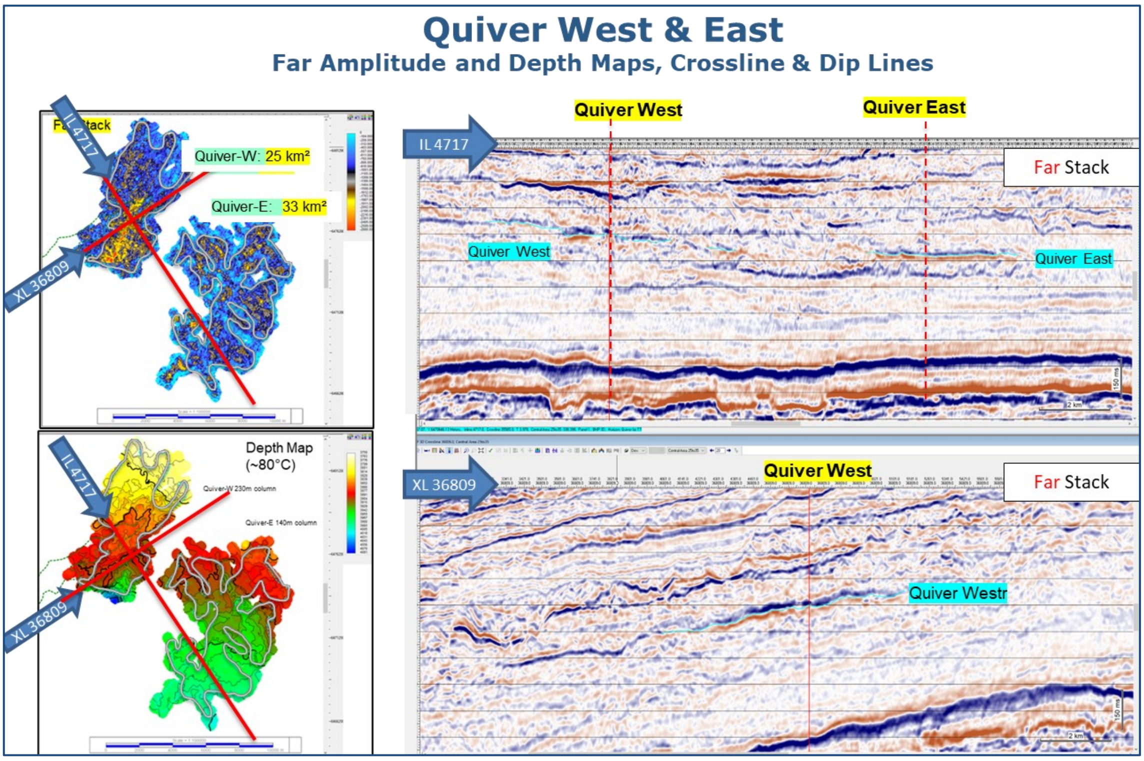
Mopane is close to Tambotie and is at a similar stratigraphic interval within the Upper Cretaceous/Cenomanian. Mopane has a strong Class IIp AVO response and appears to have channel morphology, probably somewhat confined on the outer slope margin. Mopane and Tambotie have some overlap in area and could be potentially targeted together as dual objectives.



10.14. Quiver East & West Prospects

▪ Water Depth	1,800 m
▪ Overburden thickness	2,000 m
▪ Reservoir Temperature	80°C
▪ Zone	U. Cret
▪ Reservoir Type	Fan
▪ Trap	Stratigraphic
▪ Seal	Deepwater mudstone for top and base seal
▪ AVO Type	Strong Class 2, no conformance to structure observed.

Quiver East and West are relatively subtle turbidite fans with weak, patchy Class II AVO response. Stratigraphically they can be correlated updip to the zone of interest in Tambotie and may be the downdip or distal equivalents of the same turbidite system. Quiver West has the stronger AVO response of the two prospects, and also overlies the Acacia Downdip prospect which offers the advantage of testing both Cenomanian and Albian targets.



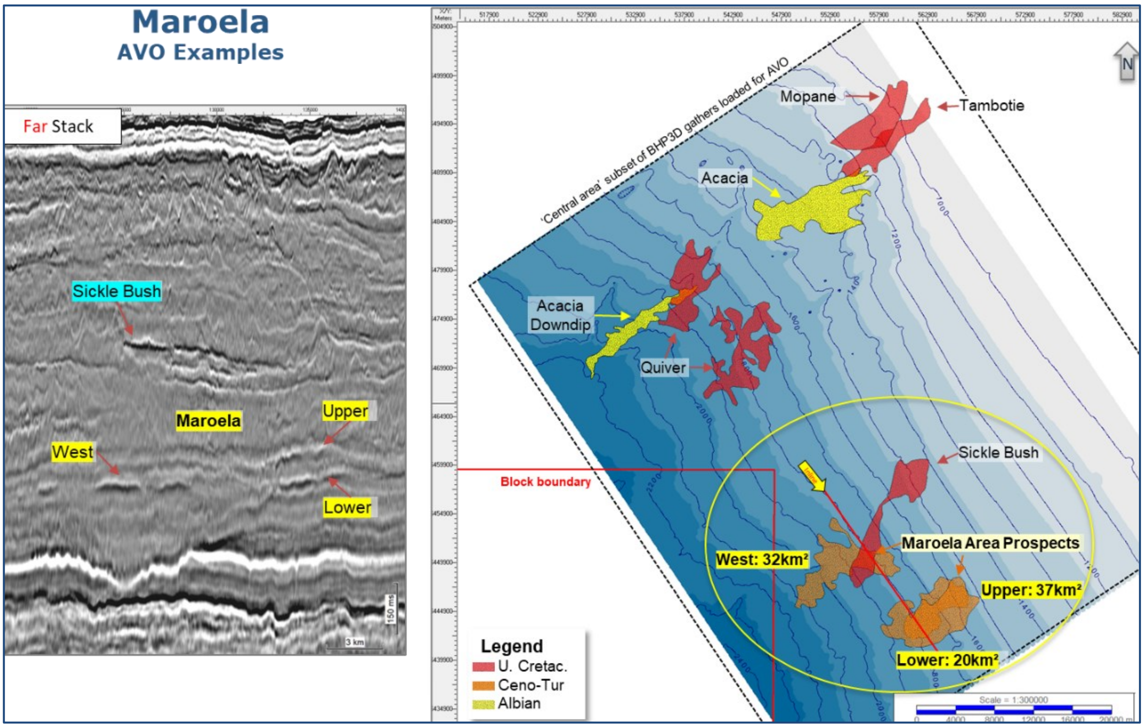
10.15. Maroela Area Prospects

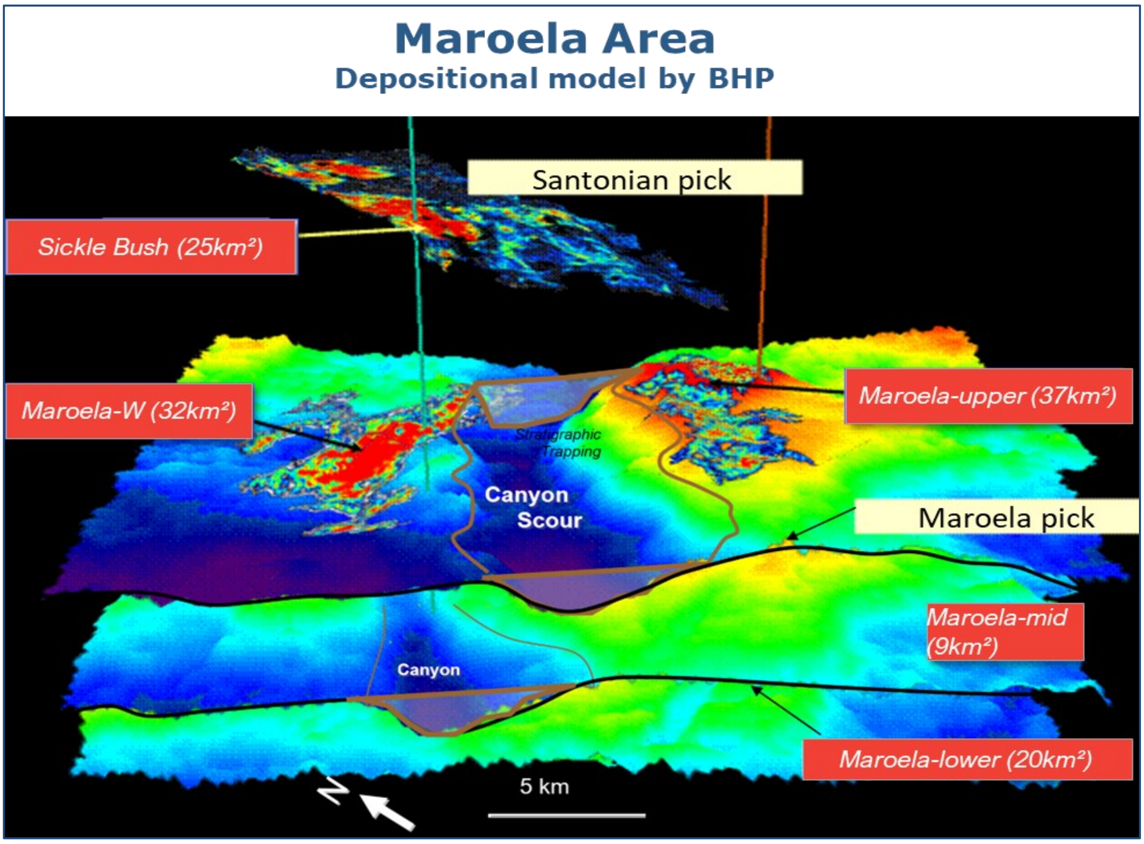
- Water Depth: 1,700 -1,800 m
- Overburden thickness: 2,200 -2,400 m
- Reservoir Temperature: 85-87°C
- Zone: Cenomanian/Turonian
- Reservoir Type: Fan, Splay
- Trap: Stratigraphic (Upper is Structural, 4-way dip)
- Seal: Deepwater mudstone for top, lateral and base seal
- AVO Type: Class 3, some conformance to structure observed.

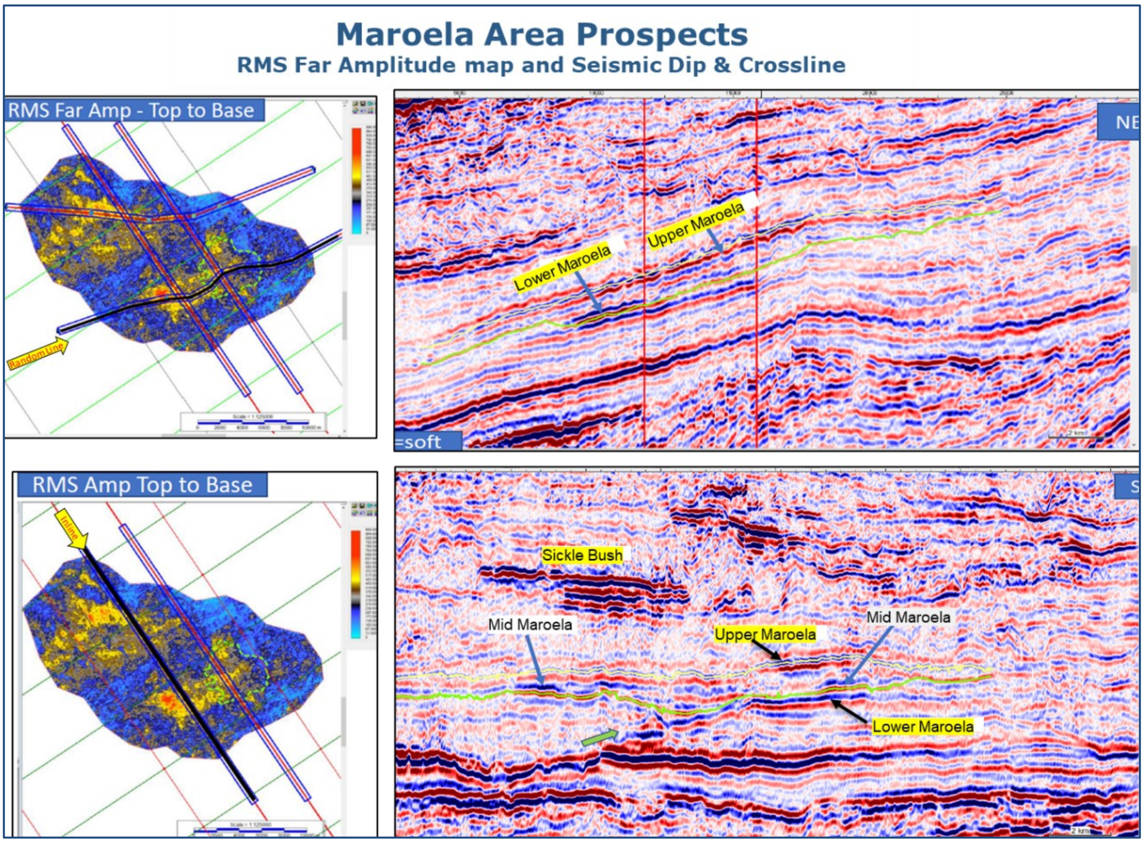
The Maroela area has long been a focus of exploration interest and Maroela Upper, Maroela Lower, and Maroela West have been at the center of this. These prospects are located above a regional topographic high at the Albian level, and Maroela Upper and Lower mapping horizons exhibit some four-way closure at the horizons of interest. In addition, they exhibit weak to strong Class III AVO response and there is some conformance to structure. Maroela West exhibits the strongest and most continuous FAR amplitude response and has the advantageous position of being located directly beneath the Sickle Bush Prospect.

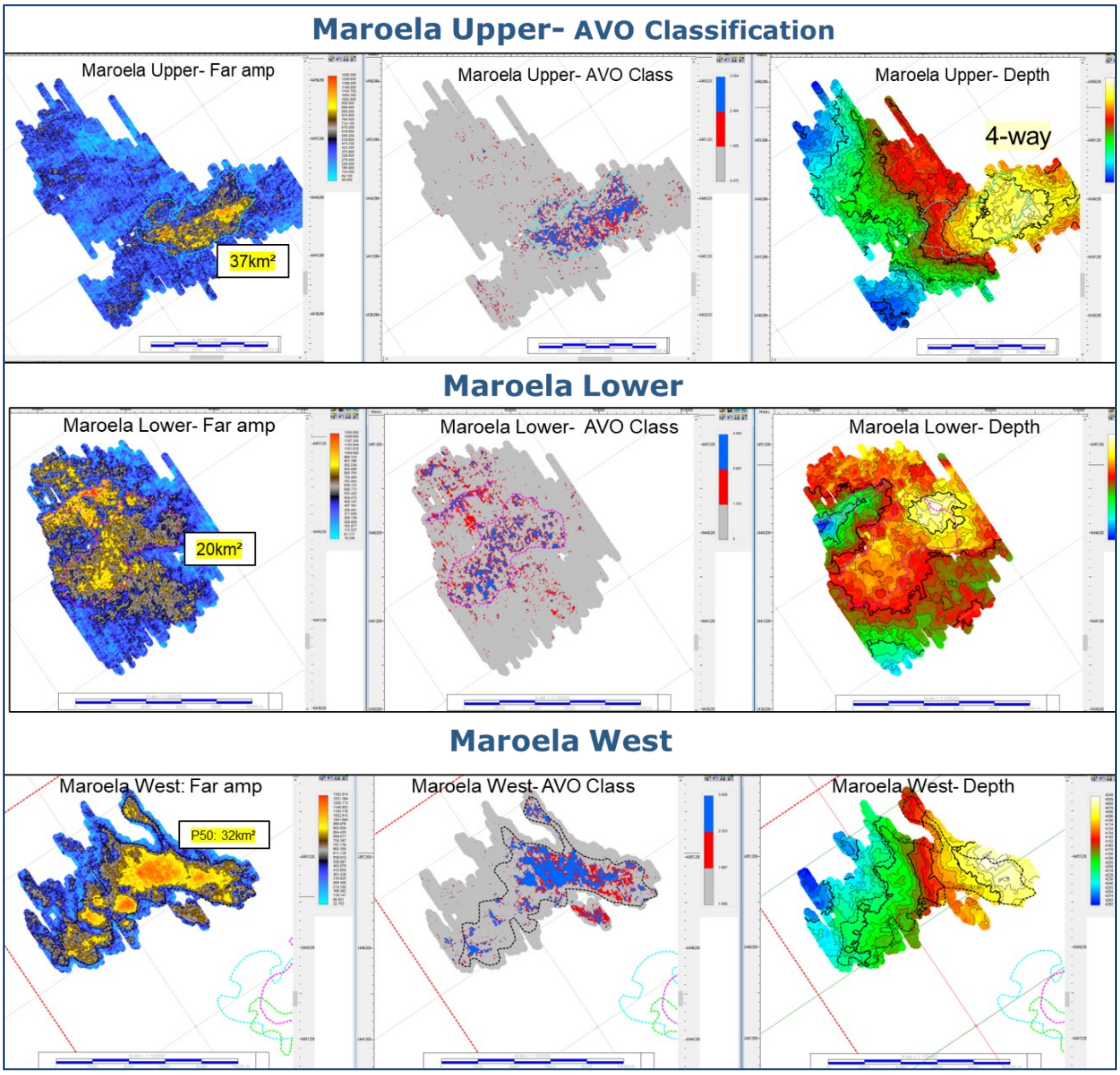
Although the AVO does appear to correspond to 4-way closer in some areas and not in others, this could be due to an imperfect depth conversion or stratigraphic influence into the trapping mechanism. BHP together with Occidental Petroleum acquired a focused 3D in this area, and it was encouragement from this early survey and the identification of the prospects in the Maroela area that led to the near block-wide acquisition of 3D in 2013.

Several erosional events are apparent in the section and may be contributing to trap formation. The Lower Maroela Prospect for example appears to have an antiform shape in part created by an unconformity surface.


Maroela
AVO Examples
Far Stack
Sickle Bush
Maroela
Upper
West
Lower
Mopane
Tambotie
Acacia
'Central area' subset of BHP3D gathers loaded for AVO
Acacia Downdip
Quiver
Sickle Bush
Block boundary
Maroela Area Prospects
West: 32km²
Upper: 37km²
Lower: 20km²
Legend
U. Cretac.
Ceno-Tur
Albian


Maroela Area
Depositional model by BHP
Santonian pick
Sickle Bush (25km²)
Maroela-W (32km²)
Maroela-upper (37km²)
Stratigraphic Trapping
Canyon Scour
Maroela pick
Maroela-mid (9km²)
Canyon
Maroela-lower (20km²)
5 km
N


Maroela Area Prospects
RMS Far Amplitude map and Seismic Dip & Crossline
RMS Far Amp - Top to Base
Random Line
NE
Lower Maroela
Upper Maroela
=soft
RMS Amp Top to Base
Inline
Sickle Bush
Mid Maroela
Upper Maroela
Mid Maroela
Lower Maroela

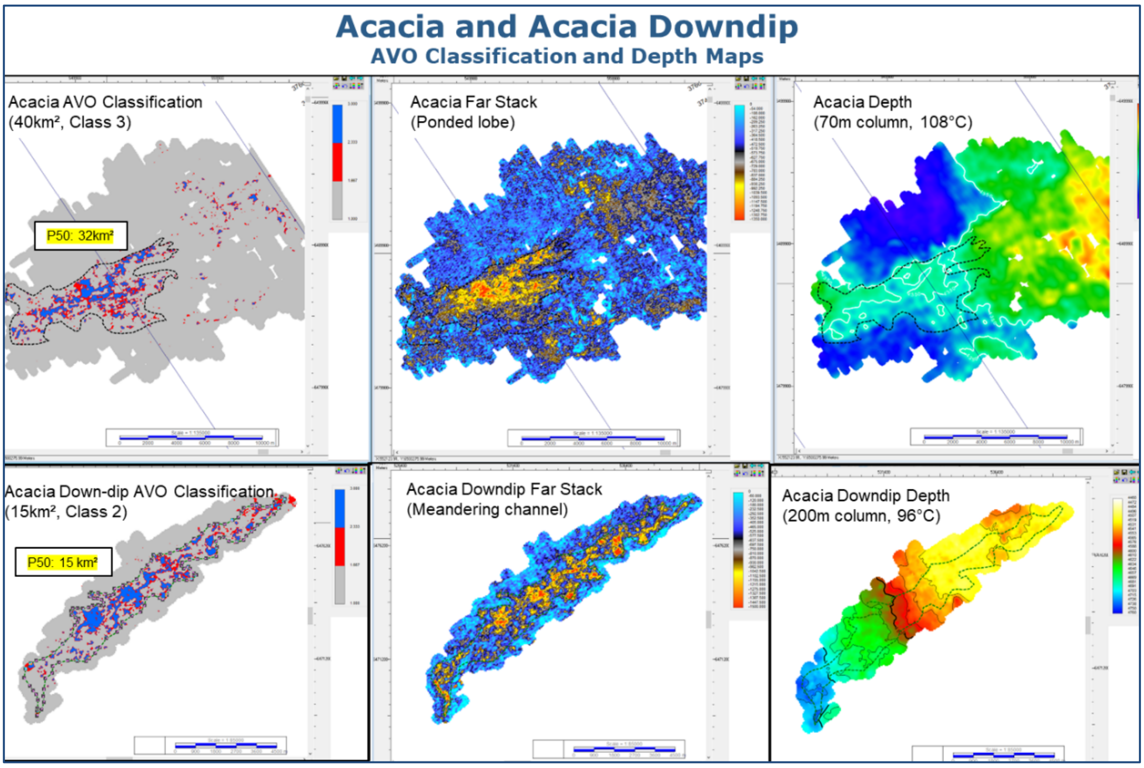


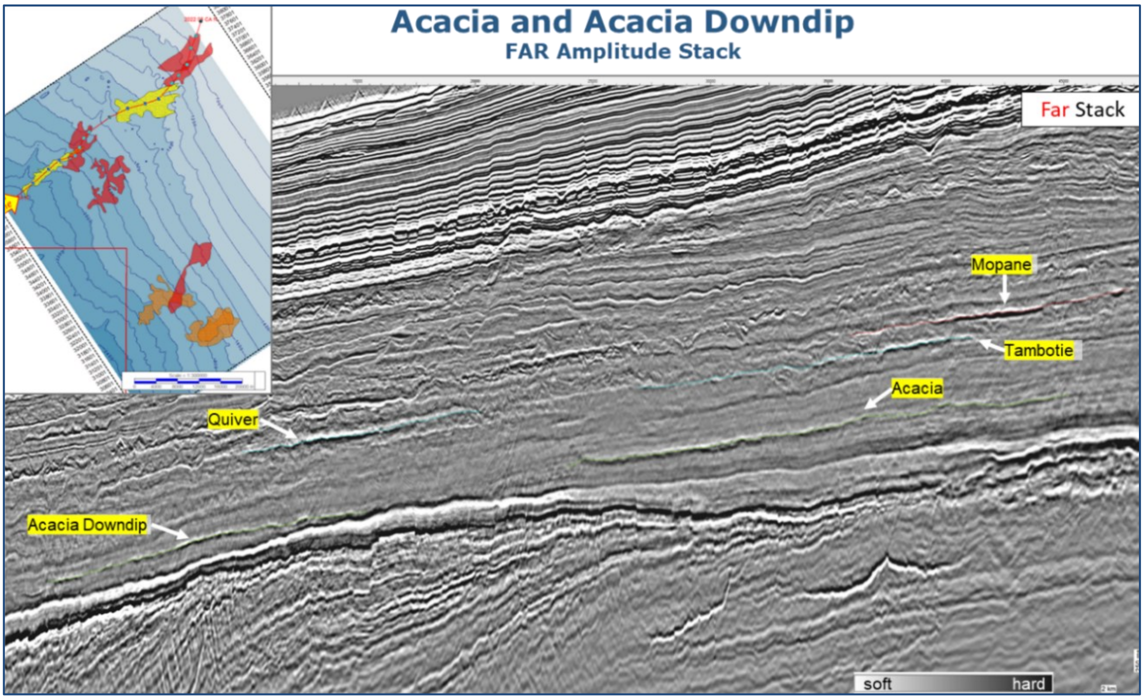
Maroela Upper- AVO Classification
Maroela Upper- Far amp
37km²
Maroela Upper- AVO Class
Maroela Upper- Depth
4-way
Maroela Lower
Maroela Lower- Far amp
20km²
Maroela Lower- AVO Class
Maroela Lower- Depth
Maroela West
Maroela West: Far amp
P50: 32km²
Maroela West- AVO Class
Maroela West- Depth

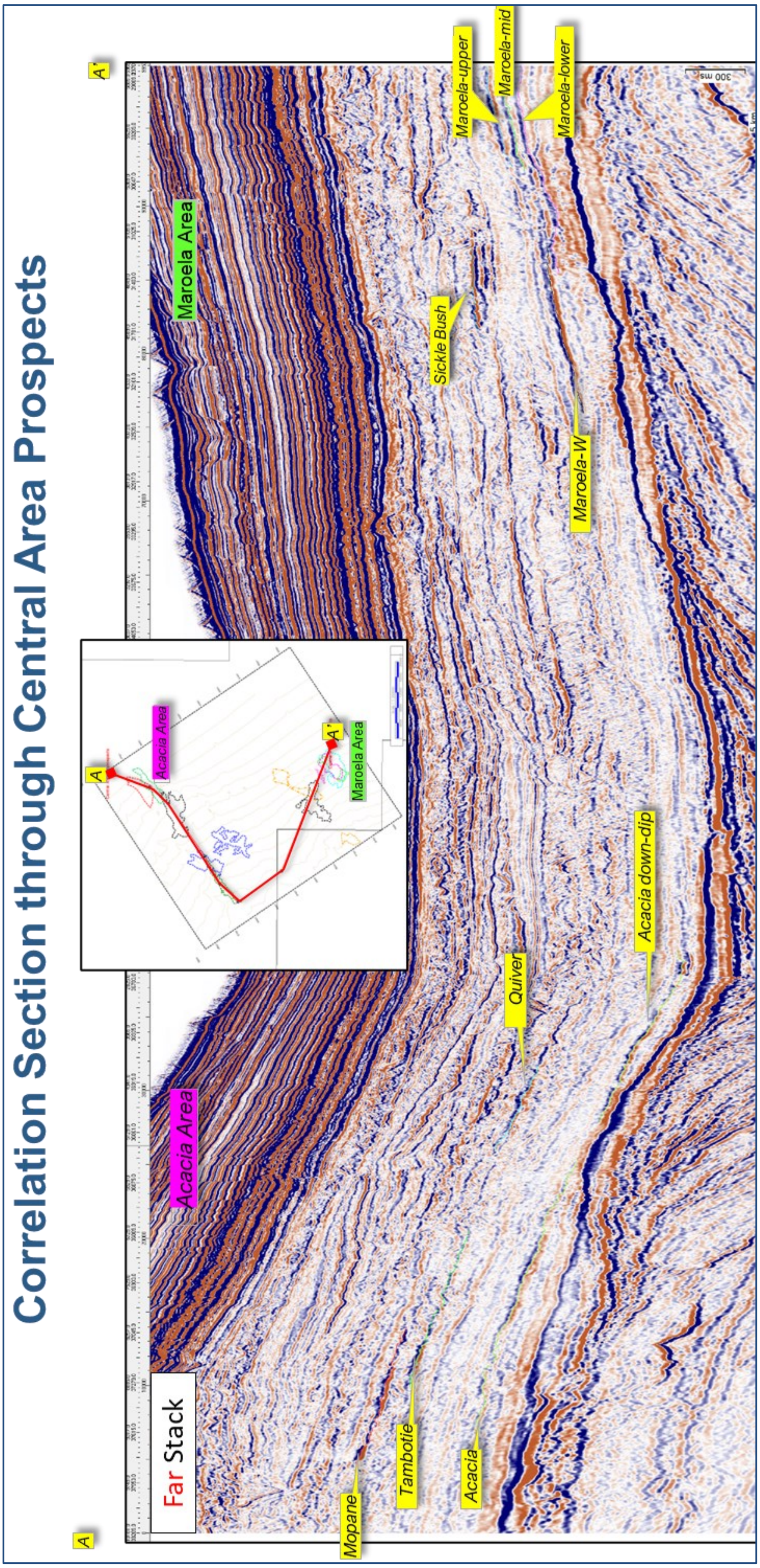
10.16. Acacia Prospect & Acacia Downdip

▪ Water Depth	1,400 & 1,900 m
▪ Overburden thickness	3,000 & 2,600 m
▪ Reservoir Temperature	108 & 91°C
▪ Zone	Albian
▪ Reservoir Type	Ponded lobe and lobe channel
▪ Trap	Stratigraphic
▪ Seal	Deepwater mudstone for top and base seal
▪ AVO Type	Class 3/2, no conformance to structure observed.

Acacia and Acacia Downdip are Albian age turbidites with both channel and lobe geometry. They are relatively narrow and strongly dip-oriented relative to the paleo Albian shoreline. Acacia has a strong Class III AVO anomaly based on Far stack amplitudes and also exhibits a Fluid Factor response. Acacia Downdip is more elongate and Far stack amplitudes appear to be more channel like, with a relatively clear cutoff of its feeder channel to provide a trap. Acacia Downdip is relatively small at 15 km^2, but it is located below Quiver West and could potentially provide a deeper secondary objective and help to de-risk Acacia located further updip.




Acacia and Acacia Downdip
FAR Amplitude Stack
Far Stack
Mopane
Tambotie
Acacia
Quiver
Acacia Downdip
soft
hard


Correlation Section through Central Area Prospects
Far Stack
A
A'
Maroela Area
Acacia Area
Maroela-upper
Maroela-mid
Maroela-lower
Sickle Bush
Maroela-W
Quiver
Acacia down-dip
Mopane
Tambotie
Acacia
300 ms