25th June 2013

The Directors
African Petroleum Corporation Ltd
Stratton House
5 Stratton Street
London
W1J 8LA

Dear Sirs

Re: Review of Exploration Acreage: African Petroleum Corporation Ltd

Introduction

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has reviewed the prospectivity of the petroleum exploration interests of African Petroleum Corporation Limited and its associated companies ("APCL"), in Blocks 8 & 9 offshore Liberia, Blocks A1 and A4 offshore Gambia, Licences CI-509 and CI-513, offshore Cote d'Ivoire and Block SL-03, offshore Sierra Leone, and we have prepared estimates as of today's date of the prospective petroleum resources associated with the following high-graded prospects: Barbet, Sunbird, Lovebird, Wildbird and Night Heron in Liberia, the Alhamdulilah prospect and Prospect M in the Gambia, the Ayame, Ayame West, Sassandra, Leraba and Cavella prospects in Cote d'Ivoire and the Altair prospect in Sierra Leone. We have used information and data available up to 31st May 2013.

For the prospective resources we have included an assessment of the geological chance of success. This dimension of risk does not incorporate the consideration of economic uncertainty and commerciality. In presenting prospective resources, ERCE assumes that the Operator of licences in which such prospective resources exist will behave in a competent manner, and execute any work programme designed to test such prospective resources in a timely and safe manner during the term specified for the licence.

We have carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1.

This letter is for the sole use of APCL and financial advisors. It may not be disclosed to any other person or used for any other purpose without the prior written approval of a director of "ERCE".

The Licences

APCL holds a 100 per cent contractor interest in a Production Sharing Contract ("PSC") covering Blocks 8 & 9 offshore Liberia. Our independent Best Estimate (P50) of prospective oil resources for the five prospects we have assessed (Table 1) in aggregate is 1875 MMstb unrisked, net attributable to APCL is 1815 MMstb unrisked and 289 MMstb risked. Our independent Mean estimate of prospective oil resources for the five prospects in aggregate is 3155 MMstb unrisked, net is 3046 MMstb unrisked and 473 MMstb net risked.

Both blocks are in their second exploration period, which began on 12th June 2012 and lasts for two years. Commitments during the second phase are a single exploration well (to a minimum depth of 2000 meters) within Block 9, and two exploration wells (to a minimum depth of 2000 meters) in Block 8, as a well commitment from the first exploration phase has been carried into the second phase in Block 8. The minimum spend for each block in the second exploration period is US$ 10 MM. The drilling of Well Bee Eater-1 has fulfilled the commitments in the second exploration period in Block 9.

For each block, there is one further optional exploration period of two years that can be entered into with a further well (to a minimum of 2000 metres) being required in each block in each period. At the end of the third period all areas not retained for appraisal and development are to be relinquished. There are also provisions for an appraisal period and an exploitation period of 25 years (with an additional term of 10 years if necessary) for each development area.

APCL holds a 60% contractor interest in PSCs covering Blocks A1 and A4 offshore Gambia, with Buried Hill Gambia BV holding the remaining 40%. The contracts were signed on 8th September 2006 with an effective date of 31st December 2007, and, following two extensions, they are still currently in the first exploration period, which runs through to 31 December 2013. Our independent Best Estimate (P50) of prospective oil resources for the Alhamdulilah prospect and Prospect M (Table 2) in aggregate is 459 MMstb unrisked, net attributable to APCL is 275 MMstb unrisked and 41.1 MMstb net risked. Our independent Mean estimate of prospective oil resources for the prospect is 593 MMstb unrisked, net is 356 MMstb unrisked and 52.6 MMstb net risked.

The commitment during the first period comprises 1000 km^2 of 3D seismic data in Block A1, 750 km^2 of 3D seismic data in Block A4 and one well which may be drilled in either block. The seismic commitment has already been met.

APCL holds a 90% contractor interest in PSCs covering Blocks CI-509 and CI-513 offshore Cote D'Ivoire. Petroci has the remaining 10% as a carried interest. The licences were awarded on 16th March 2012 and 19th December 2011 for CI-509 and CI-513 respectively. For CI-509 the licence consists of three terms of three, three and two years respectively, with a 25% relinquishment after each of the first and second terms. For CI-513 the licence consists of three exploration terms of three, two and two years respectively, with a 25% relinquishment after each of the first and second terms. Our independent Best Estimate (P50) of prospective oil resources for the five reviewed prospects (Table 3) in aggregate is 999 MMstb unrisked, net attributable to APCL is 863 MMstb unrisked and 116.4 MMstb net risked. Our independent Mean estimate of prospective oil resources for the prospects is 1808 MMstb unrisked, net is 1560 MMstb unrisked and 209.4 MMstb net risked.

The commitment, during the first period of licence CI-509 is to purchase existing 2D seismic, acquire 1,091 km^2 3D seismic data, perform geological and geophysical studies and drill one exploration well to a depth of 100 m into the Albian, with a minimum financial commitment of US $60 MM. The seismic commitment has already been met. The commitment, during the first period of licence CI-513 is to purchase existing 2D seismic data, acquire 1446 km^2 3D data, perform geological and geophysical studies and drill one exploration well to a depth of 100 m into the Albian, with a minimum financial commitment of US $60 MM. The seismic commitment has already been met.

APCL holds a 100% contractor interest in a PSC covering Block SL-03, offshore Sierra Leone, through its wholly owned subsidiary European Hydrocarbons Ltd. The licence was ratified by the government on 22nd February 2011. The licence has a duration of thirty years, the first seven of which are termed the exploration period, which is further subdivided into an initial period of three years, followed by two extension periods of two years each. The licence is currently in the initial exploration period.

Work commitments during the initial period for Block SL-03 are to purchase and interpret the existing 2D seismic data over the licence and acquire a minimum of 500 km^2 of 3D seismic data. APCL has purchased the 2D seismic data and has acquired 2535 km^2 of multi-client 3D seismic data over Block SL-03, fulfilling the seismic commitment for the initial phase. The first and second extension periods require the drilling of one exploration well to a minimum depth (below mud line) of 1300 m, or a minimum equivalent investment of US$ 30 MM. Entry to the first extension period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the second extension period. The area of the licence is 3860 km^2, and water depth varies from 100 m to over 4000 m, with the south-western half of the block being at water depths greater than 3000 m.

Our independent Best Estimate (P50) of prospective oil resources for the Altair prospect in Block SL-03 (Table 4) is 278 MMstb (gross and net) unrisked and 50.4 MMstb net risked. Our independent Mean estimate of prospective oil resources for the prospect is 434 MMstb (gross and net) unrisked and 78.8 MMstb net risked.

Work Done

In carrying out our evaluation of the interests, we have relied upon information provided by APCL which comprised details of APCL's licence interests, offset well data and associated analysis, seismic data including interpretation, basic exploration data, technical reports and volumetric estimates, where appropriate.

Our approach has been to commence our investigations with the most recent technical reports and interpreted data. From these we have been able to identify those items of basic data which require re-assessment. Where only basic data have been available or where previous interpretations of data have been considered incomplete, we have undertaken our own interpretation. A site visit was not undertaken.

In estimating petroleum in place and recoverable, we have used the standard techniques of prospect analysis. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and have used statistical methods to calculate the range of petroleum initially in place and recoverable.

We have estimated the chance of success for drilling the identified exploration prospects, using the industry standard approach of assessing the likelihood of source rock, charge, reservoir trap and seal. The result is the chance or probability of discovering hydrocarbons in sufficient quantity and which test at a sufficient rate to permit consideration for subsequent appraisal and development.

The nomenclature used in this report is presented in Appendix 2.

Professional Qualifications

ERC Equipoise is an independent consultancy specialising in petroleum reservoir evaluation. Except for the provision of professional services on a fee basis, ERC Equipoise has no commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The work has been supervised by Dr Adam Law, Geoscience Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers. He has 18 years relevant experience in the evaluation of oil and gas fields and exploration acreage, preparation of development plans and assessment of reserves and resources.

Yours faithfully

ERC Equipoise Limited

Adam Law

Geoscience Director

Table 1: STOIIP and Prospective Oil Resources, Liberia Blocks 8 and 9

Prospect	Reservoir	STOIIP (MMStb)				Unrisked Prospective Resource (MMstb)				APCL Interest	Net Unrisked Prospective Resource (MMstb)				Prospect Risk	Play Risk	COS (%)	Net Risked Prospective Resource (MMstb)			
		Low	Best	High	Mean	Low	Best	High	Mean	(%)	Low	Best	High	Mean	(%)	(%)		Low	Best	High	Mean
Barbet	Turonian	166	500	1,479	718	60	186	558	270	100	60	186	558	270	22	1	22	13	41	123	59
Sunbird	Campanian	177	461	1,187	609	63	172	448	229	100	63	172	448	229	27	1	27	17	46	122	62
	Turonian	107	307	863	429	39	115	327	162	100	39	115	327	162	19	1	19	7	22	62	31
	Cenomanian	91	264	779	376	33	99	294	141	100	33	99	294	141	18	1	18	6	18	53	25
Lovebird (Isopach)	Blue Horizon	68	293	1,218	536	25	109	456	201	100	25	109	456	201	20	1	20	5	22	91	40
	Pink Horizon	59	262	1,066	474	22	96	400	178	100	22	96	1,070	178	20	1	20	4	19	214	36
	Green Horizon	48	210	896	399	18	78	337	150	100	18	78	337	150	20	1	20	4	16	67	30
Night Heron	Turonian	254	1,117	4,603	1,904	92	416	1,742	759	100	87	356	1,338	650	14.4	1	14.4	13	51	193	94
Wildbird	Light Blue Horizon	552	2,289	8,700	3,946	144	605	2,377	1,065	100	144	605	2,377	1,065	38	24	9	13	54	214	96
	Total	**1,522**	**5,704**	**20,791**	**9,392**	**497**	**1,875**	**6,940**	**3,155**		**492**	**1,815**	**7,205**	**3,046**				**82**	**289**	**1,139**	**473**

Table 2. STOIIP and Prospective Oil Resources - Alhamdulilah and Prospect M - Gambia

Block	Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				APCL Interest (%)	Net Unrisked Prospective Resource				Prospect Risk	Play Risk	COS (%)	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)		Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)				Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
A1	SS4	Cretaceous	43	113	295	16	42	112	56	60	9	25	67	34	50	34	17	1.6	4.3	11.5	5.8
A1	SS3	Cretaceous	197	417	881	63	143	316	173	60	38	86	189	104	50	32	16	6.0	13.8	30.4	16.7
A1	SS2	Cretaceous	187	416	911	58	133	303	163	60	35	80	182	98	50	32	16	5.6	12.8	29.2	15.7
A1	SS1	Jurassic	158	399	997	34	98	276	135	60	21	59	166	81	50	26	13	2.7	7.7	21.7	10.6
A1	M	Aptian	82	231	629	13	43	141	66	60	8	26	85	40	28	35	10	0.7	2.5	8.2	3.8
Total			**666**	**1,577**	**3,713**	**183**	**459**	**1,148**	**593**		**110**	**275**	**689**	**356**				**17**	**41.1**	**101.0**	**52.6**

Table 3. STOIIP and Prospective Oil Resources – Cote D’Ivoire

Block	Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				Interest (%)	Net Unrisked Prospective Resource				Play Risk (%)	Prospect Risk (%)	COS (%)	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)		Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)				Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
CI-513	Ayame	Upper Cretaceous	179	815	3,474	65	302	1,318	569	90	58	267	1,138	502	49	28	14	8.0	36.3	154.9	68.3
CI-513	Ayame West	Upper Cretaceous	161	585	2,085	58	216	788	352	90	52	183	626	298	49	28	14	7.1	24.9	85.2	40.6
CI-513	Sassandra	Upper Cretaceous	71	320	1,408	26	118	521	237	90	23	87	300	175	49	20	10	2.2	8.3	28.6	16.6
CI-513	Cavalla	Upper Cretaceous	67	281	1,142	25	104	431	190	90	22	93	388	171	49	20	10	2.1	8.9	37.0	16.3
CI-509	Leraba	Upper Cretaceous	252	997	3,682	55	258	1,039	460	90	50	232	935	414	49	34	16	8.2	38.0	152.7	67.6
TOTAL			**731**	**2,998**	**11,792**	**229**	**999**	**4,097**	**1,808**		**206**	**863**	**3,387**	**1,560**				**27.5**	**116.4**	**458.3**	**209.4**

Table 4. STOIIP and Prospective Oil Resources - Sierra Leone

Block	Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				Interest (%)	Net Unrisked Prospective Resource				Play Risk (%)	Prospect Risk (%)	COS (%)	Net Risked Prospective Resource			
			Low (MMstb)	Best (MMstb)	High (MMstb)	Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)		Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)				Low (MMstb)	Best (MMstb)	High (MMstb)	Mean (MMstb)
SL-03	Altair	Upper Cretaceous	218	755	2,473	79	278	938	434	100	79	278	938	434	65	28	18	14.4	50.4	170.2	78.8

Competent Person's Report:

African Petroleum Corporation Limited

PREPARED FOR: African Petroleum Corporation Limited

BY: ERC Equipoise Limited

June 2013

ERC equipoise

Authors: Adam Law, Michael Braim, Glyn Pugh, Kate Overy, Don Munn

Approved by: Simon McDonald

Date released to client: June 25, 2013

ERC Equipoise Limited ("ERC Equipoise" or "ERCE") has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERC Equipoise does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

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1. Introduction

At the time of writing, African Petroleum Corporation Limited (APCL) holds interests in and operates exploration licences offshore West Africa, within the territorial waters of Senegal, the Gambia, Sierra Leone, Liberia and Cote d'Ivoire (Figure 1-1). The status of these licences is summarised in Table 1.1 below. ERC Equipoise Ltd (ERCE) has reviewed the prospectivity of these licences, using data as of 31st May 2013.

Figure 1-1 Location of APCL licences, West Africa

Currently, prospective resources are identified by APCL within the Liberia, Gambia, Sierra Leone and Cote d'Ivoire licences. We have made independent estimates of prospective resources and geological chance of success for certain prospects within these countries, which are identified by APCL as near-term drilling opportunities. The evaluation of the offshore Senegal licences is on-going, and no prospects have been identified as of the date of this report. We summarise qualitatively the prospectivity of the licences held by APCL in this country.

Country	Block/ Licence	Operator	APCL (%)	Status	Licence: Start of Current Phase	Licence: End of Current Phase	Area (km^2)	Outstanding Commitment in this Phase
Liberia	8	APCL	100%	Expl	June 2012	June 2014	2717	Two Exploration wells
Liberia	9	APCL	100%	Expl	June 2012	June 2014	2634	None
Gambia	A1	APCL	60%	Expl	Dec 2007	Dec 2013	1296	One Exploration well [1]
Gambia	A4	APCL	60%	Expl	Dec 2007	Dec 2013	1376	(see A1)
Senegal	Rufisque Offshore Profond	APCL	90%	Expl	Oct 2011	Oct 2015	10357	One exploration well
Senegal	Senegal Offshore Sud Profond	APCL	90%	Expl	Oct 2011	Oct 2014	7920	None
Sierra Leone	SL-03	APCL	100%	Expl	Feb 2011	Feb 2014	3860	None
Sierra Leone	SL-04A	APCL	100%	Expl	Sept 2012	Sept 2015	1995	One exploration well [2]
Cote d'Ivoire	CI-509	APCL	90%	Expl	March 2012	March 2015	1091	One exploration well
Cote d'Ivoire	CI-513	APCL	90%	Expl	Dec 2011	Dec 2014	1446	One exploration well

1) Transferrable to Block A4 if necessary
2) Contingent on results of 3D and that technology is available to drill in such water depths

Table 1.1 Licence Summary Table

1.1. Liberia: PSC Overview

APCL holds a 100% contractor interest in a Production Sharing Contract ("PSC") covering Blocks 8 & 9 offshore Liberia (Figure 1-2). Both blocks are in their second exploration period, which began on 12th June 2012 and lasts for two years. Commitments during the second phase in Block 8 are two exploration wells (to a minimum depth of 2000 meters), as a well commitment from the first exploration phase has been carried into the second phase. All commitments have been met for the second phase in Block 9 with the drilling of Well Bee Eater-1. The minimum spend for each block in the second exploration period is US$ 10 MM. At the end of this second phase, a further 25% of each licence must be relinquished.

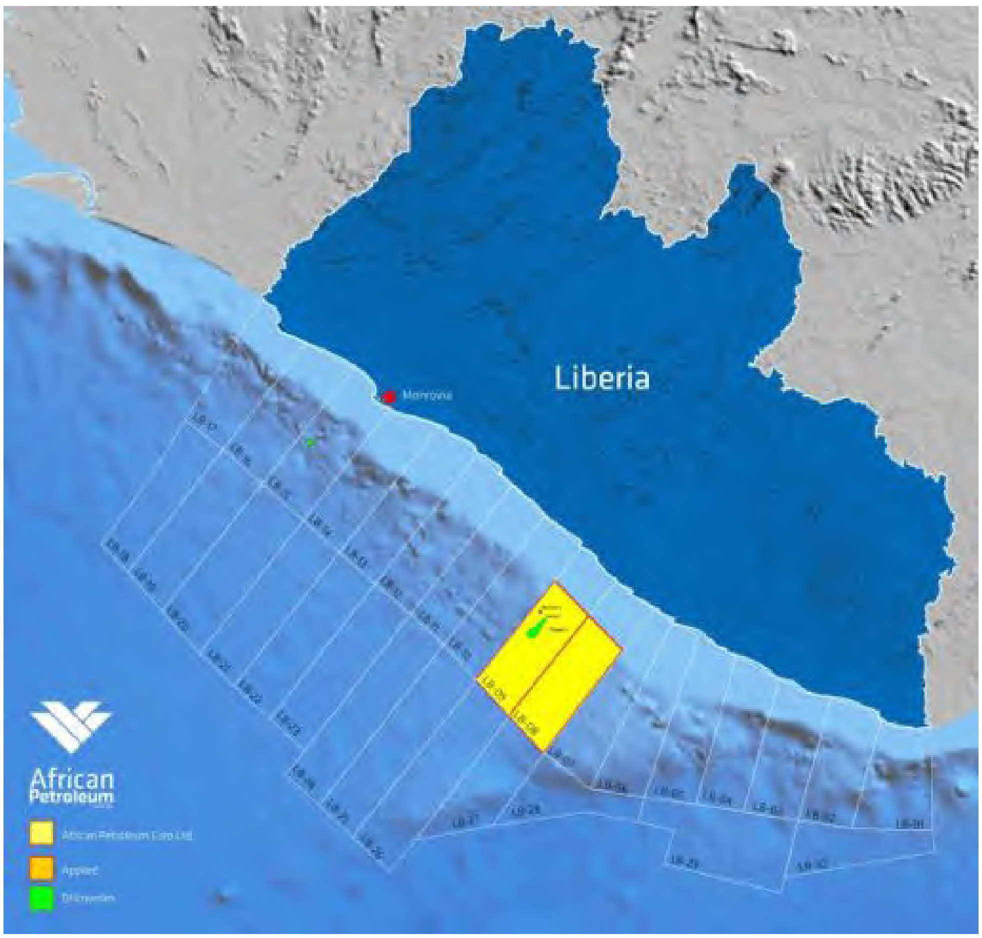


Figure 1-2 Location of Liberia Blocks 8 and 9

For each block, there is one further optional exploration period of two years that can be entered into with an additional well (to a minimum of 2000 metres) being required in each block in each period. At the end of the third period all areas not retained for appraisal and development are to be relinquished. There are also provisions for an appraisal period and an exploitation period of 25 years (with an additional term of 10 years if necessary) for each development area.

Following a 25% relinquishment at the end of the first exploration phase, Block 8 comprises an area of 2717 km^2, and Block 9 comprises 2634 km^2. Water depths range from less than 100 m to over 3000 m. Most of the block areas lie in water depths greater than 500 m.

1.2. Gambia: PSC Review

APCL holds a 60% contractor interest in Production Sharing Contracts covering Blocks A1 and A4 offshore Gambia (Figure 1-3) with Buried Hill Gambia BV holding the remaining 40%. The licences were signed on 8th September 2006 with an effective date of 31st December 2007, and, following two extensions, they are still currently in the first exploration period, which runs through to 31 December 2013.

The work commitment during the first period comprises 1000 km^2 of 3D seismic data in Block A1 and 750 km^2 of 3D seismic data in Block A4, and one well which may be drilled in either block. The seismic commitment has already been met.

There are two further optional (but automatic) exploration periods of three years each that can be entered into, with a well being required in each period in each licence. Furthermore in Block A1 relinquishment of 10% of the licence area is required at the end of the first exploration period, and 20% at the end of the second period. In Block A4 relinquishment of 10% of the licence area is required at the end of the first exploration period. In both blocks, at the end of the third period, all areas not retained for appraisal and development are to be relinquished. There are also provisions for an exploitation period, with the total term of the licences being 30 years (including the exploration periods) for each development area.

The area of the licence is 1296 km^2 for Block A1 and 1376 km^2 for Block A4. Water depths vary from 500 m to over 3000 m.

Figure 1-3 Location of Gambia Blocks A1 and A4

1.3. Senegal: PSC Review

APCL holds a 90% contractor interest in Exploration and Production Sharing Contracts (EPSC) covering Blocks Rufisque Offshore Profond (ROP) and Senegal Offshore Sud Profonde (SOSP), offshore Senegal, (Figure 1-4) via its wholly owned subsidiary African Petroleum Senegal Limited. Petrosen, the state oil company, hold a 10% carried interest.

The EPSC governing block SOSP has an effective date of 25th October 2011. The first 8.5 years of the EPSC are termed the exploration phase, which is subdivided into an initial period of three years, with two subsequent extension periods of three and two and a half years each. Work commitment in the initial exploration period is to acquire and reprocess the existing seismic data within the licence area, and also to acquire a further 2500 km^2 of 3D seismic data, all with a minimum investment of US$ 10 MM. The two extension periods have a commitment of one exploration well to a minimum depth of 3500 mss in each period, or a minimum investment of US$ 20 MM. Entry to the first extension period requires a 30% relinquishment of the licence area, and a further 20% of the initial licence area must be relinquished on entry to the third phase. The area of the licence is currently 7920 km^2. Water depth is between 1000 and 4000 m over the block.

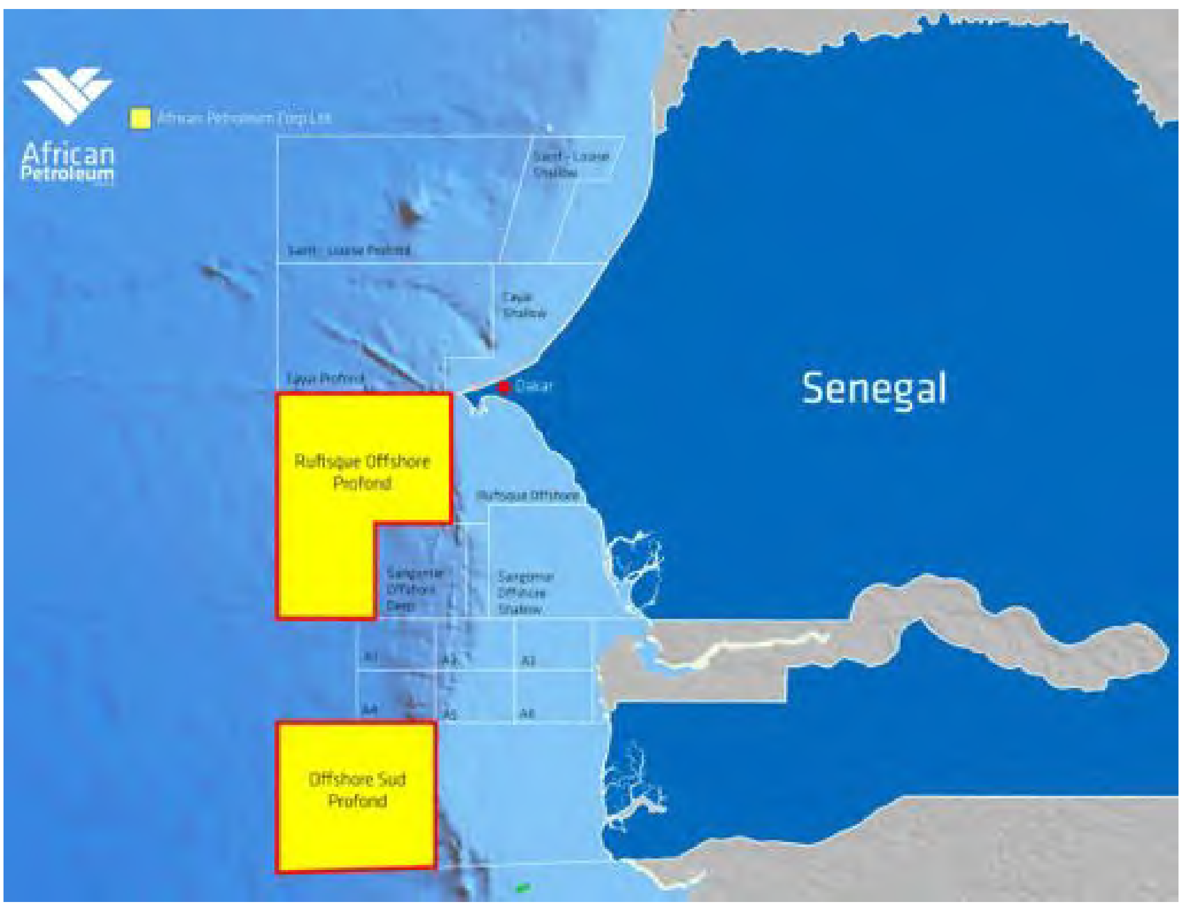


Figure 1-4 Location of Senegal ROP and SOSP Licences

The EPSC governing Block ROP is of similar structure to that governing Block SOSP. It has an effective date of 25th October 2011. The first eight years of the EPSC are termed the exploration phase, which is subdivided into an initial period of four years, with two subsequent extension periods of two years each. Work commitment in the initial exploration period is to acquire the existing seismic data within the licence area for a minimum of US$ 2 MM, and drill one exploration well to a minimum depth of 3500 m TVDSS or a minimum investment of US$ 20 MM. The two extension periods have a further commitment of one exploration well to a minimum depth of 3500 m TVDSS in each period, or a minimum investment of US$ 20 MM. Entry to the first extension period requires a 30% relinquishment of the licence area, and a further 20% of the initial licence area must be relinquished on entry to the third period. The area of the licence is currently 10357 km^2. Water depth is between 1500 and 3000 m over the block.

APCL has met the seismic commitment of the first exploration period.

Petrosen has a back-in right if an exploitation period is authorised for up to 20% of the licence, subject to contribution of its share of forward costs (excluding training). The duration of an exploitation period is 25 years from authorisation, with option for two ten year extensions at the discretion of the state.

1.4. Sierra Leone: PSC Review

APCL holds a 100% contractor interest in a PSC covering Block SL-03, offshore Sierra Leone, (Figure 1-5) through its wholly owned subsidiary European Hydrocarbons Ltd. The licence was awarded on 23rd April 2010 and ratified on 22nd February 2011. APCL also holds a 100% contractor interest in a PSC covering Block SL-04A, through its wholly owned subsidiary African Petroleum Sierra Leone Ltd. The PSC governing Block SL-04A was ratified on 21st September 2012.

The SL-03 licence has a duration of thirty years, the first seven of which are termed the exploration period, which is further subdivided into an initial period of three years, followed by two extension periods of two years each. The licence is currently in the initial exploration period.

Work commitments during the initial period for Block SL-03 are to purchase and interpret the existing 2D seismic data over the licence and acquire a minimum of 500 km^2 of 3D seismic data. APCL has purchased the 2D seismic data and has acquired 2535 km^2 of multi-client 3D seismic data over Block SL-03, fulfilling the seismic commitment for the initial phase. The first and second extension periods require the drilling of one exploration well to a minimum depth (below mud line) of 1300 m, or a minimum equivalent investment of US$ 30 MM. Entry to the first extension period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the second extension period. The area of the licence is 3860 km^2, and water depth varies from 100m to over 4000m, with the south-western half of the block being at water depths greater than 3000m.

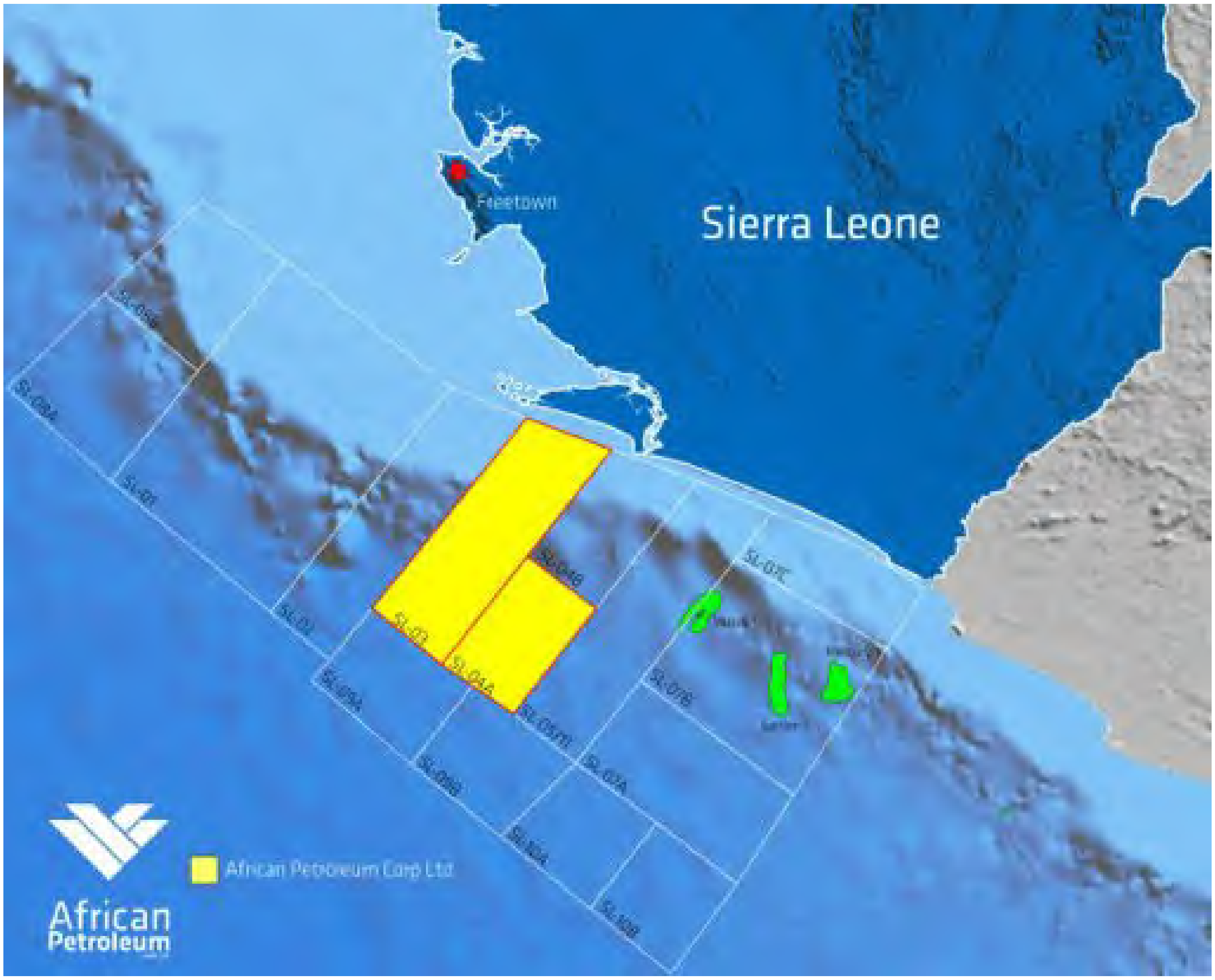


Figure 1-5 Location of Blocks SL-03 and SL-04A

The PSC covering Block SL-04A was ratified on 21st September 2012. The licence term is for thirty years, the first seven years of which are defined as the exploration period, which is further subdivided into an initial period of three years, and two subsequent periods of two years. Each well drilled in the initial exploration period extends this period by three months. Work commitments during the initial phase are to acquire at least 1500 km^2 of 3D seismic data, and drill one exploration well, (to a minimum depth of 2500m), contingent on the results of the 3D and the availability of drilling technology for such deep water. The minimum equivalent investment is US$ 10 MM. In 2011, TGS acquired 1085 km^2 of multi-client 3D seismic data over Block SL-04A. Upon licencing these data, APCL will have fulfilled the seismic commitment for the initial phase.

The subsequent two exploration periods require the drilling of one exploration well in each period, (to a minimum depth of 2500 m), or a minimum investment of US$ 50 MM. Entry to the second period requires a 50% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third phase. The area of the licence is currently 1995 km^2. Water depth is between 3000 and 4000 m over the block.

The state retains the right to a 10% carried interest during any development phase in both licences, with the option to acquire a further 5% by covering an equivalent proportion of any development costs.

1.5. Cote d'Ivoire: PSC Review

APCL holds a 90 per cent contractor interest in two PSCs governing Block CI-509 and Block CI-513, offshore Cote d'Ivoire, (Figure 1-6) via its wholly owned subsidiary African Petroleum Cote d'Ivoire Limited. The state oil company, Petroci, has a 10% carried interest.

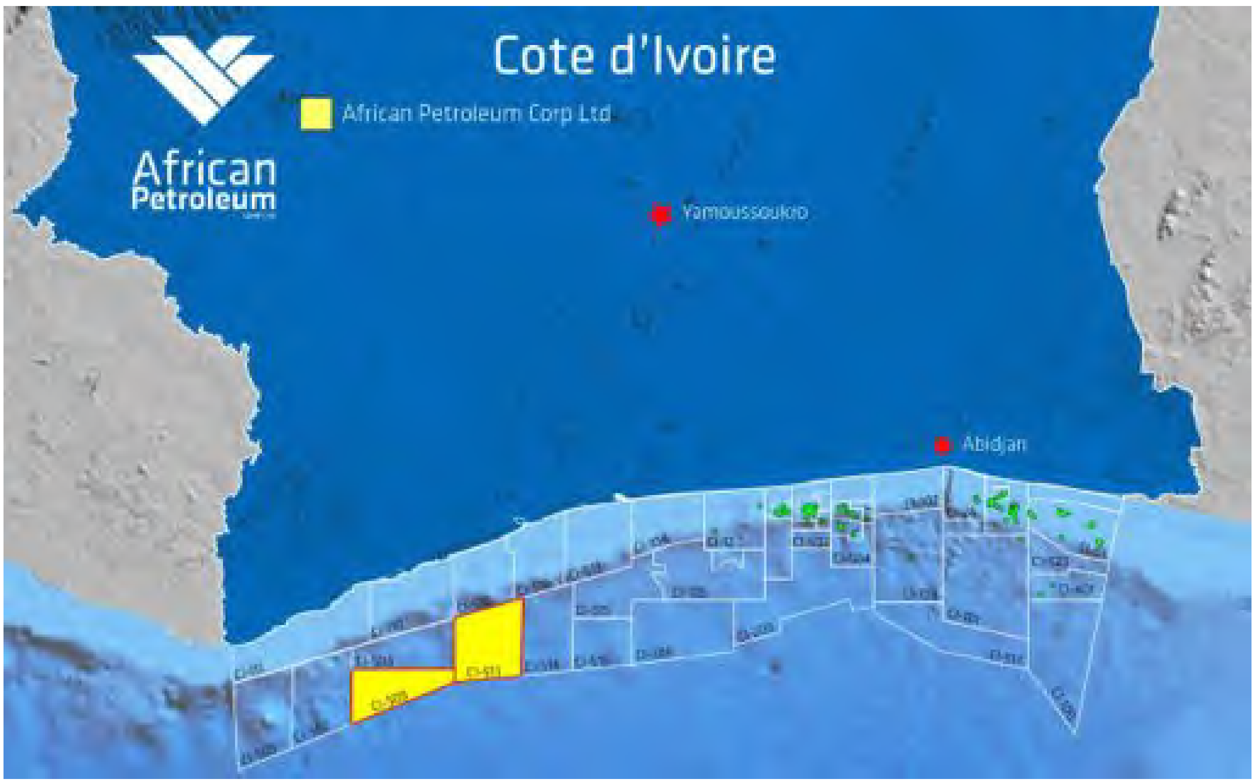


Figure 1-6 Location of Blocks CI-509 and CI-513

The PSC for Block CI-509 was awarded on 16th March 2012. The first eight years of the PSC are termed the exploration period, which is further divided into three terms of three, three and two years respectively. The licence is currently in its first exploration term. Work commitments during the first exploration term are to purchase the existing 2D seismic data, acquire 1091 km^2 (i.e. a block wide) 3D seismic survey and drill one exploration well at least 100 m into the Albian (Lower Cretaceous) section. The minimum investment is US$ 60 MM. The second and third terms have a further commitment to drill one exploration well to at least 100 m into the Albian (Lower Cretaceous) section, with a minimum investment of US$ 50 MM. Entry to the second term requires a 25% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third term. The area of the licence is currently 1091 km^2. Water depth is between 1900 and 3250 m over the block.

The PSC covering Block CI-513 has an effective date of 19th December 2011. It has a similar structure to that governing Block CI-509. The first seven years are termed the exploration period, subdivided into three terms of three, two and two years. The licence is currently in its first exploration term. Work commitments during the first exploration term are to purchase the existing 2D seismic data, acquire 1446 km^2 (i.e. a block wide) 3D seismic survey and drill one exploration well at least 100 m into the Albian (Lower Cretaceous) section. The minimum investment is US$ 60 MM. The second and third terms have a further commitment to drill one exploration well to at least 100 m into the Albian (Lower Cretaceous) section, with a minimum investment of US$ 50 MM. Entry to the second term requires a 25% relinquishment of the licence area, and a further 25% of the initial licence area must be relinquished on entry to the third term. The area under licence is currently 1446 km^2. Water depth is between 900 and 3100 m over the block.

The exploitation period of both licences is for 25 years, subject to successful award in the event of a commercial discovery. On development, Petroci has the right to acquire an interest of up to 20% in each licence, subject to payment of its portion of future costs.

In October 2012, APCL completed acquisition of 4200 km^2 of 3D seismic data covering blocks CI-508, CI-509 and CI-513, fulfilling the seismic work commitments of the first exploration phase of both PSCs. APCL is planning a two well drilling programme for the licences during 2014.

1.6. Evaluation Methodology: Prospective Resources

We have used probabilistic methods to evaluate selected prospects within Liberia Blocks 8 and 9, Gambia Blocks A1 and A4, Sierra Leone Block SL-03 and Cote d'Ivoire Blocks CI-513 and CI-509. We classify the results of our simulation as Low, Best and High estimates of prospective resources following the Petroleum Resources Management System, or PRMS (Appendix 1). We have assigned geological chance of success to each of the prospects, using the methodology described below. Estimates are made for oil only, although we recognise that, due to the significant uncertainties in the available geological information, that there is a possibility of gas charge in all licences. We present a summary of input estimates, output STOIIP and gross resources, and geological chance of success as a resource summary sheet for each prospective interval investigated. These can be found in the enclosures 1.1 to 4.5 in this document.

Inputs to our probabilistic simulation are evaluated in a consistent manner. For the structurally trapped prospective intervals in Liberia, (the Lovebird and Wildbird prospects), and the Alhamdulilah prospect in Gambia, we have made a low and high deterministic estimate of closing contour for each trap, to reflect the uncertainty in both mapping and depth conversion. For Liberia we use the gross-rock volume (GRV) derived in this manner to constrain the P90 and P10 of our GRV distribution in our probabilistic simulation. For Gambia we have used the areal extents of the low and high cases as inputs to an area times net calculation.

For the stratigraphically trapped prospects in Liberia (Barbet, Night Heron and Sunbird), Cote d'Ivoire, (Sassandra, Ayame, Ayame West, Cavalla and Leraba), and Sierra Leone, (Altair), we have made low and high estimates of area of closure, using both structural and amplitude support where possible. We have then made low and high estimates of gross reservoir thickness, derived from regional observations, calibrated against seismic data where possible. As such depositional systems also have laterally variable sand distributions, often supported by seismic data, we employ the concept of an areal net to gross ratio, varying the percentage of sand areally within the overall stratigraphic trap based on the uncertainty in seismic amplitude strength. Where appropriate, a geological shape factor is used, depending on trap shape and structural relief relative to reservoir thickness.

Estimates of reservoir porosity and net to gross ratio are made with reference to regional data, offset wells, including recent drilling by APCL in Liberia, and account for compaction and a degree of overpressure (Figure 2-4). We make low, mid and high deterministic estimates, and use these to constrain the P90, P50 and P10 inputs to a probabilistic simulation. Inputs for hydrocarbon saturation are constrained in a similar manner, with reference to regional porosity and permeability trends, calibrated to APCL's recent drilling results in Liberia.

We have estimated oil formation volume factors for a range of gas oil ratios (GOR) (from an appropriate minimum to fully saturated) for each of the prospective intervals, assuming 4^{o}C at the mudline (seabed) and geothermal gradients between 2.5 and 3.5^{o}C per 100 m, consistent with regional observation and the available well data. We assume that the minimum GOR will increase with depth below the mudline. Our estimates are calibrated against the oil samples in Well Narina-1 when estimating resources for the Liberian prospects.

Some degree of overpressure is accounted for, as it has been in our estimates of porosity, but, by reference to offset discoveries, we assume that it is unlikely to exceed 500 psi over the depth range investigated.

Recovery factors for the clastic reservoirs are estimated with reference to published information from discoveries in similar reservoir types, examples of which are tabulated below (Table 1.2). Based on this table, we estimate low, best and high recovery factors of 30%, 37.5% and 45% respectively. Again, these are used to constrain the P90, P50 and P10 of our input distribution during probabilistic simulation.

Some prospects are deep relative to mud line, and we expect reservoir quality to be reduced, despite overpressure. We reduce our recovery factor estimates accordingly where this is the case. Some prospects are relatively shallow to mud line. Where this is the case, we model a more viscous oil, (prospects materially less than 1500m below sea bed), and have reduced our low, best and high recovery factor range to 15%, 27.5% and 40% respectively. In all cases we assume that a development is able to effectively dispose of any associated gas.

Recovery factors for the carbonate reservoirs of the Wildbird prospect in Liberia and Prospect M in the Gambia are estimated by reference to more regional analogues, and are discussed in the relevant sections.

Due to the early stage of exploration within APCL's licences, we have adopted a six component risk matrix in all areas barring Liberia to estimate geological chance of success (COS), separated into play and prospect specific risks, (Table 1.3). We have adopted this form of presentation of COS to reflect the fact that deep water exploration in much of the West African Atlantic Margin is at a very early stage, and also that a number of the identified prospects have risk dependence, and thus can be grouped as a play.

Country	Field	Start Date	Np (MMstb)	Max Water Depth (m)	# Prod	Ult Recovery (MMstb)	Rec Factor	Recovery / Prod (MMstb)	STOIIP (MMstb)
Eq Guinea	Ceiba	Nov-00	112	800	18	187	40%	10	468
Eq Guinea	Zafiro	Aug-96	652	850	62	1583	40%	26	4008
Angola	Girassol	Dec-01	332	1360	32	958	45%	30	2129
Angola	Kuito	Dec-99	133	410	36	650	46%	18	1413
Brasil	Espadarte	Aug-00	67	877	10	261	31%	26	842
Brasil	Marlim	Mar-91	1720	853	101	2878	33%	28	8721
Total					259	6517			17580
Average - Arithmetic							39%	23	
Average - Weighted by STOIIP / Ult Rec							37%	25	

Hence RF Range

Low	Best	High
30	37.5	45

Table 1.2 Estimated oil recovery factors from producing Atlantic Margin fields

PLAY RISK				PROSPECT RISK		
SOURCE	RESERVOIR	SEAL		TRAP*	CHARGE	RESERVOIR
(Presence and Maturity)	(Presence)	(Presence)		(Definition and Efficacy)	(Migration)	(Efficacy)

*Incorporates trap definition and seal risk (including biodegradation risk where necessary)

Table 1.3 Play and prospect risk system

The play risk segment focuses solely on the elements required in a given play to make a hypothetical prospect successful; source, reflecting the presence and thermal maturity of available source rocks, with sufficient generation and expulsion to charge prospects; reservoir, reflecting the presence regionally of geological intervals that could potentially contain reservoir rock, and seal – the regional presence of a sealing formation with sufficient thickness and extent to trap hydrocarbons.

Prospect risk is divided into three elements. Commonly, we present seal and trap risk combined as an overall illustration of the integrity of the container, here labelled trap risk. Charge risk reflects the risk to migration of hydrocarbons from the source rock into the prospect, and reservoir risk reflects solely the efficacy, (i.e. porosity and permeability), of any identified reservoir interval.

Note that a successful well on a given prospect may reduce or remove the play risk, should the well prove reservoir, charge and seal in a given play. This will have the effect of de-risking further prospects associated with that play.

Recent drilling within Liberia Blocks 8 and 9 has de-risked the play. As a result, we adopt prospect specific risking alone, as source, reservoir, trap and seal, with the same definitions as described above (Table 1.3).

2. Liberia: Prospectivity and Plays

2.1. Introduction

All of the available deep-water acreage offshore Liberia-Sierra Leone basin is under licence (Figure 1-2). Regionally, hydrocarbons have been discovered within sandstones at a number of stratigraphic levels, from the pre-rift to early syn-rift Albian in Cote d'Ivoire, (Espoir, Foxtrot fields and a number of other discoveries), to turbiditic sandstones that have Late Cretaceous (Cenomanian/Turonian, Maastrichtian/Coniacian) to early Tertiary (Palaeocene to Eocene) ages. Recent drilling offshore Ghana has yielded a number of discoveries within these Upper Cretaceous sandstones, such as the Jubilee oil field, and the Enyenra, Tweneboa and Odum oil and gas/condensate discoveries. In the Liberia-Sierra Leone basin, recent drilling has yielded six hydrocarbon discoveries (Bee Eater, Narina, Monterrado, Mercury, Venus and Jupiter), but as yet, none has been declared commercial (Figure 2-1). Although reservoir quality in the Albian sandstones is variable, reservoir quality in the Upper Cretaceous and Tertiary sandstones is often good. Successful trap types encountered regionally are both structural and stratigraphic.

Of significance to the evaluation of the petroleum systems of Blocks 8 and 9, APCL have drilled three wells within the deeper water parts of the blocks: Wells Apalis-1, Narina-1 and Bee Eater-1. Well Apalis-1 found source rock intervals of Albian to Cenomanian age, but failed to find the prognosed reservoir. Well Narina-1 found light oil within deep-marine sandstones of Cretaceous age. The sandstones were of variable reservoir quality as the well appears to have been drilled on the edge of a fan system which can be interpreted from seismic data. The extent of the Turonian hydrocarbon bearing interval around Well Narina-1 is currently under investigation by APCL who are working with CGGV to reprocess the 3D multi-client seismic, with the hope of identifying areas of favourable reservoir within closure.

Well Bee Eater-1, completed in February 2013, also discovered hydrocarbons within similar sandstones of Cretaceous age. However, the oil bearing Turonian reservoir at Bee Eater, is interpreted as being of very low permeability and hence non-commercial. APCL interprets that Well Bee Eater-1 was drilled in a canyon system that may have been largely bypassed by sediment input.

Both wells demonstrate the viability of Cretaceous petroleum systems within the licence area.

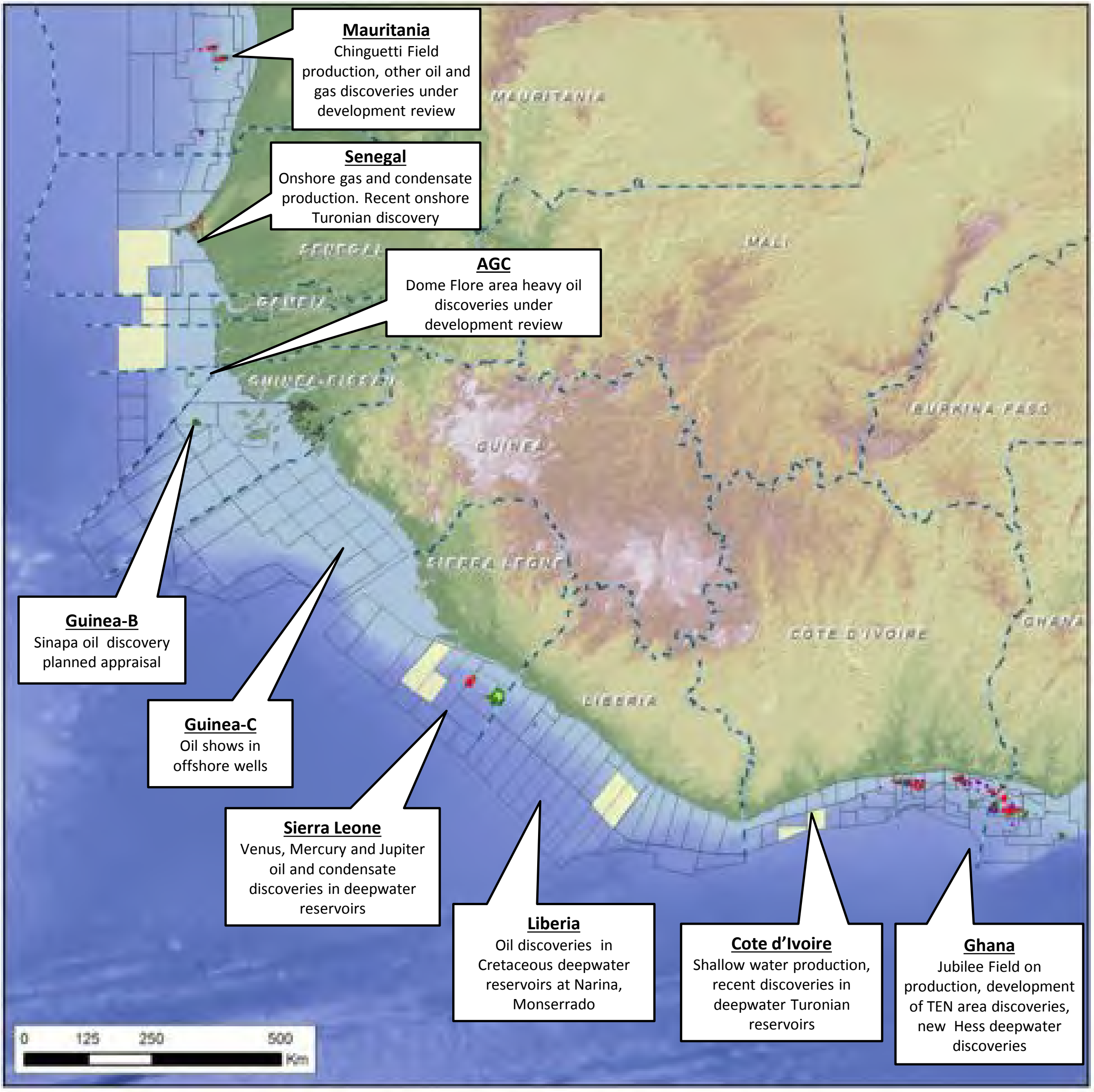


Figure 2-1 Notable discoveries, West Africa offshore

2.2. Well and Seismic Database

Exploration offshore Liberia is at an early stage. To date, five wells have been drilled in the deeper water areas in 2011 and 2012, with historical exploration drilling (up to 1985) restricted to the more shelfal areas (Figure 2-2). Data from two of these shallow water wells, Wells S/3-1 and Cestos-1, were made available to us for this evaluation. Well S/3-1 encountered oil shows in sandstones of Late Cretaceous age.

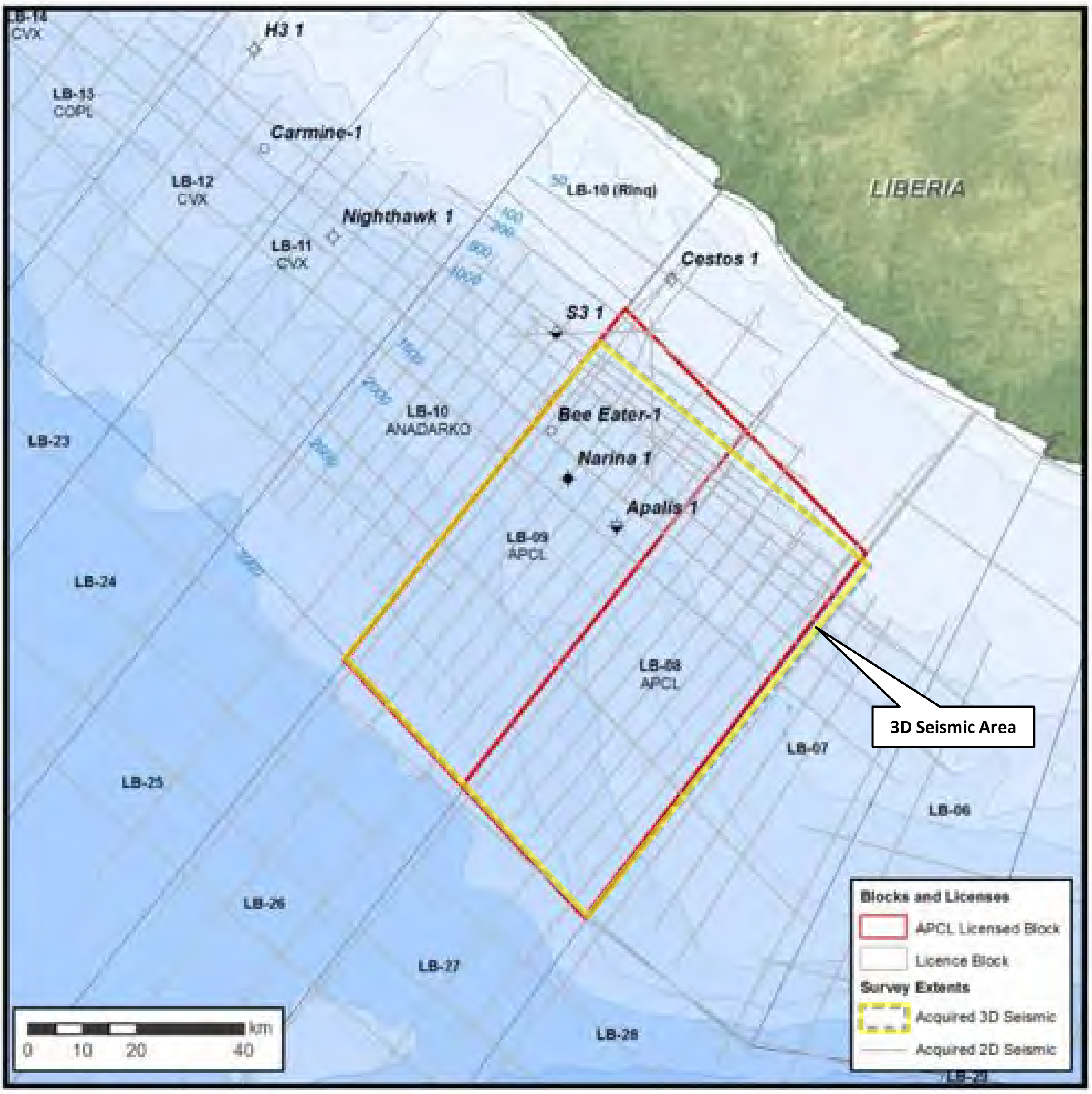


Figure 2-2 Well and seismic database, Liberia Blocks 8 and 9

APCL has drilled three exploration wells offshore Liberia in the deep water part of Block 9: Wells Narina-1, Bee Eater 1 and Apalis-1 (Figure 1-2, Figure 2-2). Well Apalis-1 was drilled in 2011, targeting a four-way dip-closed structure with possible AvO support. The well found traces of hydrocarbons, plus source rock intervals, but the prognosed reservoir sands were absent at target depth, and the well was plugged and abandoned.

Well Narina-1 was drilled by APCL in 2012, and found 16 to 21 m of net pay (light oil) within sandstones of Turonian (Cretaceous) age. Hydrocarbons were also discovered in the underlying Albian. Oil samples were collected, but no drill-stem testing was undertaken. Analysis of the oil samples indicates an API gravity for the Turonian oil of about 38 degrees, and about 45 degrees for the Albian hydrocarbons. Mobilities from formation pressure measurements and permeability from side-wall core measurements show the reservoir to be of relatively low permeability at this location.

Well Bee Eater-1 was drilled by APCL in January and February 2013. The well found oil-bearing sandstones of Cretaceous age, but of very low permeability and hence the well is considered non-commercial. Post-drill interpretation of the seismic data has helped APCL revise the depositional model for this Turonian fan system. The Bee Eater-1 well is interpreted to have encountered a bypass zone in both the Turonian and Cenomanian, with immature sandstones that are poorly sorted and tight. Post-well mapping of key seismic events, tied to Well Bee Eater-1, reveals the possibility of finding better quality sandstones in 'basin-floor fan' units down-dip. Potentially sealing shale units and source rock units were also found in the Bee-Eater-1 well.

Well Apalis-1 and in particular Wells Bee Eater-1 and Narina-1 help de-risk seal and hydrocarbon charge for the Cretaceous play on-block.

The primary seismic dataset for our evaluation was the recently acquired 5170 km^2 of 3D seismic data over the deeper water area of Blocks 8 and 9, including certain products to review amplitude versus offset (AvO) effects. These seismic data cover both recently drilled deep water wells. In addition, a grid of 2D seismic data was also made available, with average line spacing of around 4.5 km. These data provide a tie to Well S/3-1, although the well lies some 200m from the nearest seismic line. In general, the data quality of the 3D volume is good, and of suitable fidelity to enable us to undertake our review of identified prospectivity. However, local complexity in the shallow geology causes the signal to degrade considerably at the prospective levels in certain areas. APCL are currently reprocessing these data in an attempt to improve signal quality. APCL intend to utilise this dataset to update the CPR in the next 3-6 months. It is hoped that these data will support maturation of additional prospects and further clarification of risk and volumes for prospects within this CPR.

2.3. Plays and Petroleum Geology: Blocks 8 and 9

APCL has identified a number of plays within Blocks 8 and 9, at similar stratigraphic levels to those proven successful elsewhere along the West African margin (Figure 2-3). Recent drilling within Blocks 8 and 9 has demonstrated a working petroleum system within the mid to lower Cretaceous, with drilling finding light oil within deep marine sandstones of Turonian age, and also in sandstones of Albo-Aptian age.

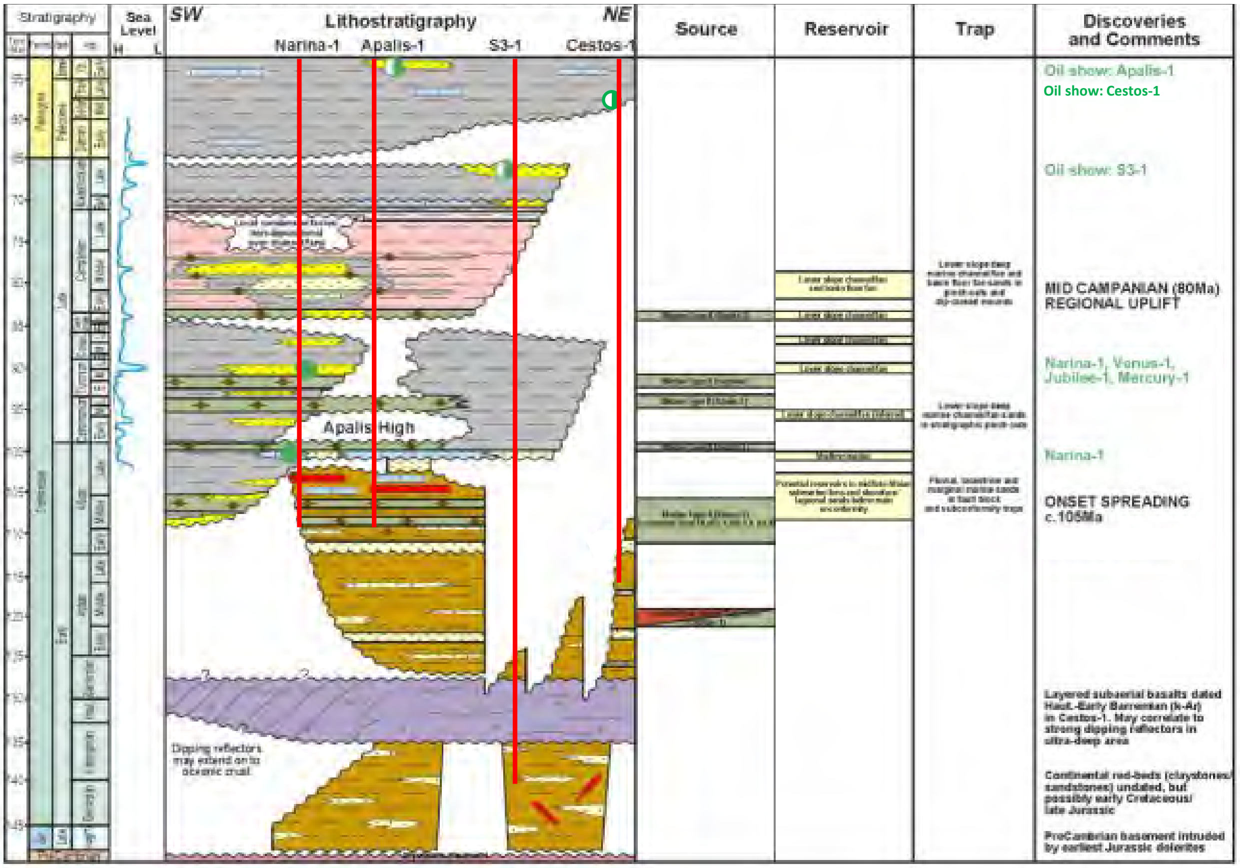


Figure 2-3 Petroleum systems and plays, Liberia Blocks 8 and 9

Structural traps are identified at the pre-rift to early syn-rift (Albian) level, as tilted fault blocks, with hydrocarbons sourced from the Albian or Lower Cretaceous source rocks, and seal provided by post-rift mud drape. Structural and stratigraphic traps are also identified at several potential reservoir levels within the Late Cretaceous and Lower Tertiary, again potentially sourced from the Turonian and / or Albian source rocks. Traps are sealed by coeval marine shales and muds. As is encountered regionally, there is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous and Early Tertiary section, and this seismic evidence has been used in trap definition.

The most significant play in the area is that of Cenomanian to Turonian age deep-marine channel-fan systems, as structural and stratigraphic traps. In addition, an emerging lower Cretaceous microbial carbonate reservoir play has been identified, sourced from coeval lacustrine source rocks and sealed by shales deposited during the subsequent drowning of the lacustrine systems by the onset of significant subsidence and marine inundation later in the Cretaceous. We have evaluated prospects within both of these play systems. Prospectivity in the shallower Cretaceous and Tertiary intervals is still being re-evaluated by APCL as of the date of this report, and no leads have been matured to prospect status.

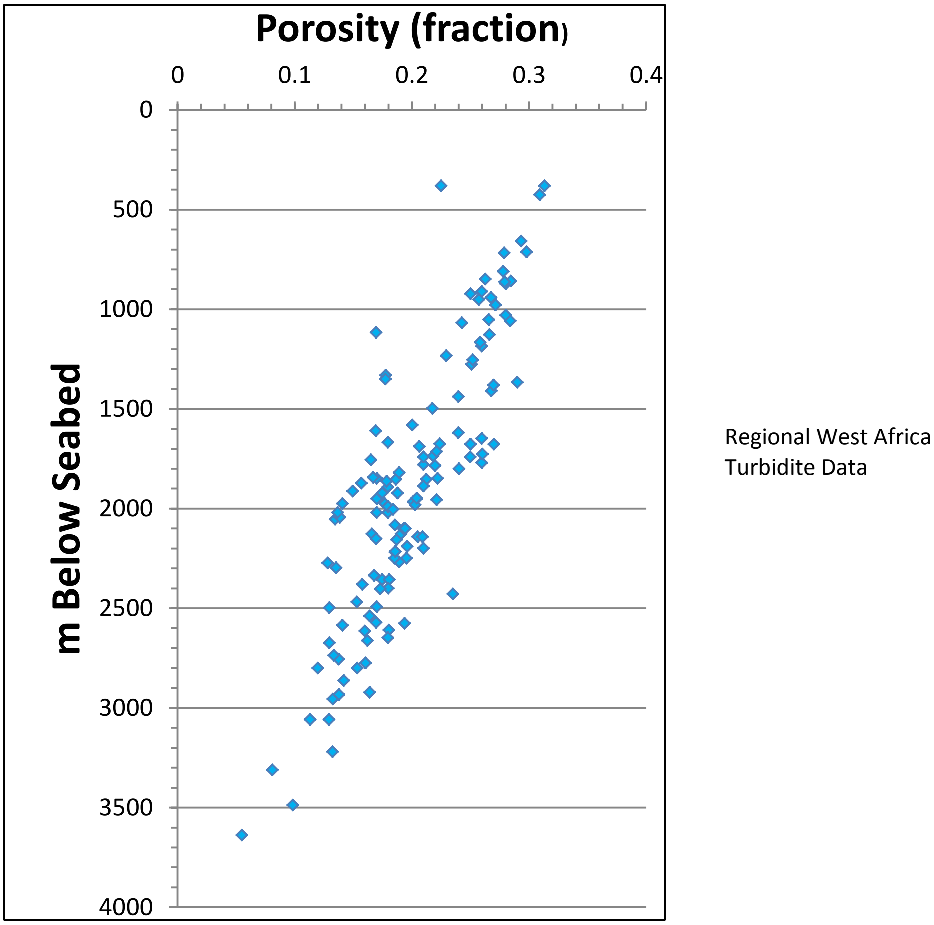


Figure 2-4 Porosity/depth trend, published West Africa turbidite reservoirs

2.4. Play and Prospect Risk: Liberia Blocks 8 and 9

Of the prospects reviewed, all but the Wildbird prospect fall within the Cenomanian to Turonian channel/fan play. In our opinion, recent drilling has de-risked source and reservoir presence for this play. However, reservoir quality in recent wells is variable. In our risking of Cenomanian to Turonian prospectivity, (Barbet, Sunbird, Lovebird and Night Heron prospects), we have removed the play element to our risking matrix, and see a low risk to hydrocarbon charge for individual prospects. Key risk is therefore to trap integrity and reservoir quality. We use a four component risk matrix as outlined in Section 1.6 to define geological chance of success for these prospects.

The Wildbird prospect has been recently identified by APCL as part of its review of further play fairways within the Liberian licences. The play concept is of early Aptian bio-constructed carbonate build-ups within the restricted lacustrine environment that existed at this time. Porosity and permeability within the bioclastic microbial limestones is potentially enhanced by hydrothermal activity resulting from the early rifting. Later post-rift subsidence and drowning by marine conditions provides the top seal via the deposition of Cretaceous marine muds. It is envisaged that the play is charged or by Aptian source rocks deposited in the offset lagoonal facies, with possible charge from later (but on-lapping) Cretaceous marine source rocks (as other plays on the blocks). Both potential source rocks provide lateral seal (Figure 2-16). Regionally, lacustrine microbial carbonate reservoirs can be found in Congo and Angola, where there is some production, but also in the Campos and Santos basins in Brazil.

The microbial carbonate play is emerging within Blocks 8 and 9, and has not been demonstrated to be effective by drilling. We adopt the play and prospect risking as discussed in Section 1.6 to risk the Wildbird prospect as a result, discounting biodegradation risk as the prospect is at significant depth. Our estimate of play risk for the Cretaceous microbial carbonate play is summarized in below.

PLAY	Source	Reservoir Presence	Seal	Play Risk
Cretaceous Carbonate	0.8	0.6	0.5	20%

Table 2.1 Play risk: Cretaceous carbonate play, Liberia Blocks 8 and 9

2.5. Liberia Blocks 8 and 9: Leads and Prospects

Following the drilling of Wells Narina-1 and Bee Eater-1, APCL is re-evaluating the prospectivity within Blocks 8 and 9, and has developed a number of potential traps (Figure 2-5), several of which (marked in orange, Figure 2-5) have been matured to prospect status. We have assessed the prospective resources for certain of these prospects that APCL has identified as viable near-term drilling opportunities, Barbet, Sunbird, Lovebird, Night Heron and Wildbird. A number of the prospects have multiple reservoir targets. Our evaluation of these prospects follows the methodology described in Section 1.6. The results of Wells Narina-1 and Bee Eater-1 would indicate that oil charge is probable, and thus only oil cases have been evaluated. However, as we state in Section 1.6, a gas charge cannot be discounted due to the uncertainties in source rock evaluation and basin modelling. Input parameters, STOIIP, prospective resources and geological chance of success for each of the evaluated prospects are summarised in Table 1 of this report, and are also presented in the resource summary sheets as Enclosures 1.1 to 1.9 of this document.

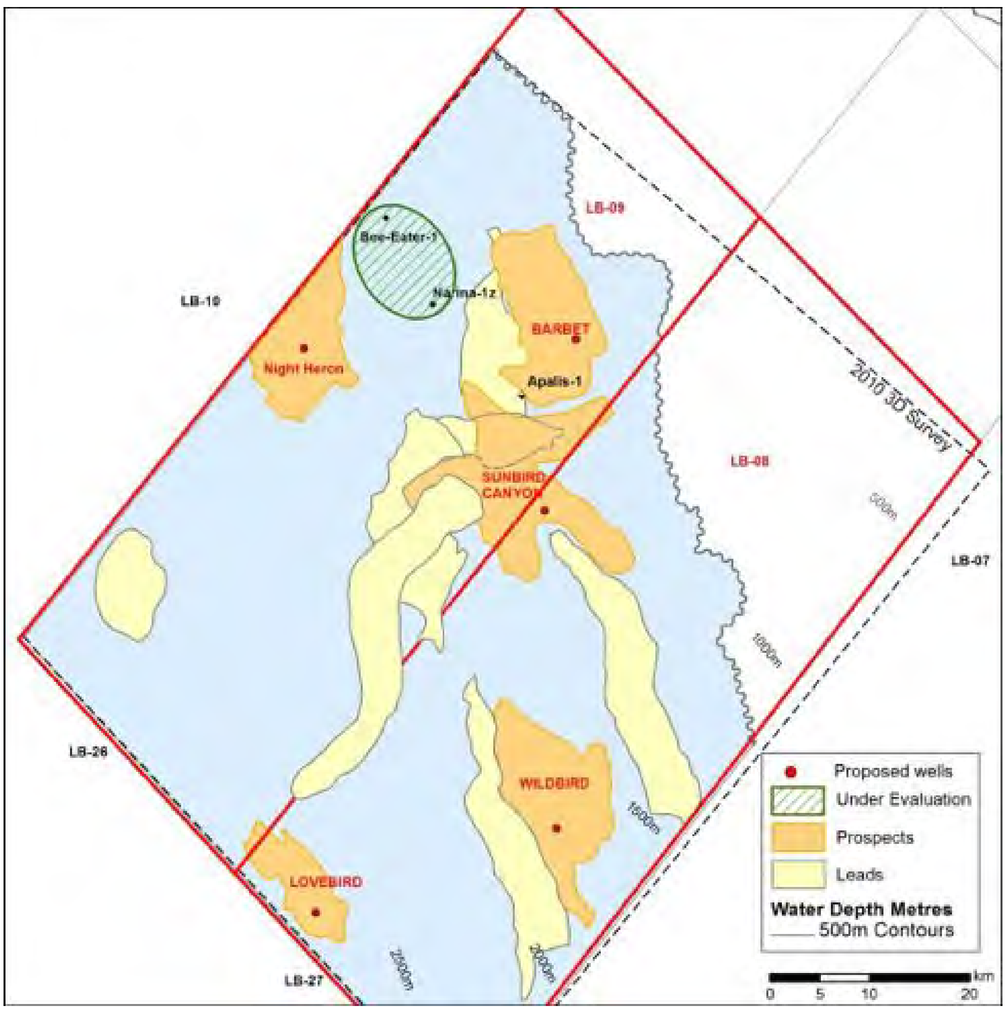


Figure 2-5 Leads and Prospects, Liberia Blocks 8 and 9

2.5.1. Barbet Prospect

The Barbet prospect is identified as a stratigraphic trap, around 14 km to the east of and up-dip from Well Narina-1 within Block 9 (Figure 2-6). A single target reservoir is mapped within the Turonian. Seismic amplitude anomalies are also identified within the area of the trap that may provide support for reservoir development. The Turonian is mapped at between 3000 and 3600 m TVDSS over the area of the prospect, in a water depth of around 750 to 770 m.

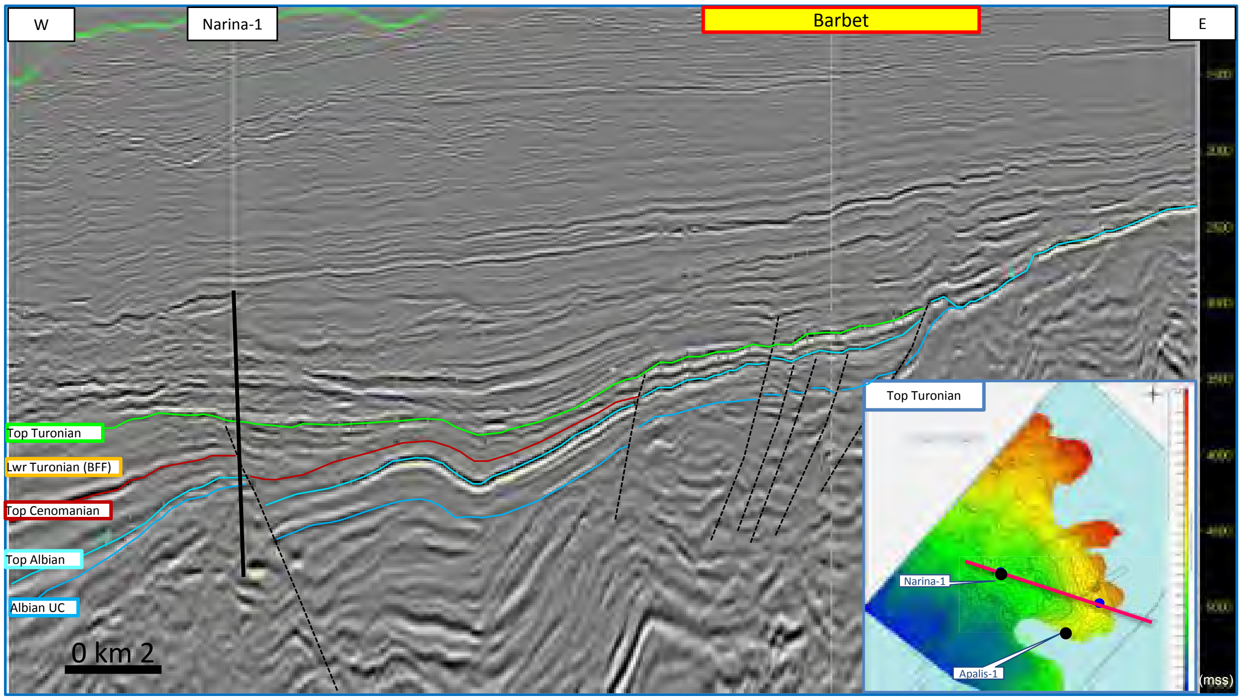


Figure 2-6 Seismic line - depth (m TVDSS) over the Barbet prospect

We have used an area/net pay methodology to estimate prospective resources for the Barbet prospect. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes on the far offsets. Our high case extends the prospect down-dip, to include a larger area of anomalous amplitudes above an observed amplitude shut-off (Figure 2-7). These are used to constrain the P90 and P10 inputs of our probabilistic simulation. These polygons approximate to an oil column height of 200 and 700 m respectively.

Amplitudes are variable within the area of closure, and we apply an areal net to gross ratio to better constrain sand distribution within the trap. Gross reservoir thickness estimates are computed from the mapped seismic interval, net to gross ratio from regional analogue, and porosity from a regional porosity/depth trend (Figure 2-4). Fluid parameters and recovery factors are estimated as described in Section 1.6.

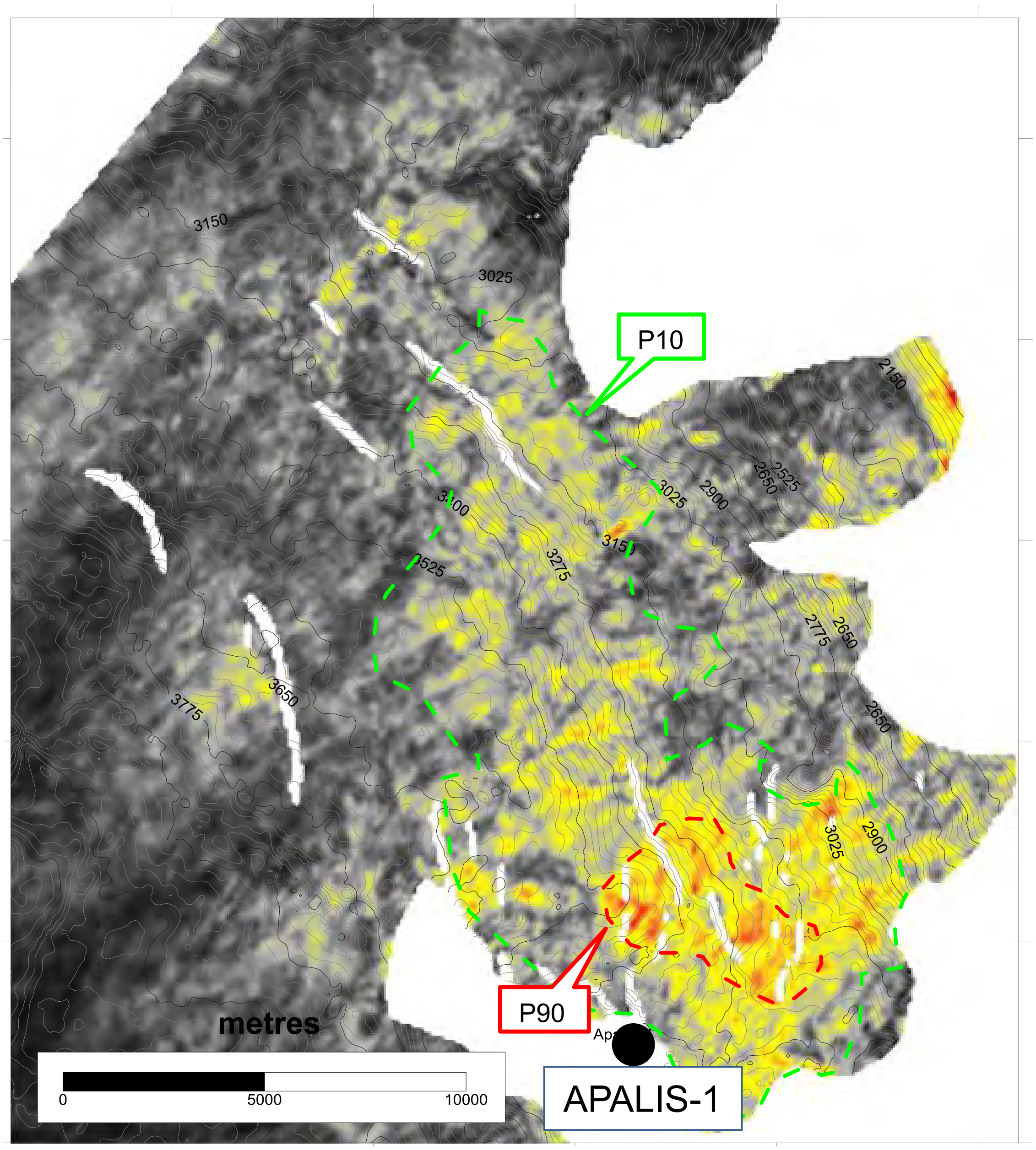


Figure 2-7 Barbet: far offset amplitudes with Top Turonian depth contours (m TVDSS).

We have used the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Barbet prospect. Key risk to the Barbet prospect is to trap/containment, as the trap requires pinch-out of the reservoir in three directions to seal. There is also a subsidiary risk to reservoir, as the Turonian reservoir encountered in Well Narina-1 is of relatively poor quality, which is countered by seismic evidence over the prospect to support reservoir development. As a result, we attribute a geological chance of success of 22% to the Barbet prospect.

2.5.2. **Sunbird Canyon Prospect**

The Sunbird canyon prospect is also identified as a stratigraphic trap, around 5 km to the south of Well Apalis-1, within Blocks 8 and 9, mapped as a large canyon system. There are three potential reservoir targets within the prospect; within the Campanian, the Turonian, (as encountered in Well Narina-1), and in the underlying Cenomanian. Reservoir is prognosed at between 3000 m TVDSS and 3600 m TVDSS in a water depth of around 1300 m.

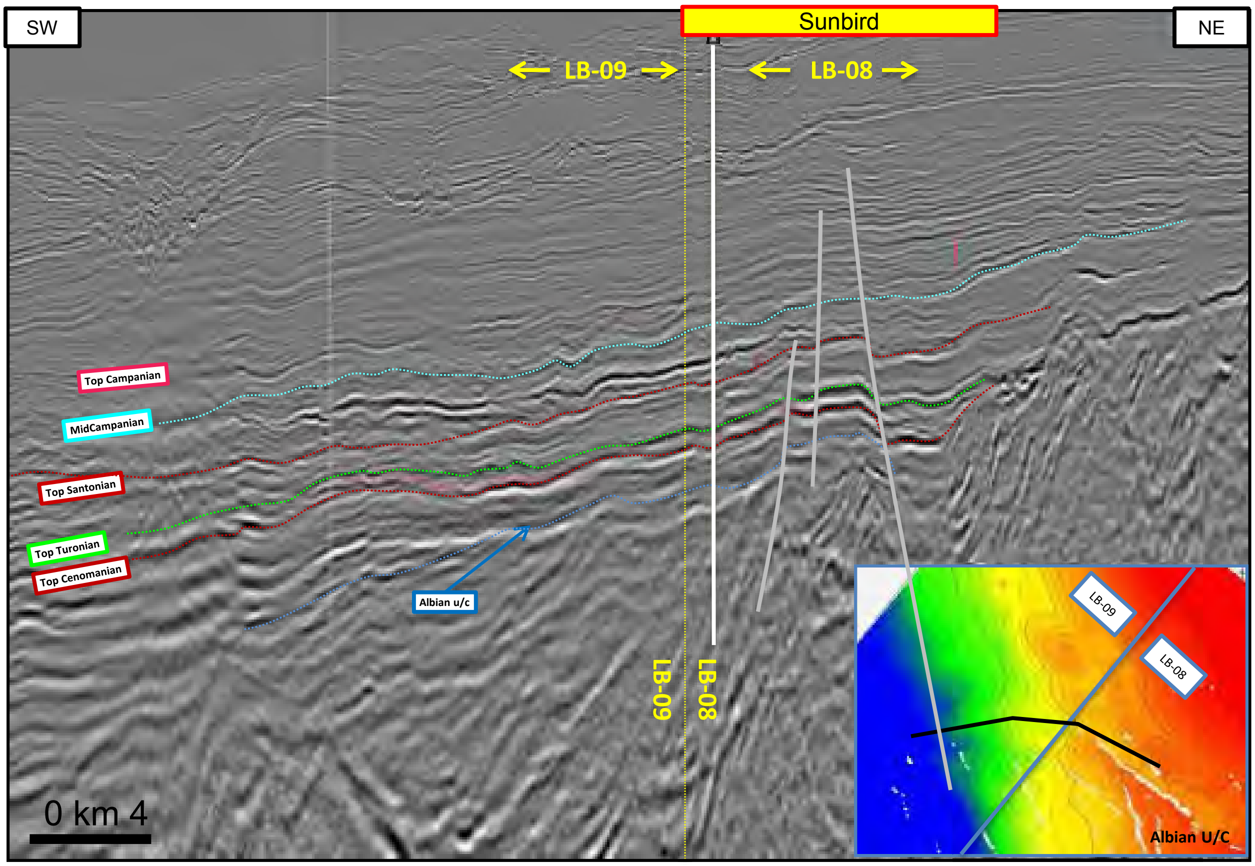


Figure 2-8 Regional seismic line along axis of the Sunbird canyon system

We have used an area/net pay methodology to estimate prospective resources for the Sunbird canyon prospect. At all three prospective layers, the prospect divides into two discrete 'canyons' separated by an intra-basinal high (e.g. Figure 2-9). For the Campanian and Turonian prospective intervals, in the low case we restrict the area of the accumulation to the brightest area of anomalous amplitudes on the far offsets in the northerly of the two canyons, where amplitude response is better. Our high case extends the prospect down-dip, to include a larger area of anomalous amplitudes above an observed amplitude shut-off, and also includes the southerly of the two canyons, as this would now be in charge communication. The low and high case polygons approximate to an oil column height of 200 m and 600 m respectively.

For the deeper Cenomanian, the prospect is mapped as a single canyon to the south of the intra-basinal high. The low and high case polygons approximate to an oil column height of 200 m and 700 m respectively. Our low and high estimates of area are used to constrain the P90 and P10 of our probabilistic simulation.

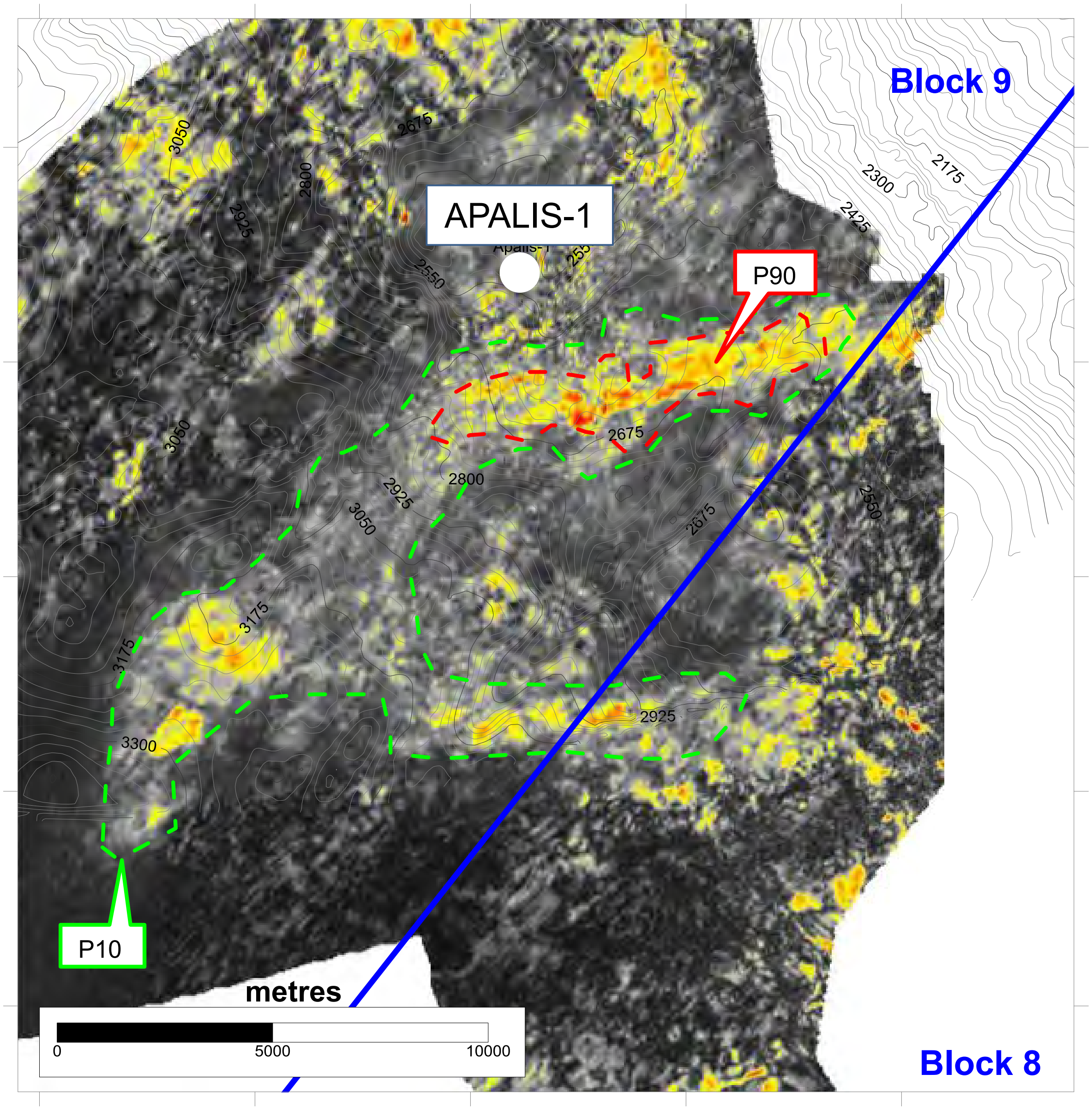


Figure 2-9 Sunbird: Campanian far offset amplitudes with Cenomanian depth contours (m TVDSS)

Amplitudes are variable within the area of closure, and we apply an areal net to gross ratio to better constrain sand distribution within the trap for all three prospective layers. Gross reservoir thickness estimates are computed from the mapped seismic interval, net to gross from regional analogue, and porosity from the observed porosity/depth trend (Figure 2-4). Fluid parameters and recovery factors are estimated as described in Section 1.6.

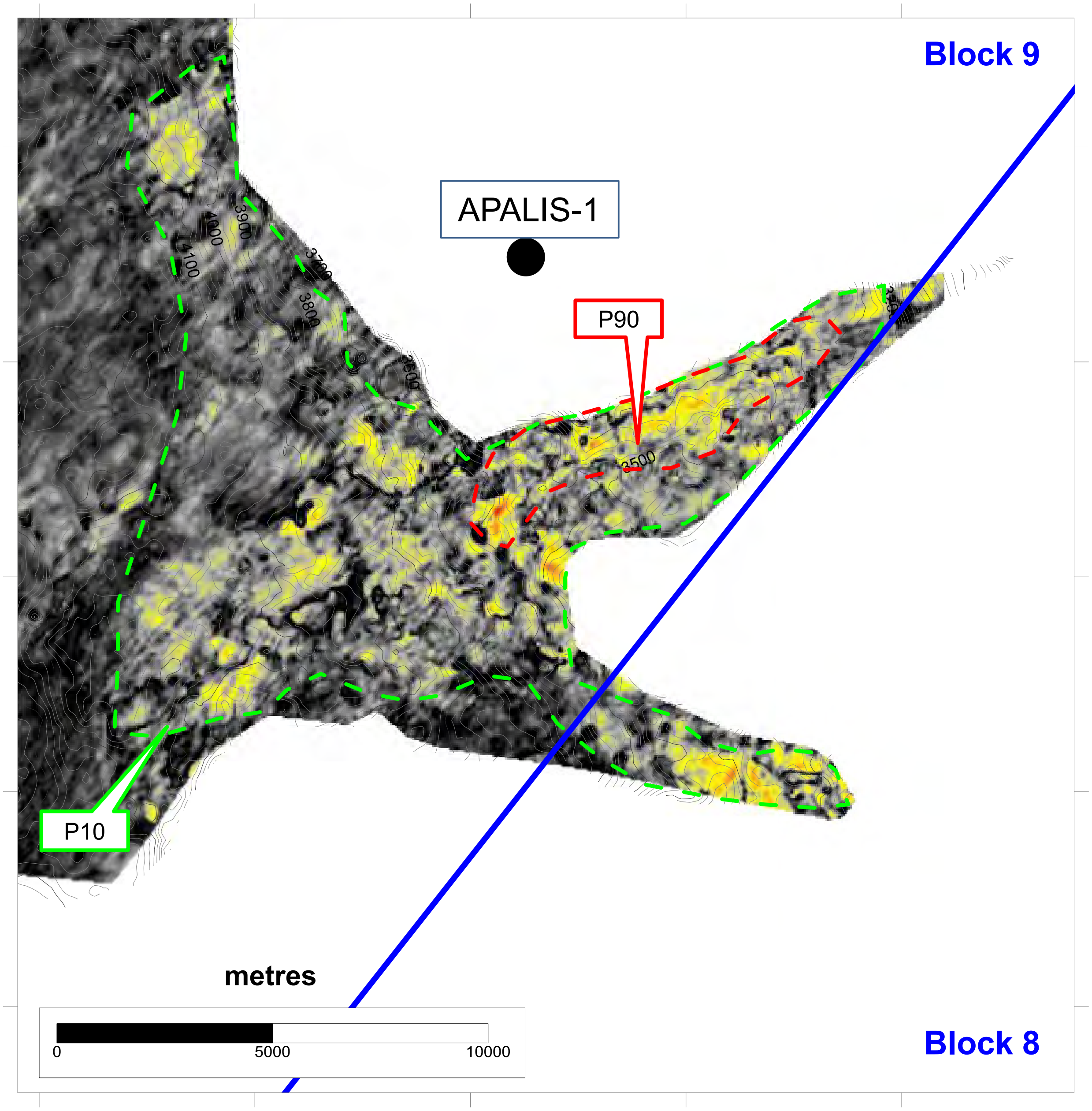


Figure 2-10 Sunbird Turonian: far offset amplitudes with Top Turonian depth contours (m TVDSS)

We have used the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the three prospective intervals of the Sunbird prospect. Key risk to all three prospective layers is to trap/containment, as the trap requires pinch-out of the reservoir in three directions to seal. There is also a subsidiary risk to reservoir at the two deeper levels, as the Turonian reservoir encountered in Well Narina-1 is of relatively poor quality, and Cenomanian reservoirs are yet to be proven on block. However, there is seismic evidence for reservoir development, and hence we see this risk as favourable. Reservoir risk is low for the Campanian as it is developed in the offset Well Narina-1, and there is seismic evidence for reservoir presence. As a result, we attribute a geological chance of success of 27%, 19% and 18% to the Campanian, Turonian and Cenomanian prospective intervals of the Sunbird canyon prospect.

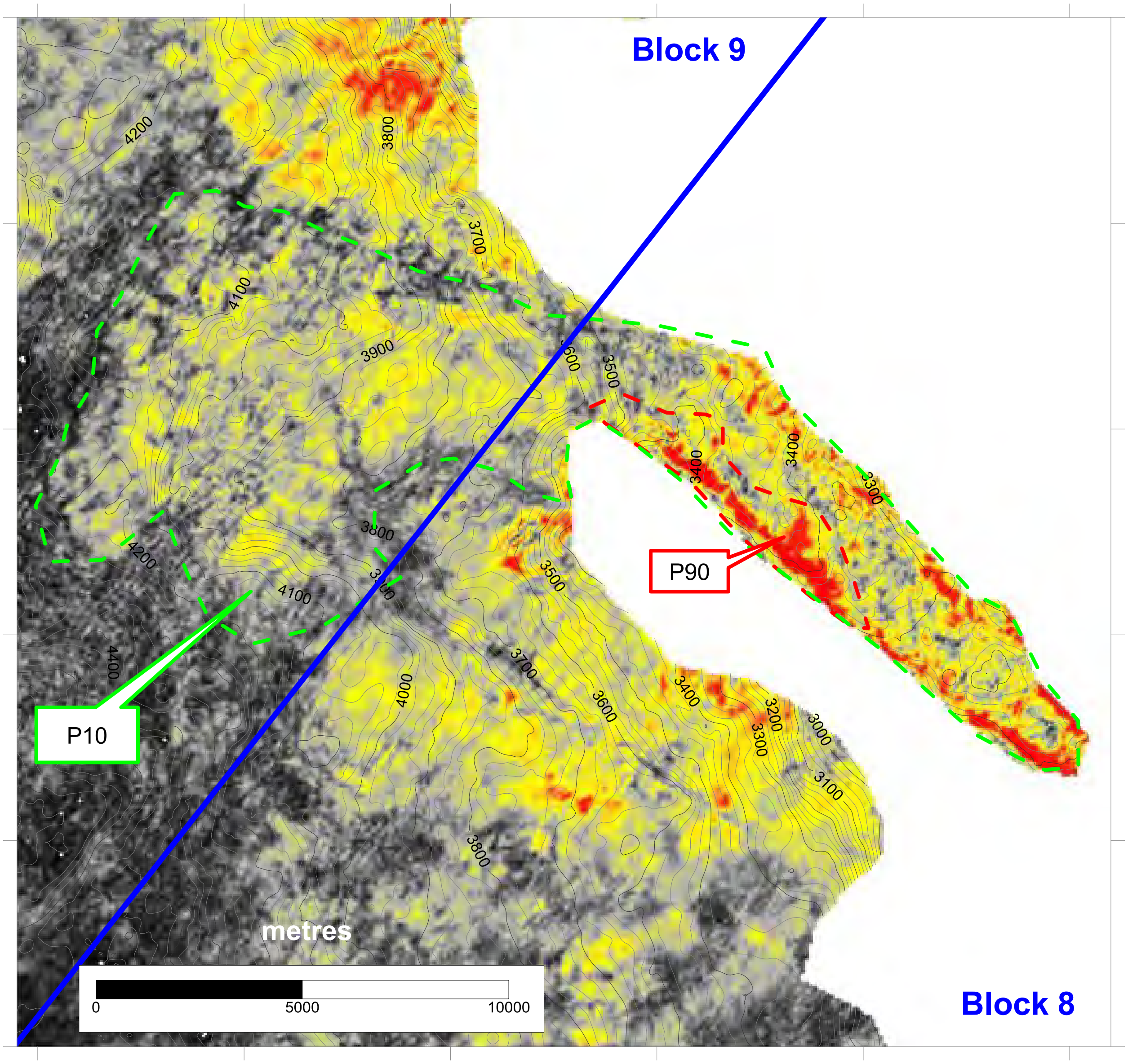


Figure 2-11 Sunbird Cenomanian: far offset amplitudes with Cenomanian depth contours (m TVDSS)

2.5.3. **Night Heron**

Night Heron is a Turonian basin floor fan system which lies 8 Km south west of Well Bee Eater-1. It is mainly within Block 9, but extends into Block 10. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out. Reservoir is prognosed at between 4100 m TVDSS and 4700 m TVDSS in a water depth of around 1750 m (Figure 2-12) APCL has selected a provisional well location which lies on the 3D survey location – In-line 1098, X-line 6103. They are currently seeking partners to drill the Night Heron well in early 2014.

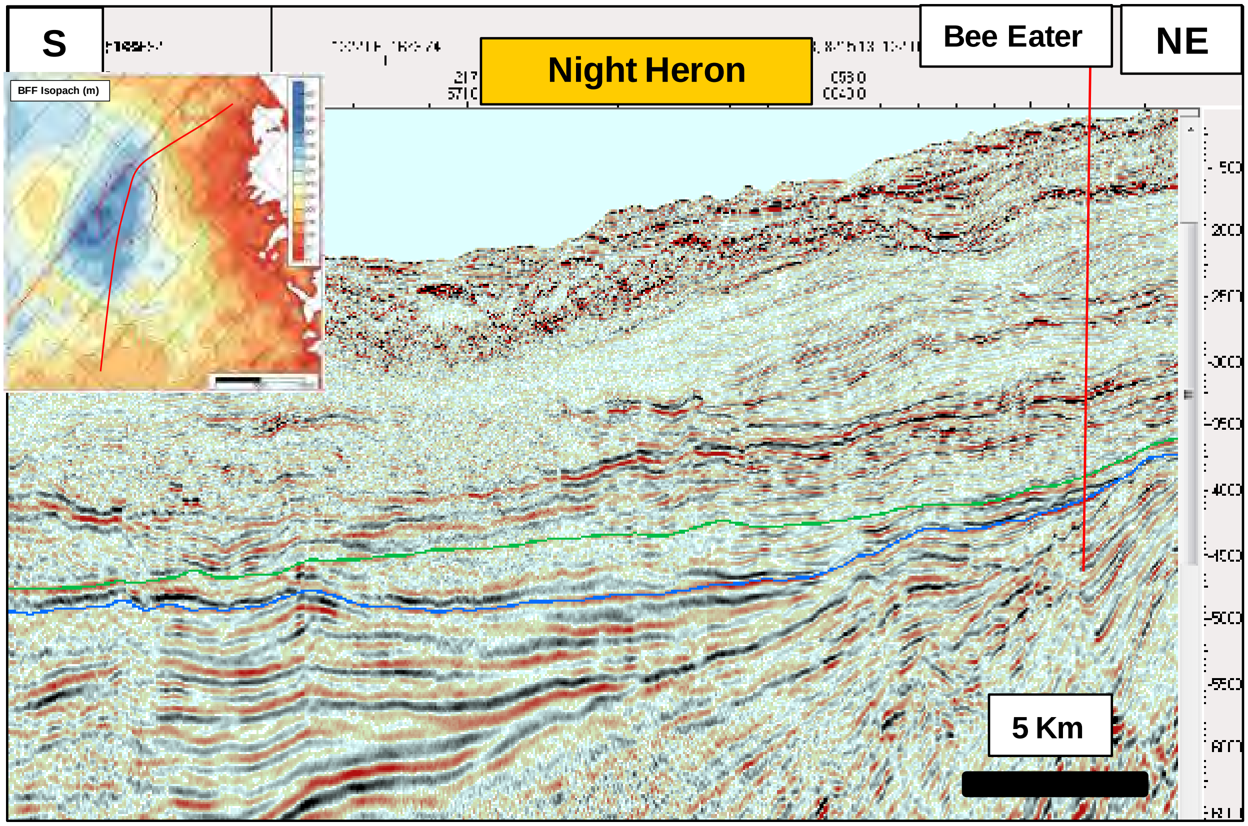


Figure 2-12: Arbitrary line across Night Heron, PSDM - Depth (m TVDSS)

Cenomanian reservoir potential also exists beneath the Turonian basin floor fan and work by APCL is on-going to determine prospectivity.

Well Bee Eater-1 found an organic-rich Turonian shale section overlying a hydrocarbon bearing thin-bedded low permeability sandstone. Another shale dominated package underlies the sandstone. Although the Turonian interval is considered non-commercial for Bee Eater, the prospectivity down-dip is appealing. APCL interprets that the well was drilled in a canyon system that may have been largely bypassed by sediment input. The 3D seismic indicates a significant thickening of this Turonian interval towards the south west and there is some amplitude support for the occurrence of a lobate fan straddling Blocks 9 & 10.

An area times net approach was adopted using the full stack PSDM depth volume to provide an SNA extraction and constrain areal extent and estimate an areal N/G to account for lateral variability within the reservoir (Figure 2-13). As night Heron falls partly off block. ERCE correct for this using the ratio of on-block to off-block area in reporting of net unrisked and net risked results.

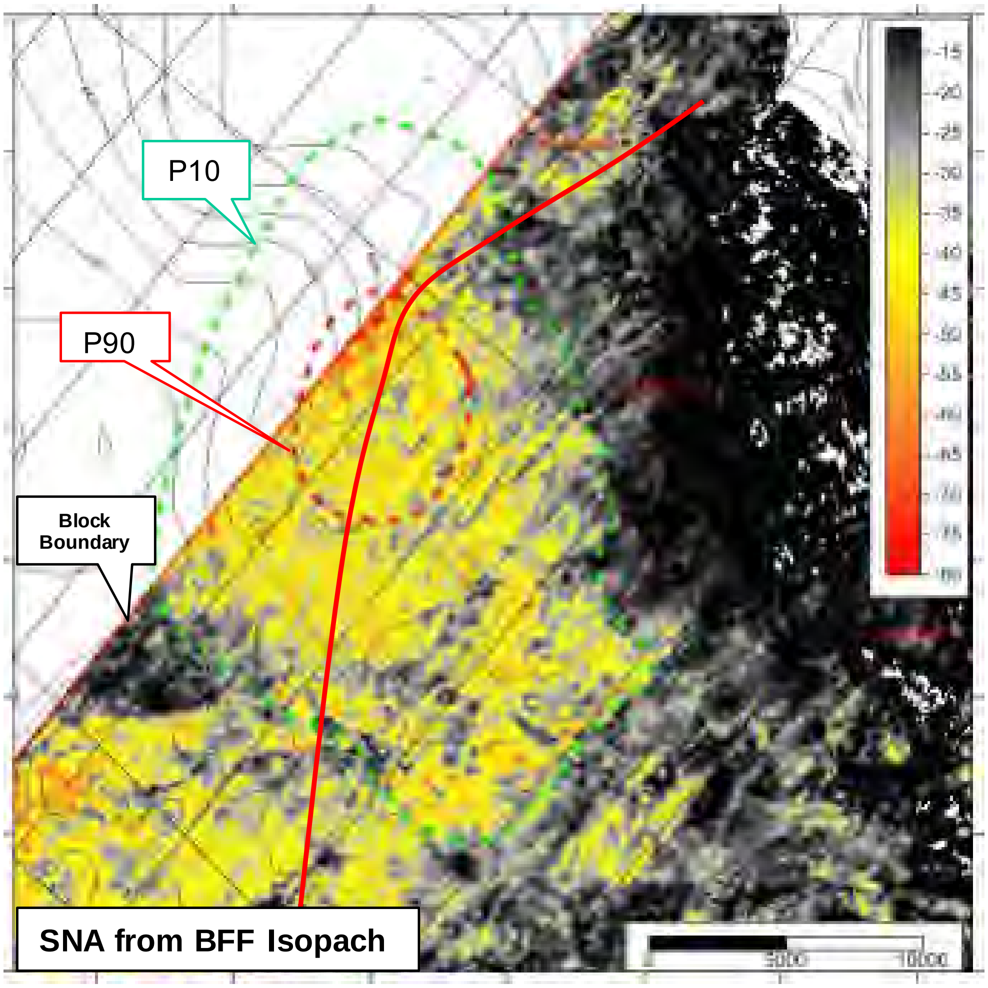


Figure 2-13: SNA from Basin Floor Fan Isopach (m) - PSDM

We have used the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Turonian interval of the Night Heron prospect. Recent drilling results suggest that there is a low risk to hydrocarbon charge. The observations at Bee Eater-1 also indicate that shale seals are also likely at a coeval interval. Reservoir is a significant risk due to the poor Turonian reservoir development in Well Bee Eater-1. The Turonian reservoir encountered in Well Narina-1 is also of relatively poor quality. However, there is seismic evidence on the 3D survey for a possible improvement in reservoir development over the prospective area. The definition of the trap is the key risk, as the seismic evidence for closure/reservoir pinch-out is ambiguous over the 2D data in Block 10. There appears to be evidence of the reservoir interval thinning in the critical north westerly direction but 3D data would be required to reduce trap risk any further. As a result, we attribute a geological chance of success of 14.4 %, to the Night Heron prospect.

2.5.4. **Lovebird Prospect**

The Lovebird prospect is mapped as a four-way dip closure to the south of Block 8 (Figure 2-14). Three prospective layers are mapped by correlation to up-dip wells, and are prognosed to be of Cenomanian age. Thus, as with the Sunbird canyon prospect, these reservoirs are not proven on block, but seismic mapping and regional geological work suggests the sands may be derived from the east, via a canyon system identified in block LB-07. The three prospective intervals are termed Upper, Middle and Lower, or, Blue, Pink, and Green, based on horizon colour. Structural relief at the Pink horizon is between 50 and 200 m, depending on the estimate, and thus the prospect is relatively low relief in some realisations.

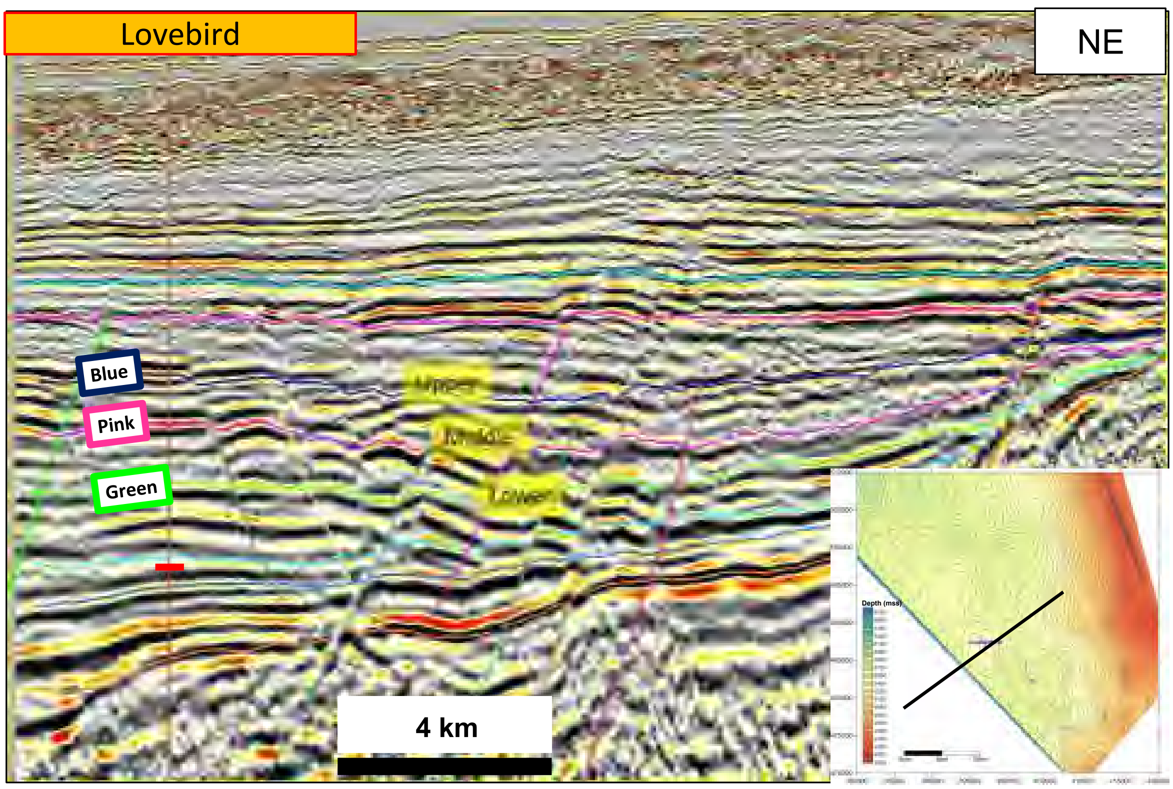


Figure 2-14 Seismic line over the Lovebird prospect

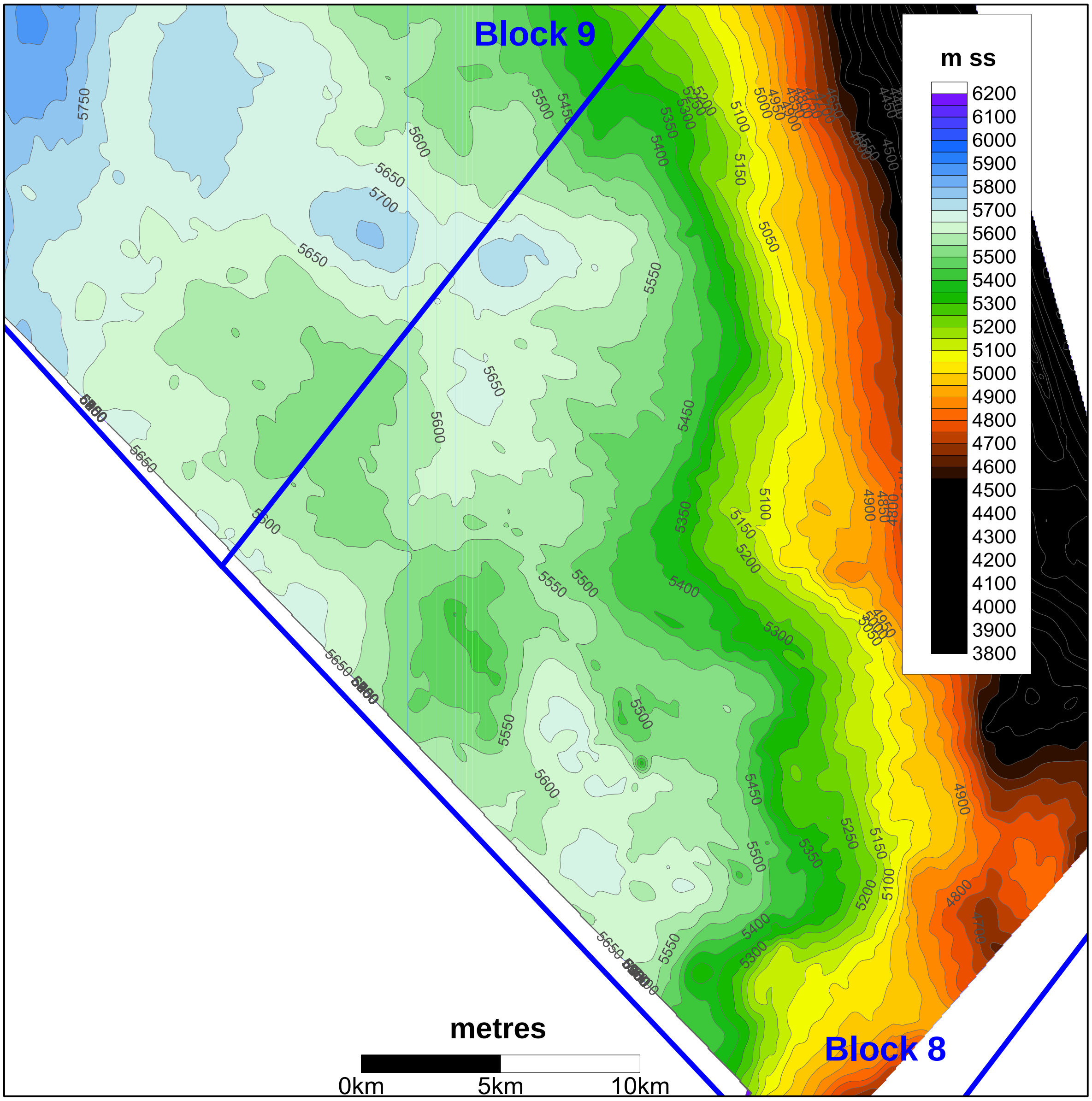


Figure 2-15 Lovebird prospect: Top Pink horizon depth (m TVDSS), high case.

The prospect is mapped to the edge of the available 3D (Figure 2-15), which coincides with the southern boundary of Block 8, but closure can be mapped south of the 3D area on the available 2D lines. Reservoir depth is prognosed at between 5000 and 5900 m TVDSS, in a water depth of 2850 m at the prospect crest. Thus, reservoir rock, if present, will be at comparable depths below mud line to the Barbet prospect.

We use a gross-rock volume/net to gross methodology to estimate prospective resources for the Lovebird prospect. APCL's evaluation of the Lovebird prospect is on-going, and of the three interpreted horizons, the Pink horizon is the best defined. We review pick, depth conversion and thickness uncertainty for this interval to generate a range of gross-rock volumes for this interval, with the prospect full to spill (Figure 2-15). Assuming the Pink horizon provides an accurate representation of the Blue and Green horizons, we then estimate gross-rock volumes for these two intervals by isopach.

Reservoir thickness and net to gross ratio estimates are derived from regional analogues, with reservoir porosity derived from our regional porosity/depth trend (Figure 2-4). Fluid properties and recovery factors are estimated as described in Section 1.6. Our volumetrics are restricted to the portion of the Lovebird prospect on Block 8. We would expect a further evaluation of the prospective resources of the Lovebird prospect to occur subsequent to the completion of the APCL evaluation, and the prospective resources associated with the prospect in this report may therefore be subject to change.

The key risks to the Lovebird prospect are to the development of reservoir at the prognosed Cenomanian intervals, as they are not proved in wells elsewhere on the block, and to source, as the prospect requires a source rock deeper than that proven by drilling. There is also risk to trap/containment, as the structure is not fully defined by the 3D seismic data volume, and is of low relief in some realisations. We assign a geological chance of success to the Lovebird prospect of 20% as a result.

2.5.5. Wildbird Prospect

The Wildbird prospect is mapped on 3D seismic data towards the south of Block 8 as a large four-way dip-closed high (Figure 2-17), at a depth of between 4000 to 4600 m TVDSS, in a water depth of around 2000 m. Structural relief is up to 600 m and area of closure up to 170 km^2. The conceptual geological model is discussed above, but is that the prognosed microbial carbonate reservoir of Albian age is developed between the mapped 'red' and 'light blue' seismic events (Figure 2-16), with lateral seal developed to the north-east of the prospect within contemporaneous lagoonal facies which also provide the primary source rock. This lateral seal is required to close the prospect. Basin modelling undertaken by APCL suggests that the Albian lagoonal and later Cretaceous source rocks would be mature for oil generation.

We have accepted this model as a geological concept and have used it to make estimates of prospective resources for the Wildbird prospect. We then risk the model accordingly.

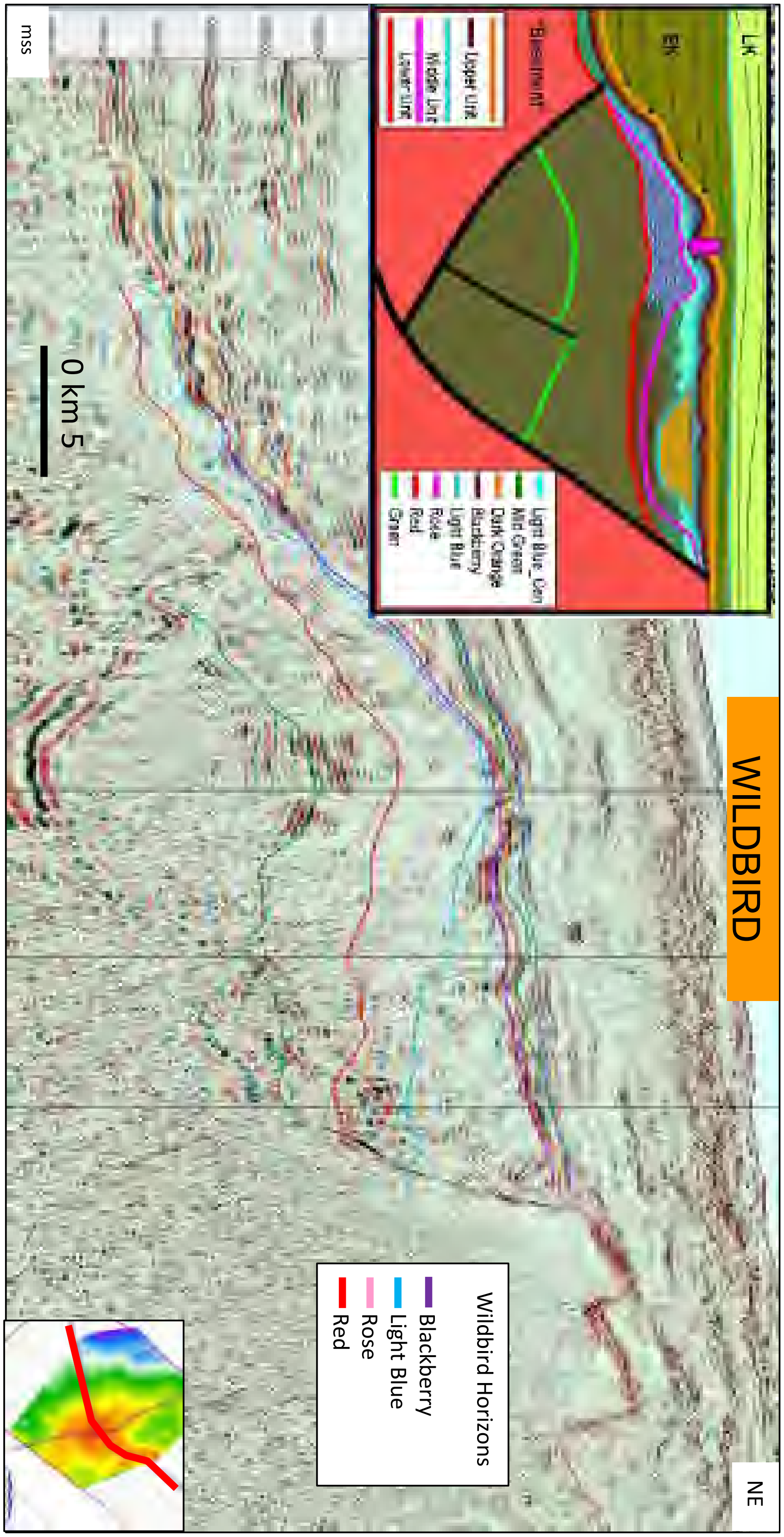


Figure 2-16 Seismic line and prospect geo-seismic sketch, Wildbird prospect

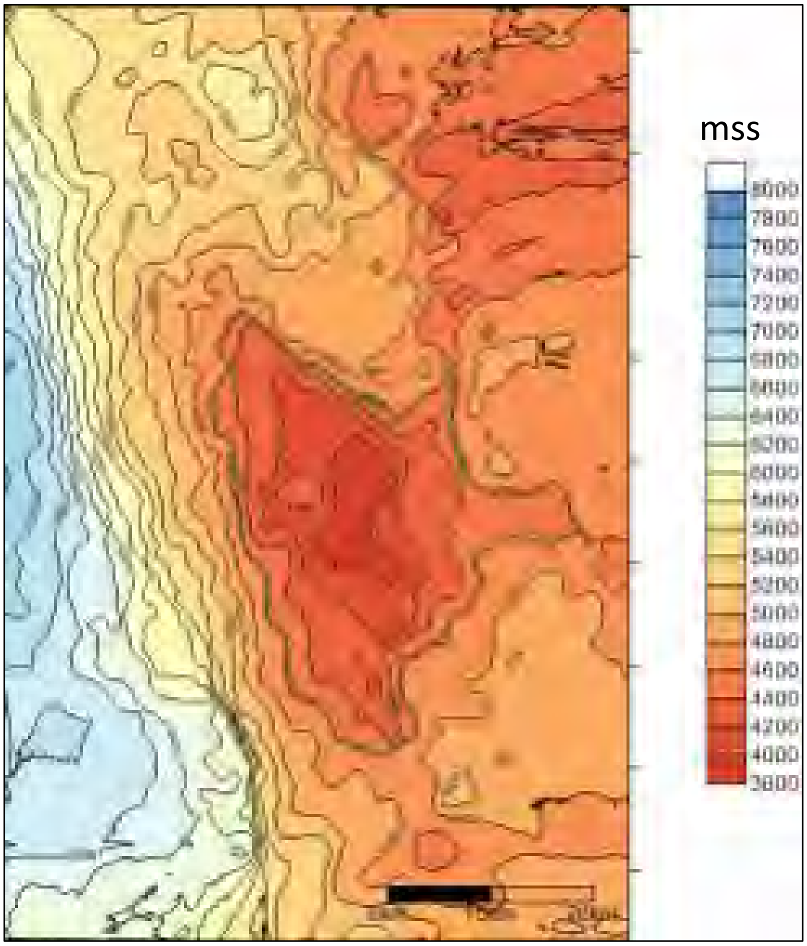


Figure 2-17 Wildbird: Top Reservoir depth map (m TVDSS). Spill point - green contour.

The Wildbird prospect is a large container, but there is considerable uncertainty in reservoir thickness, structural mapping and degree of charge from the offset kitchen areas. We evaluate the prospect in a similar manner to the Lovebird prospect, by perturbing the above variables. In our low case, we choose a shallow contact at 4250 m TVDSS to simulate under-filling or lateral breach via onlapping thief zones, and also employ a reservoir thickness of 80 m from offset analogue. Our high case assumes the prospect is filled to spill, and that the 'red' seismic event marks base reservoir. Estimates of reservoir net to gross ratio and porosity are derived from the available analogues, and are necessarily wide. Fluid parameters and recovery factors are derived as described in Section 1.6.

The Wildbird play is emerging and is of high risk. We attribute a play risk of 24% as a result (Section 2.4). The key prospect risk to the Wildbird prospect is that of containment or trap, as there is evidence for erosion at the crest of the feature, and it is reliant on the development of lagoonal facies to the north-east and overlying marine shales to provide lateral seal and support the hydrocarbon column heights modelled here. We attribute a prospect risk of 38% Wildbird, which, when combined with the play risk, gives an overall chance of success for the Wildbird prospect of 9%.

3. Gambia: Prospectivity and Plays

3.1. Introduction

Although only one exploration well (Well Jammah-1) exists offshore Gambia, exploration drilling has been undertaken to the north and south within Senegalese and Guinea Bissau waters (Figure 2-1, Figure 3-1). A number of oil and gas discoveries have been made onshore Senegal, and the large Dome Flore and Dome Gea discoveries to the south of the blocks are each reported to contain a million barrels of biodegraded oil (c.10-13^{o} API) in place within sandstones of Oligocene (Tertiary) age. Some lighter (30-34^{o} API) oil has also been encountered in deeper intervals. More regionally, oil and gas discoveries have been made to the north offshore Mauritania and in Guinea Bissau (Sinapa). the recently drilled Venus and Mercury wells in Sierra Leone have also encountered hydrocarbons.

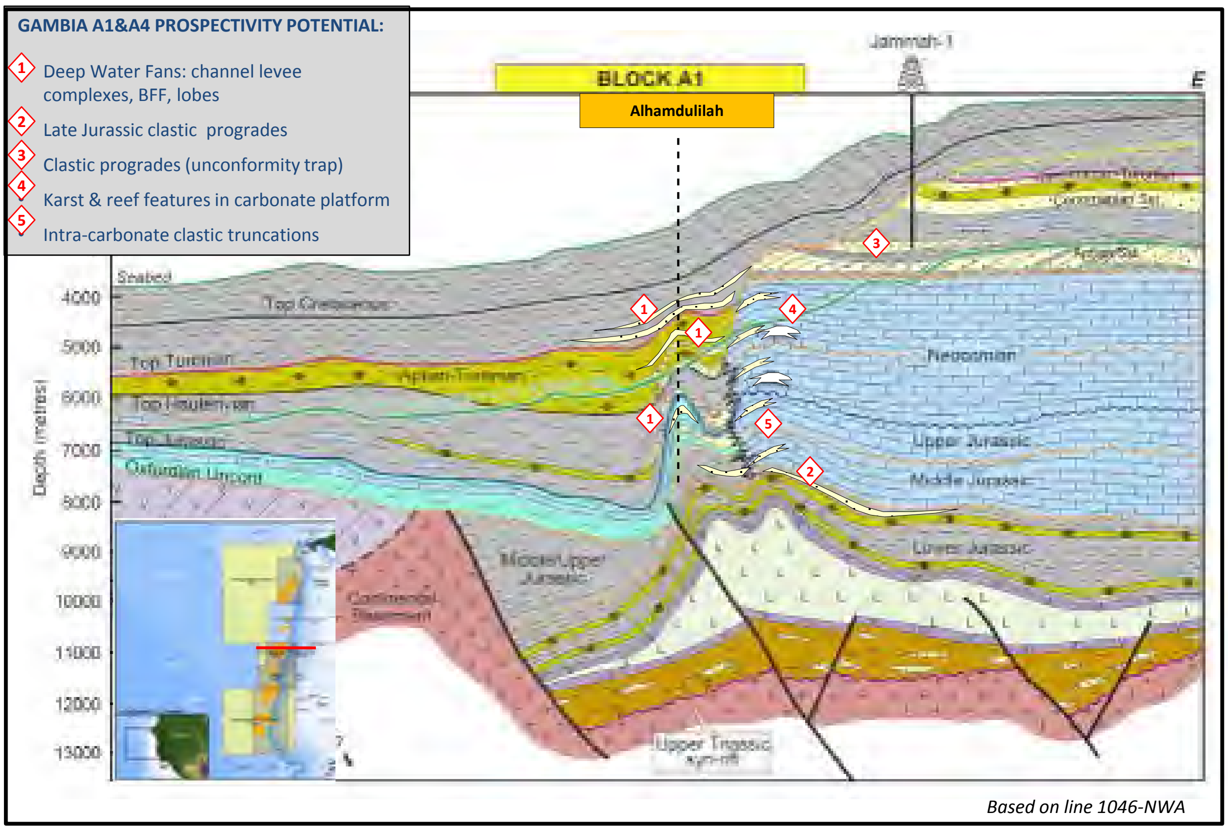


Figure 3-1 Plays, Gambia Blocks A1 and A4

The range of hydrocarbon types encountered is suggestive of multiple sourcing, and the age of the reservoirs suggest late timing of oil generation, consistent with a late Cretaceous source for the heavy oil, although there are no published data to confirm this. Regionally, the gas source could be any of the older potential source rocks discussed below.

3.2. Well and Seismic Database

Exploration offshore Gambia is also at an early stage, and no wells have been drilled in the deeper water areas. The nearest well to Blocks A1 and A4, (and the only well offshore Gambia) is Well Jammah-1, some 15 km to the east of Block A1, (Figure 3-2). This well contains oil shows within sandstones of Late Cretaceous age. The well drilled to 3020 m MD, reaching total depth in an interval of uncertain age; perhaps Cenomanian to Albian.

A regional grid of 2D seismic data was made available to us for our evaluation, with an average line spacing of around 2-3 km on Block A1, and up to 8 km on Block A4 (Figure 3-2, Figure 3-3). In addition a 2003 vintage 3D seismic data volume was available for analysis, covering 2,008 km^2. However, APCL is using 2010 vintage 3D seismic data (2,566km^2) processed to pre-stack time-migration in their current evaluation, and we have adopted these data for our review. In general, seismic data quality was found to be good.

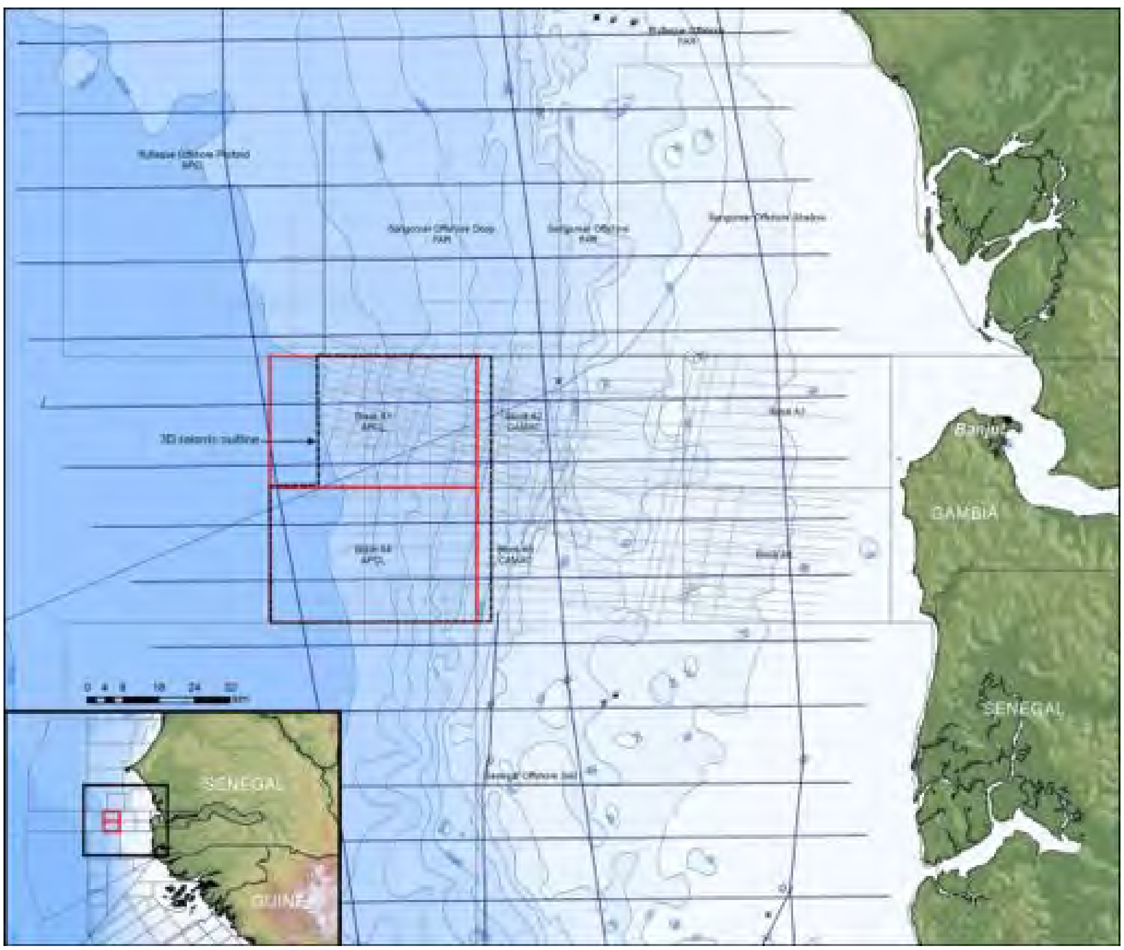


Figure 3-2 Wells, 2D and 3D seismic data, (red outline) Gambia Blocks A1 and A4

The 2D seismic data was sufficient to enable a well to seismic tie to be made to Well Jammah-1 (Figure 3-3). Despite its shelfal location, we were able to extrapolate some stratigraphy into the deeper water, although the key Upper Cretaceous section is not sampled adequately by the well, leading to uncertainty in the age of the deeper clastic section that forms the potential reservoir interval for the Alhamdulilah prospect.

3.3. Plays and Petroleum Geology: Blocks A1 and A4

Some of the plays identified by APCL offshore Gambia are similar to those described for Liberia in Section 2.3 above, with structural and stratigraphic traps identified at a number of Cretaceous intervals, (Figure 3-1), and reservoirs prognosed as being of deep marine turbidites or other mass transport systems. However, plate tectonic reconstructions suggest that rifting occurred earlier along the Senegalese and Gambian margin, beginning in the Lower Jurassic. Thus, there is the potential for deeper Jurassic age source and reservoir in the area.

There is some seismic evidence for the presence of reservoir intervals, as is common regionally, although evidence is less compelling in the deeper intervals (Figure 3-5). Of the identified traps in this play fairway, only one has currently been matured to prospect status by APCL; the Alhamdulilah prospect.

Regionally, reservoirs within the Cretaceous are associated with a deep marine depositional environment, and are generally expected to be of good to excellent quality, with the possibility of some overpressure. A similar depositional environment is prognosed for the deeper, Jurassic age reservoirs, with possible fan-delta like geometries identifiable on seismic landward (eastward) of the Alhamdululah prospect (Figure 3-7).

In addition to the Jurassic and Cretaceous clastic plays, APCL has identified a number of closures along the margin of a carbonate platform of Jurassic to Aptian age, partially penetrated by Well Jammah-1 (Figure 3-3, Figure 3-4). These closures are currently being evaluated by APCL, and only one, Prospect M, has been evaluated to prospect status, and we assess the prospective resources for Prospect M in this section.

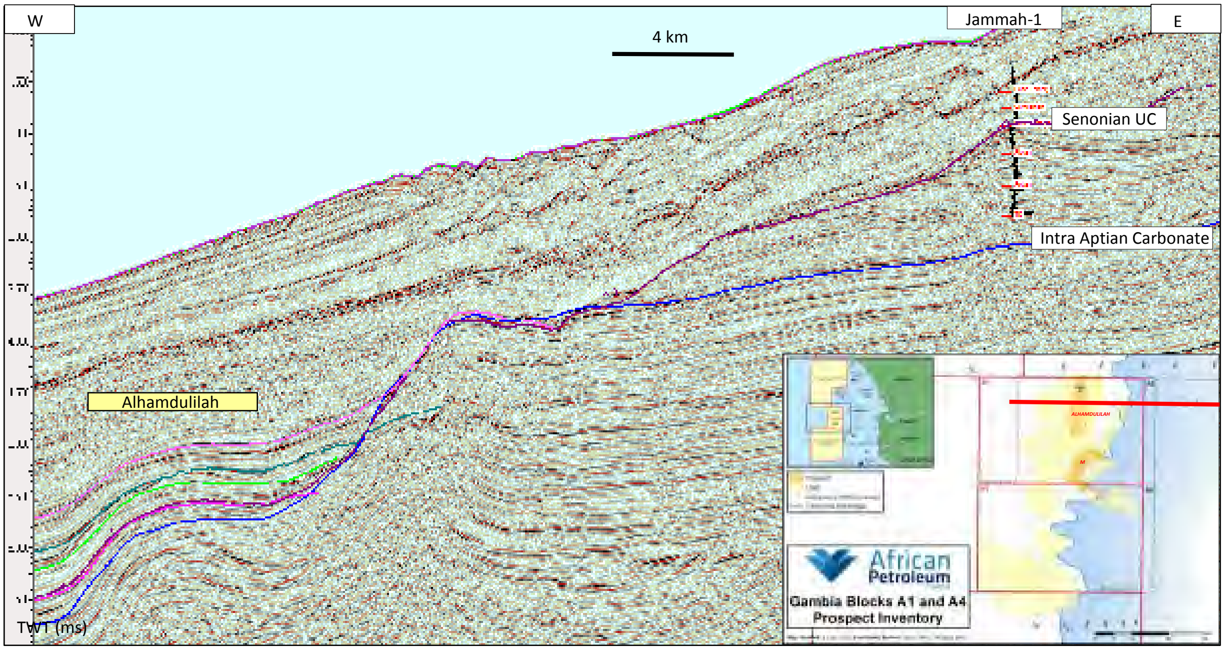


Figure 3-3 Well to seismic tie – Well Jammah-1 to the Alhamdulilah prospect

There is good evidence for the presence of source rocks in the Gambian margin. The youngest source interval that could possibly generate oil is the Cenomanian-Turonian marine source rock, proven in the Casamance Shelf wells, and present in basins to the north. Published data indicate kerogen is a mixed Type II/III locally, and Type II in wells to the south, with HI of between 370-660 mg/gC in >2% TOC rocks (TOC's in the DSDP-367 well, 300 km to the west, are in excess of 5% in black shales of Albian to Turonian age). This section is absent in Well Jammah-1, probably as a result of erosion.

There is also the possibility of Necomian and Jurassic source rocks. Necomian black shales are described in the DSDP-367 well. Jurassic (Toarcian) source rocks are inferred to be present based on analogue evidence and plate tectonic reconstructions that place proven Jurassic source rocks in Morocco, Portugal, Nova Scotia and north-eastern Brazil in proximity to the Senegal-Gambia basin. These are documented as having a HI of around 450 mg/gC and a TOC of up to 6%.

Regional thermal information shows a high degree of variability, with gradients from 25 to 45 °C/km, likely as a result of drilling on salt domes, where geothermal gradients are elevated, or in areas locally affected by volcanics. Blocks A1 and A4 are at the northernmost margin of the salt basin, so at worst only limited local effects are anticipated. Using data from Well Jammah-1, we infer a geothermal gradient of 30° C/km at the location of the well. This would put the Cenomanian-Turonian source locally into the oil window around the Alhamdulilah prospect. However, uncertainty in both depth conversion and geothermal modelling do not rule out the possibility that the Cenomanian-Turonian could be mature regionally for hydrocarbon generation. Deeper Neocomian or Jurassic source rocks, if present, would be mature for oil generation under this model.

3.4. Play Risk

In our evaluation of APCL's Gambian blocks we note that a number of the prospective plays require further definition to mature the identified leads to prospect status. As a result, our evaluation is limited to the determination of independent estimates of prospective resource for the Alhamdulilah prospect and Prospect M. We have used play and prospect risk for both prospects, to allow for consistency in comparison between our evaluations where a play risk is appropriate.

Based on the review above, we see source risk as the key risk to the Lower Cretaceous and Jurassic clastic play. Although a number of source rock intervals are present regionally, only those within the Cretaceous are demonstrated to be present proximal to Blocks A1 and A4. Data are limited, but modelling would suggest that those within the Cenomanian-Turonian could be immature for oil generation in all but a small area of the blocks. As a result, we assign a source risk of 0.7. Note that the uncertainty in both source rock presence and thermal data is such that there is a possibility of gas charge, although, like Liberia, Sierra Leone and Cote d'Ivoire, it is impossible to quantify this chance at present.

We see seal risk for this play to be relatively low, as there is seismic evidence similar to that interpreted regionally for the presence of seal. Seal risks for the multiple stacked sands prognosed for the Alhamdulilah prospect are handled as a prospect specific risk. The inferred depositional environment for this interval would also suggest that sealing intervals would be developed. We have therefore assigned a seal risk of 0.9 to this play.

Seismic evidence for the presence of reservoir is also good, but less convincing than that observed regionally and in our evaluation of Liberia Blocks 8 and 9. However, we assign a reservoir presence risk of 0.8. It is possible that the younger, Cretaceous reservoirs identified could be locally sourced via exhumation of the coeval carbonate platform to the east, and thus be composed of detrital carbonate material. This is reflected in the reservoir risk for the Alhamdulilah prospect itself.

For the carbonate platform play, the key risk is that of top seal. Seismic reflectivity is highly variable above the top of the platform carbonates (Figure 3-3), as the event is a strong regional unconformity. In places, the overlying clastic section can be interpreted immediately above this unconformity. Although the latter is factored into prospect specific risk to top seal, the seismic evidence for the presence of a regional seal above the unconformity is not compelling. The top seal is provided by a down-lapping carbonate prone Aptian-Albian section where the Senonian unconformity is not immediately above the reservoir section. Analogues suggest there is a general lack of support for intra-formational seals in similar settings, and therefore we assign a risk to the carbonate platform play seal of 0.5 as a result.

The presence of a strong angular unconformity at the top of the carbonate platform structures is, however, likely to have enhanced reservoir quality within the carbonates themselves, as a result of subareal exposure and karstification. Thus, we assign a risk of 0.9 to the reservoir presence element of the carbonate platform play, and review the prospect specific reservoir efficacy risk on a prospect by prospect basis dependent on the seismic evidence for erosion.

A number of the identified structures along the buried carbonate platform margin are relatively shallow to mudline, and thus biodegradation of any oil charge is possible. However, as we have only estimated prospective resources for Prospect M, we have not carried a play risk to biodegradation.

Our final play risks for the Lower Cretaceous clastic and the buried carbonate platform plays are summarised in Table 3.1 below.

PLAY	Source	Reservoir Presence	Seal	**Play Risk**
Cretaceous to Jurassic Clastic Play	0.7	0.8	0.9	**50%**
Carbonate Platform Margin	0.7	0.9	0.5	**28%**

Table 3.1 Play risk, Gambia Blocks A1 and A4

3.5. Gambia: Leads and Prospects

In all, 13 leads and prospects have been identified by APCL within Blocks A1 and A4, with areas of closure varying from around 4 km^2 to 63 km^2 (Figure 3-4). Of the identified prospective intervals, a number are best classified as leads, and require further technical work to mature them to prospect status (yellow, Figure 3-4). Structural closure is identified within the Lower Cretaceous, and a number of slope fans can be identified as seismic amplitude anomalies within the Upper Cretaceous section. In addition, a number of closures are mapped along the edge of the buried carbonate platform margin at Top Aptian level, and APCL are currently evaluating the potential for a deeper, Barremian age seal, which might provide further prospectivity within the carbonate platform play.

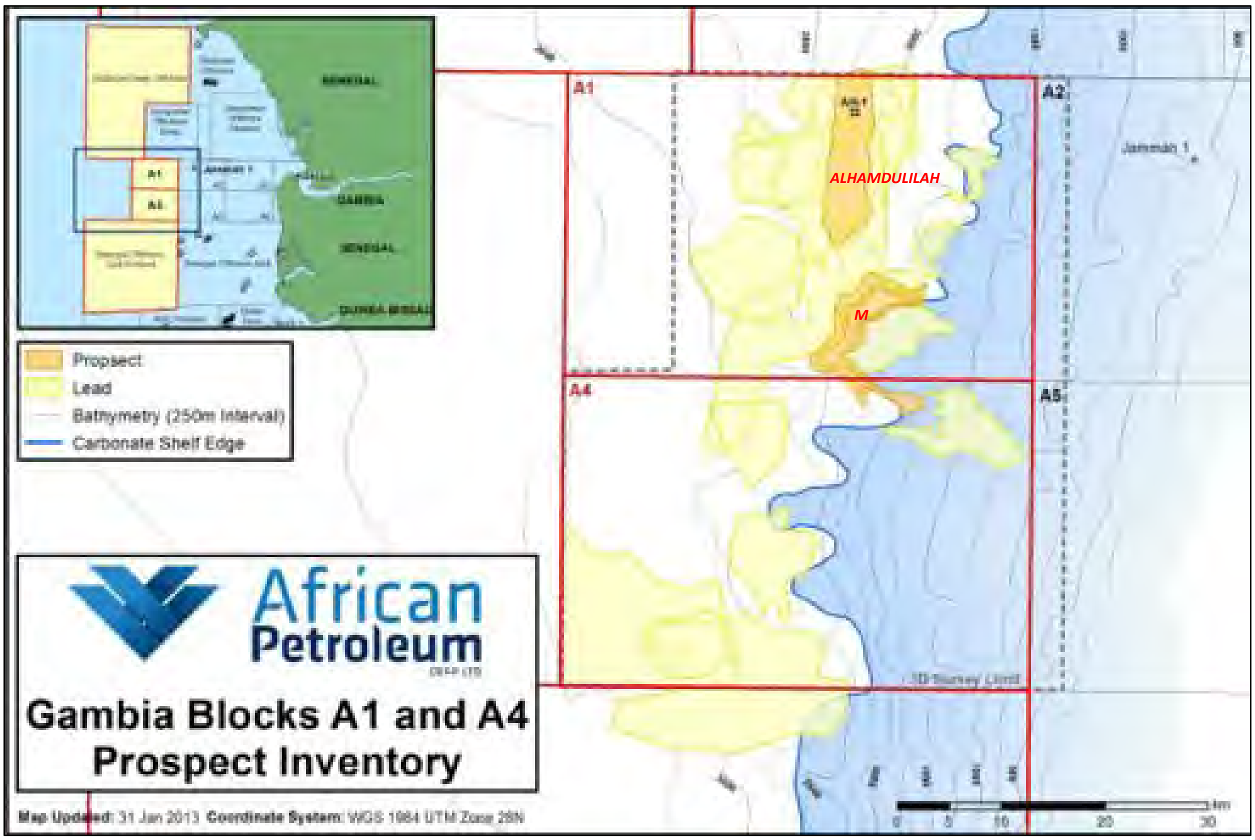


Figure 3-4 Leads and prospects identified by APCL in Gambia Blocks A1 and A4

In this section, we briefly describe our evaluation of the Alhamdulilah prospect and Prospect M. A summary of input parameters for the calculation of prospective resources, results and risks for each of the prospective layers evaluated is given in the resource summary sheets in Enclosures 2.1 to 2.5 of this document.

In 2010 APCL acquired a further 2566 km^2 of 3D data over both blocks. A re-evaluation of the identified leads and prospects is on-going using these data, with the evaluation of the Alhamdulilah prospect and Prospect M completed.

3.5.1. Alhamdulilah Prospect

The Alhamdulilah prospect is identified as a four-way dip-closed structural high within the centre of the deep water portion of Block A1 (Figure 3-3, Figure 3-5). We have evaluated four prospective intervals in total, (Figure 3-5). Reservoir ages are currently prognosed by APCL to be of Lower Cretaceous (Turonian) to perhaps Lower Jurassic. The prospect extends northwards of Block A1 into Senegalese waters, and we have restricted our calculations to the proportion of the prospect that lies within Block A1. The bulk of the prospect does, however, lie within Gambian territory.

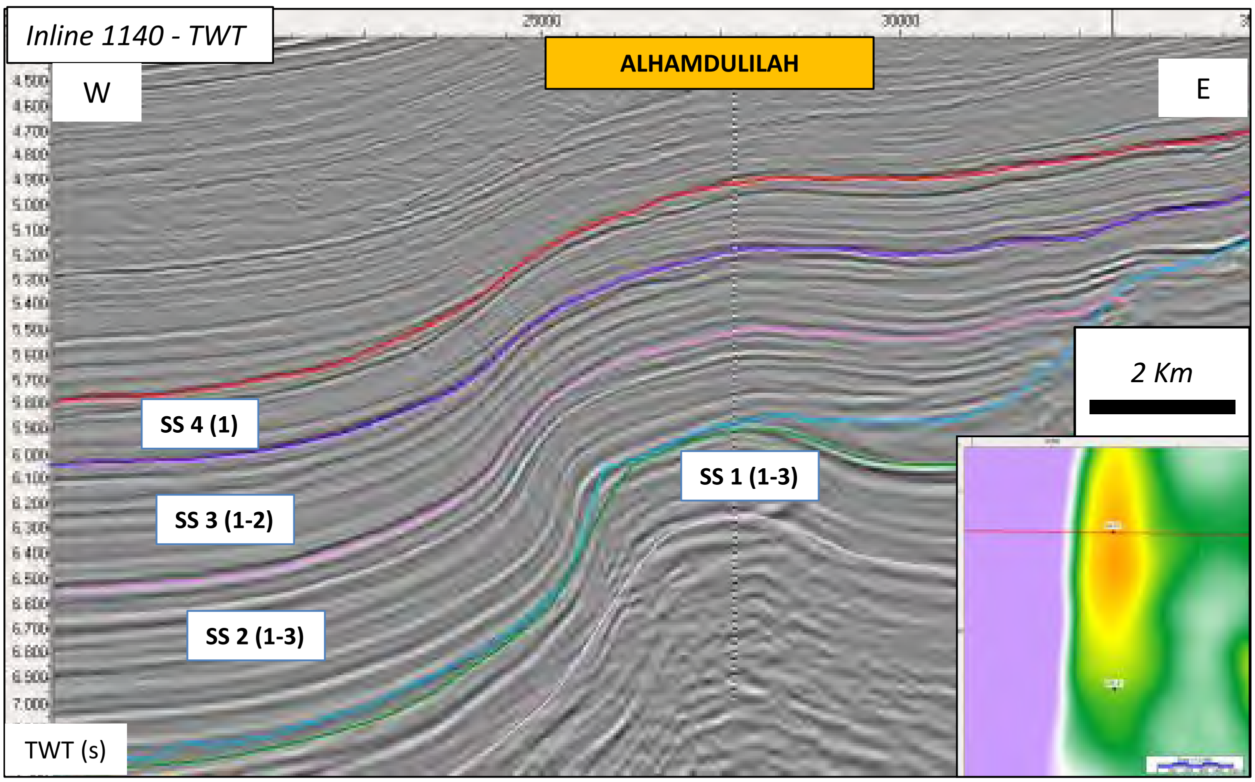


Figure 3-5 Seismic line over the Alhamdulilah prospect

The prospective intervals within the Alhamdulilah structure lie between 4230 m TVDSS and 5970 m TVDSS, or around 2010 to 3750 metres below sea bed. This is relatively deep, and, despite the estimates of overpressure, it is possible that porosity, and thus reservoir quality, to be relatively poor (Figure 2-4). Our estimates of recovery factor for the deeper prospective intervals reflect this.

There is uncertainty in the degree of structural closure, as although mapped reflectors are relatively bright and continuous, the structure is of low relief. We have account for this by undertaking various depth conversions of the mapped structure from the time domain 3D seismic data, restricting our analysis to closure demonstrable on-block (Figure 3-6). At SS-1 level, closure continues to the north, off-block and also off the 3D seismic data. We have reviewed the available 2D seismic data northwards to determine the spill point at this level.

Where seismic facies analysis suggests the potential for stacked pay intervals, these have been modelled probabilistically. Estimates of gross rock volume derived in this way are combined with the estimates of net reservoir thickness based on mapped seismic thicknesses, and porosity and fluid information are derived as described in Section 1.6 to compute probabilistic estimates of resources for each reservoir interval.

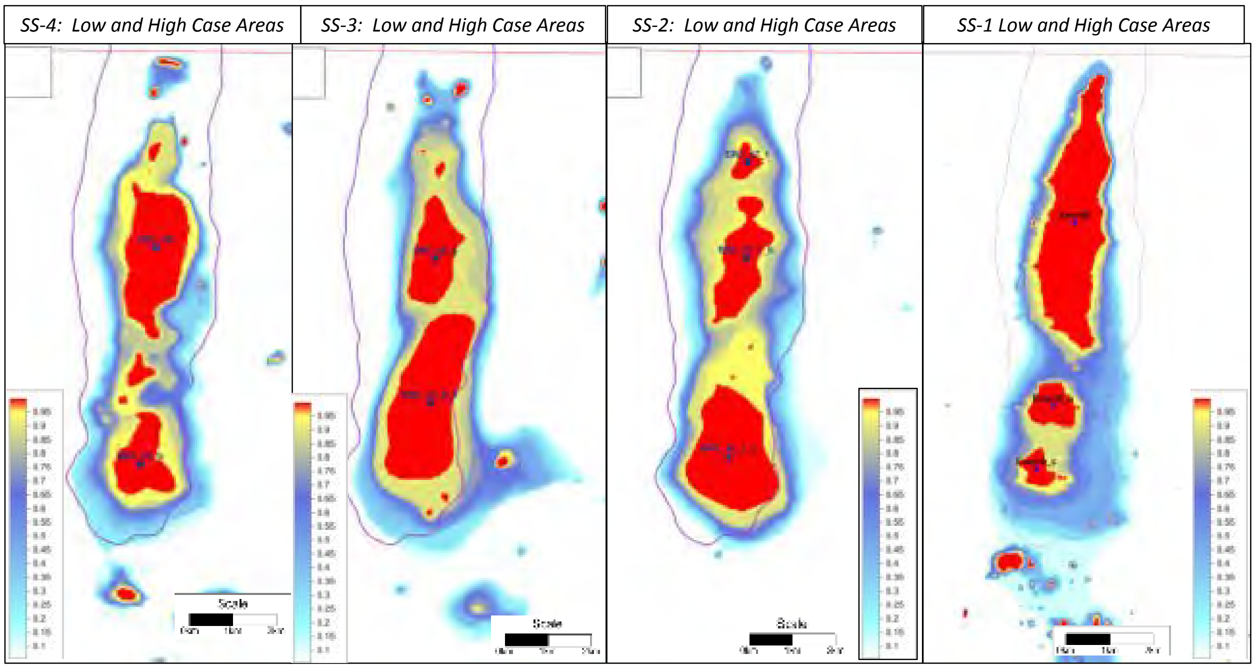


Figure 3-6: Area of closure, Alhamdulilah prospect layers SS1 to SS4

Recovery factors used are as described in Section 1.6 of this report, but modified to reflect the depth of burial of the deeper prospective intervals.

We have reviewed the prospect specific risk for each of the prospective intervals independently. Although the Alhamdulilah trap is a four-way dip-closed feature, the time closure is subtle, and the prospect is relatively deep. There is also seabed canyoning which may cause uncertainty in the imaging and thus trap closure.

Seismic evidence for seal is relatively good over the Alhamdulilah trap. However, there is evidence for downcutting/erosion between layers and above the prospect there is also evidence for downlapping events onto the topmost reflector.

The key risk to the Alhamdulilah prospect is that of reservoir efficacy. There are indications of fan-like geometries within the 3D seismic data (Figure 3-7), and some events can be mapped for the shallower reservoir layers. However, the Cretaceous reservoirs may alternatively comprise the eroded talus from the coeval carbonate platform to the east, and reservoir quality rock may not be developed as a result. Finally, our estimate of overpressure may be incorrect, and any sandstones present may have the reservoir quality sufficiently degraded via compaction to render them non-reservoir.

As a result, the prospect specific risks to the prospective intervals of the Alhamdulilah prospect vary from 26% to 34% and from 13% to 17% when combined with the play risk.

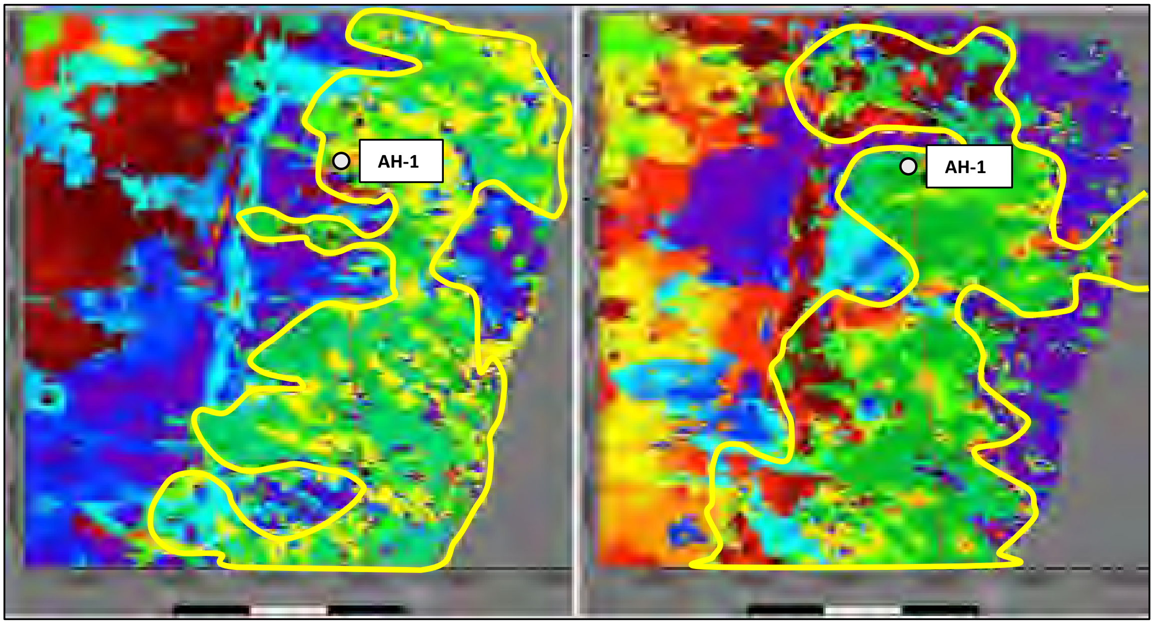


Figure 3-7 Alhamdulilah prospect seismic facies interpretation, Cretaceous intervals

3.5.2. Prospect M

A number of structures have been identified by APCL at the Aptian level (i.e. top carbonate) along the buried carbonate platform margin that runs through Blocks A1 and A4 (Figure 3-1). Of these, one structure, Prospect M, has been matured to prospect status and is of sufficient size to warrant independent estimates of resources (Figure 3-8).

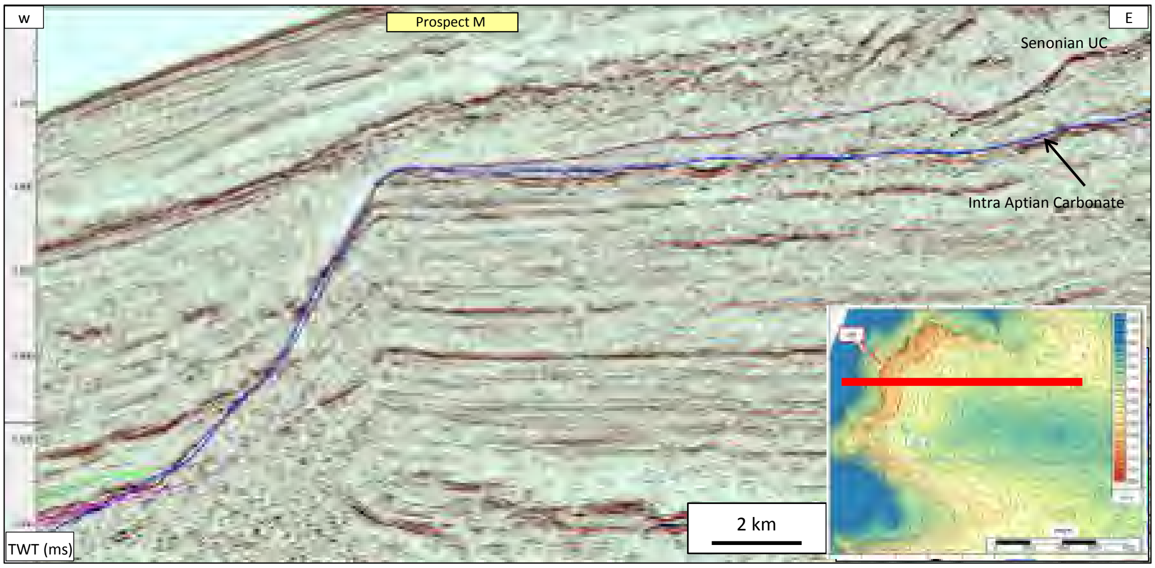


Figure 3-8 Seismic line through Prospect M

We have evaluated the uncertainty in gross rock volume for Prospect M, and combined this with reservoir net to gross ratio and porosity from analogue to generate estimates of STOIIP and prospective resources. We have simulated uncertainty in seismic pick and also depth conversion, to generate a range of spill points for the structure (Figure 3-9). These are used to make low and high case estimates of gross-rock volume.

Due to the shallow nature of Prospect M, we have assumed relatively high (but moveable) oil viscosities, as discussed in Section 1. Recovery factor estimates are made with reference to this, and also to analogue, where uncertainty in both reservoir quality and also the degree of fracturing (and hence dual permeability) leads to a wide range in uncertainty in ultimate recovery. Our low case recovery factor being affected primarily by early onset of water cut via fractures and an adverse mobility ratio, and the high case making allowance for better oil mobility and improved matrix porosity and permeability, leading to a more efficient sweep. We therefore use a recovery factor range from 10% to 35%, and use these as the P90 and P10 estimates on a log-normal distribution in our probabilistic simulation of prospective resources.

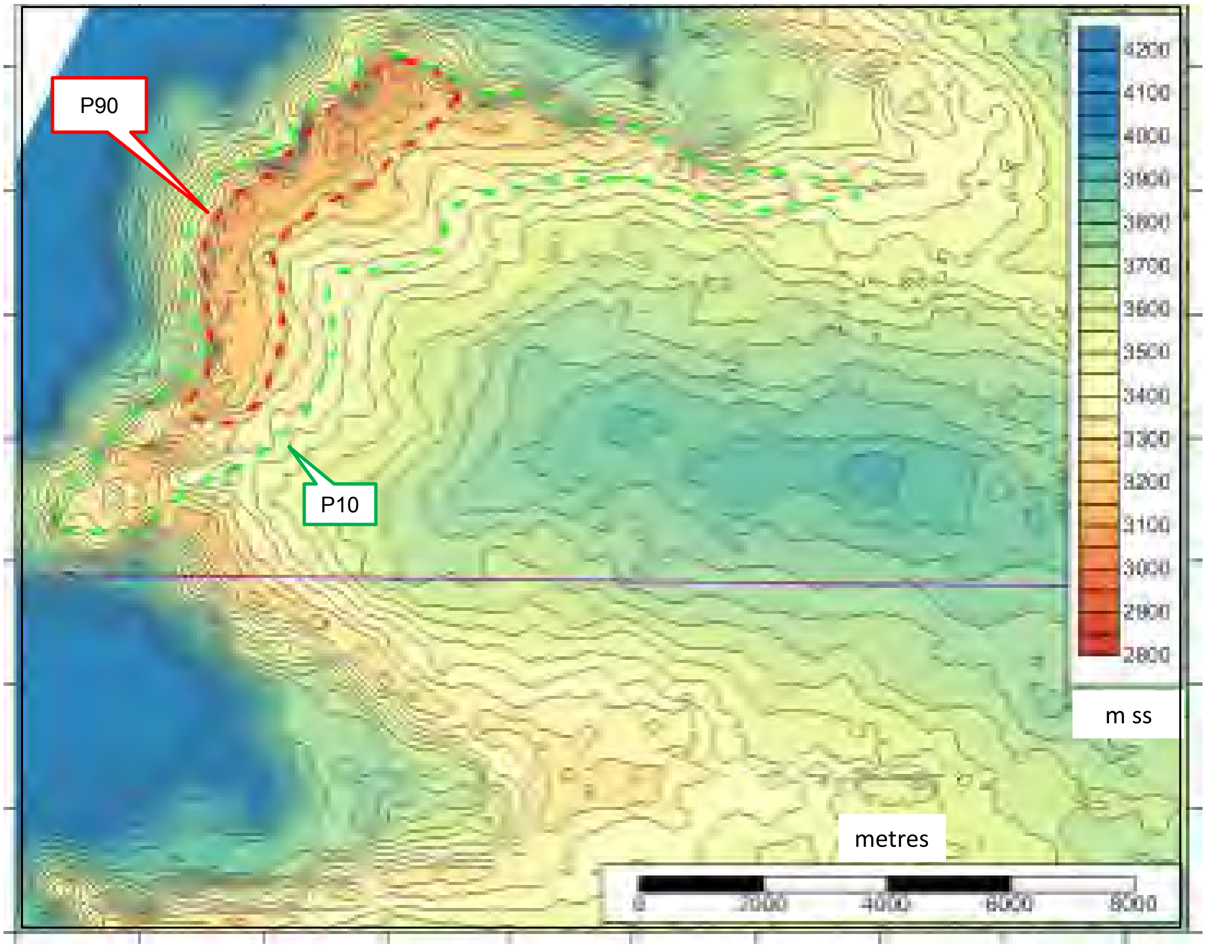


Figure 3-9 Low and high case closure, Prospect M, top Aptian depth (m TVDSS)

There is pick and depth conversion uncertainty associated with Prospect M, but we see a good chance of a closure being developed within the 3D seismic area, and assign a prospect specific risk to trap of 0.9 as a result. Downlapping events are observed onto the crest of the prospect (Figure 3-8), but the overlying seismic signature is relatively transparent, thus we see a good chance of the prospect being sealed relative to the play risk. However, the prospect is relatively shallow, at around 1000 m to 1100 m below the seabed, and there is a risk to biodegradation of any oil charge. Thus, we associate a risk of 0.6 to biodegradation. As it is established practice, we place this risk into containment or trap risk, which results in an overall trap risk of 0.9 * 0.6, or 54%

There is evidence for the development of reservoir quality rock, with a seismic character that has been associated with the development of karstification in the analogues used. We also note that the prospect is very close to the platform edge and the erosional unconformity is quite pronounced, again suggesting a period of subareal exposure. Thus, we see the prospect specific risk to reservoir efficacy as 0.8. Charge risk is also favourable, with the prospect located at the edge of the buried platform margin, proximal to the deeper potential kitchen areas. We therefore associate a charge risk of 0.8 to the prospect.

Thus, we assign a prospect specific risk of 35%, which, when combined with the play risk for the carbonate platform margin, gives an overall COS of 10%.

4. Sierra Leone: Prospectivity and Plays

As with offshore Liberia, to the south-east, all of the deep-water acreage offshore Sierra Leone is under licence (Figure 4-1). A discussion of regional hydrocarbon occurrences is presented in Section 2.1. APCL's licences, SL-03 and SL-04A-10 lie to the north-west of the country's territorial waters, around 200 to 300 km north-west of the recent Venus, Mercury and Jupiter discoveries made by Anadarko (Figure 4-1).

Figure 4-1 Offshore licences and discoveries, Liberia and Sierra Leone

A regional grid of 2D seismic data is available to APCL for the evaluation of offshore Sierra Leone (Figure 4-2). In addition APCL has licenced c. 2500 km^2 of 3D seismic data covering the deeper water area of Block SL-03, and is negotiating the licencing of further 3D seismic data covering part of Block SL-04A-10.

Well data offshore Sierra Leone are sparse. Historical exploration was restricted to the shelf, and resulted in the drilling of two exploration wells (Wells A-1 and A-1-2), which were plugged and abandoned as dry holes. Data from both wells are available to APCL. Recent drilling by Anadarko in the deeper waters of licence SL-07B-10 has yielded a number of discoveries, (Wells Jupiter-1, Venus-1 and Mercury-1), but these well data are not available to APCL.

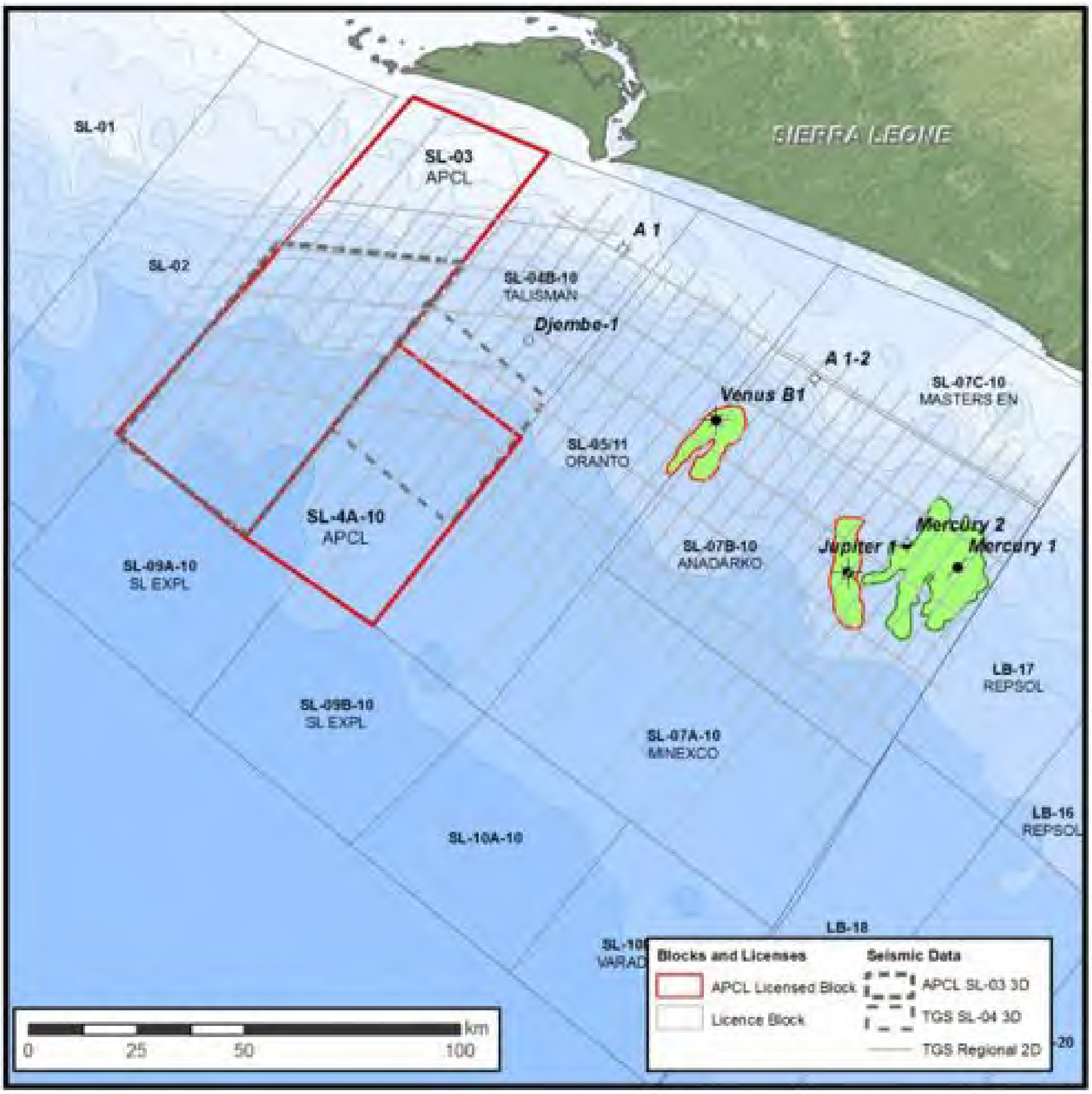


Figure 4-2 Well and seismic database, offshore Sierra Leone

The play fairways identified offshore Sierra Leone are very similar to those identified offshore Liberia (Figure 2-3), as structural traps within the Lower Cretaceous syn-rift section, and, primarily, as stratigraphic traps within turbiditic sands of Cretaceous age, (Campanian, Cenomanian and Turonian). Sourcing from regional marine (Cenomanian) or lacustrine (Albo-Aptian) source rocks is hypothesized. For the syn-rift structural play, the presence of Albo-Aptian reservoirs is demonstrated by the shallow water Wells A-1 and A-1-2, which also had indications of the development of source rocks within the

Cretaceous syn-rift section. Although the data are not available, the recent Anadarko wells are publically documented as having found hydrocarbons within post-rift Cretaceous turbidites, potentially de-risking this play.

Blocks SL-03 and SL-04A-10 are towards the north-western edge of the seismically identified Cretaceous basin, immediately adjacent to a large structural lineament, the Sierra Leone Transform System. Submarine canyon development is therefore prognosed to occur to the south and east of this lineament, providing sediment input into the blocks during Cretaceous time. As is encountered regionally, there is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous section in the blocks.

APCL's evaluation of the recently licenced 3D seismic data is on-going, and as yet only one prospect Altair has been matured to drillable prospect status. However, a number of other Cretaceous channel/fan systems have been identified within Block SL- 03 (Figure 4-3).

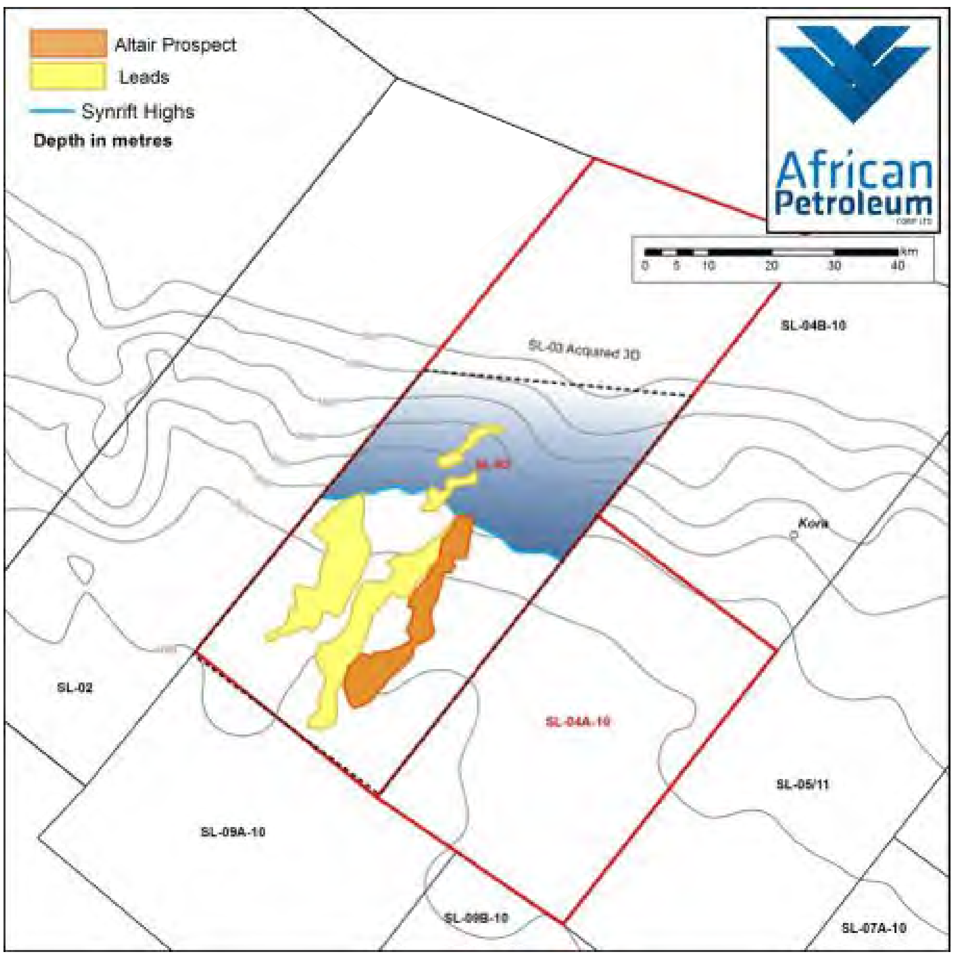


Figure 4-3 Leads, Sierra Leone Block SL-03

4.1. Play Risk

Although there has been recent drilling along strike of APCL's Sierra Leone licences, these wells lie some 100 km to the east. We have therefore attributed a play risk, albeit favourable, to Cretaceous channel-fan prospectivity within Blocks SL-03 and SL-04A-10. As with our review of Liberia, there is strong seismic evidence for reservoir and seal rocks being present, and offset drilling would indicate the same, from the limited published information. However, there is as yet no proven source rock within APCL's licences, and we see this as the key risk to play. The reported results of offset drilling, and APCL's own basin modelling would suggest that source risk would be favourable.

Our final play risk for the Cretaceous channel-fan systems in APCL's Sierra Leone licences is summarised in Table 3.1 below.

PLAY	Source	Reservoir Presence	Seal	**Play Risk**
Cretaceous Play	0.8	0.9	0.9	**65%**

Table 4.1 Play risk, Sierra Leone Block SL-03

4.1. Sierra Leone: Leads and Prospects

APCL is currently evaluating the recently licenced 3D seismic data over Block SL-03, and has identified a number of Cretaceous channel-fan systems, varying in areal extent from 20 km^2 to 150 km^2. Of the mapped channel fan systems, one, Altair, has been matured to prospect status by APCL, and we have made independent estimates of prospective resources and risks for this prospect.

A summary of input parameters for the calculation of prospective resources, results and risks for the Altair prospect is given in the resource summary sheet in Enclosure 3.1 of this document.

4.1.1. Altair

The Altair prospect is a turbidite channel prospect mapped at a seismic event described as Turonian by APCL (Figure 4-4). There is, however, uncertainty in this stratigraphy, as it is established by jump correlation using regional seismic data, due to the lack of deep water wells on block. It is a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out, in a similar manner to prospectivity within APCL's Liberia and Cote d'Ivoire acreage. A single target reservoir is identified within the trapped area. The prospect has anomalous seismic amplitudes associated with it, (Figure 4-5), which may indicate reservoir development. The top structure is mapped between 6200 – 6800 ms TWT over the area of the prospect. Our depth conversion indicates a crestal depth of approximately 5400 m TVDSS beneath a water depth of 3300 m, giving 2100 m of sediment above top reservoir.

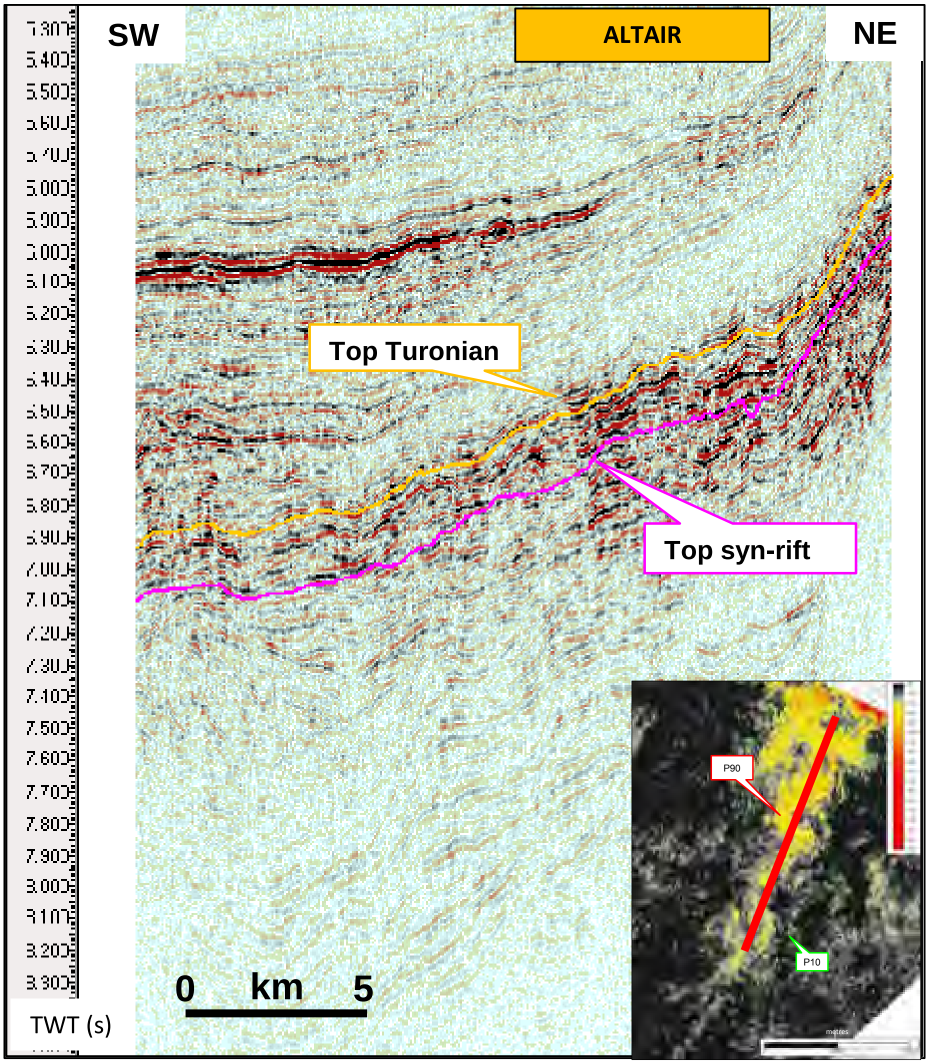


Figure 4-4 Dip seismic line (full offsets), Altair prospect

The seismic image suggests that Altair is a turbidite channel constrained in the north east by a well-defined canyon. Two distinct canyon systems feed erosive channels at the break of slope. A south west trending fault, which is almost perpendicular to the main canyon feeders, alters bathymetric relief and diverts the Altair channel southwards.

ERCE has made estimates of prospective resources for the Altair prospect using an identical methodology to our evaluation of Liberian prospectivity. An area net approach was adopted using optimized seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the reservoir. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a column height of 200 m. Our high case extends the prospect down-dip to a column height of 800 m, and laterally to incorporate weaker amplitude responses (Figure 4-5). These polygons were used to constrain the P90 and P10 area inputs of our probabilistic simulation.

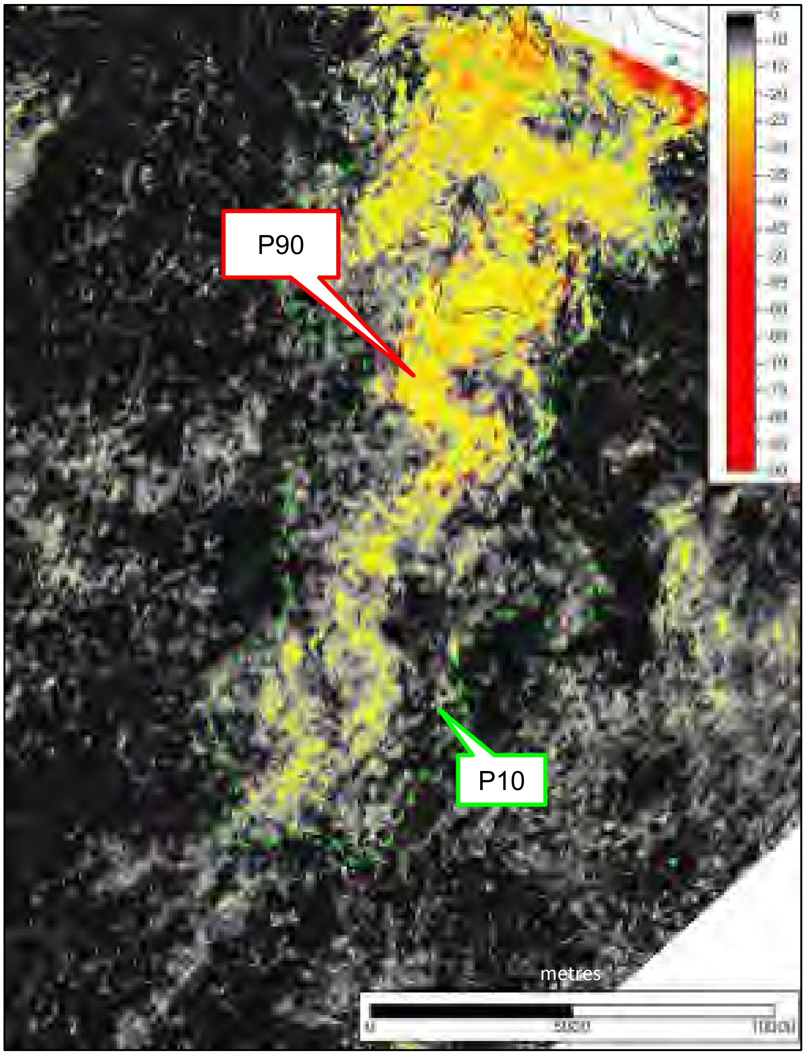


Figure 4-5 Seismic amplitude (gradient stack) and Top Turonian depth (m TVDSS), Altair prospect

Net pay is estimated from the mapped seismic interval and regional analogue, with porosities and fluid properties estimated as described in Section 1.6.

We have used the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Altair prospect. Key risk is to trap integrity, due to the coalescing of a number of mapped fan systems up dip towards the pinch-out of Altair, with subsidiary risk to charge, as this is as yet unproven on block. This gives a prospect specific risk of 28% which, when combined with the play risk, gives an overall chance of success of 18% for the Altair prospect.

5. Cote d'Ivoire: Prospectivity and Plays

5.1. Introduction

Offshore Cote d'Ivoire has been actively explored for hydrocarbons for a number of years, and much of the offshore shelf is under licence. Recently, exploration has moved into deeper waters, targeting the regional post-rift (Cretaceous) play and APCL has identified a number of prospects and leads within the western licence Blocks of CI-513 and CI-509 (Figure 5-1).

There are two main play types identifiable offshore Cote d'Ivoire, (Figure 5-2), as structural traps within the Lower Cretaceous (Aptian to Albian) syn-rift section, and as stratigraphic traps within post rift turbiditic sands of Cenomanian to Turonian age. Sourcing is prognosed from regional marine (Turonian) or lacustrine (Albo-Aptian) source rocks.

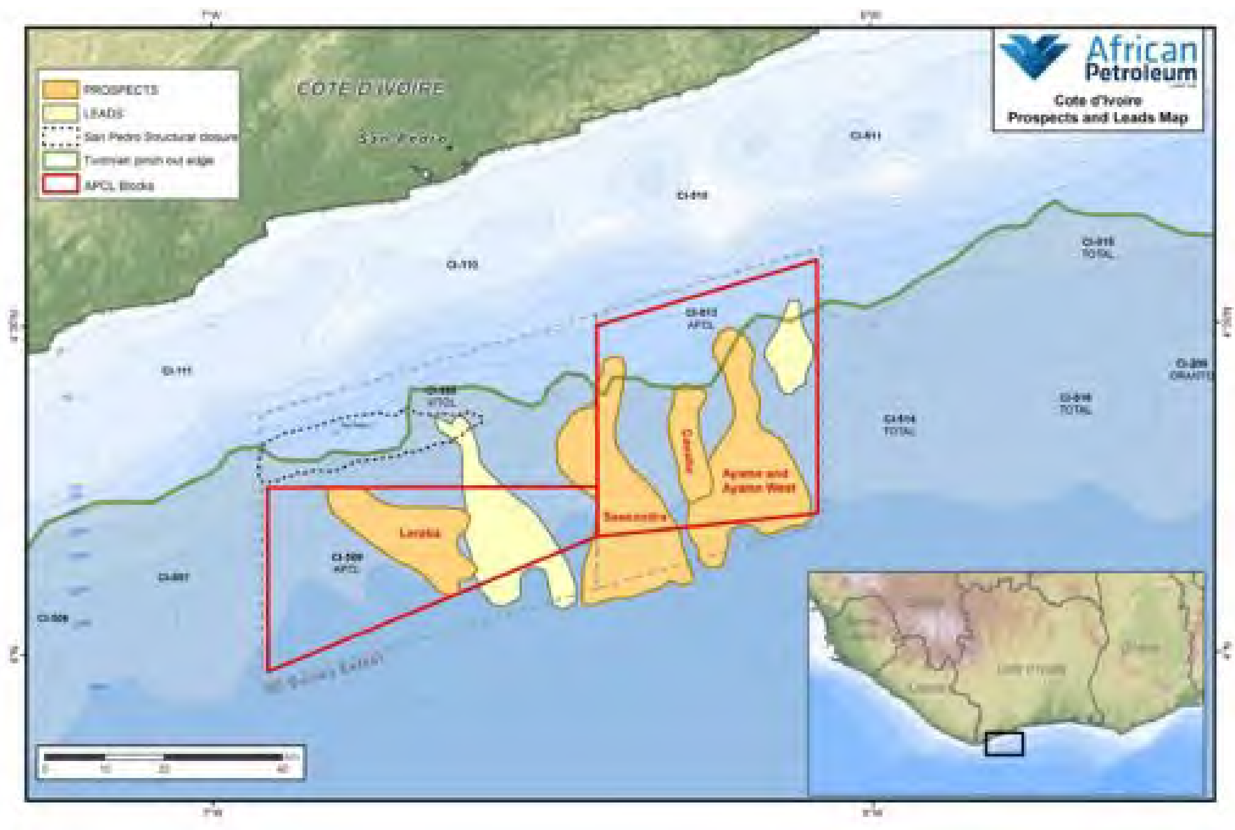


Figure 5-1 CI-509 and CI-513 Prospects and Leads, offshore Cote d'Ivoire

Historically, exploration has been restricted to the narrow shelf area, and has yielded a number of commercial fields, both oil and gas, including Foxtrot, Baobab and Espoir. All of these fields lie within the Lower Cretaceous (Aptian) syn-rift play. Recently, exploration has moved into deeper waters, targeting the regional post-rift (Cretaceous) play. Well Paon-1X, c. 300 km to the east of Blocks CI-105 and CI-513, drilled by Tullow Oil plc and partners in licence CI-103 during 2012, is reported to have found hydrocarbons in turbiditic sandstones of Cretaceous age. Well Kosrou-1X, some 150 km east of Blocks CI-105 and CI-513 shows reservoir development within the post-rift Cretaceous section, particularly within the Turonian to Cenomanian section.

Evaluation of prospectivity within Blocks CI-509 and CI-513 is at an early stage, and a working petroleum system is not proven on block. However, a number of Cretaceous channel/fan systems have been identified using both 2D and 3D seismic data, which have generated around seven potential traps at the date of this report, five of which are considered prospects for this report (Figure 5-1).

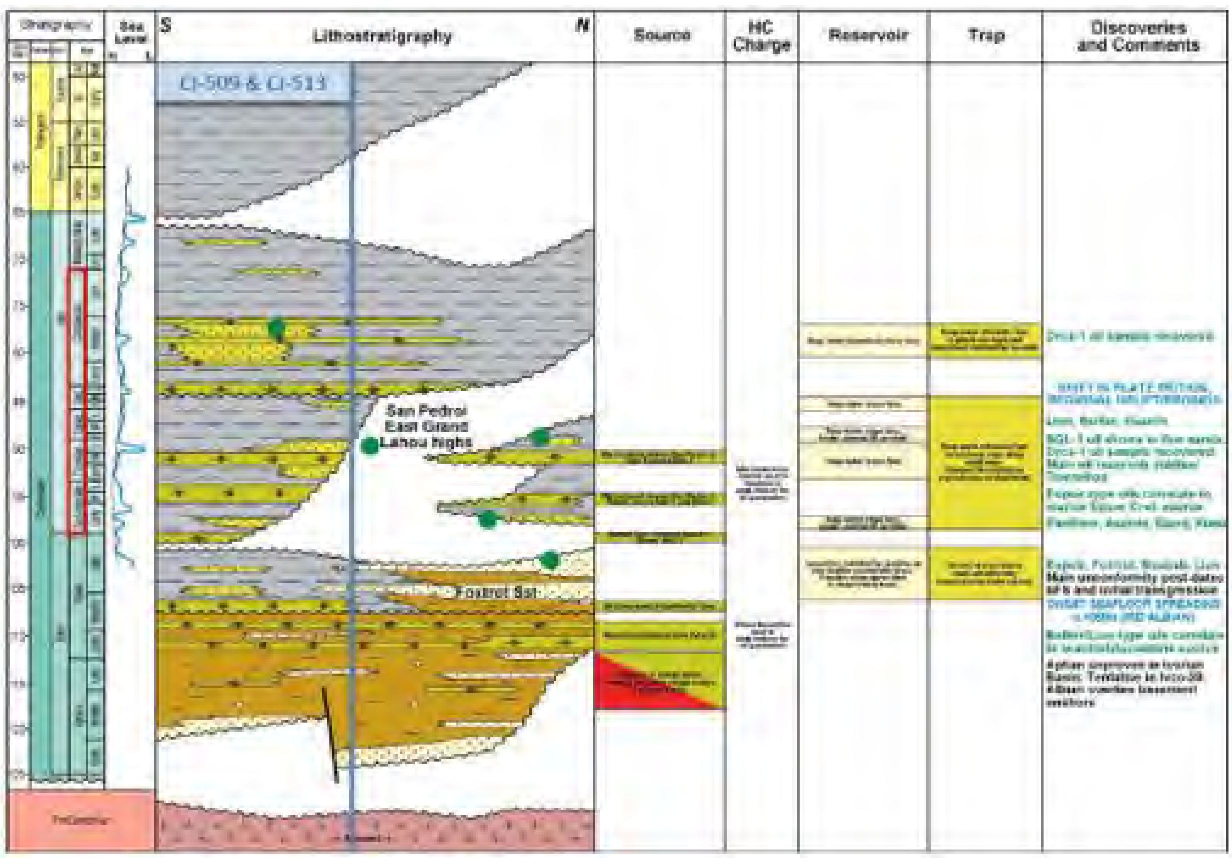


Figure 5-2 Petroleum systems and plays, offshore Cote d'Ivoire

5.2. Well and Seismic Database

APCL has obtained a regional database of 2D seismic data offshore Cote d'Ivoire, which provides well to seismic ties to Well San Pedro-1 (Figure 5-3). The primary data set used for our evaluation is that provided by the recently acquired 3D seismic data. At the time of writing, these data were processed to pre-stack time-migration, and we have used this volume, plus available AvO processed volumes, to evaluate the prospectivity of the CI-513 licence, currently only the full-stack seismic product has been used to assess the prospectivity in Block CI-509.

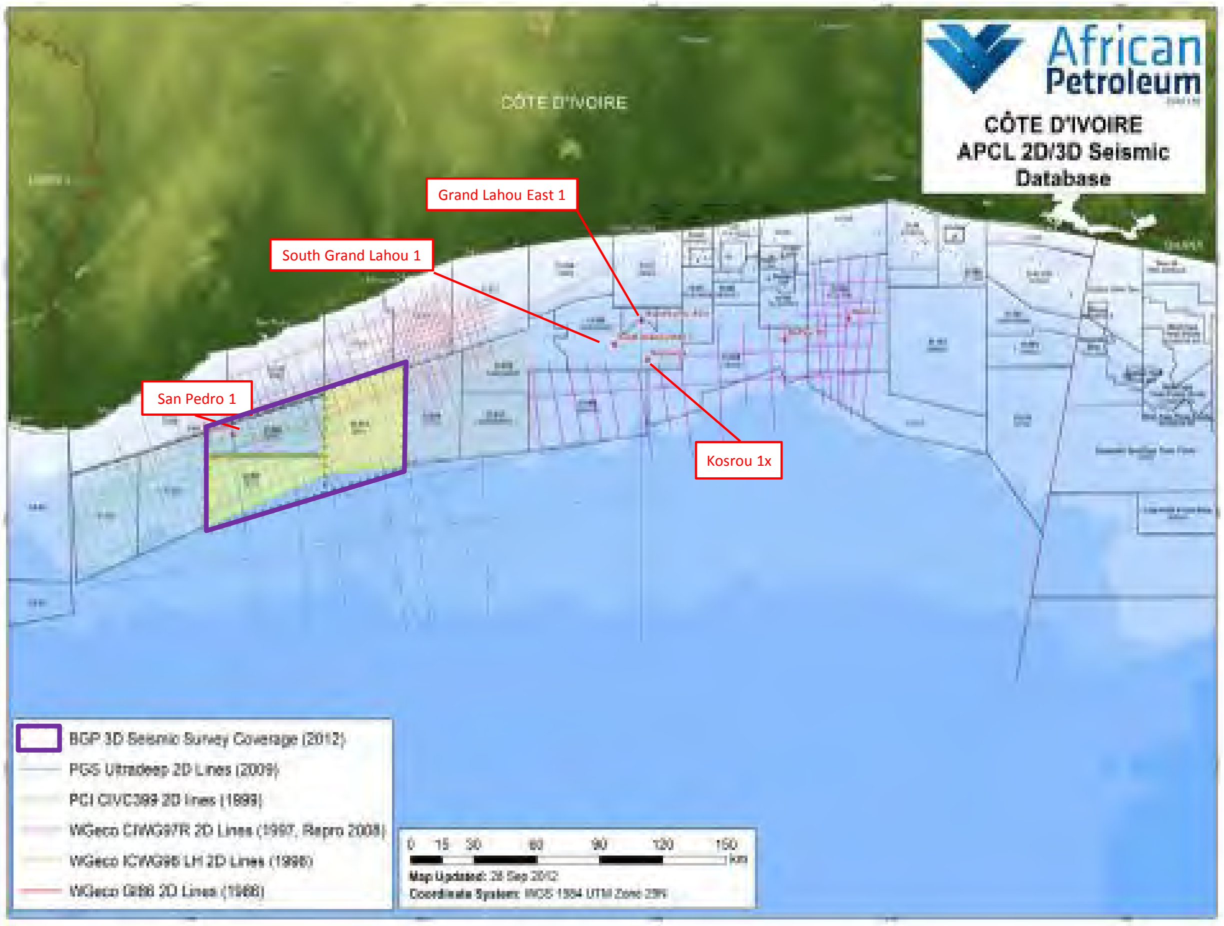


Figure 5-3 Well and seismic database, offshore Sierra Leone

5.3. Plays and Petroleum Geology: Blocks CI-509 and CI-513

The primary play being explored within Blocks CI-509 and CI-513 is the Cretaceous post-rift turbidite play (Figure 5-2). There is reasonable seismic evidence for the presence of reservoir bearing intervals within the Upper Cretaceous section of the blocks. However, dating of the age of these post-rift turbidite channel/fan systems is uncertain, due to the paucity of well and seismic data, with stratigraphy extrapolated into APCL's licences via regional seismic correlation. The presence of a regional Turonian source rock is hypothesized to charge any identified traps. This is not proven on block, but evidence from offset drilling in Block CI-105 demonstrates the presence of source rocks developed within the

Cenomanian to Turonian, and basin modelling studies indicate that the Turonian may be mature for oil generation local to the licences.

A number of Cretaceous channel/fan systems have been identified using both 2D and 3D seismic data (Figure 5-1) and we have independently evaluated the Prospective Resources and geological chance of success for five of these. In addition, the Lower Cretaceous syn-rift play may be viable within the licences, particularly to the north. Evaluation of this play by APCL is on-going, and no prospective resources have been assessed for this play.

5.4. Play Risk

Exploration offshore Cote d'Ivoire is at an early stage, and there are limited well data available. As a result, ERCE has adopted a play and prospect risk system in our evaluation of the Cote d'Ivoire prospective resources within the Cretaceous channel-fan play, in an identical manner to our review of Liberia, the Gambia and Sierra Leone.

In a similar manner to Liberia, the Gambia and Sierra Leone, there is seismic evidence for the presence of seal and reservoir rock, and thus the key risk is to source, and we see source risk as the key risk to the Creteaceous clastic play. Sourcing is prognosed from regional marine (Turonian), modelled as having limited hydrocarbon generating potential, or lacustrine (Albo-Aptian) source rocks, the maturity of which are interpreted to be in the very early oil window. As a result, we assign a play source risk of 0.6. Note that the uncertainty in both source rock presence and thermal maturity is such that there is a possibility of gas charge, although it is impossible to quantify this chance at present.

Our final play risk is summarised in Table 5.1 below.

PLAY	Source	Reservoir Presence	Seal	**Play Risk**
Cretaceous Clastic Play	0.6	0.9	0.9	**0.49**

Table 5.1 Play risk, Cote d'Ivoire Blocks CI-509 and CI-513

5.5. Cote d'Ivoire Blocks CI-509 and CI-503: Leads and Prospects

Prospectivity has been identified by APCL at a number of levels, with the evaluation of the Cretaceous clastic turbidite channel-fan play being the most advanced. ERCE has made independent assessments of prospective resources and geological chance of success for five prospects within this play: Ayame, Ayame West, Sassandra, Cavella and Leraba (Figure 5-1).

A summary of input parameters for the calculation of prospective resources, results and risks for each of the prospective layers evaluated is given in the resource summary sheets in Enclosures 4.1 to 4.5 of this document.

5.5.1. Ayame & Ayame West

The Ayame and Ayame West prospects are identified as Upper Cretaceous fans which lie mainly within Block CI-513 (Figure 5-4). The prognosed trapping mechanism is stratigraphic, with areal extents defined by amplitude truncation and structural pinch-out. A single target reservoir is prognosed for both, within stratigraphy identified as Turonian, although stratigraphy is uncertain in both licences, as it is established via long distance seismic ties. The prospects have anomalous seismic amplitudes associated with them, (Figure 5-5), which may indicate reservoir development. The top structure is mapped between 5400 – 6300 ms TWT over the area of the prospect, and our depth conversion places the crest of the trap at approximately 4200 m TVDSS beneath a water depth of 2500 m.

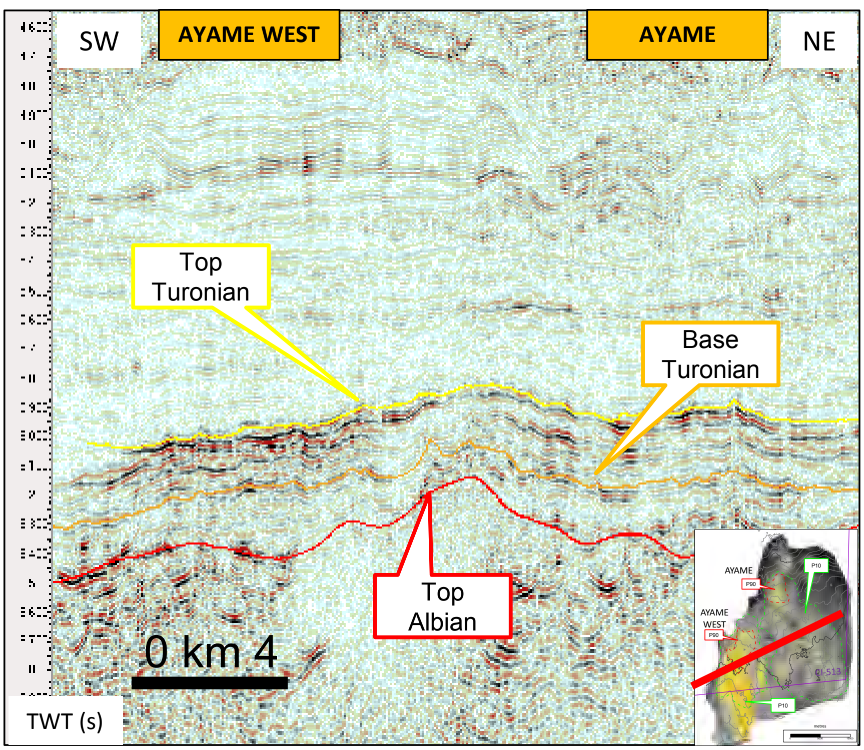


Figure 5-4 Strike Line, Ayame and Ayame West prospects

Evaluation of the Ayame and Ayame West prospects is undertaken in an identical manner to our evaluations of the stratigraphically trapped channel-fan prospects in APCL's Liberia and Sierra Leone licences. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 5-5). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.6.

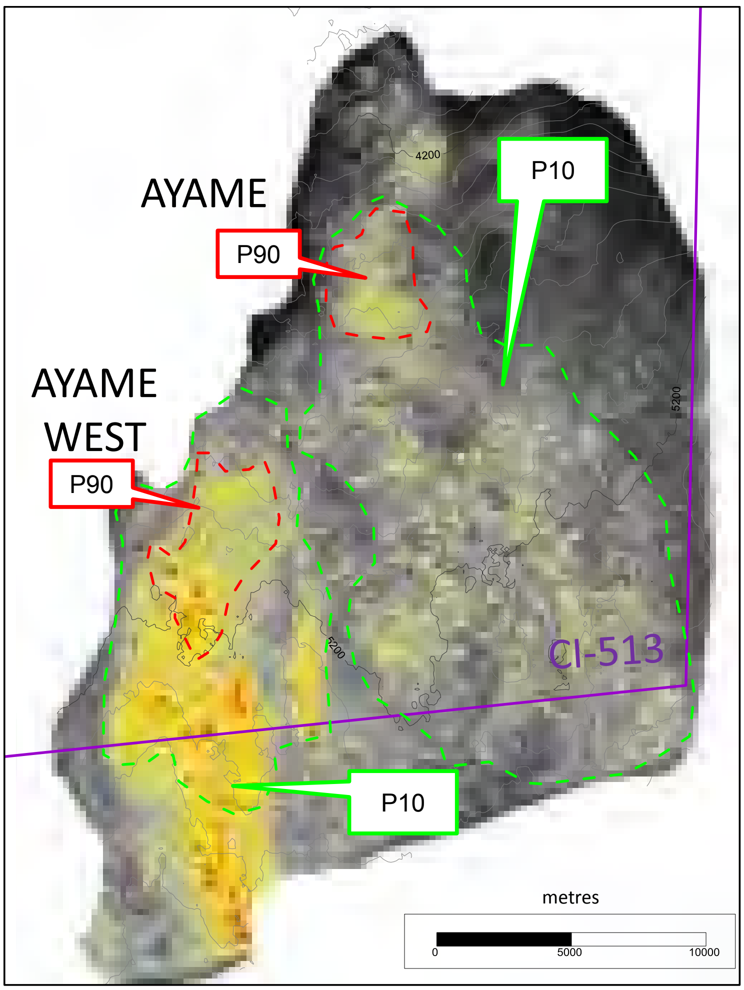


Figure 5-5 Ayame: Seismic amplitude (gradient stack) and Top Turonian depth (m TVDSS)

We use the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Ayame and Ayame West prospects. Key risk is to trap, and we attribute a trap risk of 50% to both prospects, giving a prospect specific chance of success of 28% for both prospects. When combined with the play risk, this gives an overall chance of success of 14%.

A proportion of the closure areas for both the Ayame and Ayame West prospects fall outside Block CI-513 in our high case (6 km^2 and 11 km^2 respectively). This is corrected for in our summary tables of net risked and unrisked prospective resources at the beginning of this document by computing the area of the prospect off-block at P90, P50 and P10 and scaling accordingly.

5.5.2. Sassandra

The Sassandra prospect is mapped as a deep-water fan system at Top Turonian level, and lies within Blocks CI-513 and CI-509, approximately 20km west along strike from the Ayame prospect. It is a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 5-6). A single target reservoir is prognosed within the Turonian, and, as with other prospects on block, has similar uncertainty in the stratigraphic age of the prospective interval. The prospect has anomalous amplitudes associated with it (Figure 5-7) which may indicate reservoir development. The top structure is mapped between 5000 – 6000 ms TWT over the area of the prospect, and our depth conversion predicts a crestal depth of approximately 4400 m TVDSS beneath a water depth of 2500 m.

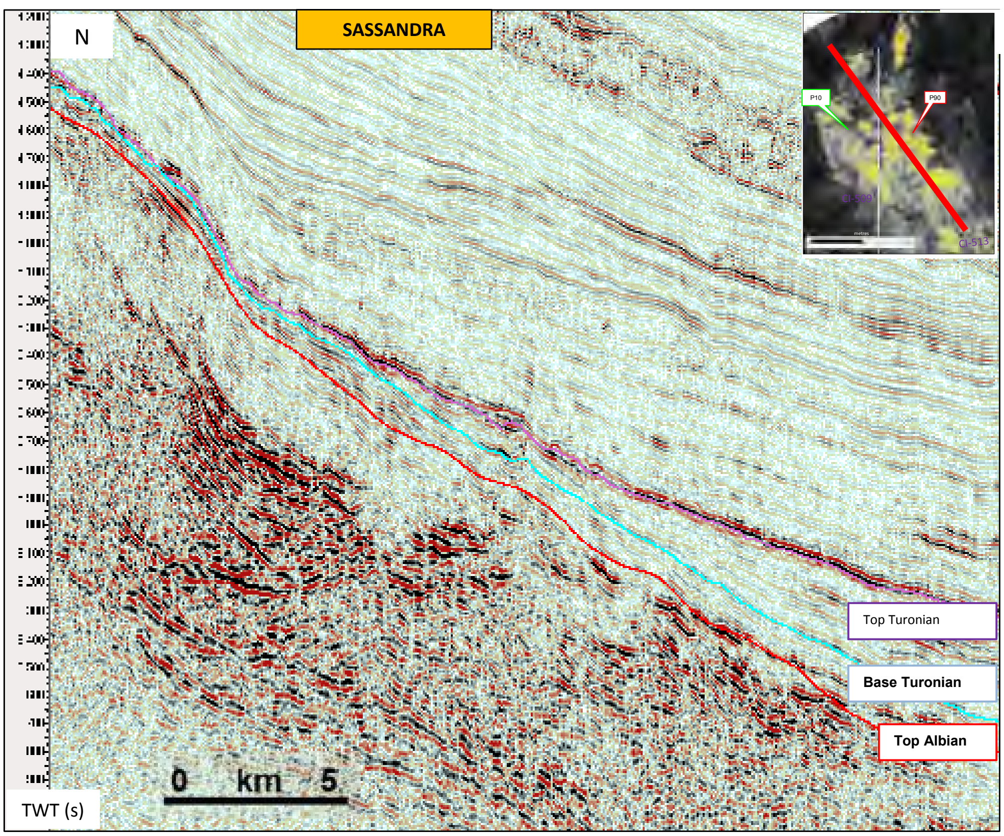


Figure 5-6 Dip seismic line, Sassandra prospect

Evaluation of the Sassandra prospect is undertaken in an identical manner to our evaluation of the Ayame and Ayame West prospects. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 5-7). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation. As far offset data are only available for CI-513 (at the time of writing) we have used amplitudes from the full-stack volume to map the extent of the prospect to the west, off block (Figure 5-7).

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.6.

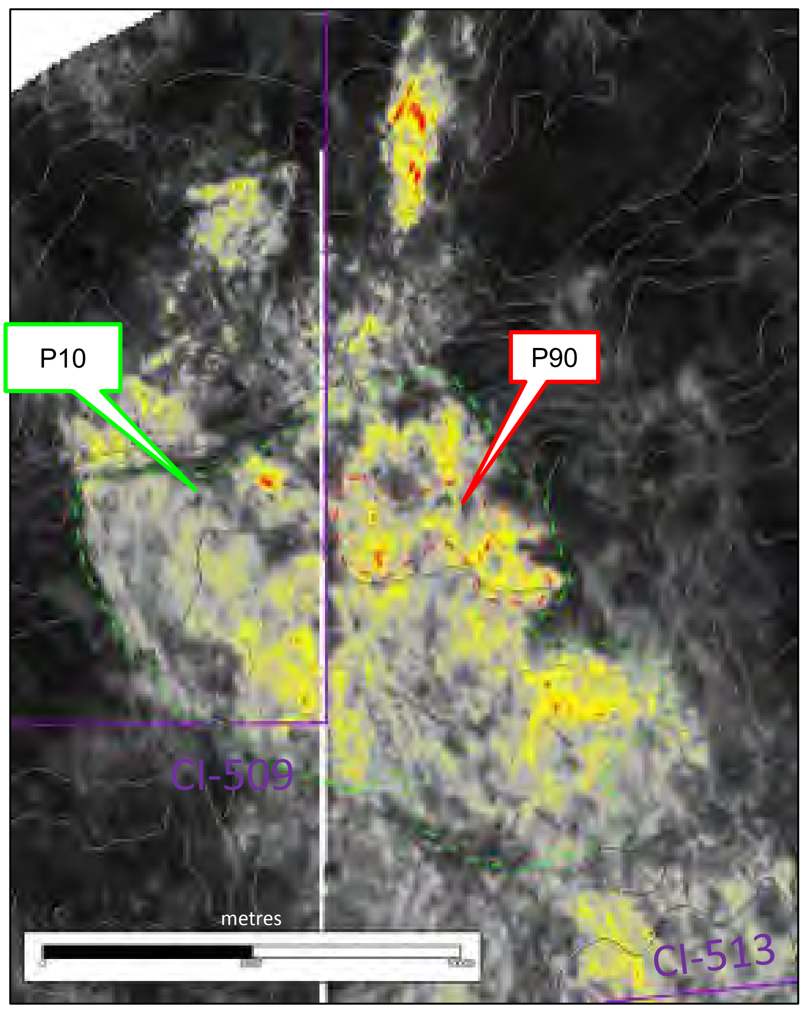


Figure 5-7 Sassandra prospect: Seismic amplitude and Top Turonian depth (m TVDSS)

We use the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Sassandra prospect. Key risk is to trap, and we attribute a trap risk of 40%. This is a lower value than our estimates for the Ayame and Ayame West prospects, as the up-dip termination of the trap is less well defined, and requires a larger area for pinch-out or bypass. Seismic amplitude support for reservoir presence is less over the Sassandra prospect relative to Ayame. Thus, we estimate a prospect specific chance of success for the Sassandra prospect of 20%, which, when combined with the play risk, gives an overall chance of success for the Sassandra prospect of 10%.

A proportion of the closure area for the Sassandra prospect falls outside Blocks CI-513 and CI-509 in our high case (33 km^2). This is corrected for in our summary tables of net risked and unrisked prospective resources at the beginning of this document by computing the area of the prospect off-block at P90, P50 and P10 and scaling accordingly.

5.5.3.**Cavalla**

The Cavalla prospect is an Upper Cretaceous Fan which lies between the Ayame and Sassandra prospects within Block CI-513. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 5-8). A single target reservoir is prognosed within the Turonian/Cenomanian interval, (with similar stratigraphic uncertainty to other prospects on block), which lies stratigraphically beneath the Ayame prospect. The prospect has anomalous seismic amplitudes associated with it (Figure 5-9) which may indicate reservoir development. The top structure is mapped between 4600 – 5900 ms TWT over the area of the prospect, and we estimate a crestal depth of approximately 3900 m TVDSS beneath a water depth of 2500 m. The prospect is more steeply dipping than other fan systems mapped on block.

Evaluation of the Cavalla prospect is undertaken in an identical manner to our evaluation of the Ayame, Ayame West and Sassandra prospects. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 5-9). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

Net pay estimates are estimated from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.6.

We use the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Cavella prospect. Key risk is to trap, and we attribute a trap risk of 40%. As with the Sassandra prospect, this is a lower value than our estimates for the Ayame and Ayame West prospects, as the up-dip termination of the trap is less well defined, and requires a larger area for pinch-out or bypass. Seismic amplitude support for reservoir presence is less over the Cavella prospect relative to Ayame. Thus, we estimate a prospect specific chance of success for the Cavella prospect of 20%, which, when combined with the play risk, gives an overall chance of success for the Cavella prospect of 10%.

The Cavalla prospect is contained entirely within APCL's licences.

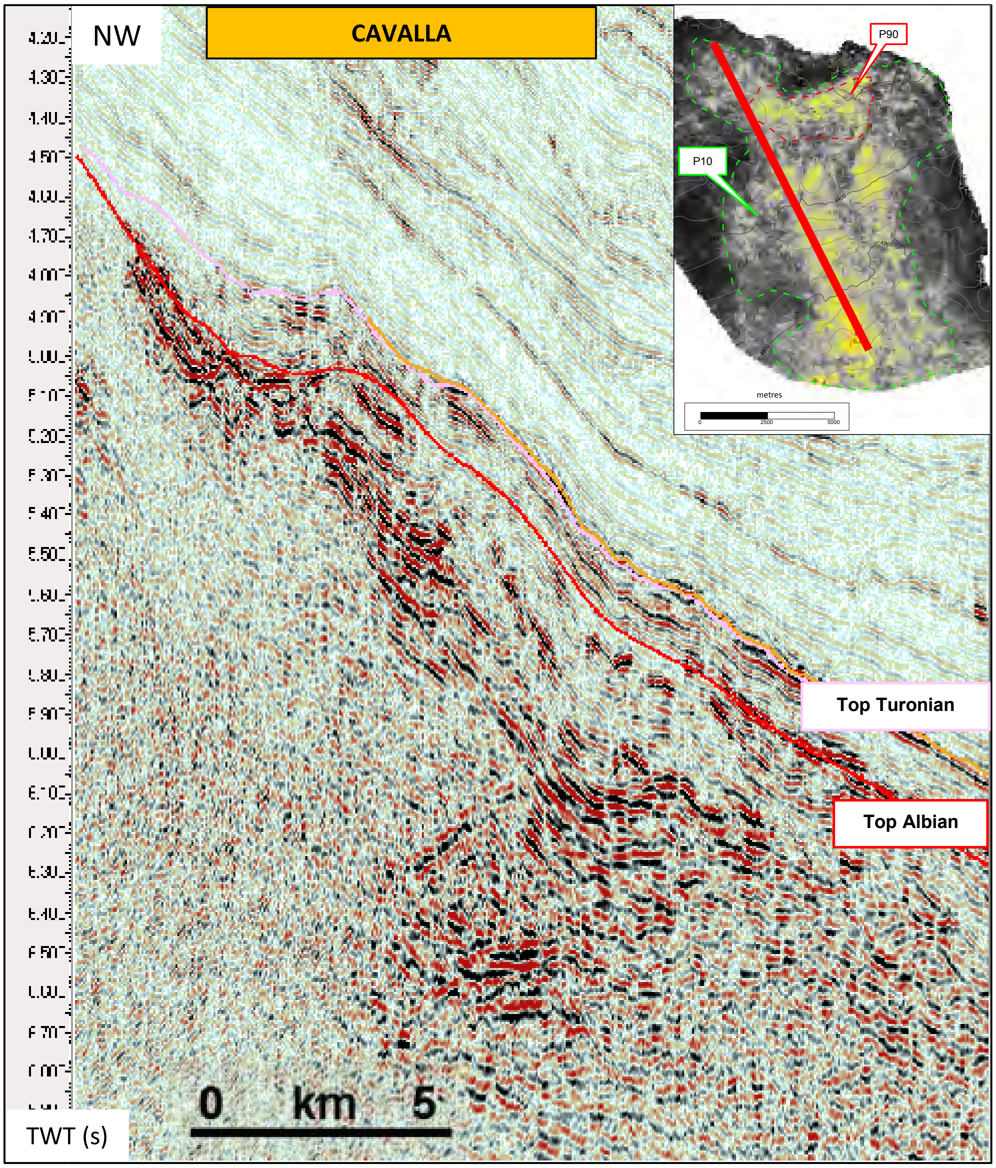


Figure 5-8 Dip seismic line, Cavalla prospect

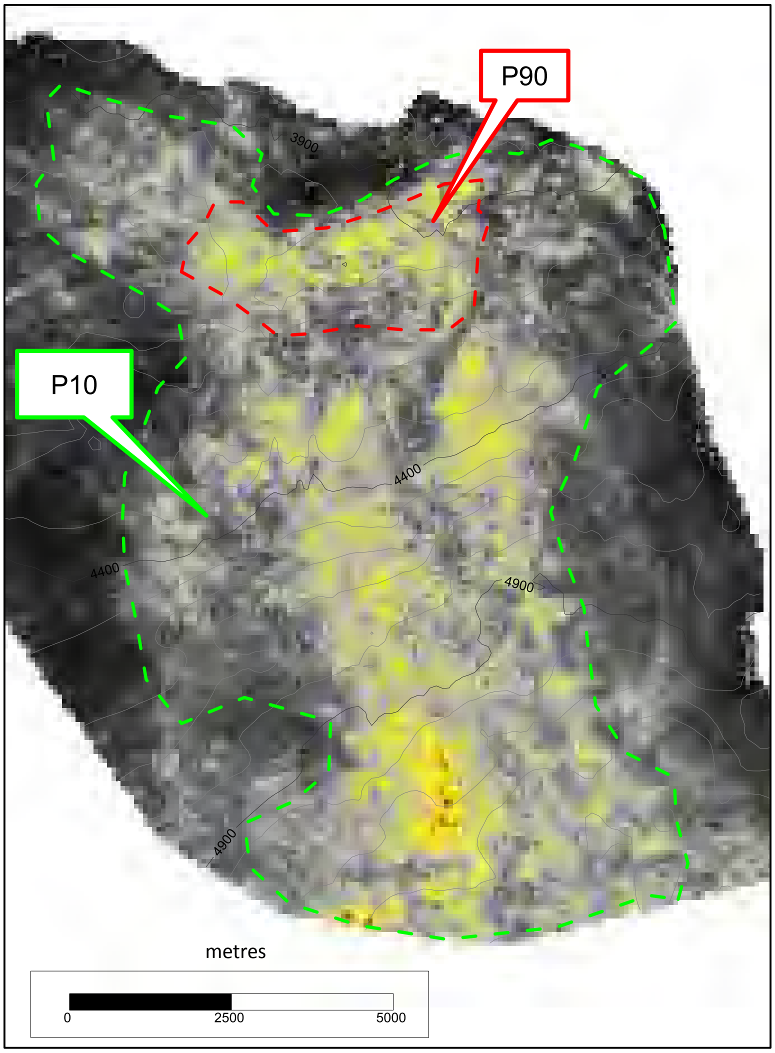


Figure 5-9 Seismic amplitude (gradient stack) and Top fan depth (m TVDSS), Cavalla prospect

5.5.4. Leraba

As with the other evaluated prospectivity within Blocks CI-509 and CI-513, the Leraba prospect is an Upper Cretaceous fan which lies within Block CI-509. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinch-out (Figure 5-10). The prospect has anomalous seismic amplitudes associated with it (Figure 5-11) which may indicate reservoir development. Unlike the other Cote D'Ivoire prospects evaluated in this report, no offset seismic volumes were available for our review of Leraba at the time of writing. The seismic amplitude response and character on the full-stack data is however consistent with that observed over other prospects in Block CI-513 where more seismic products were available.

The top structure is mapped between 4600 – 5200 ms TWT over the area of the prospect, and we estimate a depth at the crest of approximately 3700 m TVDSS beneath a water depth of 2500 m.

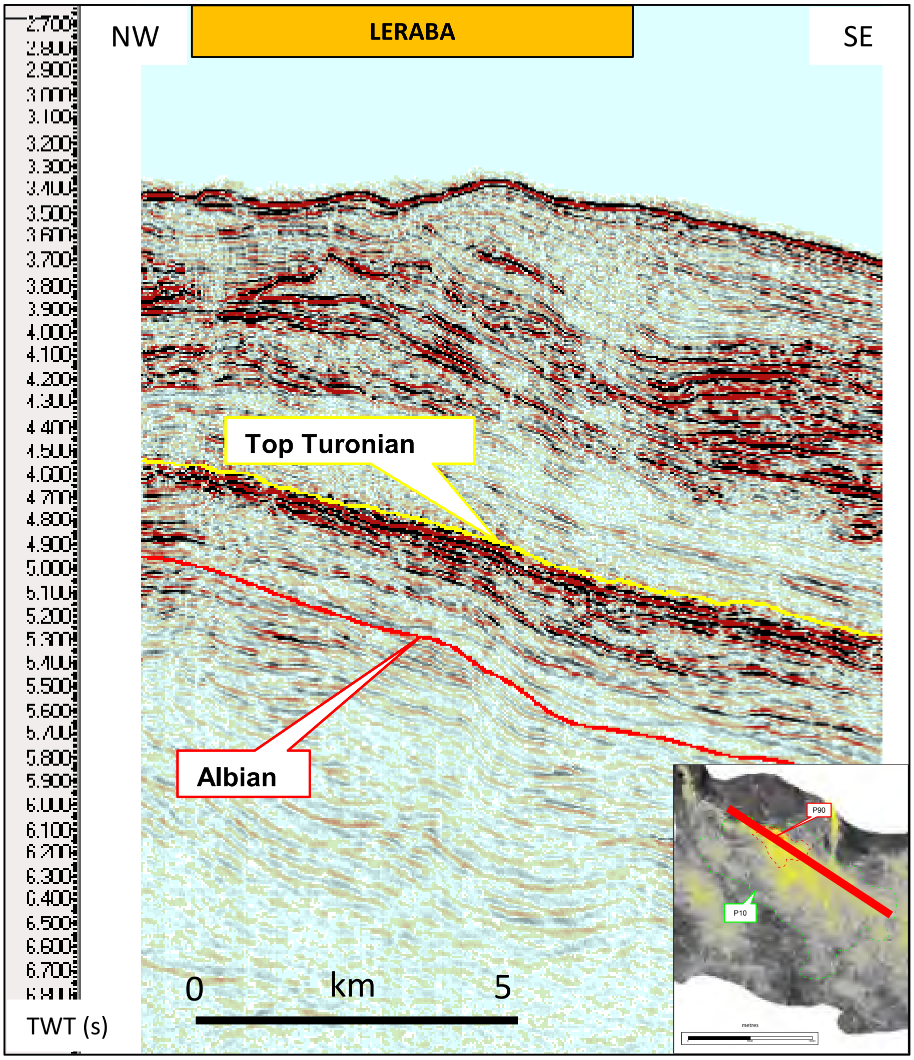


Figure 5-10 Dip seismic line, Leraba prospect

Evaluation of the Leraba prospect is undertaken in an identical manner to our evaluation of the other Cretaceous fan systems evaluated in this section. An area net approach is adopted using anomalous seismic amplitudes to constrain areal extent and define an areal net to gross to account for lateral variability of sand distribution within the closure area. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes and a 200 m column height. Our high case extends the prospect down-dip to 800 m of column height, to include a larger area of anomalous amplitudes (Figure 5-11). These polygons are used to constrain the P90 and P10 area inputs of our probabilistic simulation.

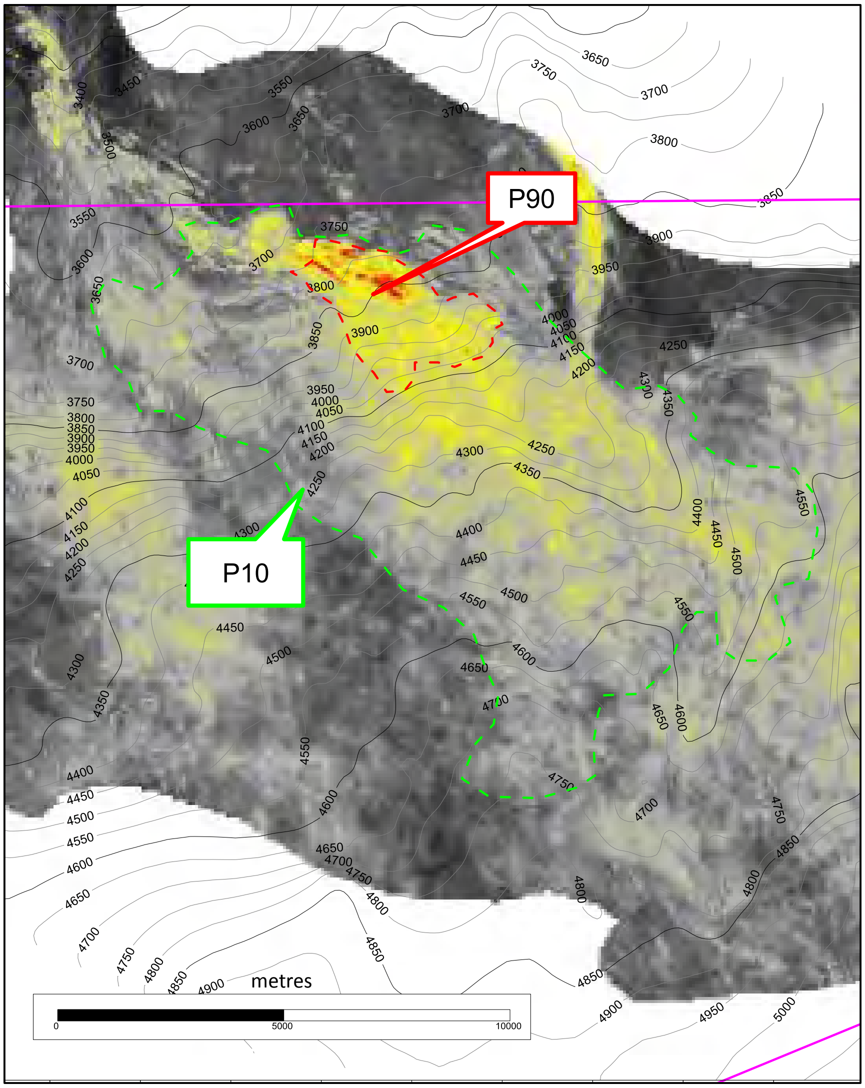


Figure 5-11: Seismic amplitudes, Leraba prospect, overlay of Top Reservoir m TVDSS

Net pay estimates are derived from mapped seismic interval thickness and from regional analogues with porosity, fluid parameters and recovery factors estimated as described in Section 1.6. The prospect is relatively shallow to mud line, and we have modelled a more viscous oil, as described in Section 1.6.

We use the prospect risk matrix presented in Section 1.6 to determine the geological chance of success for the Leraba prospect. Key risk is to trap, and we attribute a trap risk of 60%, as the up-dip extent of the prospect is fairly well defined on seismic data. Although no off-set 3D seismic data were available, the seismic evidence for reservoir presence is again comparable to that of Ayame West. Thus, we estimate a prospect specific chance of success for the Leraba prospect of 34%, which, when combined with the play risk, gives an overall chance of success for the Leraba prospect of 16%.

The Leraba prospect is contained entirely within APCL's licences.

6. Senegal: Prospectivity and Plays

Prospectivity identified within APCL’s Sengalese licences is seen as being similar to that identified offshore Gambia, (Figure 6-1), and a description of the regional petroleum systems and main play types expected is given in Section 3.

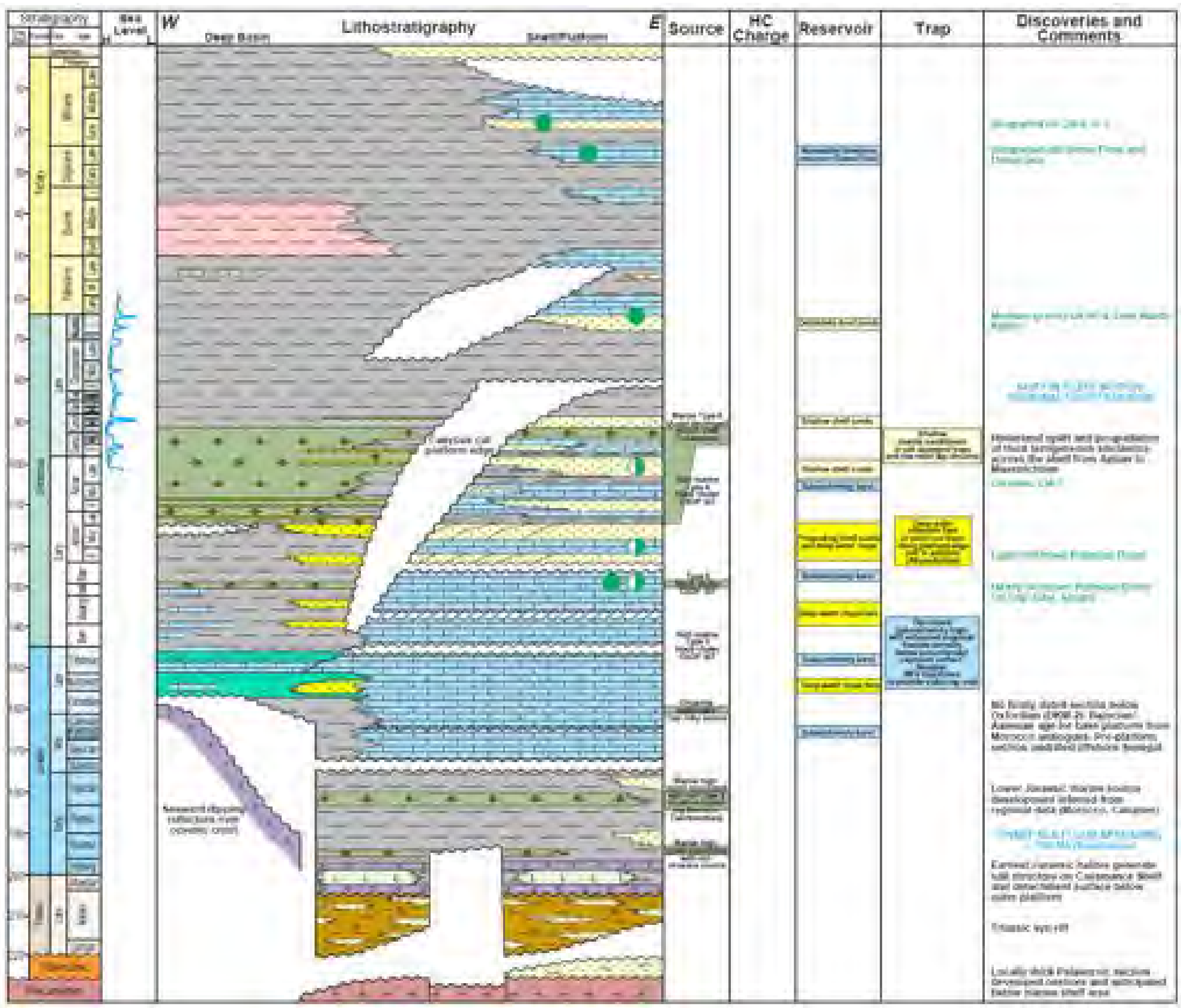


Figure 6-1 Petroleum systems and plays, offshore Senegal

In 2012, APCL acquired 3600 km^2 of multi-client 3D seismic data over the Offshore Sud Profond licence. In addition, 1500 km^2 of legacy 3D data over the Rufisque Offshore Profond licence is currently being reprocessed by APCL, and legacy 2D seismic data (c. 7000 line km) have also been acquired. APCL expects to begin prospect evaluation once seismic processing is complete, which is expected later in 2013. At present, a number of conceptual Cretaceous post-rift leads are identified by APCL (Figure 6-2).

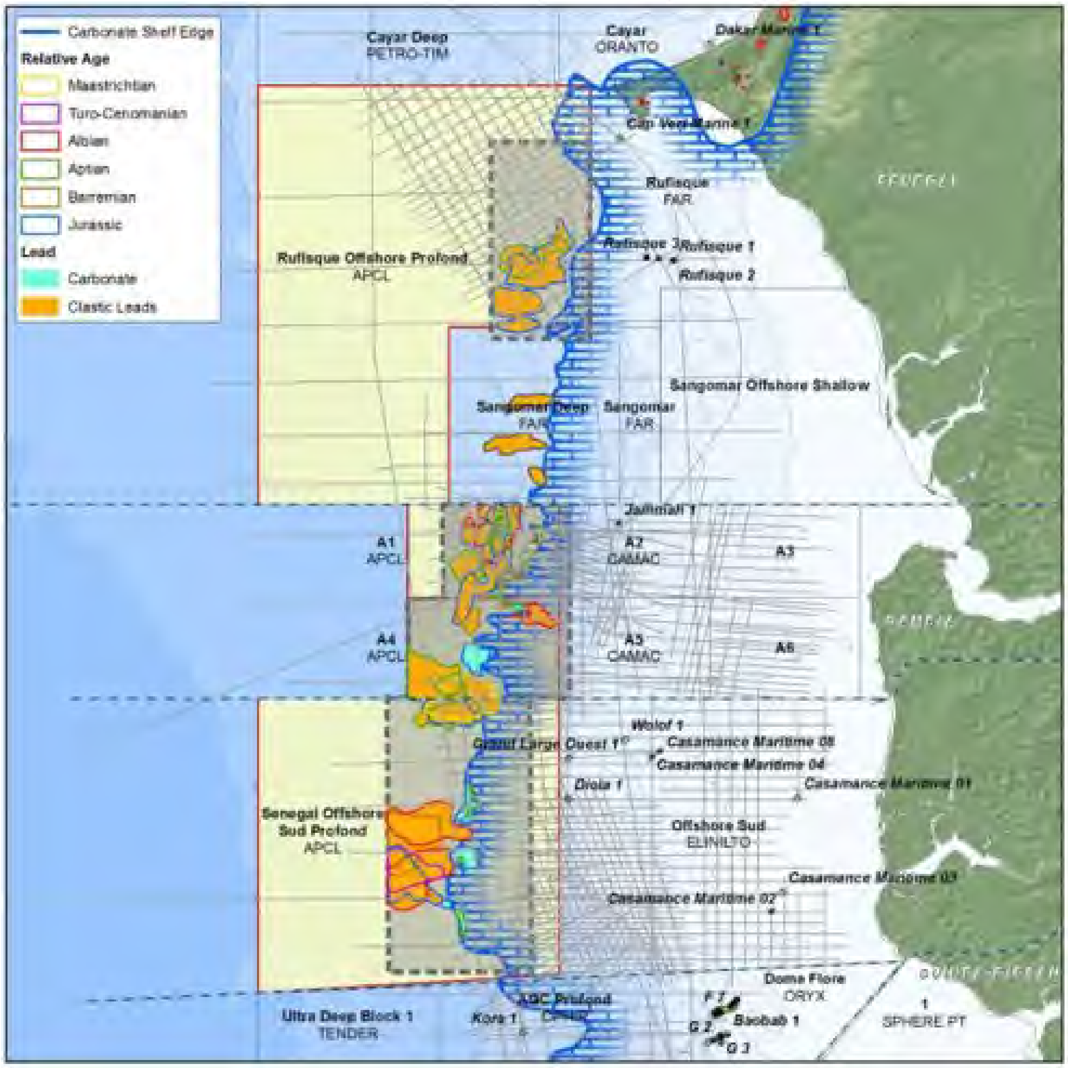


Figure 6-2 leads, offshore Senegal Blocks ROP and SOSP

7. Appendix 1: SPE PRMS Guidelines

SPE/WPC/AAPG/SPEE Petroleum Reserves and Resources Classification System and Definitions

The Petroleum Resources Management System

Preamble

Petroleum Resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum Resources managements system provides a consistent approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum Resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum Resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing Reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of Resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum Resources. It is expected that the SPE-PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, hereinafter referred to as the SPE-PRMS, can be viewed at

www.spe.org/specma/binary/files6859916Petroleum_Resources_Management_System_2007.pdf .

Overview and Summary of Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "Resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE Resources classification system. The system defines the major recoverable Resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

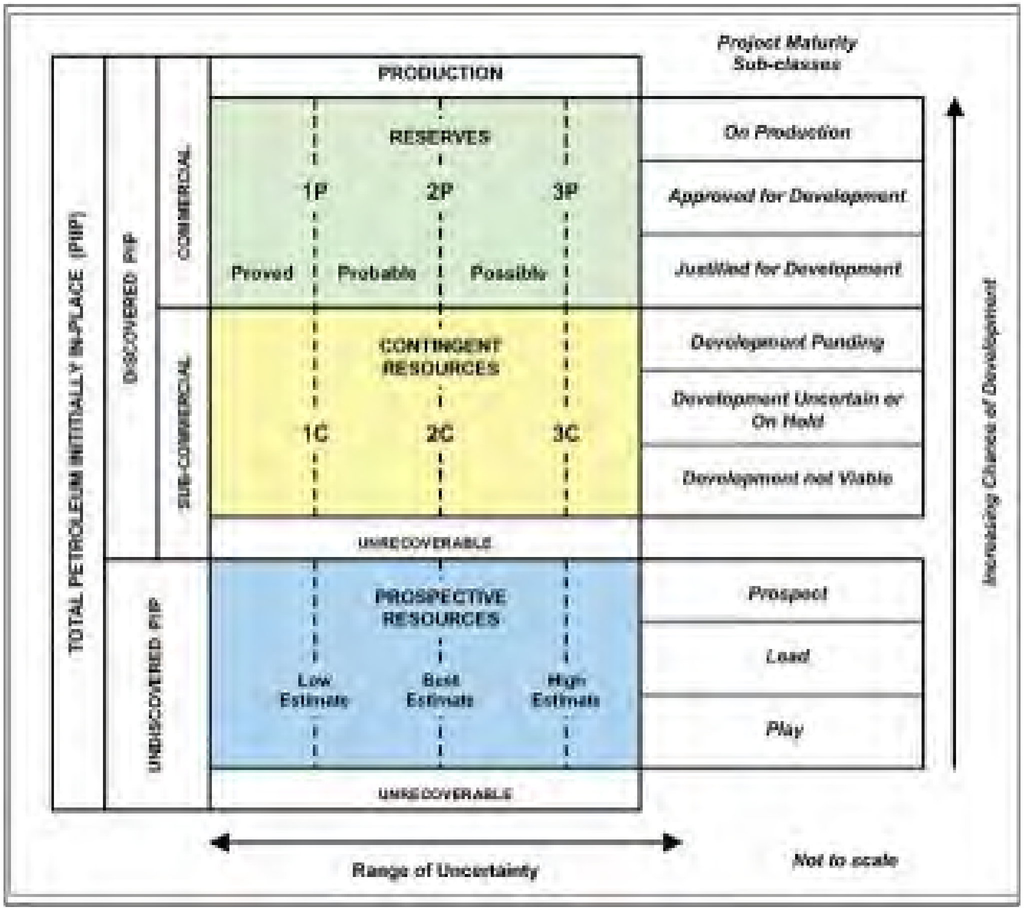


Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Development", that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the Resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE

Total Petroleum Initially in Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations.

It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total Resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE

Discovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

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. The area of the reservoir considered as Proved includes:

the area delineated by drilling and defined by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved Reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.

Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Contingent Resources are 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 may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE

Undiscovered Petroleum Initially in Place is that quantity of petroleum that is estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

• There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

• There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

• There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete Resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

8. Appendix 2: Nomenclature

8.1. Units

°C	degrees Celsius
°F	degrees Fahrenheit
bbl	barrel
cp	centipoises
ft	feet
ftMDRKB	feet below Kelly Bushing
ftTVDSS	feet subsea
km	kilometres
m	metres
M or MM	thousands and millions respectively
m/s	metres per second
md	millidarcy
mTVDSS	metres subsea
psia	pounds per square inch absolute
psig	pounds per square inch gauge
pu	porosity unit
rb	reservoir barrels
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit

8.2. Reserves and Resources Classifications

Low	Low estimate of Prospective Resources, as defined in SPE PRMS 2007
Best	Best estimate of Prospective Resources, as defined in SPE PRMS 2007
High	High estimate of Prospective Resources, as defined in SPE PRMS 2007
COS	Geological Chance of Success associated with Prospective Resources
P10	10 per cent probability = Proved + Probable + Possible, or 3P
P50	50 per cent probability = Proved + Probable, or 2P
P90	90 per cent probability = Proved, or 1P

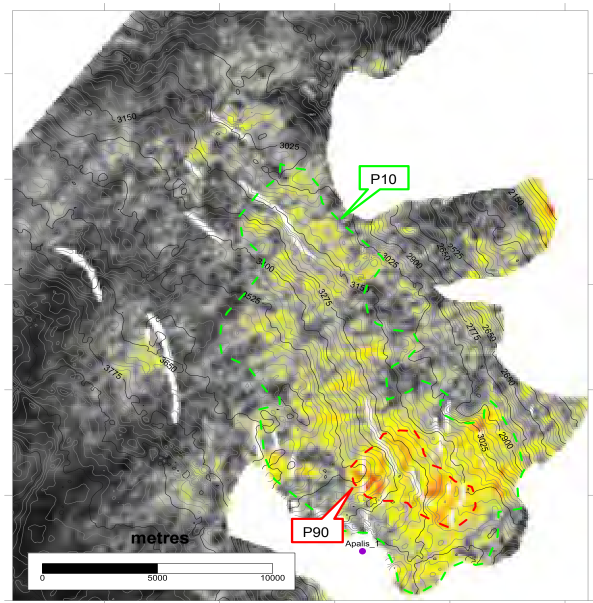
8.3. Abbreviations

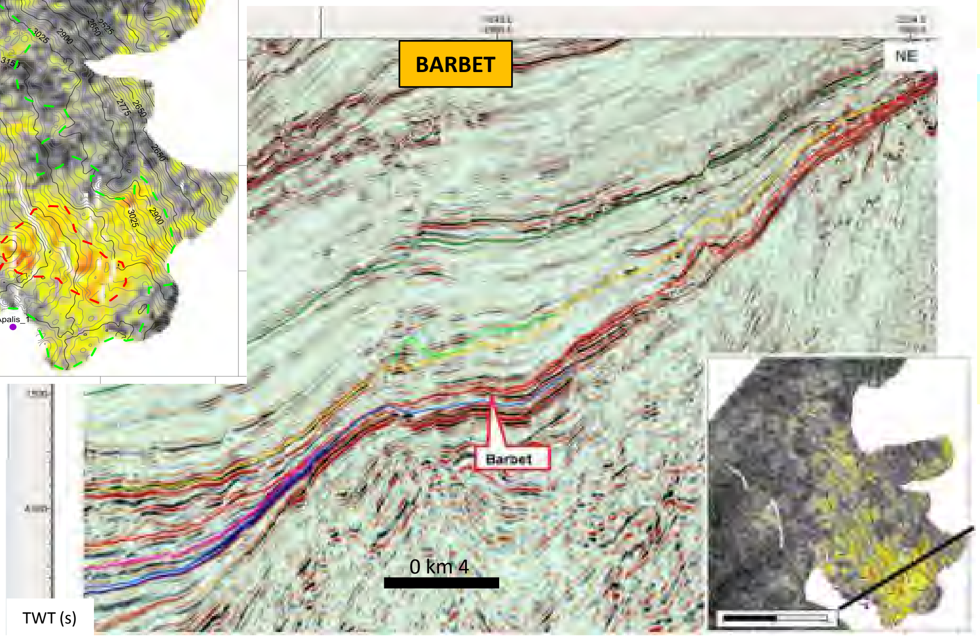
AvO	amplitude variation with offset
Bo	oil shrinkage factor or formation volume factor, in rb/stb

CPI	computer processed information log
FVF	formation volume factor
FWL	free water level
GRV	gross rock volume
GWC	gas water contact
KB	kelly bushing
kh	permeability thickness
MD	measured depth
MSL	mean sea level
N/G	net to gross ratio
OWC	oil water contact
Phi	porosity
PSC	production sharing contract
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
RFT	repeat formation tester
So	oil saturation
Soi	initial oil saturation
SS	Subsea
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TD	total depth
TOC	total organic carbon
TVD	true vertical depth
TWT	two way time
Vsh	shale volume

Enclosures: Resource Summary Sheets

Enclosure 1.1: Summary Description Sheet: Barbet Prospect





Summary	
Block	9
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	3000
Water depth (m)	750

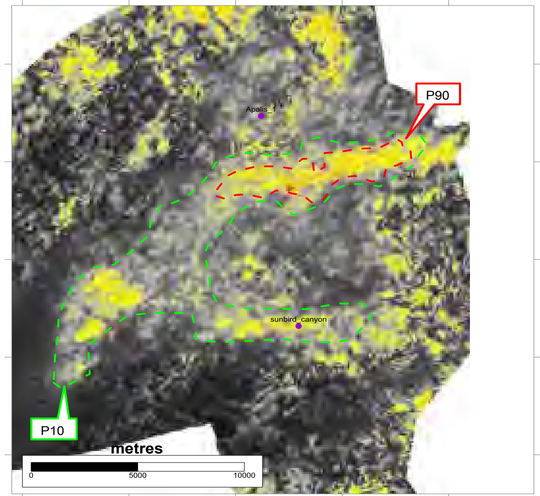
Notes

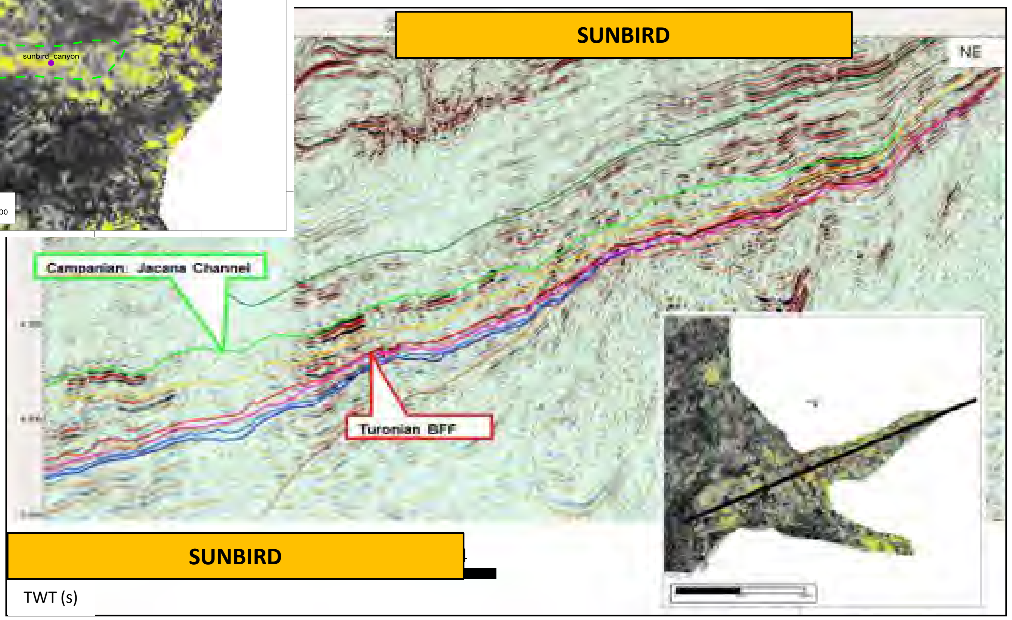
Stratigraphic trap with amplitude support.

Geological Risk Matrix	
Charge	90%
Reservoir	70%
Trap	50%
Seal	70%
COS	22%

	Area (km^2)	Shape F. (frac)	Areal N/G (%)	Net Thick. (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	14	0.85	62	22	13	73	1.35	166	0.300	60
Best	37	0.90	80	34	17	80	1.50	500	0.375	186
High	98	0.95	98	53	20	88	1.65	1,479	0.450	558
Deterministic inputs, probabilistic STOIIP and Rec Resource									**Mean**	270

Enclosure 1.2: Summary Description Sheet: Sunbird Prospect, Campanian Reservoir





Summary	
Block	8 & 9
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	3000
Water depth (m)	1300

Notes

Stratigraphic trap with amplitude support. Split by intra-canyon high.

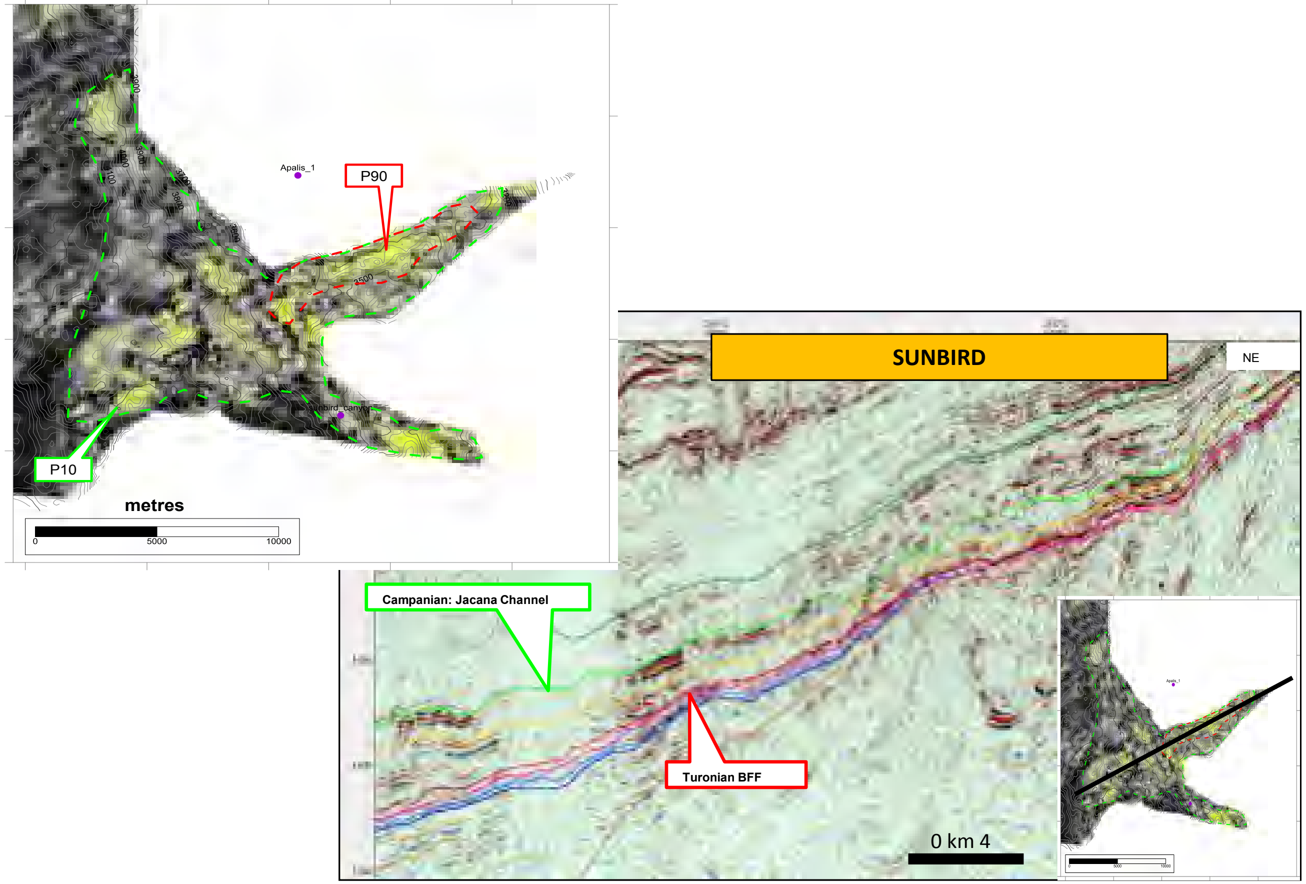
Geological Risk Matrix	
Charge	80%
Reservoir	80%
Trap	60%
Seal	70%
COS	27%

	Area (km^2)	Shape F. (frac)	Areal N/G (%)	Net Thick. (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	12	0.70	43	27	18	73	1.30	177	0.300	63
Best	27	0.80	69	42	21	80	1.45	461	0.375	172
High	61	0.90	95	66	24	88	1.65	1,187	0.450	448
									Mean	229

Deterministic inputs, probabilistic STOIIP and Rec Resource

Enclosure 1.3: Summary Description Sheet: Sunbird prospect, Turonian Reservoir

ERC equipoise



Summary	
Block	8 & 9
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	3300
Water depth (m)	1300

Notes

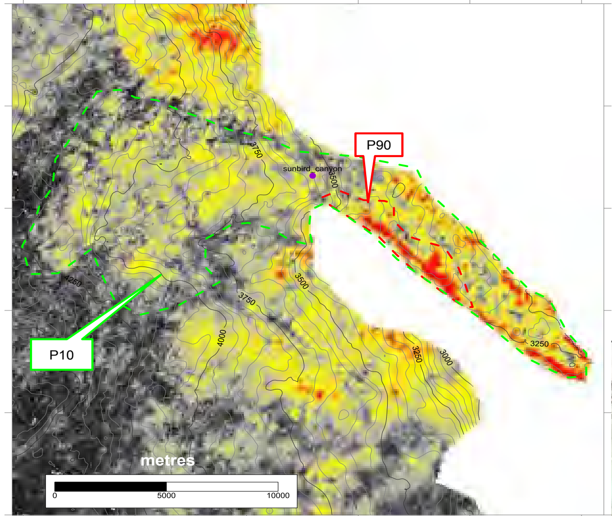
Stratigraphic trap with amplitude support. Split by intra-canyon high.

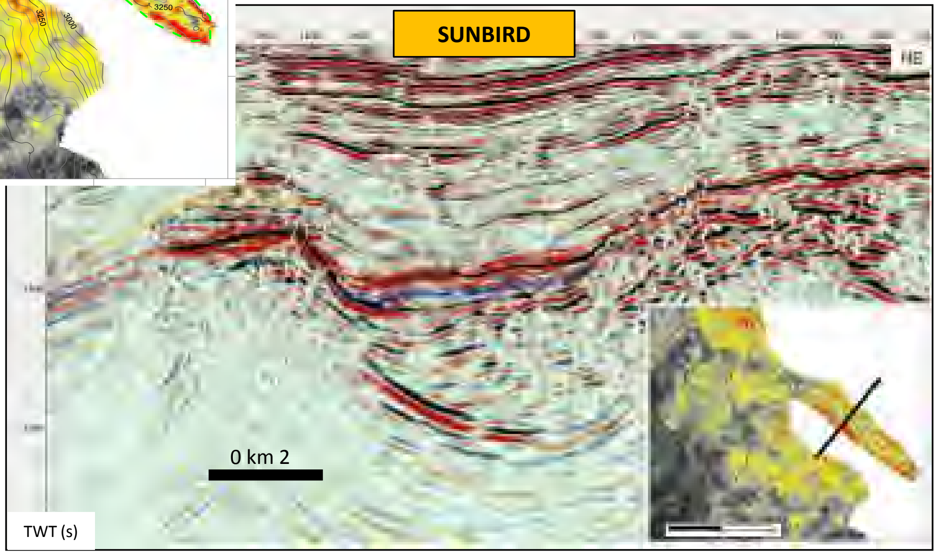
Geological Risk Matrix	
Charge	90%
Reservoir	60%
Trap	50%
Seal	70%
COS	19%

	Area (km^2)	Shape F. (frac)	Areal N/G (%)	Net Thick. (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	8	0.85	65	24	14	73	1.40	107	0.300	39
Best	21	0.90	80	37	17	80	1.58	307	0.375	115
High	53	0.95	94	58	20	88	1.75	863	0.450	327
									Mean	162

Deterministic inputs, probabilistic STOIIP and Rec Resource

Enclosure 1.4: Summary Description Sheet: Sunbird Prospect, Cenomanian Reservoir





Summary	
Block	8 & 9
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	3500
Water depth (m)	1300

Notes

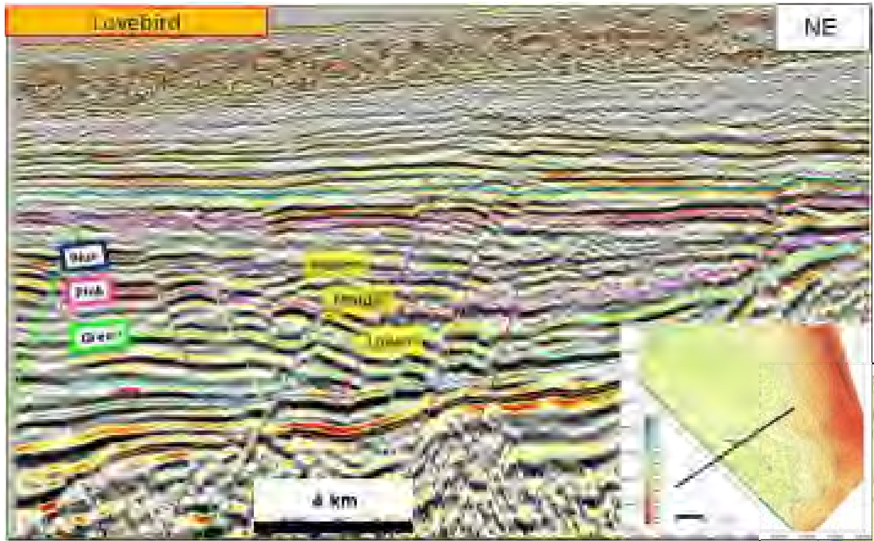
Stratigraphic trap with amplitude support. Split by intra-canyon high.

Geological Risk Matrix	
Charge	100%
Reservoir	50%
Trap	60%
Seal	60%
COS	18%

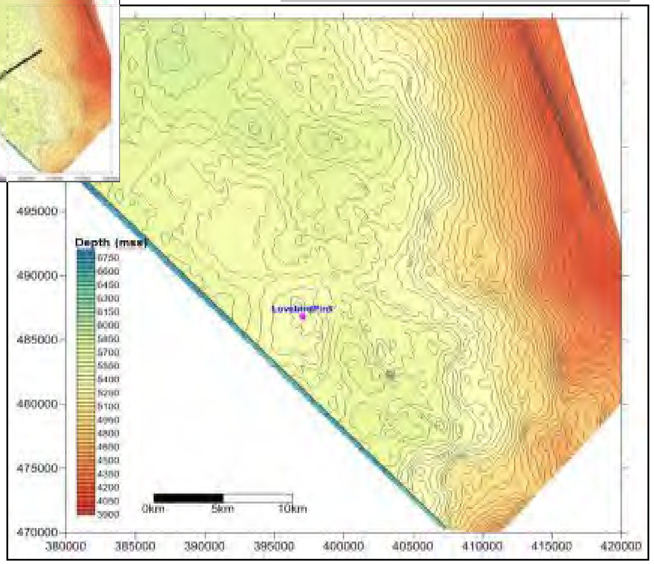
	Area (km^2)	Shape F. (frac)	Areal N/G (%)	Net Thick. (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	10	0.60	71	21	14	73	1.40	91	0.300	33
Best	25	0.70	85	33	17	80	1.58	264	0.375	99
High	65	0.80	99	51	20	88	1.75	779	0.450	294
									Mean	141

Deterministic inputs, probabilistic STOIIP and Rec Resource

Enclosure 1.5: Summary Description Sheet: Lovebird Prospect, Blue Horizon



High Case Pink Depth Map



Summary	
Block	8
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	5000
Water depth (m)	2850

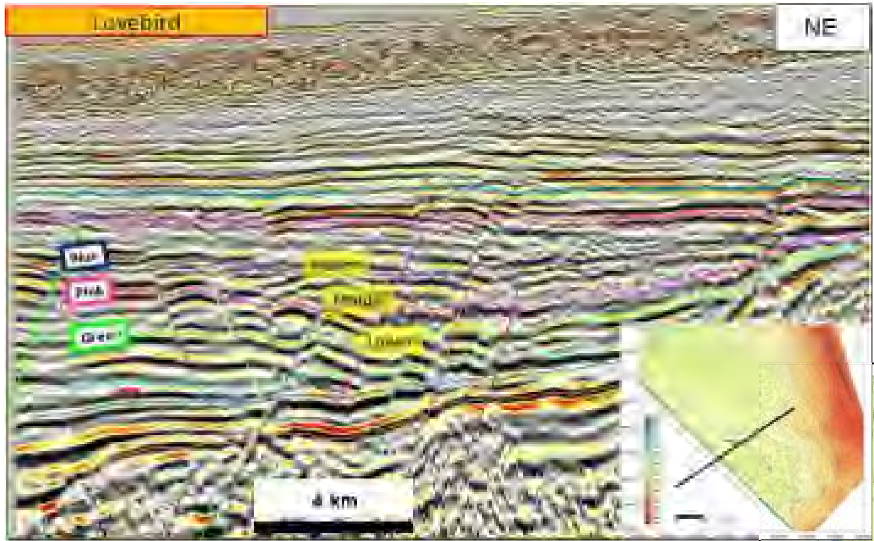
Notes

Four way dip closure to south of Block 8. Three potential reservoirs identified. Blue and Green horizon volumetrics derived assuming ispoachous to Pink.

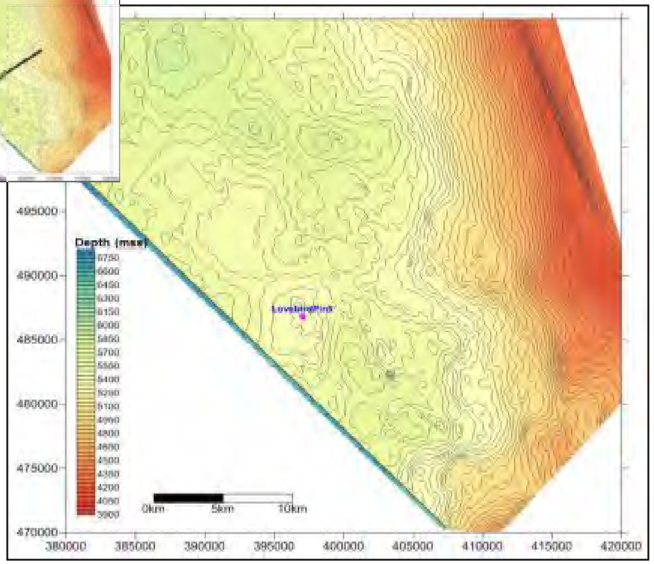
Geological Risks	
Charge	54%
Reservoir	60%
Trap	70%
Seal	90%
COS	**20%**

	GRV (MMm^2)	N/G (%)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	354	30	14	60	1.50	68	0.30	25
Best	1310	54	19	70	1.80	293	0.38	109
High	4849	73	24	80	2.10	1,218	0.45	456
							Mean	201

Enclosure 1.6: Summary Description Sheet: Lovebird Prospect, Pink Horizon



High Case Pink Depth Map



Summary	
Block	8
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	5400
Water depth (m)	2850

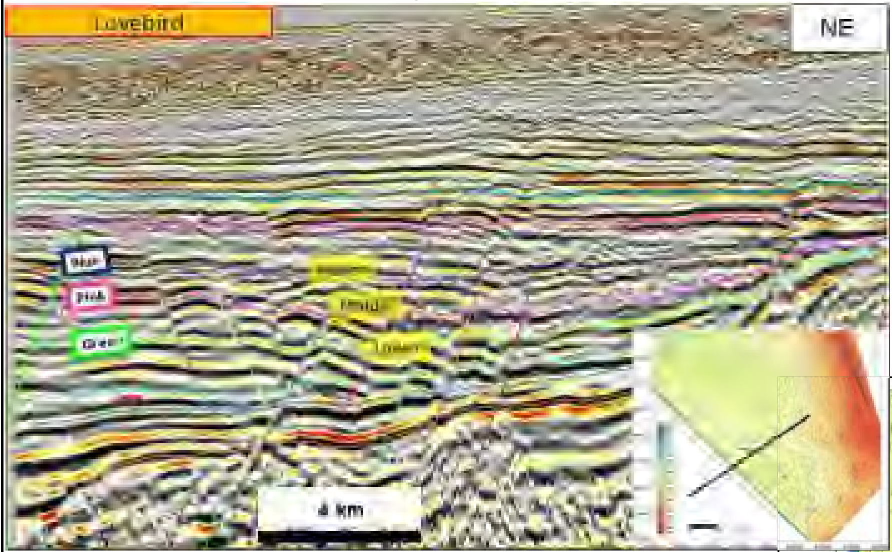
Notes

Four way dip closure to south of Block 8. Three potential reservoirs identified. Blue and Green horizon volumetrics derived assuming ispoachous to Pink.

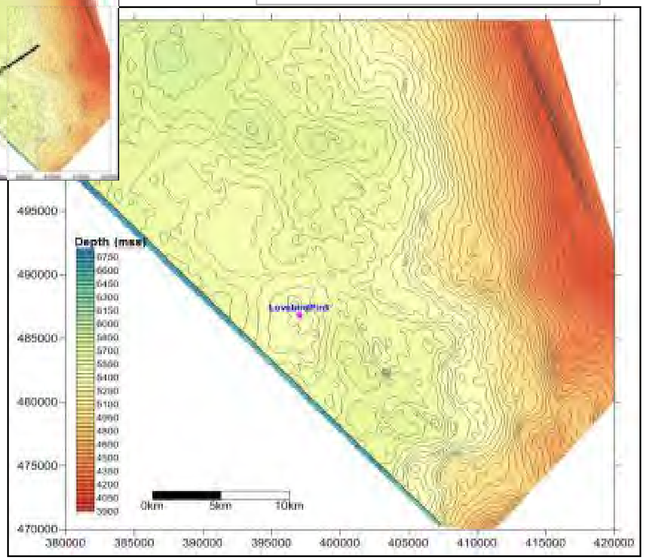
Geological Risks	
Charge	54%
Reservoir	60%
Trap	70%
Seal	90%
COS	**20%**

	GRV (MMm^2)	N/G (%)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	354	30	12	60	1.55	59	0.30	22
Best	1310	54	17	70	1.88	262	0.38	96
High	4849	73	22	80	2.20	1,066	0.45	400
							Mean	178

Enclosure 1.7: Summary Description Sheet: Lovebird Prospect, Green Horizon



High Case Pink Depth Map



Summary	
Block	8
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	5800
Water depth (m)	2850

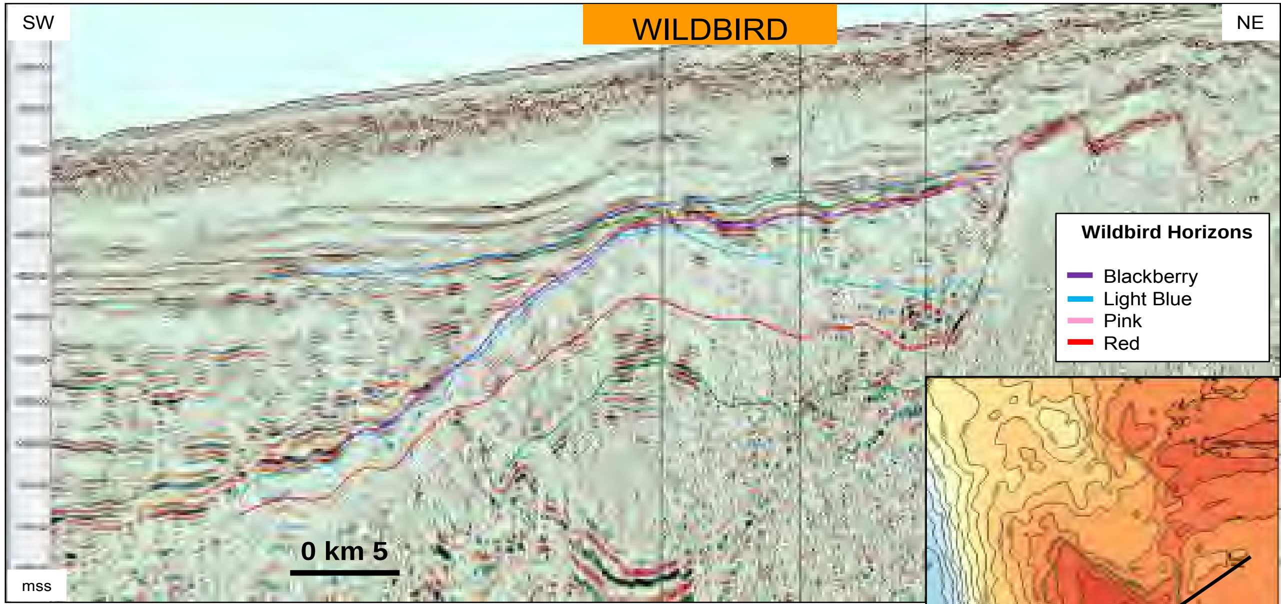
Notes

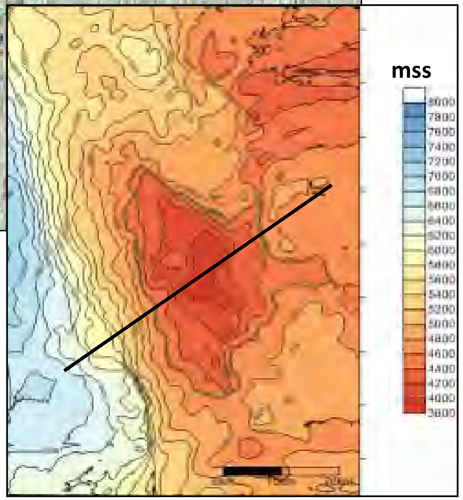
Four way dip closure to south of Block 8. Three potential reservoirs identified. Blue and Green horizon volumetrics derived assuming ispoachous to Pink.

Geological Risks	
Charge	54%
Reservoir	60%
Trap	70%
Seal	90%
COS	**20%**

	GRV (MMm^2)	N/G (%)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	354	30	10	60	1.60	48	0.30	18
Best	1310	54	15	70	1.95	210	0.38	78
High	4849	73	20	80	2.30	896	0.45	337
							Mean	150

Enclosure 1.8: Summary Description Sheet: Wildbird Prospect





Summary	
Block	8
APC Interest (%)	100
Fluid	Oil
Crest (m ss)	4000
Water depth (m)	2250 m

Notes

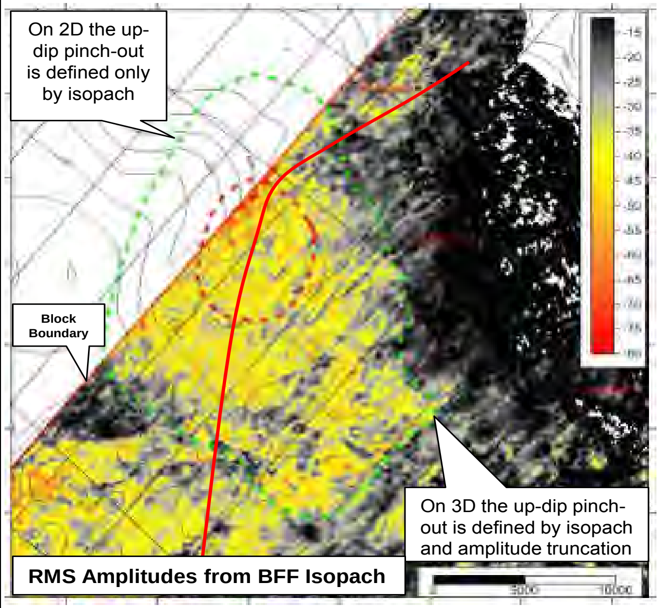
Four way dip closed high.

Play Risk		Prospect Risk	
Source	80%	Trap	60%
Seal	60%	Charge	90%
Reservoir Pres.	50%	Reservoir Eff.	70%
	24%		38%
COS		9%	

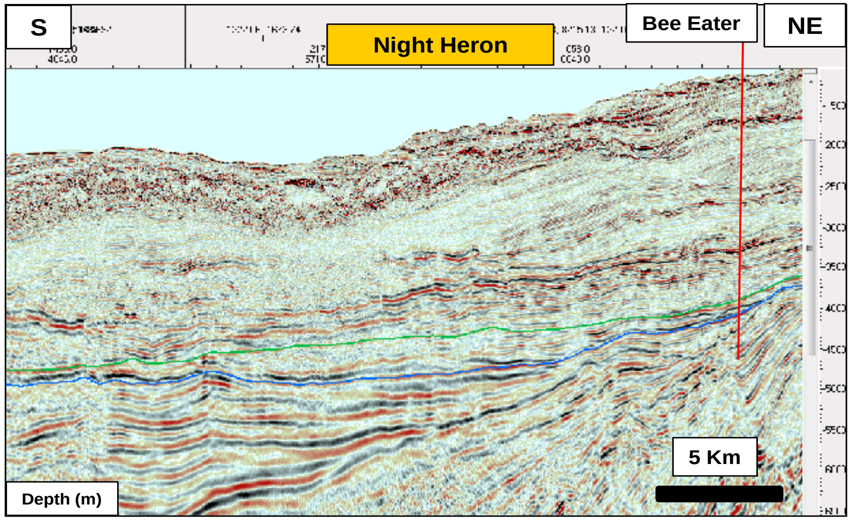
	GRV (MMm^2)	N/G (%)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	5,007	20	10	50	1.45	552	0.20	144
Best	15,839	40	16	63	1.65	2,289	0.26	605
High	50,102	60	25	80	1.85	8,700	0.35	2,377
Deterministic inputs, probabilistic STOIIP and Rec Resource							**Mean**	1,065

Enclosure 1.9: Summary Description Sheet: Night Heron Prospect

PSDM 'SNA' Extraction



Seismic Line



Arbitrary line across Night Heron, PSDM (Depth m)

Summary

Block	9 & 10
APCL Interest (%)	100% of Block 9
Fluid	Oil
Crest (m ss)	4200
Water depth (m)	1750

Notes

Night Heron is a Turonian basin floor fan system which mainly lies within block 9, offshore Liberia. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinchout. An area net approach was adopted using the full stack PSDM depth image volume to provide SNA extraction and constrain areal extent and estimate an areal N/G to account for lateral variability within the reservoir. Night Heron falls partly off block. ERCE correct for this using the ratio of on-block to off-block area in reporting of net unrisked and net risked results.

Prospect Risk	
Charge	90%
Reservoir	50%
Trap	40%
Seal	80%
COS	**14.4%**

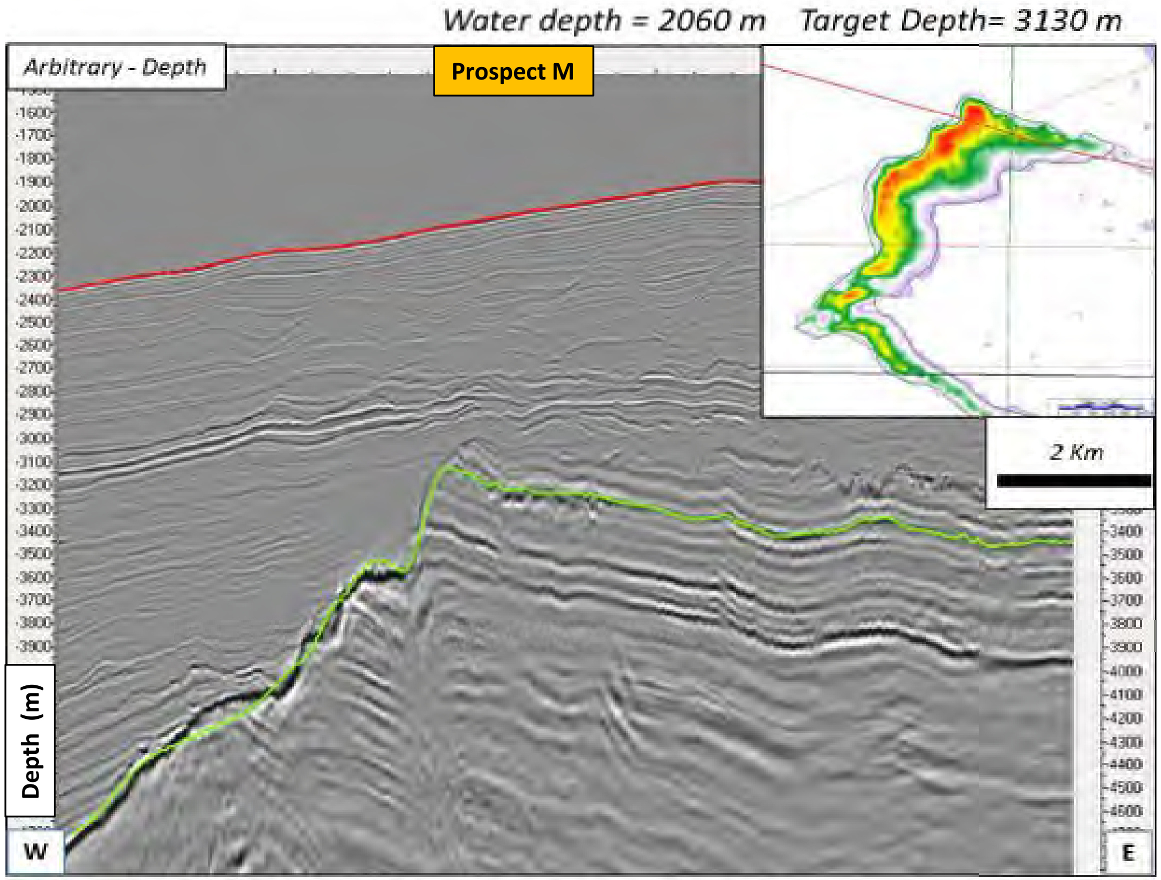
	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	20	0.70	20	13	73	1.80	254	0.300	92
Best	73	0.85	38	16	80	1.58	1117	0.375	416
High	263	0.99	55	19	88	1.40	4603	0.450	1742
								Mean	**759**

Deterministic inputs, probabilistic STOIIP and Rec Resource

Enclosure 2.1: Summary Description Sheet

ERC equipoise

Top Structure Map | Seismic Line



Summary - M - Cret	
Block	A1
Working Interest (%)	60
Fluid	Oil
Crest (m)	3130 (1070 bml)
Water depth (m)	2220

Notes

Structural high along edge of buried carbonate platform margin of probable Lower Cretaceous and Jurassic age. Seismic evidence favourable for reservoir development. Lower Bo model used to reflect relatively shallow nature of prospect. The prospect is close to the shelf margin and so is well placed for charging. The strong rugose seismic events are interpreted as Karstified Limestones.

Play Risk		Prospect Risk	
Source	70%	Trap	54%
Seal	50%	Mig	80%
Res. Pres	80%	Res Eff	80%
	28%		35%
COS	10%		

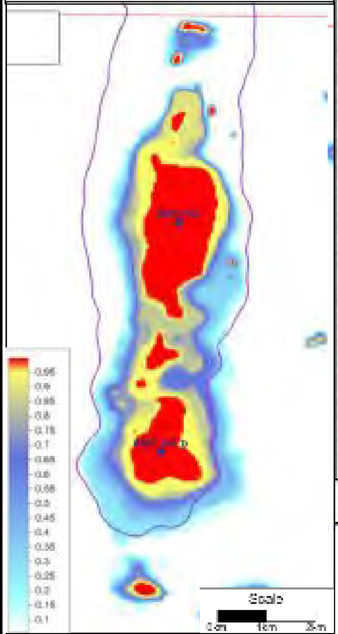
	Area (Km2)	Stack F. (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	8	1	15	10	55	1.25	82	0.10	13
Best	14	1	30	16	65	1.17	231	0.23	43
High	26	1	60	22	75	1.10	629	0.35	141
Deterministic inputs, probabilistic STOIIP and Rec Resource								**Mean**	66

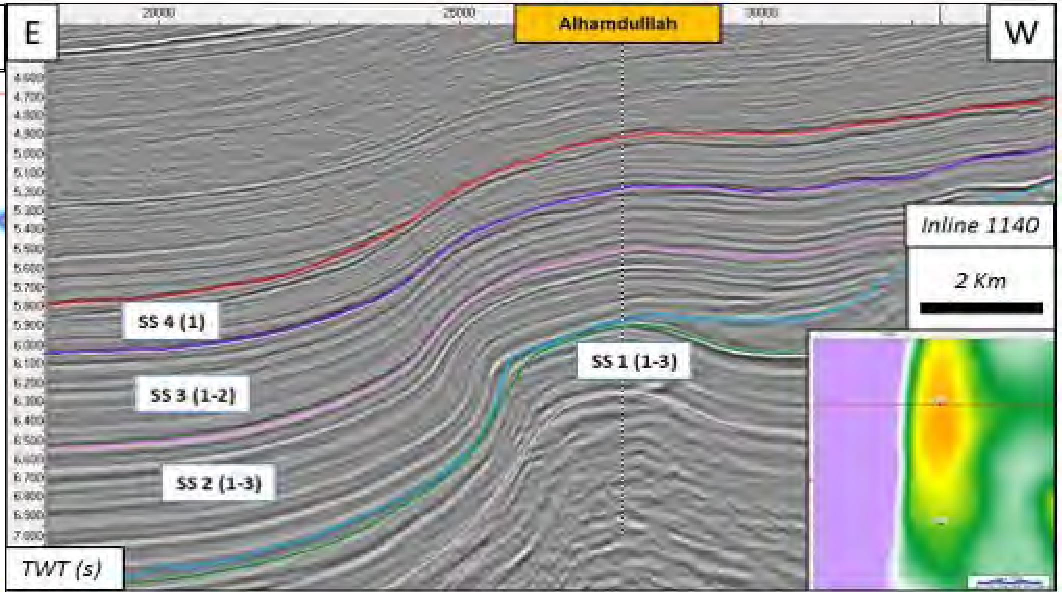
Enclosure 2.2: Summary Description Sheet

Top Structure Map

Seismic Line

2010 Migration Velocity Data – SS-4: Probability Above Spill





Summary - SS - 4	
Block	A1
Working Interest (%)	60
Fluid	Oil
Crest (m)	4230 (2010 bml)
Water depth (m)	2220

Notes

Four way dip closed anticlinal structure. The SS-4 interval has a gross thickness over the crest area of 360 m. Downlap of seismic events across the crest of the SS-4 structure slightly downgrades SS-4 seal. The interval is believed to be Cenomanian in age and the seismic character of generally planar events is interpreted as representing thin bedded turbidites.

Play Risk		Prospect Risk	
Source	70%	Trap	80%
Seal	90%	Mig	85%
Res. Pres	80%	Res Eff	50%
	50%		34%
COS	17%		

	Area (Km2)	Stack F. (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	6	1	10	16	68	2.20	43	0.30	16
Best	11	1	19	20	75	1.67	113	0.38	42
High	21	1	35	24	83	1.35	295	0.45	112
								Mean	56

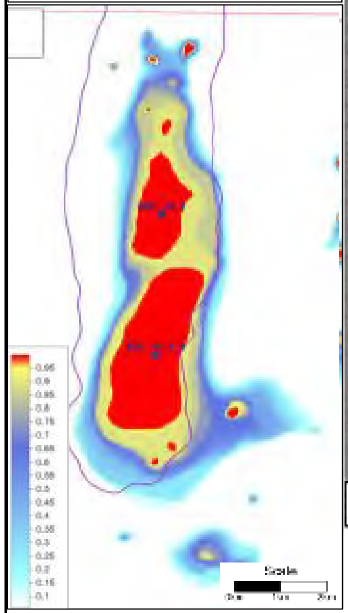
Deterministic inputs, probabilistic STOIIP and Rec Resource

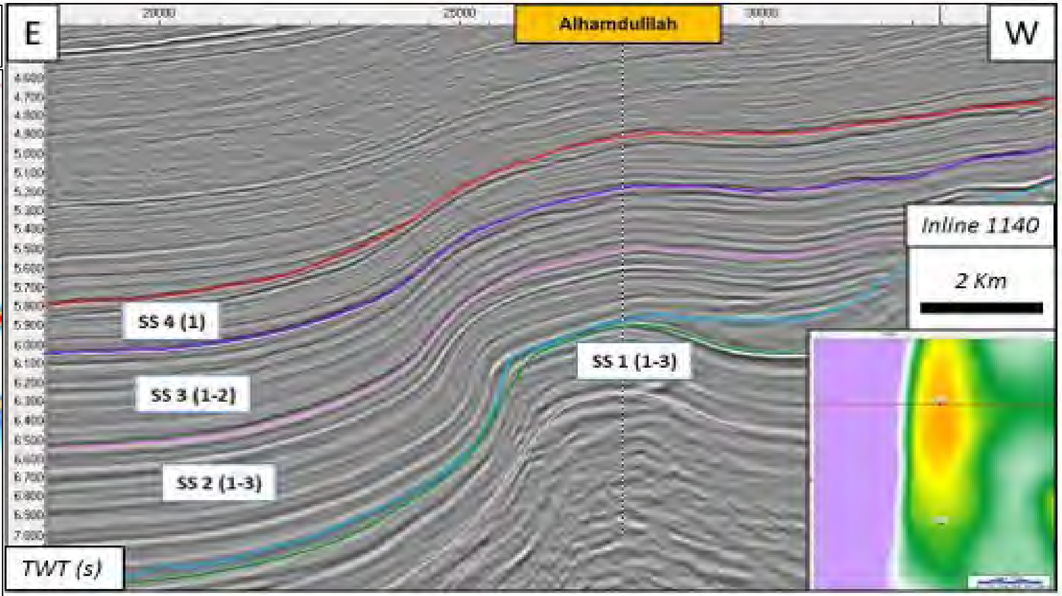
Enclosure 2.3: Summary Description Sheet

Top Structure Map

Seismic Line

2010 Migration Velocity Data – SS-3: Probability Above Spill





Summary - SS - 3	
Block	A1
Working Interest (%)	60
Fluid	Oil
Crest (m)	4590 (2370 bml)
Water depth (m)	2220

Notes

Four way dip closed anticlinal structure. The SS-3 interval has a gross thickness over the crest area of 550 m. Seals to deeper reservoirs may be eroded by overlying reservoirs. From seismic, the prospective reservoir has been interpreted as being an Albian deep water channel-lobe complex.

Play Risk		Prospect Risk	
Source	70%	Trap	75%
Seal	90%	Mig	85%
Res. Pres	80%	Res Eff	50%
	50%		32%
COS		16%	

	Area (Km2)	Stack F. (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	12	1	20	15	68	2.27	197	0.25	63
Best	17	1.5	35	18	75	1.73	417	0.34	143
High	25	2	60	20	83	1.40	881	0.45	316
Deterministic inputs, probabilistic STOIIP and Rec Resource								**Mean**	173

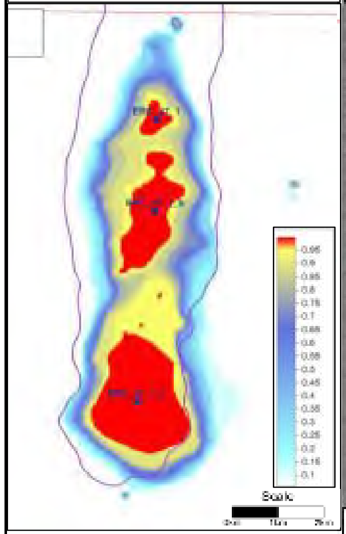
ERC equipoise

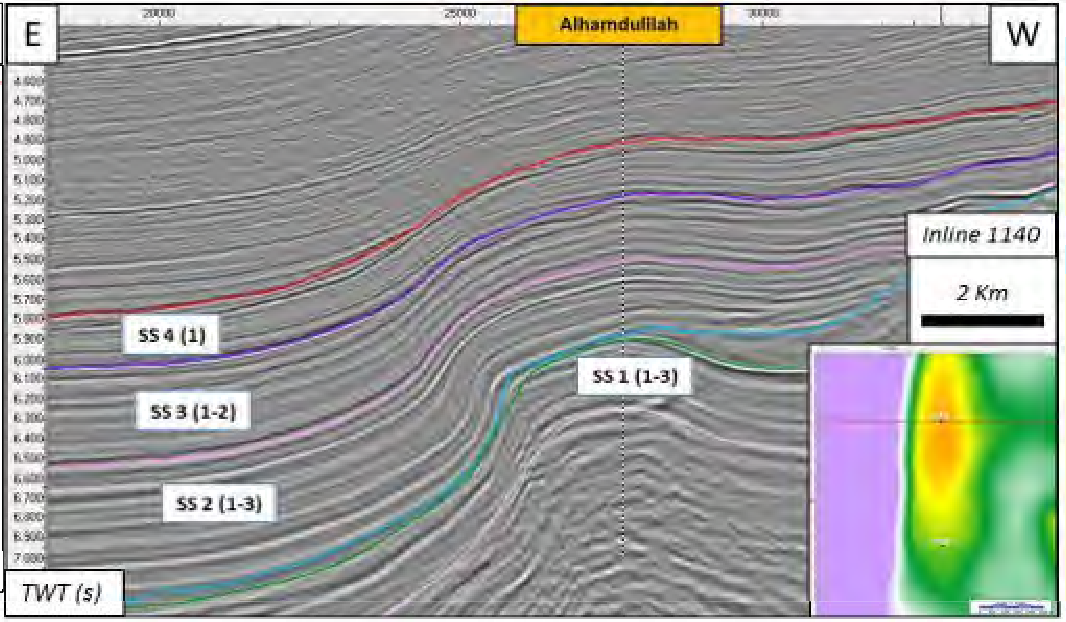
Enclosure 2.4: Summary Description Sheet

Top Structure Map

Seismic Line

2010 Migration Velocity Data – SS-2: Probability Above Spill





Summary - SS - 2	
Block	A1
Working Interest (%)	60
Fluid	Oil
Crest (m)	5140 (2920 bml)
Water depth (m)	2220

Notes

Four way dip closed anticlinal structure. The SS-2 interval has a gross thickness over the crest area of 830 m. The prospective reservoir has been interpreted as a stacked series of channel/lobe sets. Seals to deeper reservoirs may be eroded by overlying reservoirs.

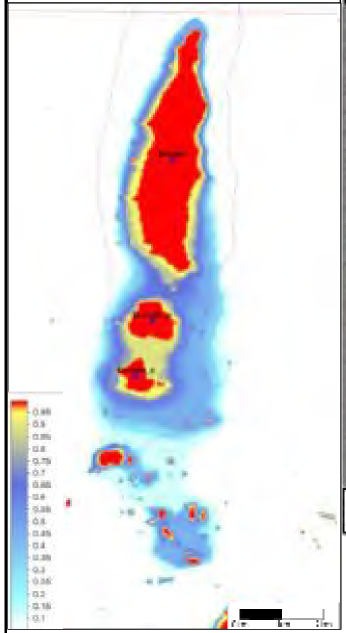
Play Risk		Prospect Risk	
Source	70%	Trap	75%
Seal	90%	Mig	85%
Res. Pres	80%	Res Eff	50%
	50%		32%
COS		16%	

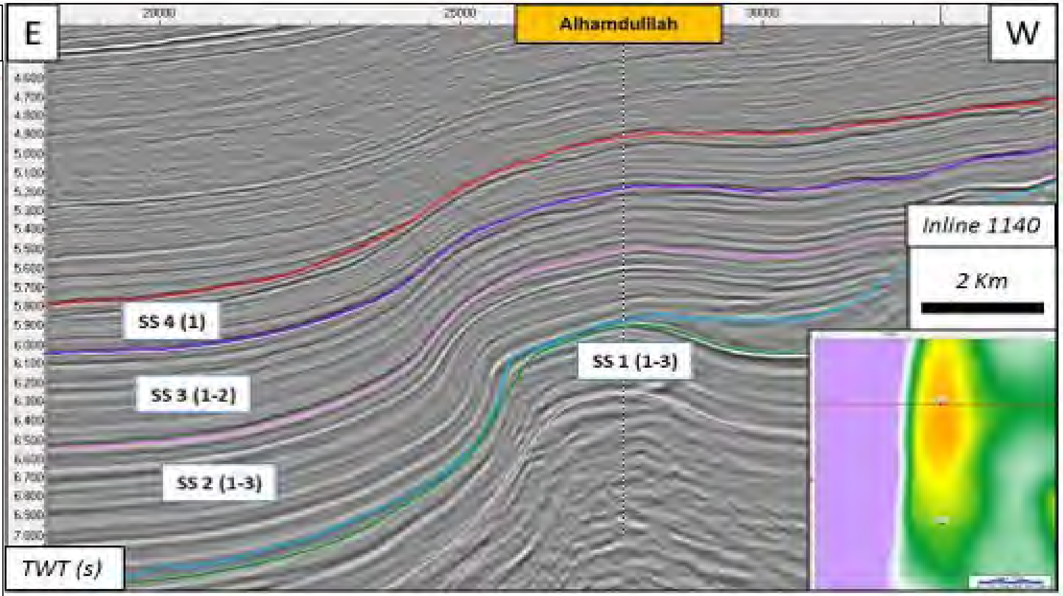
	Area (Km2)	Stack F. (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	12	1	20	11	68	2.31	187	0.25	58
Best	17	2	35	14	75	1.83	416	0.32	133
High	25	3	60	17	83	1.51	911	0.40	303
Deterministic inputs, probabilistic STOIIP and Rec Resource								**Mean**	163

Enclosure 2.5: Summary Description Sheet

Top Structure Map	Seismic Line

2010 Migration Velocity Data – SS-1: Probability Above Spill





Summary - SS - 1	
Block	A1
Working Interest (%)	60
Fluid	Oil
Crest (m)	5970 (3750 bml)
Water depth (m)	2220

Notes

Four way dip closed anticlinal structure.The SS-1 interval has a gross thickness over the crest area of 890 m. The prospective reservoir lies under an unconformity and is believed to be Jurassic in age, its seismic character suggests a channel & channel-levee complex. Regional porosity trends indicate low porosities are likely to be encountered if hydrostatic pressures are assumed.

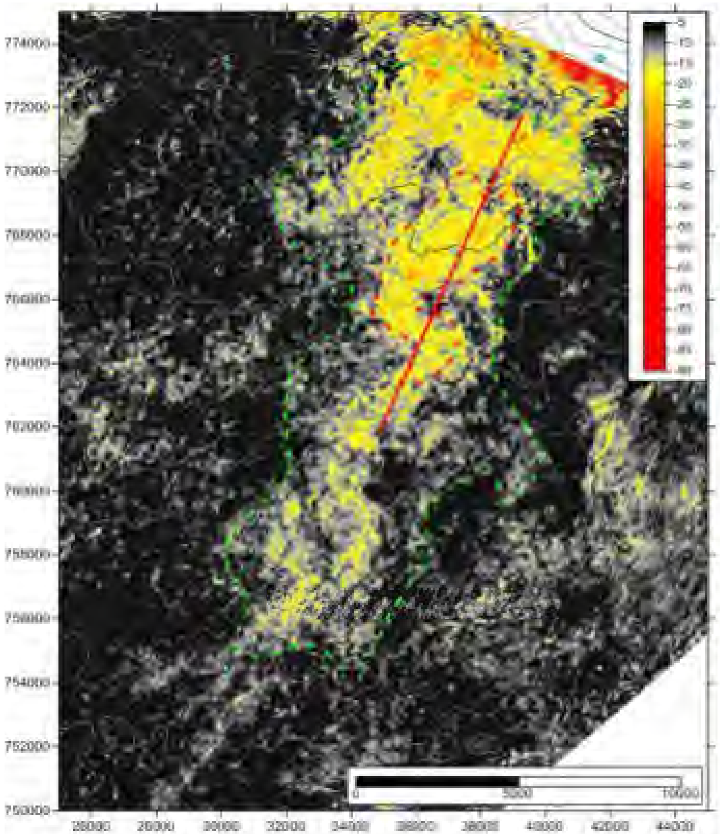
Play Risk		Prospect Risk	
Source	70%	Trap	65%
Seal	90%	Mig	80%
Res. Pres	80%	Res Eff	50%
	50%		26%
COS	13%		

	Area (Km2)	Stack F. (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	17	1	20	8	50	2.49	158	0.15	34
Best	30	2	35	11	60	1.96	399	0.24	98
High	54	3	60	13	70	1.62	997	0.40	276
								Mean	135

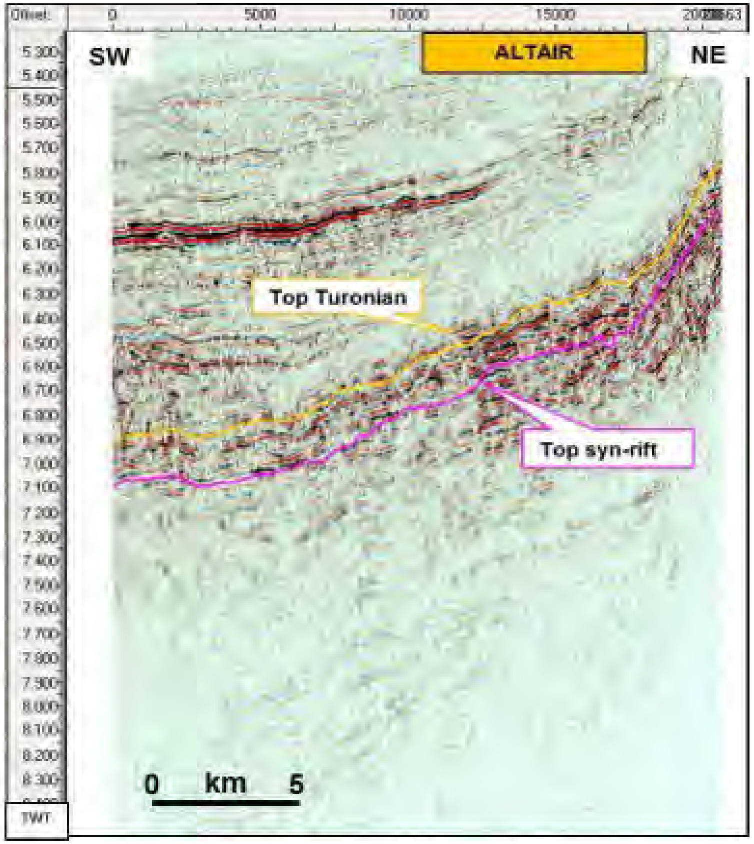
Deterministic inputs, probabilistic STOIIP and Rec Resource

Enclosure 3.1: Summary Description Sheet

'Grad' NRMS Extraction



Arbitrary Dip Line, 'Grad' TWT



Summary	
Block	SL-03
APCL Interest (%)	90
Fluid	Oil
Crest (m ss)	5400
Water depth (m)	3300

Notes

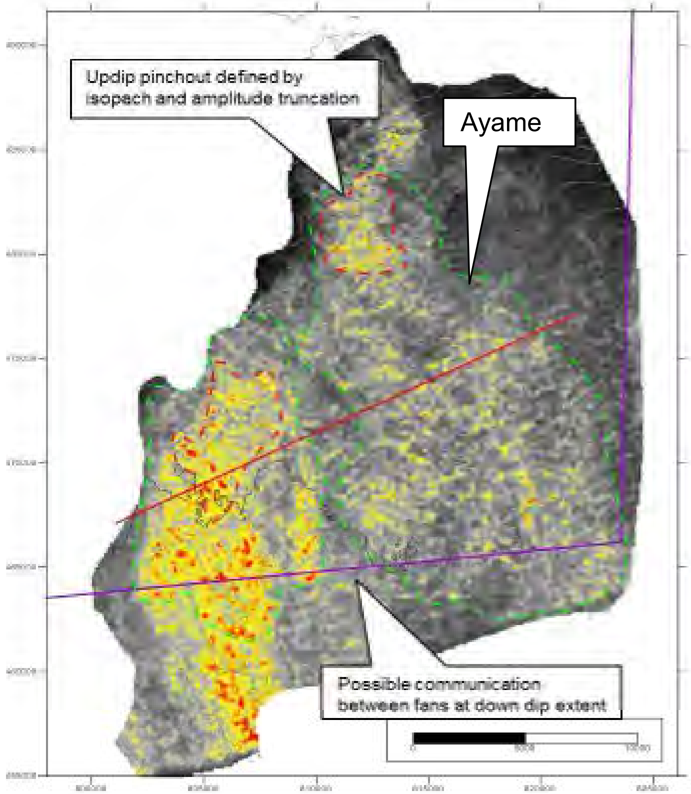
Altair is a Turonian turbidite channel prospects within the SL-03 Block offshore Sierra Leone. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinchout. Recent discoveries in nearby blocks confirm a working hydrocarbon system (Venus-B1, Jupiter-1 and Mercury-1). The Sierra Leone wells A-1 and A1-2 proved good reservoir and potential source rocks. Two distinct canyon systems feed erosive channels at the break of slope. An area net approach was adopted using a pseudo-gradient volume SNA extraction to constrain areal extent and define an areal N/G to account for lateral variability of sand distribution within the reservoir.

Play Risk		Prospect Risk	
Source	80%	Trap	50%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	80%
	65%		28%
COS	18%		

	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	11	0.70	29	15	73	2.05	218	0.30	79
Best	32	0.82	56	18	80	1.62	755	0.38	278
High	92	0.94	83	21	88	1.34	2473	0.45	938
								Mean	434

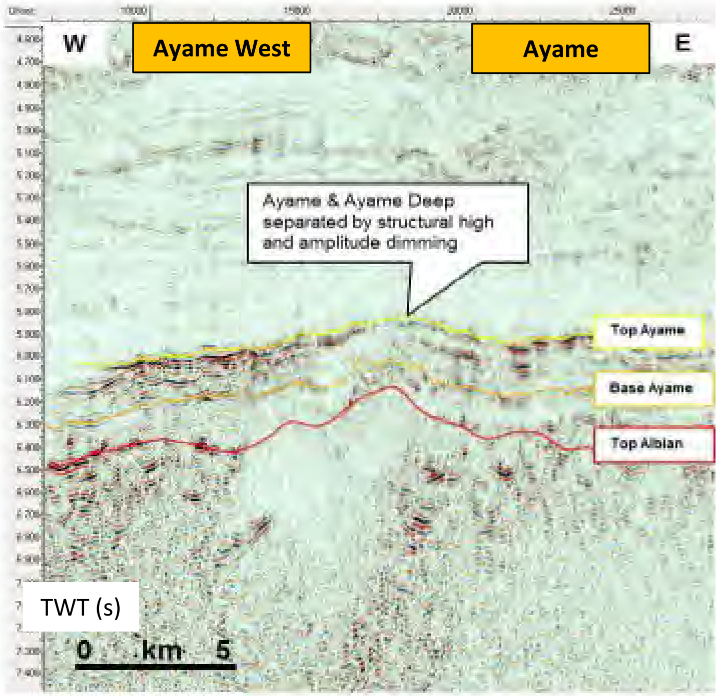
Enclosure 4.1: Summary Description Sheet

Grad 'SNA' Extraction



Seismic Line
TWT

Arbitrary strike line across Ayame and Ayame Deep, 'Gradient' Volume (Filtered Fars minus Filtered Mids)



Summary	
Block	CI-513
APCL Interest (%)	90
Fluid	Oil
Crest (m ss)	4200
Water depth (m)	2500

Notes

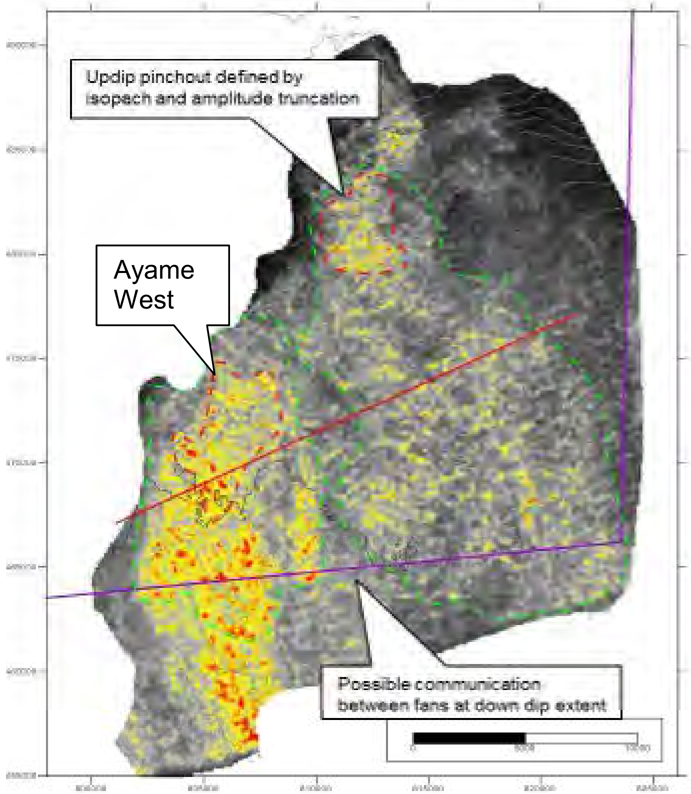
Ayame is an Upper Cretaceous fan which mainly lies within block CI-513, offshore Cote D'Ivoire. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinchout. The prospect has very good amplitude support. An area net approach was adopted using pseudo-gradient volume SNA / NRMS extractions to constrain areal extent and define an areal N/G to account for lateral variability of sand distribution within the reservoir for low and high case area polygons. These seismically defined polygons were then filled to column heights of 200m and 800m respectively and used to constrain the P90 and P10 area inputs of our probabilistic simulation.

Play Risk		Prospect Risk	
Source	60%	Trap	50%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	80%
	49%		28%
COS	14%		

	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	11	0.70	20	17	73	1.81	179	0.30	65
Best	40	0.85	38	20	80	1.49	815	0.38	302
High	149	0.99	55	23	88	1.26	3474	0.45	1318
								Mean	569

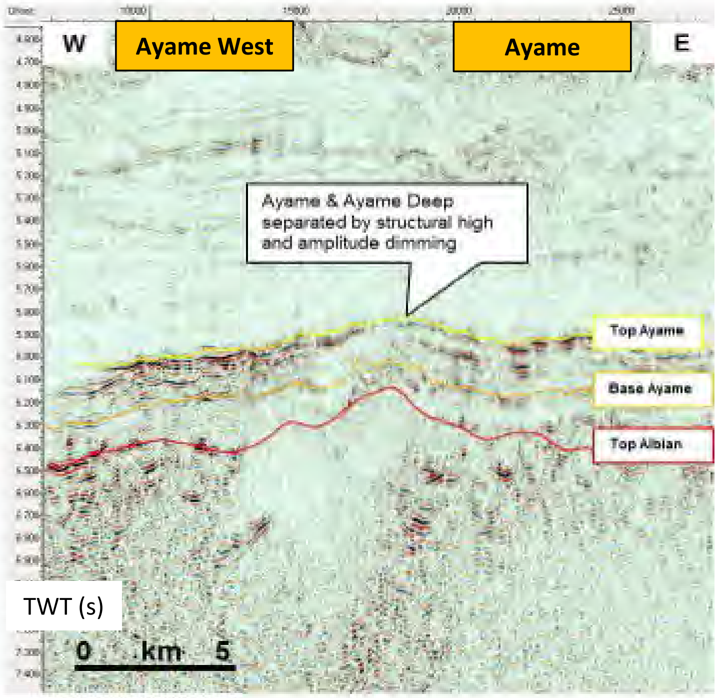
Enclosure 4.2: Summary Description Sheet

Grad 'SNA' Extraction



Seismic Line TWT

Arbitrary strike line across Ayame and Ayame Deep, 'Gradient' Volume (Filtered Fars minus Filtered Mids)



Summary

Block	CI-513 & Open
APCL Interest (%)	90% in CI-513
Fluid	Oil
Crest (m ss)	4900
Water depth (m)	2700

Notes

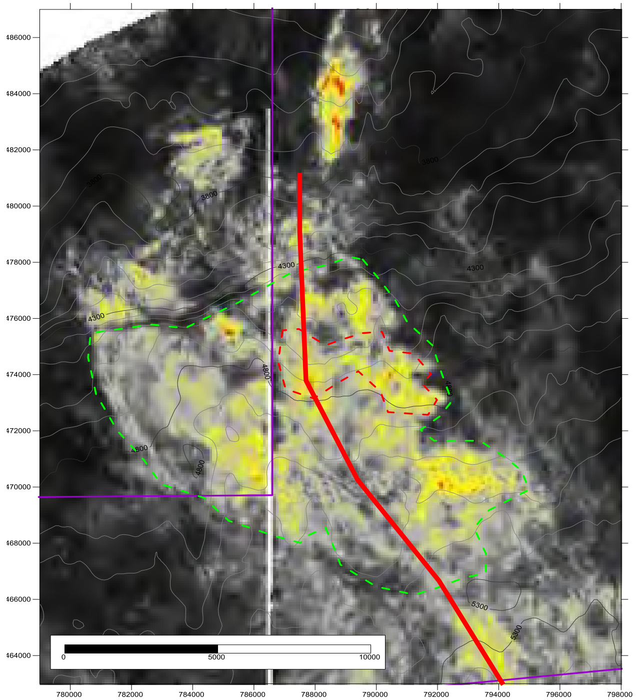
A second prospect within the same reservoir interval was identified and volumetrically assessed. Ayame West is separated from Ayame by a structural high, isopach thinning and amplitude dimming. The prospect was assessed in the same manner as Ayame with a but with Low Case column height of 600m filling down to the point at which amplitudes between the two fans brighten allowing possible communication. The upper end of the Ayame West fan lies down-dip of Ayame and less than 1km away from the thinning low amplitude saddle between the two prospects.

Play Risk		Prospect Risk	
Source	60%	Trap	50%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	80%
	49%		28%
COS		14%	

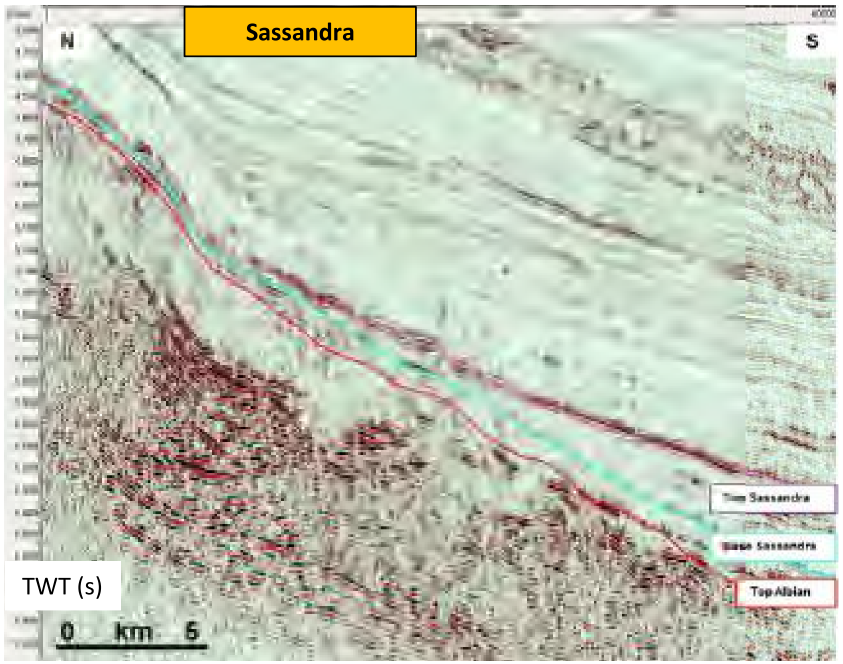
	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	10	0.61	25	14	73	1.94	161	0.30	58
Best	30	0.80	47	18	80	1.59	585	0.38	216
High	93	0.99	69	21	88	1.34	2085	0.45	788
								Mean	352

Enclosure 4.3: Summary Description Sheet

Full Stack - RMS Extraction



Arbitrary Dip Line, 'Grad' TWT



Summary	
Block	CI-513 / CI-509
APCL Interest (%)	90% of CI-513
Fluid	Oil
Crest (m ss)	4400
Water depth (m)	2500

Notes

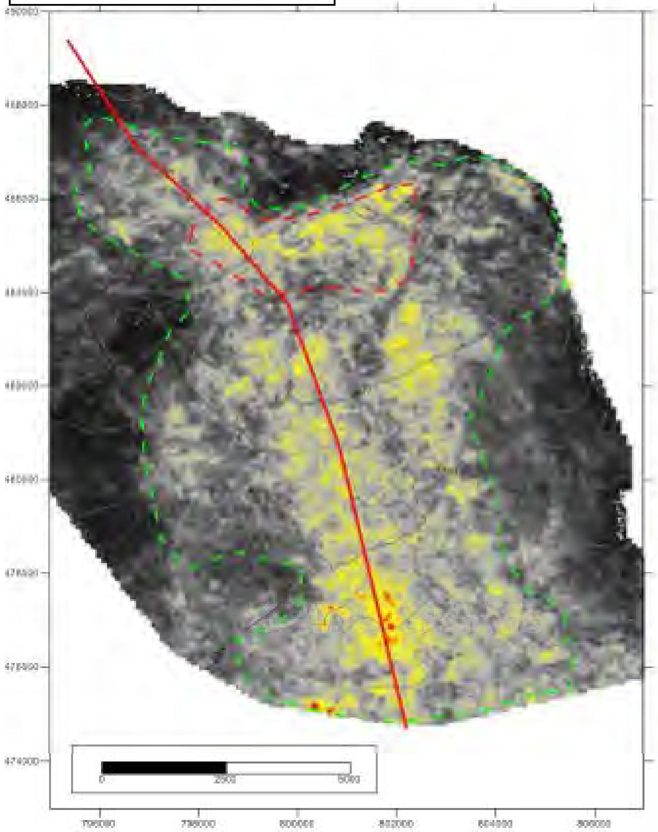
This sheet refers to volumes associated with Blocks 513 and CI-509. Sassandra is an Upper Cretaceous fan which straddles blocks CI-513 and CI-509. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinchout. A single target reservoir is identified within the Turonian. The prospect has good amplitude support. An area times net approach was adopted using a pseudo-gradient volume NRMS extraction to constrain prospect size. Angle stacks were not available outside of Block CI-513, so an RMS extraction on the full stack volume was used to determine NW extent. In our low case, we restrict the area of the accumulation to the brightest area of anomalous amplitudes. Our high case extends the prospect down-dip.

Play Risk		Prospect Risk	
Source	60%	Trap	40%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	70%
	49%		20%
COS	10%		

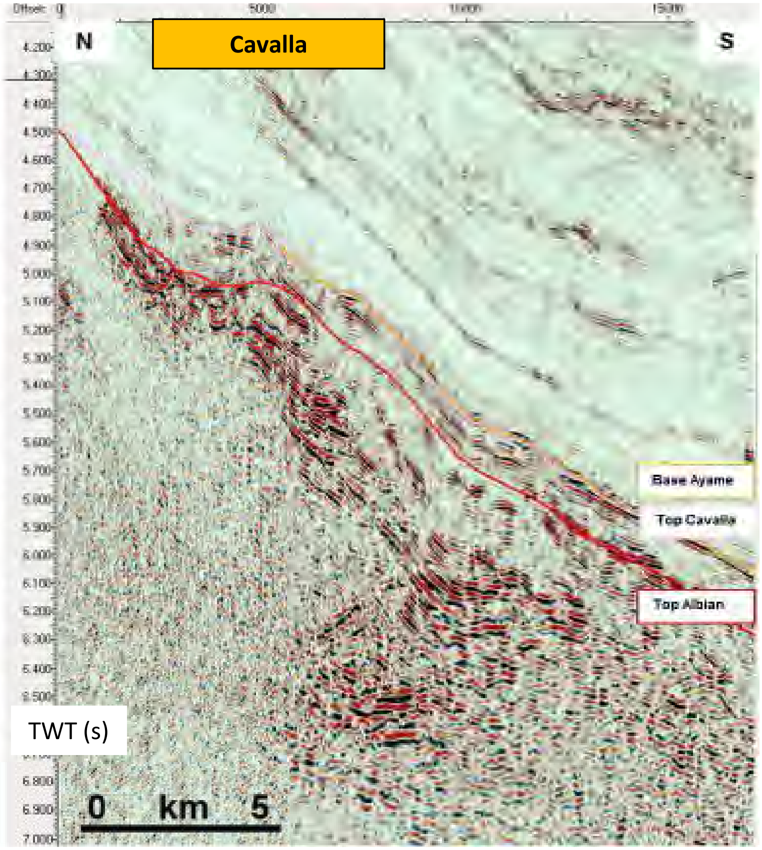
	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	6	0.70	15	16	73	1.85	71	0.30	26
Best	23	0.84	28	19	80	1.52	320	0.38	118
High	92	0.98	42	22	88	1.29	1408	0.45	521
								Mean	237

Enclosure 4.4: Summary Description Sheet

'Grad' NRMS Extraction



Arbitrary Dip Line, 'Grad' TWT



Summary	
Block	CI-513
APCL Interest (%)	90
Fluid	Oil
Crest (m ss)	3900
Water depth (m)	2500

Notes

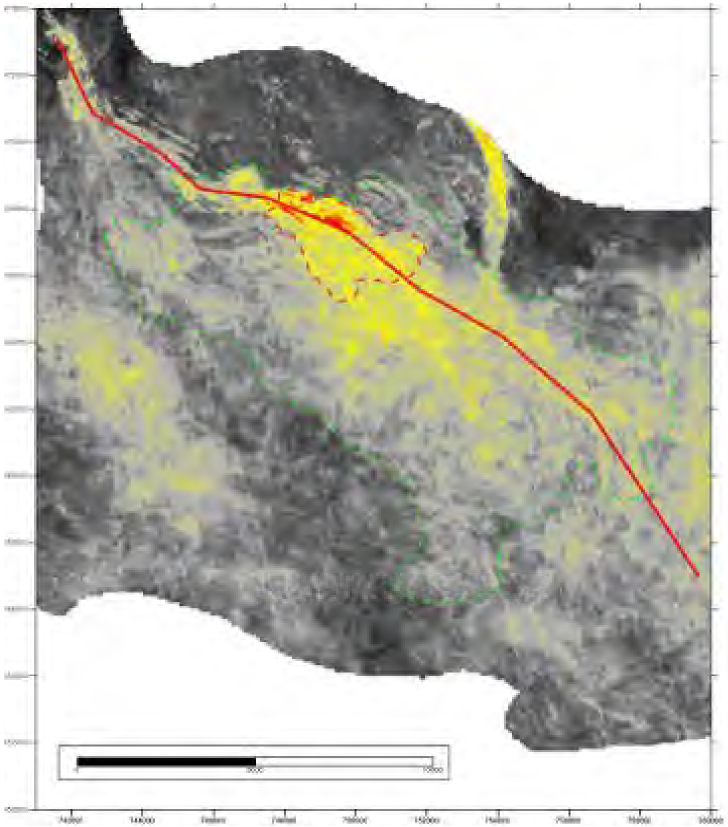
Cavalla is an Upper Cretaceous Fan which lies between the Ayame and Sassandra prospects of Block CI-513 offshore Cote D'Ivoire. It is identified as a stratigraphic trap, with areal extents defined by amplitude truncation and structural pinchout. A single target reservoir is identified within the Turonian/Cenomanian interval which lies stratigraphically beneath the Ayame Prospect. For the amplitude analysis, the top reservoir has been shifted up 30ms to bracket strong negative amplitudes on the 'Gradient' volume, and the base reservoir has been shifted up 50ms to remove Albian related amplitudes. An area net approach was adopted using pseudo-gradient volume SNA / NRMS extractions to constrain extent of the low and high case area polygons. These seismically defined polygons were then filled to column heights of 200m and 800m respectively.

Play Risk		Prospect Risk	
Source	60%	Trap	40%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	70%
	49%		20%
COS	10%		

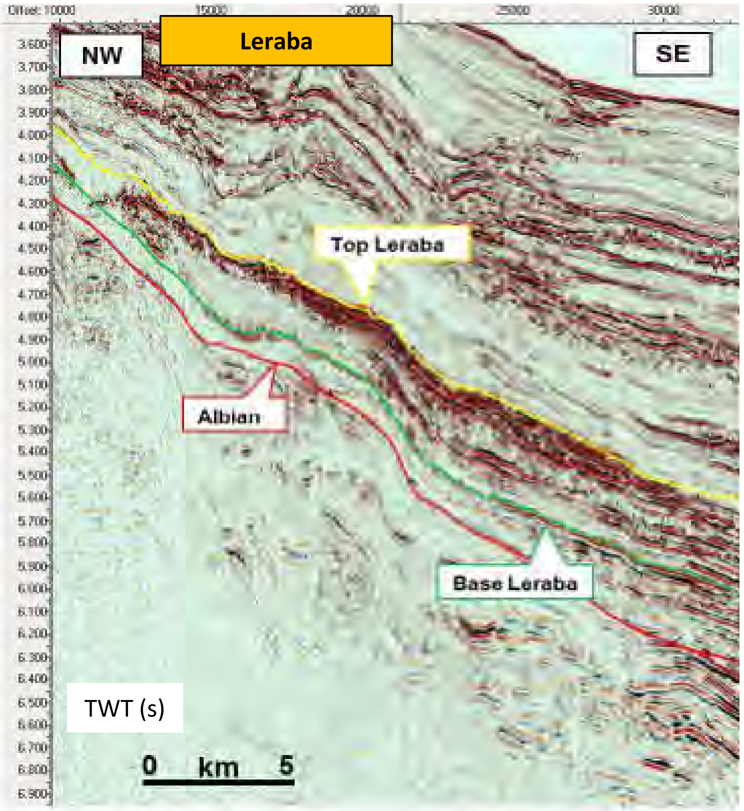
	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	4	0.71	20	19	73	1.85	67	0.30	25
Best	13	0.85	38	22	80	1.52	281	0.38	104
High	46	0.99	55	25	88	1.29	1142	0.45	431
								Mean	190

Enclosure 4.5: Summary Description Sheet

Full Stack RMS Extraction



Arbitrary Dip Line, TWT



Summary	
Block	CI-509
APCL Interest (%)	90
Fluid	Oil
Crest (m ss)	3700
Water depth (m)	2500

Notes

Leraba is an Upper Cretaceous fan. It is identified as a stratigraphic trap, with extents defined by amplitude truncation and structural pinchout. The final processing products and AvO volumes are yet to be delivered for CI-509, however the 'Geotrace raw migration stack' volume is of high quality and is deemed suitable for deriving a volumetric range for Leraba. An area net approach was adopted using an RMS extraction to constrain extent and define an areal N/G to account for lateral variability of sand distribution. In our low case, we restrict the area to the brightest area of anomalous amplitudes. Our high case extends the prospect down-dip and SW to include a secondary channel system.

Play Risk		Prospect Risk	
Source	60%	Trap	60%
Seal	90%	Mig	70%
Res. Pres	90%	Res Eff	80%
	49%		34%
COS	16%		

	Area (km^2)	Areal N/G (frac)	Net (m)	Porosity (%)	So (%)	Bo (rb/stb)	STOIIP (MMstb)	Rf (frac)	Rec Res. (MMstb)
Low	5	0.76	39	21	73	1.50	252	0.15	55
Best	18	0.88	75	24	80	1.34	997	0.28	258
High	61	1.00	111	27	88	1.21	3682	0.40	1039
								Mean	460