31 May 2012

The Directors
Europa Oil & Gas (Holdings) plc
6 Porter Street
London
W1U 6DD

Attention: Mr H Mackay

Dear Sirs

Re: Competent Person's Report of Certain Petroleum Interests of Europa Oil & Gas (Holdings) plc and its Subsidiaries

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared this Competent Person's Report (CPR) on certain petroleum exploration and production interests of Europa Oil & Gas (Holdings) plc and its subsidiaries ("Europa"). The CPR has been compiled in accordance with and satisfies the AIM Guidance Note for Mining, Oil and Gas Companies dated June 2009 ("AIM Guidance Note").

Europa holds interests in three producing oil fields onshore the United Kingdom and holds exploration licences onshore and offshore the United Kingdom and onshore France and Romania. This CPR reports on the three producing fields, a gas discovery onshore France and undrilled prospects in certain exploration licences onshore the United Kingdom.

We have estimated the volumes of reserves and prospective resources in these interests as at 31 December 2011 using data and information available up to 28 April 2012. ERCE has not carried out any economic modelling of the fields. The economic cut-off dates for each field have been supplied by Europa. 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.

We have prepared estimates of resources using the March 2007 SPE/WPC/AAPG/SPEE Petroleum resources Management System (PRMS) as the standard for classification and reporting. These definitions are set out in Appendix 1.

Licence Interests

The licences owned by Europa and included in this CPR are summarised in the table below:

Country	Block/ Licence / (Field)	Operator	Europa Interest (%)	Status	Licence Expiry Date	Area (km^2)	Outstanding Commitment in this licence phase
United Kingdom	DL003 (West Firsby)	Europa	100.00	Prod	Dec 2020	4	None
United Kingdom	DL001 (Crosby Warren)	Europa	100.00	Prod	Oct 2017	9	None
United Kingdom	PL199-2 (Whisby)	Blackland Park Expl	65.00*	Prod	Nov 2015	4	None
United Kingdom	PEDL181	Europa	50.00	Expl	Sept 2014	540.5	70km 2D seismic
United Kingdom	PEDL 180 182	Egdon Resources	33.33	Expl	Jul 2014	140	One Well
United Kingdom	PEDL 143	Europa	40.00	Expl	Sep 2013	91.8	One Well
Onshore France	Béarn des Gaves	Europa	100.00	Expl	Mar 2015**	528	Eu 2.49MM
Onshore France	Tarbes Val d'Adour	Europa	100.00	Expl	Jan 2015**	234.5	Eu 0.97MM

Notes

**) Europa has a 65.00 per cent interest in production from Well 4*

***) The Béarn des Gaves and Tarbes Val d'Adour licences have recently expired; Europa has submitted renewal requests for a further three years*

In the above table, "Prod" means production, "Expl" means exploration.

UK Fields

Europa has interests ranging from 65 to 100 per cent in the West Firsby, Crosby Warren and Whisby producing oil fields onshore the United Kingdom. The total oil production rate from these fields amounts to some 200 stb/d. Our estimates of ultimate and remaining oil reserves from existing wells by field are presented in Table 1 and the remaining reserves in aggregate as at 31 December 2011 are as follows:

Remaining Oil Reserves (Mstb)	Proved	Proved + Probable	Proved + Probable + Possible
Total Remaining Oil Reserves at 31 Dec 2011	349	683	1156
Remaining oil reserves attributable to Europa at 31 Dec 2011	287	609	1057

Our forecasts of production from each of these fields, and in aggregate, are presented in Table 2.

Onshore UK Prospects

We have reviewed three undrilled prospects in the UK licences, namely Wressle, Broughton and Holmwood. Europa's interests range from 33.33 to 40.00 per cent. We consider there is an equal likelihood that either oil or gas may be discovered in the Holmwood prospect. Our estimates of total unrisked and risked prospective oil resources by prospect, assuming oil is discovered at Holmwood, are presented in Table 3 and the unrisked and risked prospective resources attributable to Europa are summarised as follows:

Prospective Oil Resources (Mstb)	Low	Best Estimate	High	Mean
Total Unrisked	1580	6020	21610	9880
Total Unrisked Attributable to Europa	580	2230	8040	3670
Total Risked Attributable to Europa	170	660	2360	1080

Our estimates of total unrisked and risked prospective gas resources in the event that gas is discovered at Holmwood, are presented in Table 4 and the unrisked and risked prospective gas resources attributable to Europa are summarised as follows:

Prospective Gas Resources (bcf)	Low	Best Estimate	High	Mean
Total Unrisked	1.67	7.13	25.71	11.73
Total Unrisked Attributable to Europa	0.67	2.85	10.29	4.69
Total Risked Attributable to Europa	0.18	0.74	2.67	1.22

The Wressle prospect is due to be drilled in 2012. A planning application to drill the Holmwood prospect has been refused. An appeal against this decision has been initiated by the licence owners, the result of which should become available later in 2012.

Berenx

Europa has a 100 per cent interest the Béarn des Gaves licence onshore France, which contains the Berenx discovery. Berenx contains very sour gas in a deep (greater than 5500 m depth), highly over-pressured, low porosity fractured reservoir of Upper Jurassic to Middle Cretaceous age that was tested at a flow rate of 0.3 MMscf/d in one of two wells drilled some 40 years ago. No gas samples were recovered during testing, but high H2S readings were recorded during testing and the nearby Lacq field has a gas composition with high mole fractions of H2S (10%) and CO2 (15%). There is considerable uncertainty as to the size and shape of the Berenx "Deep" discovery, as well as to the reservoir characterisation and potential productivity.

Our estimates of contingent gas resources in the deep reservoir in the Berenx discovery are summarised as follows:

Contingent Gas Resources (bcf)	1C	2C	3C
Berenx "Deep"	31	134	623

During the drilling of the Berenx wells there were also strong gas indications within the shallow allochtonous section in Well Berenx-1, although not in the slightly downdip Well Berenx-2. Gas shows were concentrated in the same carbonate interval that forms the deep reservoir that is repeated at 2100-2800 m in the over-thrust. No test was carried out on this Berenx "Shallow" interval. Structural definition in the complex zone of imbricate thrusting is presently inadequate to understand the possible trapping mechanism. We see the Berenx Shallow target as a lead at present, having an area of some 10 to 12 km^2 and possibly containing some 75 bcf gas initially in place but requiring further geotechnical data and work to develop into a prospect. Europa plans to acquire some new 2D seismic lines to clarify the structure.

The key risk for the future development potential of Berenx will be demonstrating the presence of an efficient open fracture system which can sustain commercial flow rates. An appraisal well is required to test the potential reservoir zones using modern drilling, completion and testing techniques and also to sample the fluids to establish the gas composition. In addition, the acquisition and PSDM processing of a sizeable 3D seismic survey will be required in order to define the trap size and configuration.

Tarbes

Europa has a 100 per cent interest in the Tarbes Val d'Adour, which contains two small oil fields that produced oil predominantly from Aptian Albian reefal carbonates in the 1980s and have been closed in since 1986. The cumulative production from both fields was some 77,000 stb of 27 deg API gravity oil. Further development potential is identified at updip locations within these fields, which will require further seismic acquisition and studies better to define the structural interpretation and control on trapping.

Confirmations and Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation and engineering and economics assessment. Except for the provision of professional services on a time-based fee basis, ERCE has no commercial arrangement with any other person or company involved in the interests which are the subject of this report. ERCE confirms that it is independent of Europa, its directors, senior management and advisers.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets. ERCE considers that the scope of the CPR is appropriate and includes and discloses all information required to be included therein and was prepared to a standard expected in accordance with the AIM Guidance Note.

The work has been supervised by Mr Simon McDonald, Engineering Director of ERCE, a post-graduate in Petroleum Engineering, a Chartered Petroleum Engineer and a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has 35 years relevant experience in the evaluation of oil and gas fields and acreage, preparation of development plans and assessment of reserves. Other key personnel involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Source Data and Methodology

In carrying out our evaluation of these interests, we have relied upon information provided by Europa which comprised details of Europa's licence and acreage interests, basic exploration and engineering data, technical reports, interpreted seismic, well and other data, costs and commercial data, development plans, production data and reviews of the performance of the producing fields.

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.

In estimating petroleum in place and recoverable, we have used standard techniques of petroleum engineering. These techniques combine geophysical and geological knowledge with detailed information concerning 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 presented our own view of risks, where appropriate.

Site visits were not considered to be necessary for the purpose of this report.

The CPR relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The CPR, of which this letter forms part, must therefore be read in its entirety.

The nomenclature used in this report and attached tables is presented in Appendix 2.

Yours faithfully

ERC Equipoise Limited

Simon McDonald
Engineering Director

Table 1. Ultimate and Remaining Oil Reserves at 31 December 2011

Field	Ultimate Reserves (Mstb)			Cumulative Production (MMstb)	Remaining Reserves (Mstb)			Europa Interest (%)	Attributable Remaining Reserves (Mstb)		
	P90	P50	P10		P90	P50	P10		P90	P50	P10
West Firsby	1669	1920	2280	1528	141	392	752	100	141	392	752
Crosby Warren	772	819	866	739	33	80	127	100	33	80	127
Whisby	886	922	986	712	174	210	274	65	113	137	178
Total	3327	3661	4132	2979	348	682	1153		287	609	1057

Table 2. Forecasts of Oil Production by Field and in Aggregate

Field	West Firsby			Whisby			Crosby Warren			Total			Total Attributable to Europa		
Europa Interest	100			65			100			100					
Year	P90 (stb/d)	P50 (stb/d)	P10 (stb/d)	P90 (stb/d)	P50 (stb/d)	P10 (stb/d)	P90 (stb/d)	P50 (stb/d)	P10 (stb/d)	P90 (stb/d)	P50 (stb/d)	P10 (stb/d)	P90 (stb/d)	P50 (stb/d)	P10 (stb/d)
2012	89.6	102.5	109.2	66.9	71.6	78.6	29.0	35.0	41.7	185.4	209.1	229.5	162.0	184.0	202.0
2013	77.4	96.1	105.3	57.3	63.1	71.7	21.4	30.1	38.0	156.1	189.3	215.1	136.0	167.2	190.0
2014	67.0	90.2	101.6	50.5	56.3	65.1	17.0	26.7	34.5	134.5	173.2	201.1	116.8	153.5	178.4
2015	58.2	84.7	98.0	44.5	50.3	59.0	13.5	23.7	31.2	116.3	158.6	188.3	100.7	141.0	167.6
2016	50.7	79.5	94.6	39.2	44.9	53.6	11.0	21.0	28.3	100.9	145.4	176.4	87.2	129.7	157.7
2017	44.3	74.7	91.3	34.6	40.1	48.6		18.6	25.7	78.9	133.4	165.5	66.8	119.4	148.5
2018		70.3	88.1	30.4	35.8	44.1		16.5	23.3	30.4	122.5	155.4	19.8	110.0	140.0
2019		66.1	85.0	26.8	31.9	40.0		14.6	21.1	26.8	112.7	146.1	17.4	101.5	132.1
2020		62.2	82.1	23.6	28.5	36.3		13.0	19.1	23.6	103.7	137.5	15.4	93.7	124.8
2021		58.6	79.2	20.8	25.4	32.9		11.5	17.3	20.8	95.6	129.5	13.5	86.7	117.9
2022		55.2	76.5	18.3	22.7	29.9		10.4	15.7	18.3	88.3	122.1	11.9	80.4	111.6
2023		52.1	73.9	16.2	20.3	27.1			14.2	16.2	72.3	115.2	10.5	65.2	105.7
2024		49.1	71.3	14.2	18.1	24.6			12.9	14.2	67.2	108.8	9.3	60.9	100.2
2025		46.4	68.9	12.5	16.1	22.3			11.7	12.5	62.5	102.9	8.2	56.9	95.1
2026		43.8	66.6	11.1	14.4	20.2			10.6	11.1	58.2	97.4	7.2	53.1	90.3
2027		41.4	64.3	10.2	12.9	18.3			10.0	10.2	54.2	92.7	6.6	49.7	86.2
2028			62.1		11.5	16.6					11.5	78.8		7.5	72.9
2029			60.0		10.4	15.1					10.4	75.1		6.8	69.8
2030			58.0			13.7						71.7			66.9
2031			56.1			12.4						68.5			64.2
2032			54.2			11.3						65.5			61.5
2033			52.4			10.3						62.7			59.1
2034			50.7									50.7			50.7
2035			49.0									49.0			49.0
2036			47.4									47.4			47.4
2037			45.8									45.8			45.8
2038			44.3									44.3			44.3
2039			42.9									42.9			42.9
2040			41.5									41.5			41.5
2041			40.2									40.2			40.2
Total (Mstb)	141	392	752	174	210	274	34	81	130	349	682	1156	288	609	1060
Production to Dec 11 (Mstb)	1528	1528	1528	712	712	712	739	739	739						
Ultimate Reserves* (Mstb)	1669	1920	2280	886	922	986	773	820	869						

Table 3. STOIIP and Prospective Oil Resources - UK Onshore (if Oil is Discovered at Holmwood)

Block	Prospect	Reservoir	STOIIP			Unrisked Prospective Resource				Europa Interest (%)	Net Unrisked Prospective Resource				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)
PEDL 182	Broughton	Penistone	0.75	2.51	8.74	0.15	0.55	1.99	0.91	33.33	0.05	0.18	0.66	0.30	36	0.02	0.07	0.24	0.11
	Broughton	Chatsworth	0.88	2.79	8.66	0.18	0.60	1.94	0.94	33.33	0.06	0.20	0.65	0.31	32	0.02	0.06	0.20	0.10
PEDL 180	Wressle	Penistone	0.95	3.53	12.50	0.20	0.77	2.89	1.31	33.33	0.07	0.26	0.96	0.44	36	0.02	0.09	0.35	0.16
	Wressle	Chatsworth	1.13	3.38	10.12	0.24	0.73	2.28	1.10	33.33	0.08	0.24	0.76	0.37	32	0.02	0.08	0.24	0.12
PEDL 143	Holmwood**	Portland Sst	1.23	3.75	11.42	0.26	0.82	2.61	1.24	40.00	0.10	0.33	1.04	0.49	32	0.03	0.10	0.33	0.16
	Holmwood**	Corallian	2.60	11.63	43.96	0.55	2.54	9.90	4.40	40.00	0.22	1.01	3.96	1.76	25	0.06	0.26	1.00	0.44
TOTAL			7.55	27.59	95.40	1.58	6.02	21.61	9.88		0.58	2.23	8.04	3.67		0.17	0.66	2.36	1.08

*) COS means chance of success (or exploration risk factor)

**) The COS for Holmwood reflects the chance of finding hydrocarbons; we consider there is an equal likelihood of finding oil or gas

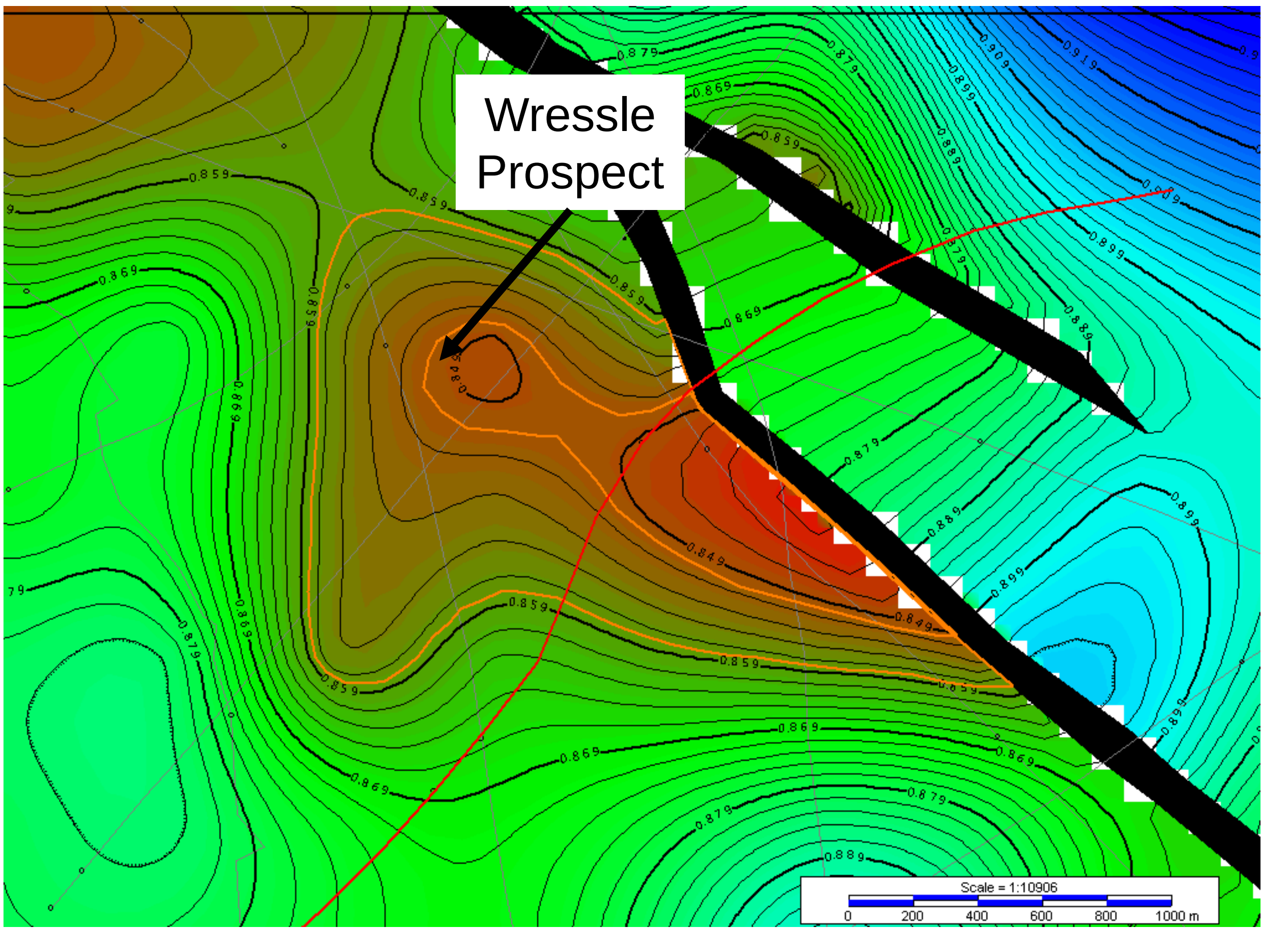
Table 4. GIIP and Prospective Gas Resources in Holmwood if Gas is Discovered

Block	Prospect	Reservoir	GIIP			Unrisked Prospective Resource				Europa Interest (%)	Net Unrisked Prospective Resource				COS* (%)	Net Risked Prospective Resource			
			Low (Bcf)	Best (Bcf)	High (Bcf)	Low (Bcf)	Best (Bcf)	High (Bcf)	Mean (Bcf)		Low (Bcf)	Best (Bcf)	High (Bcf)	Mean (Bcf)		Low (Bcf)	Best (Bcf)	High (Bcf)	Mean (Bcf)
PEDL143	Holmwood**	Portland	0.49	1.48	4.53	0.31	0.95	2.96	1.42	40.00	0.13	0.38	1.18	0.57	32	0.04	0.12	0.37	0.18
	Holmwood**	Corralian	1.83	8.31	30.12	1.36	6.17	22.75	10.32	40.00	0.54	2.47	9.10	4.13	25	0.14	0.62	2.29	1.04
TOTAL			2.32	9.79	34.66	1.67	7.13	25.71	11.73		0.67	2.85	10.29	4.69		0.18	0.74	2.67	1.22

*) COS means chance of success (or exploration risk factor)

**) The COS for Holmwood reflects the chance of finding hydrocarbons; we consider there is an equal likelihood of finding oil or gas

Competent Person's Report on Certain Petroleum Interests of Europa Oil & Gas (Holdings) plc



PREPARED FOR: Europa Oil & Gas plc

BY: ERC Equipoise Limited

Month: May

Year: 2012

Authors: Adam Law, Nigel Banks, Kevin Dean, Paul Compton

Approved by: Simon McDonald

Date released to client: May 2012

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1. Onshore UK fields

1.1. West Firsby

1.1.1. Introduction

The West Firsby field is located onshore the United Kingdom north of the city of Lincoln in Licence DL003 (Figure 1.1). The production licence expires in December 2029. Europa has a 100 per cent interest in the field.

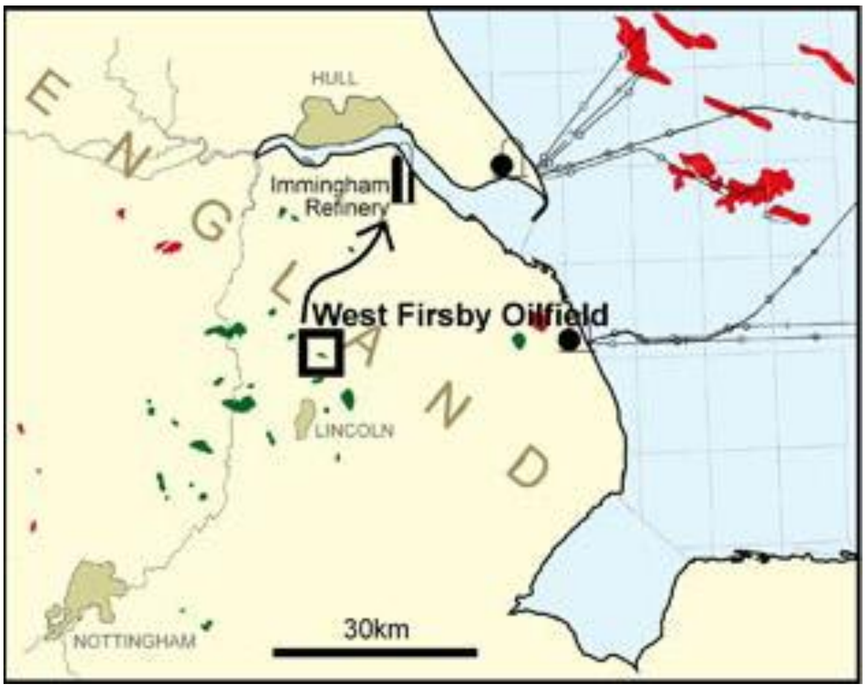


Figure 1.1: West Firsby oil field location map

The field was discovered in 1987. Oil production commenced in 1991 from Well WF-1Z, which continued to produce until 2005, when it was sidetracked as Well WF-8. Wells WF-2 and WF-3 had previously been drilled to appraise the field but had failed to produce oil in commercial quantities. Well WF-2 is used as a water disposal well, whilst Well WF-3 remains shut-in. The oil is produced from poor to fair quality Carboniferous sandstones of early Westphalian age at a depth of approximately 5200 ft ss.

Six more wells have since been drilled in the field. Well WF-4 was drilled in 1992. Well WF-4 commenced production in 1992 and continued producing until 2002 since when it has been shut in due to high water production and H_2S levels. Well WF-5 was drilled in 1995 and ceased production in 2003 when it was sidetracked as Well WF-7, which continues to produce. Well WF-6 was drilled in 2006 and remains on production. Well WF-8 encountered the reservoir deep to prognosis and has not been produced. Well WF-9 commenced production in March 2011 at a rate of some 40 stb/d and had declined to just over 20 stb/d by end 2011.

Europa acquired its interest in the field in 2003 from Tullow. The monthly averaged oil rate from the three currently producing wells has ranged from 20 to 140 stb/d in 2011, with an average for the year of 90 stb/d. At the beginning of the year, the water cut was some 90 per cent but when Well WF-9 came on stream it decreased to 84 per cent. The oil is transported by truck for sale at the refinery at Immingham.

1.1.2. Reservoir Description

The West Firsby field is located within a hanging wall anticline. The field trends NW-SE (Figure 1.2) and is located on the downthrown side of the fault towards the north-eastern margin of the Gainsborough Trough. Closure is provided by a combination of dip within the structure and by faulting on the northern, eastern and southern flanks. The western closure is less well defined.

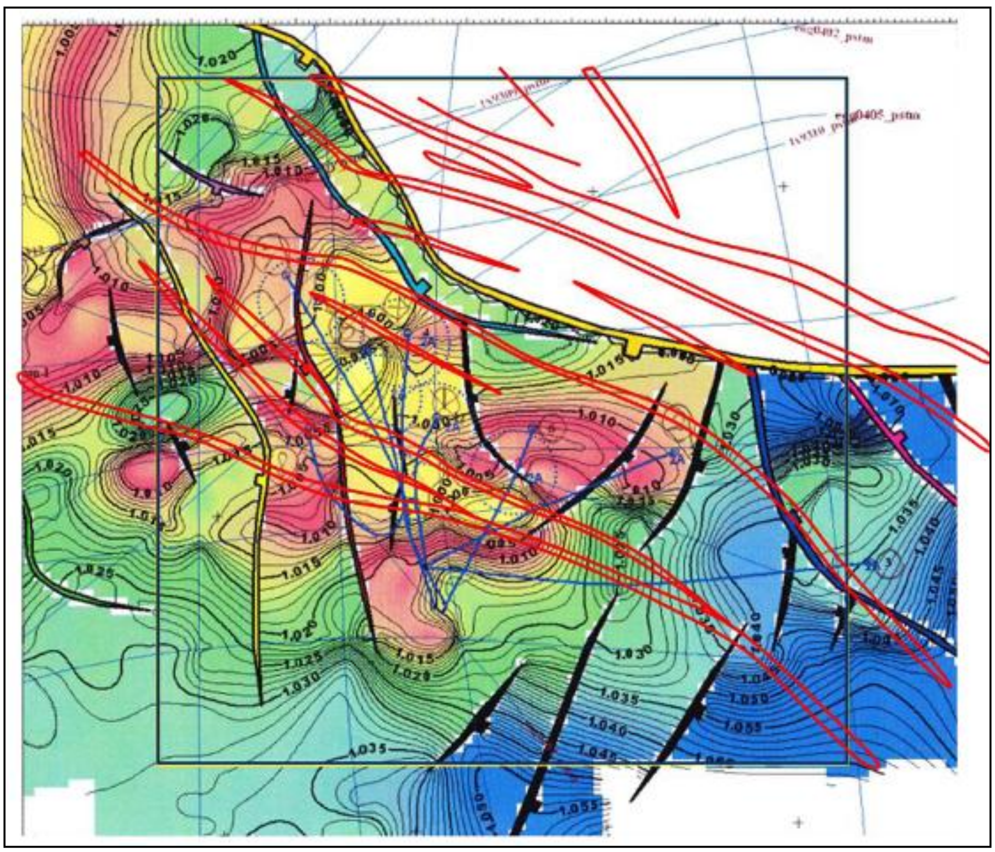


Figure 1.2: West Firsby top zone 2 TWT structure map

The reservoir is composed of Carboniferous age Late Namurian and Westphalian-A sediments deposited in a marine/deltaic environment grading to fluvial/continental, with facies controlled layering and submergence/emergence cycles. The reservoir is distinctly stratified. Superimposed on this stratification are subtler lateral trends that are controlled primarily by channel dominated sequences. The reservoir has a gross thickness of some 350 ft and is divisible into three major units named Zones 1, 2, and 3 (Figure 1.3).

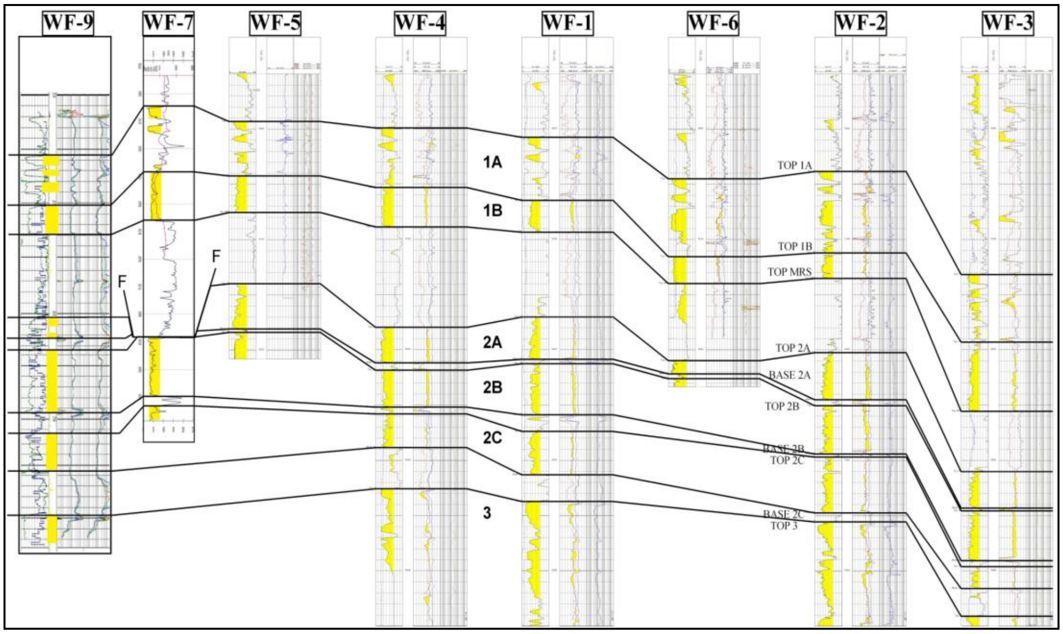


Figure 1.3: West Firsby correlation panel

Zone 3 is a sandstone of good reservoir quality, deposited in an upper shoreface environment and overlain by a field wide shale. Porosity is typically 16 to 20 per cent and core permeabilities range from 0.1 to several hundred millidarcies.

The overlying Zone 2 comprises a series of three channel/channel abandonment sequences; each sub-zone is separated by an extensive shale/coal layer. Porosity is lower, ranging from 11 to 16 per cent and core permeabilities range from 0.1 to up to 100 md. The youngest zone, Zone 1, is separated from the underlying zone by a thick shale unit. The porosity and permeability of Zone 1 are comparable to Zone 2.

Petrophysical evaluation of the reservoir is hampered by the low water resistivity, which appears to vary with depth. Each of the three reservoir zones has a different free water level, ranging from ca 5100 ft ss in Zone 1 to 5400 ft ss in Zone 3. There is a significant transition zone above each free water level.

The oil is a waxy crude, with an API gravity of 35 deg and a gas oil ratio of some 200 scf/bbl. At ambient temperature the oil solidifies and requires chemical additives to maintain liquid properties. The in-situ reservoir fluid viscosity is approximately 1.5 cp, which is marginally favourable for water flooding.

The initial reservoir pressure was 2500 psi and the reservoir temperature 150 deg F. The reservoir fluid is undersaturated, with a bubble point pressure of just under 1100 psi.

1.1.3. Field Performance

The initial oil rate from Well WF-1 in 1991 and 1992 ranged between 100 and 300 stb/d. The field oil rate increased at the end of 1992 to 400 stb/d when Well WF-4 was brought on stream. The oil rate increased again in 1995 with the drilling of Well WF-5 and reached a peak of 800 stb/d shortly after Well WF-6 was brought on stream in late 1996. Thereafter a natural decline set in.

Figure 1.4 presents the oil and water production performance of the field and shows that the drilling of Well WF-7 in 2004 and more recently Well WF-9 in 2011, resulted in increases in production and slowed the rate of decline in the oil rate. Oil production has been associated with large volumes of water production from the outset, with field water cuts generally exceeding 70 per cent from an early stage of production. Wells WF-6 and -7 are artificially lifted using jet pumps. The total field oil rate is currently some 120 stb/d.

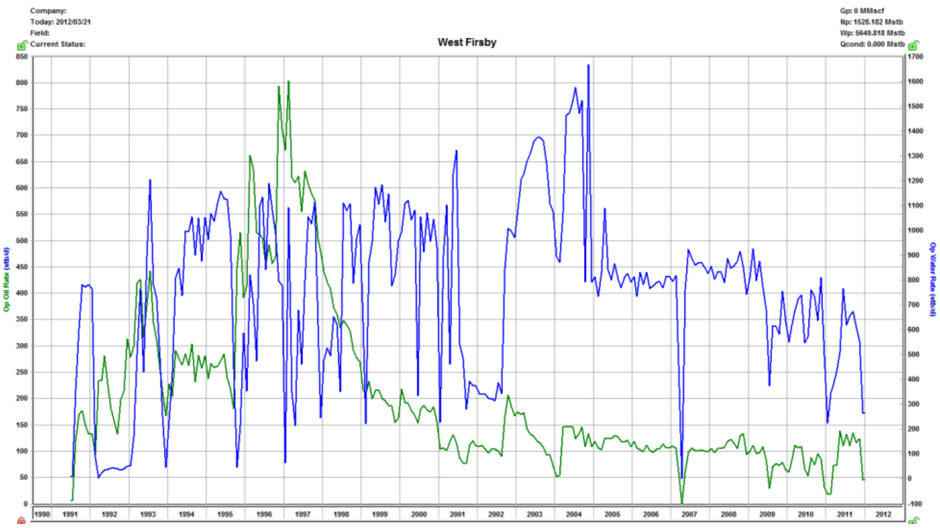


Figure 1.4: West Firsby oil and water production history

The current status of the wells is summarised in Table 1.1

Well	Cum Oil Prod at 31/12/11 (Mstb)	Status
WF-1	386	Abandoned; used as donor for WF-8
WF-2	-	Water disposal well; water into Zone 2
WF-3	-	Failed to flow on test; suspended
WF-4	196	Closed in due to high water cut
WF-5	356	Abandoned; used as donor for WF-7
WF-6	579	Flowing under jet pump
WF-7		Flowing under jet pump
WF-8	-	Suspended
WF-9	9	Drilled in 2011; Flowing under beam pump

Table 1.1: Well status and cumulative production

1.1.4. Oil in Place, Reserves and Production Forecasts

The stock tank oil initially in place (STOIIP) has previously been estimated at between 9.9 MMstb and 13.7 MMstb. A reservoir simulation study carried out in 1997 by Tullow reported a STOIIP of 12.9 MMstb. Recent re-mapping of the field using re-processed seismic data set was carried out by Merlin Energy Resources in 2010 and reported a new STOIIP of 20.6 MMstb

We have not prepared independent estimates of oil in place as our assessment of remaining reserves is based on decline curve analysis. Furthermore, the cumulative oil production to end 2011 of 1.5 MMstb is about 12 per cent of the 1997 simulation study STOIIP and our forecasts of remaining reserves at all levels of confidence are below 18 per cent of this STOIIP estimate.

Figure 1.5 shows the monthly averaged oil rate and water cut plotted against cumulative oil production from beginning of field life~~.~~ The oil rate has increased in 2011 due to the impact of the new Well WF-9.

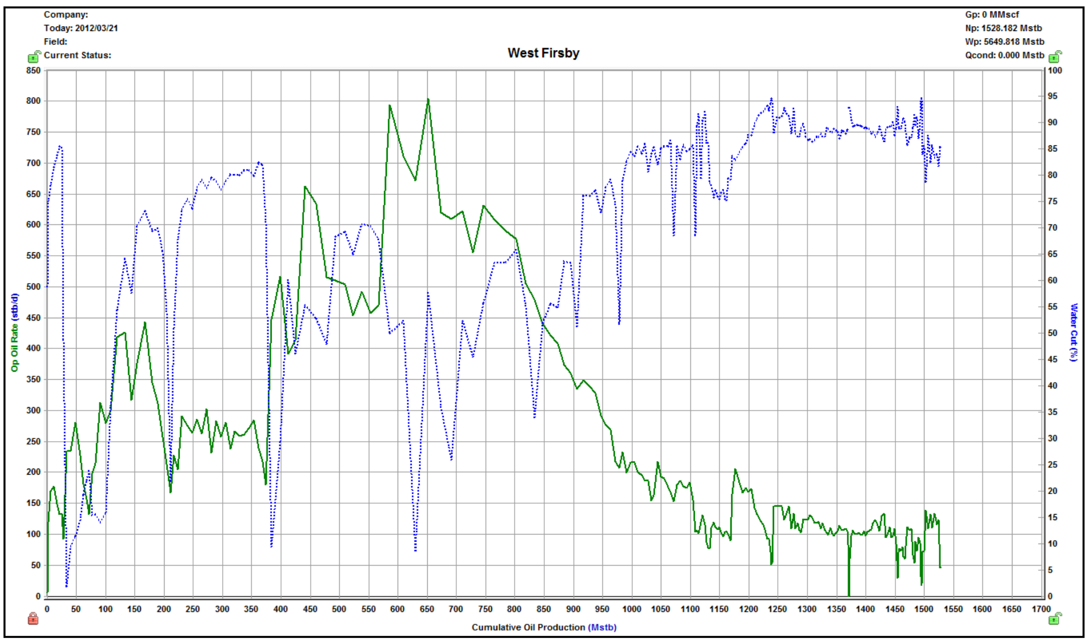


Figure 1.5: West Firsby oil rate and water cut vs. cumulative oil production

We have estimated remaining reserves for West Firsby from the existing producing wells based on decline curve performance analysis of each well. We have prepared Proved, Probable and Possible forecasts of production for each well assuming respectively conservative, most likely and optimistic decline trends fitted to the historic data, and aggregated these to derive the total field forecasts.

An economic cut off rate of 40 stb/d has been applied to the production forecasts, based upon economic modelling carried out by Europa.

Our estimates of ultimate and remaining oil reserves (Mstb) for West Firsby as at 31 December 2011 are presented in Table 1.2

	Proved	Proved + Probable	Proved + Probable + Possible
Ultimate Oil Reserves	1669	1920	2280
Cum Production to 31 Dec 2011	1528	1528	1528
Remaining Reserves at 31 Dec 2011	141	392	752

Table 1.2: West Firsby ultimate and remaining oil reserves

Table 2 presents our forecasts of production.

The relatively modest recovery factor projected for the existing wells indicates there may be scope for additional infill drilling in the field. Recent drilling of Well WF-9 in 2011, however, yielded disappointing production results demonstrating that pressure support and sweep across the field are still not understood. Consequently no new drilling is proposed until after infill seismic has resolved the in-field fault pattern and dynamic modelling has identified un-drained fault panel areas outside existing well penetrations.

1.2. Whisby

1.2.1. Introduction

The Whisby field is located onshore the United Kingdom west of the city of Lincoln in Licence PL199 (Figure 1.6). The production licence expires in November 2015, although extensions are usually granted on application.

Europa has a 65.00 per cent interest in the horizontal Well W-4. This interest was earned following a farm-in agreement. Europa paid for 100 per cent of the cost of the well and received 75 per cent of the revenues until payback, which has now occurred. The operator of the field is Blackland Park Exploration Ltd, which holds a 35 per cent interest in Well W-4.

Prior to the farm in, the Whisby field had produced 250 Mbbl oil over a ten year period declining to less than 5 stb/d in 2002. Well W-4 came on stream in early 2003. Peak monthly averaged oil flow rate was 200 stb/d, which has since declined to a current rate of a little below 80 stb/d and a water cut of some 68 percent.

The oil is transported by truck for sale at Immingham.

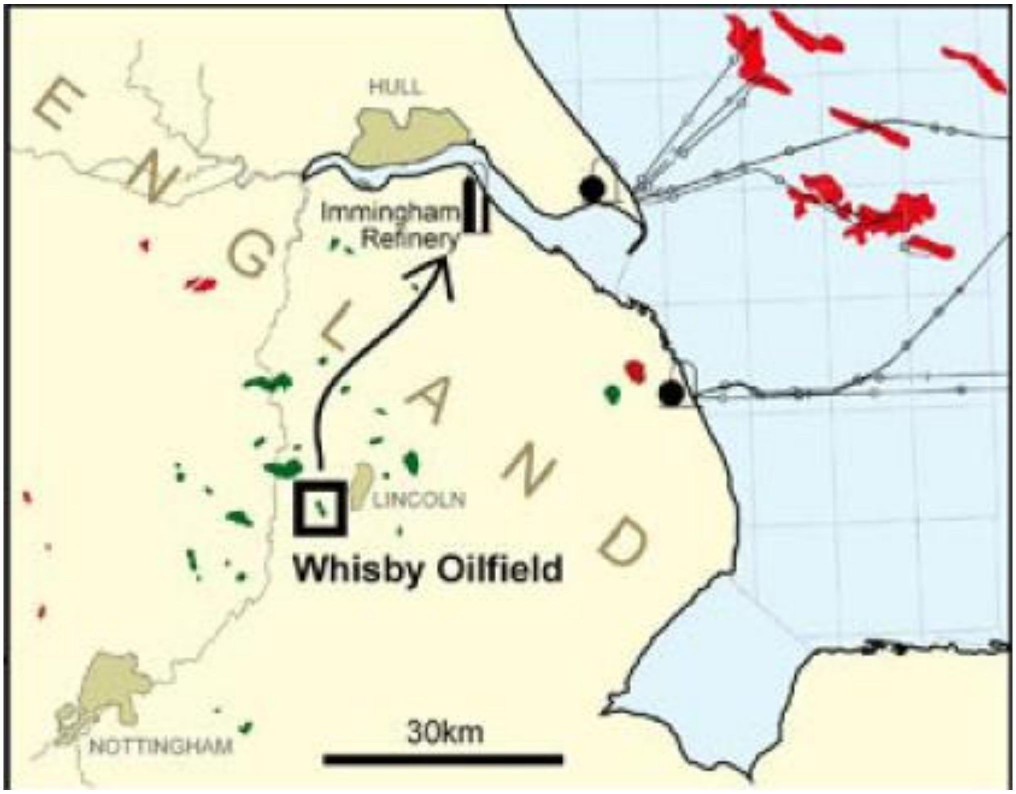


Figure 1.6: Whisby oil field location map

1.2.2. Reservoir Description

The structure of the Whisby field comprises a horst block forming a closure with approx 60 metres of relief at Dinantian level (Figure 1.7). This area is believed to have been emergent during the Namurian leading to the deposition of a thin Basal Westphalian Sand unit, also known as the Rough Rock, that rests discordantly on the Dinantian Limestone.

Figure 1.8 presents a correlation panel through the vertical Whisby wells and others in the area. The reservoir exhibits lateral thickness changes and appears to be a channel deposit of medium to very coarse grade containing well sorted clean quartz sand. The gross thickness varies from 1.7 to 4.0 m in Wells W-1 to W-3. The reservoir quality is very good, with net to gross ratio of 1.0, porosity ranging from 13 to 17 per cent and permeabilities from core averaging 100 to 200 md. The good reservoir properties are thought to be due to extensive re-working during deposition on the hard underlying limestone.

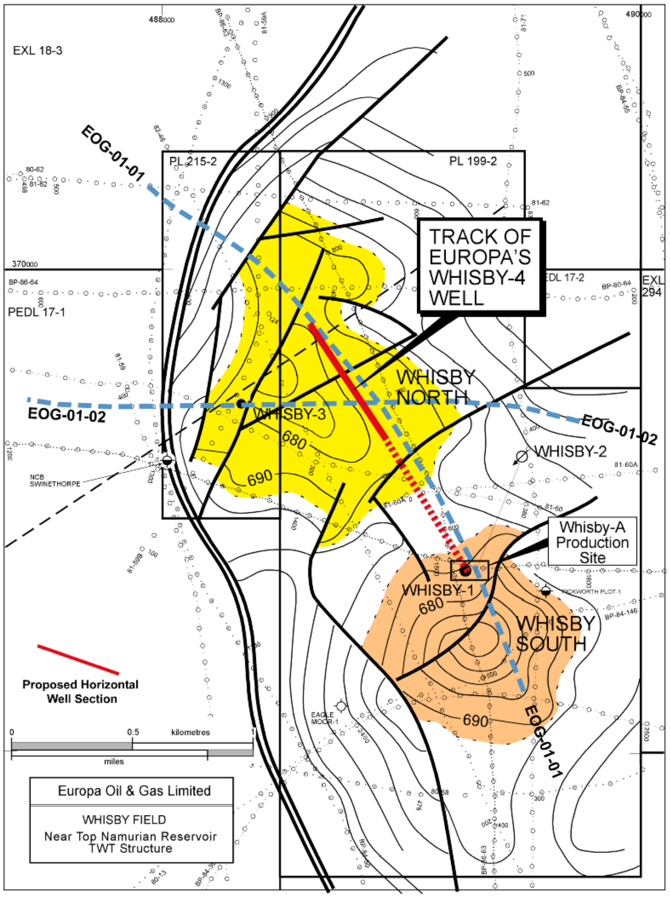


Figure 1.7: Whisby top structure time map

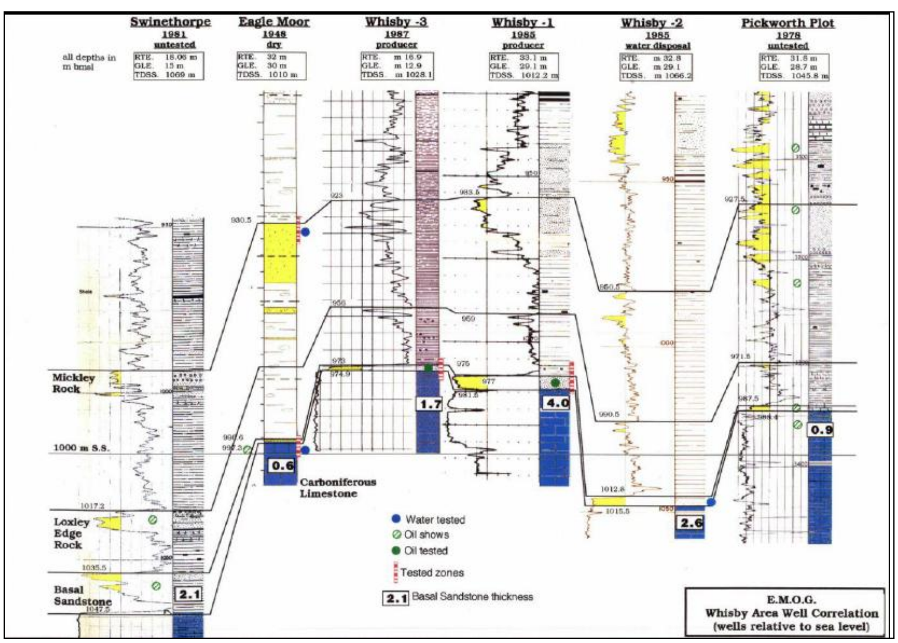


Figure 1.8: Whisby area well correlation panel

Horizontal Well W-4, drilled into the northern part of the field (Figure 1.9), encountered an additional overlying thin reservoir unit, the Loxley Edge sandstone of Westphalian-A age. This unit is absent in Wells W-1 and W-2 and only 0.3 m thick in Well W-3. The Loxley Edge sandstone is also a channel sand and wraps around the northern end of the Whisby high. The reservoir properties are comparable to the Basal sands.

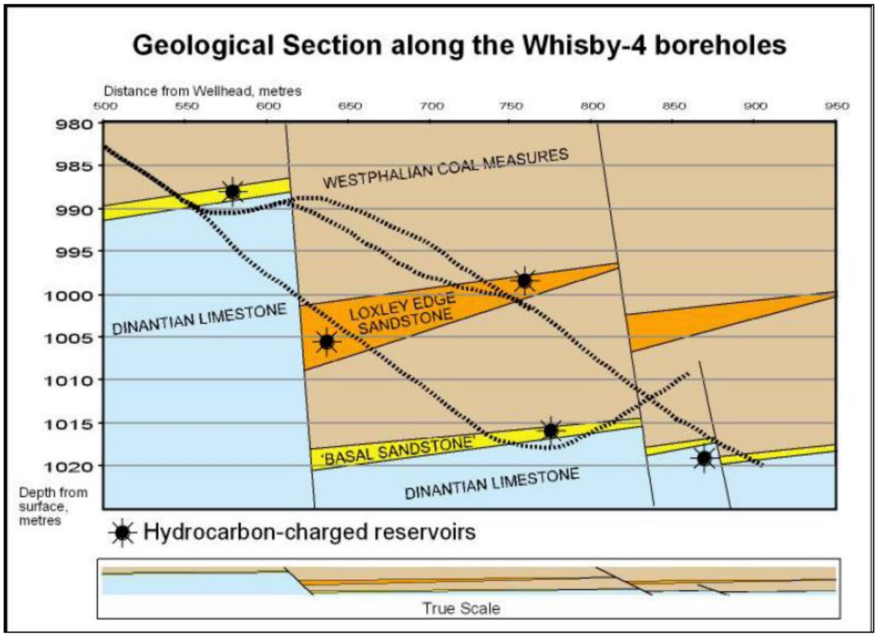


Figure 1.9: Cross-section Well W-4

The oil is relatively light, with an API gravity of 35 deg and a very low gas oil ratio of 5 scf/bbl. The in-situ reservoir fluid viscosity is approximately 4 cp.

The initial reservoir pressure was 1630 psi and the reservoir temperature 124 deg F. The reservoir fluid is highly undersaturated, with a bubble point pressure of 80 psi.

1.2.3. Field Performance

Well W-1 produced 0.25 MMstb oil from the southern structure before production ceased due to high water cut. Well W-3 has produced 0.07 MMstb from the Whisby North structure and is no longer in production. Well W-2, located to the north east of Well W-1 encountered the reservoir below the oil water contact and is used for water disposal.

Well W-4 comprises the original hole plus two sidetracks, all of which are open to production in the well. The well is pumped using a beam pump. Figure 1.10 presents the daily oil and water production rates as well as the daily liquid rate since commencement of production in 2003. The oil rate is declining gradually, commensurate with an increase in water production. The total liquid rate remains essentially constant, indicating a strong pressure support. The current oil rate is a little below 80 stb/d and a water cut of some 68 percent.

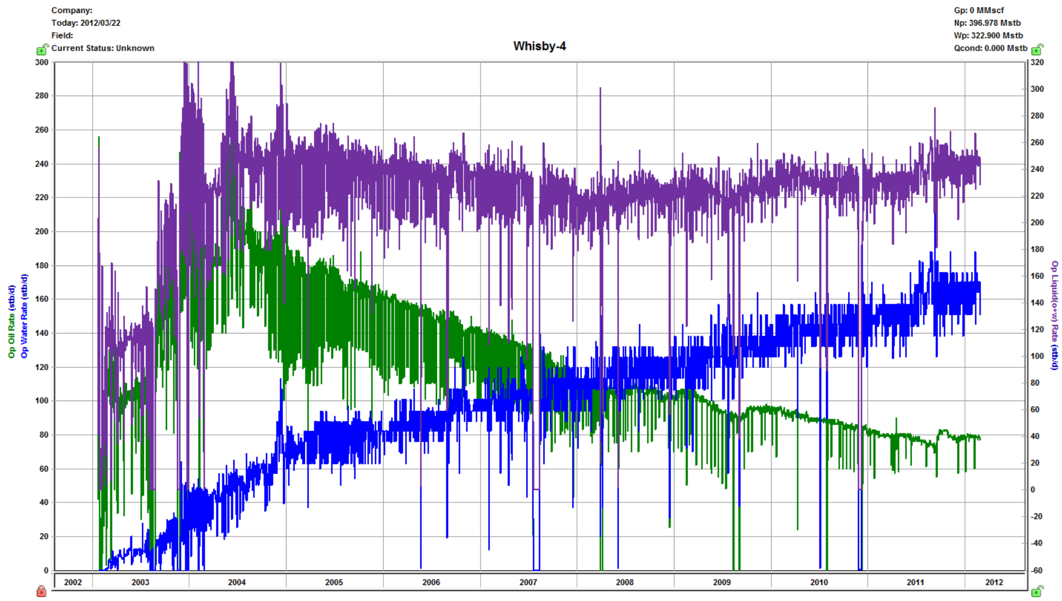


Figure 1.10: Well Whisby-4 production history

1.2.4. Oil in Place, Reserves and Production Forecasts

We have reviewed the 2D seismic data over the structure and have calculated a range of STOIIP for the Basal Sandstone of between 1.2 and 1.9 MMstb, depending on the level of the oil water contact. We have not computed the STOIIP of the Loxley Edge Sandstone, which may be contributing to the production from Well W-4.

Cumulative oil production from Whisby North to date, including Well W-3, amounts to 462 Mstb, whilst a further 250 Mstb was produced from Wells W-1.

We have prepared estimates of remaining reserves for Well W-4 based on decline analysis of the well's production performance. Figure 1.11 shows the monthly averaged oil rate plotted against cumulative production

A cut off of 10 stb/d has been used for the production forecasts, as advised by Europa based on its economic modelling.

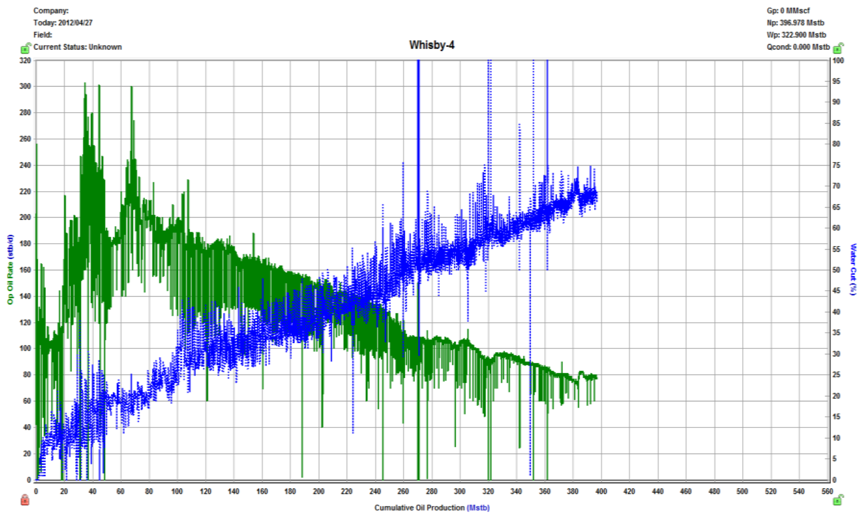


Figure 1.11: Well Whisby-4 oil rate and water cut vs. cumulative oil production

Our estimates of gross remaining oil reserves and remaining reserves attributable to Europa (Mstb) for Well Whisby-4 as at 31 December 2011 are presented in Table 1.3.

	Proved	Proved + Probable	Proved + Probable + Possible
Remaining Reserves at 31 Dec 2011	174	210	274
Remaining Reserves Attributable to Europa at 31 Dec 2011	113	137	178

Table 1.3: Whisby-4 remaining oil reserves

Table 2 presents our forecasts of production.

1.3. Crosby Warren

1.3.1. Introduction

The Crosby Warren oil field is located onshore the United Kingdom north east of the town of Scunthorpe in Licence DL001 (Figure 1.12). The production licence expires in October 2017. Europa has a 100 per cent interest in the field.

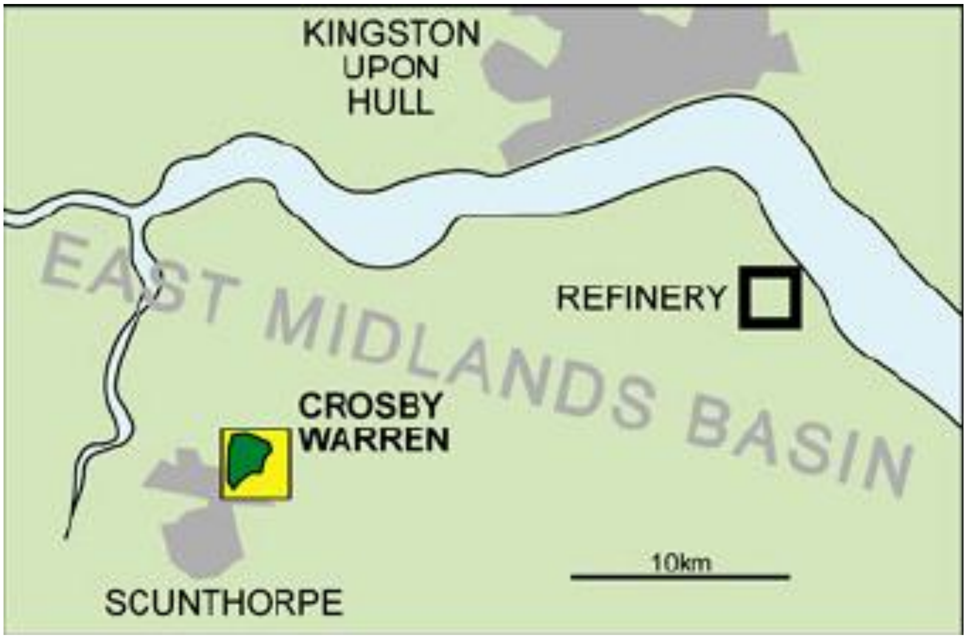


Figure 1.12: Crosby Warren oil field location map

The oil field was discovered in 1987 and brought on stream one year later. Another well, CW-2 was drilled in 1988 but was not produced. A third well, CW-3 was drilled in 1995 but no flow to surface was achieved and the well was turned to a water disposal.

Europa has a 100 per cent interest in the field following its acquisition in 2006. Well CW-2 was sidetracked in 2007 to target an undrained area in the west of the field and was completed as a pumped producer. The field currently produces 40 bbl/d light oil at a water cut of some 50 per cent from Well CW-1. The oil is transported by truck for sale at the Immingham refinery. The minor volumes of gas produced are also sold, but are immaterial from a valuation perspective and so have not been considered further.

1.3.2. Reservoir Description

The Crosby Warren field is fault bounded to the north, west and south and dip closed to the east (Figure 1.13). The reservoir comprises the Beacon Hills Flags sandstone of Upper Namurian / Lower Westphalian age. The reservoir is at a depth of 1540 m ss and comprises channelised sands ranging in gross thickness from 10 m at Well CW-1 to 24 m at Well CW-3Z. The net to gross ratio is typically 75 per cent and the porosity is about 14 per cent. Figure 1.14 presents a correlation panel.

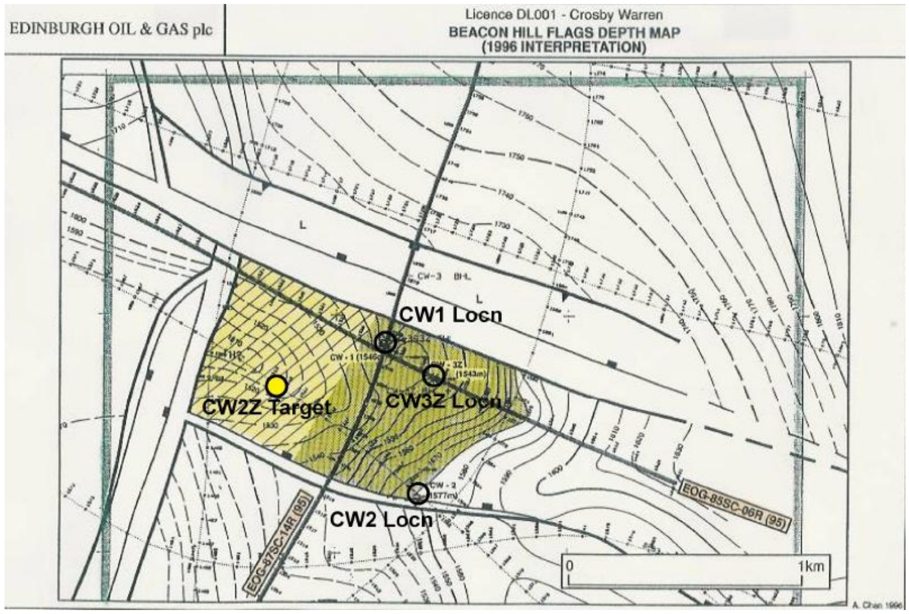


Figure 1.13: Crosby Warren top structure depth map (after Scott Pickford, 1996)

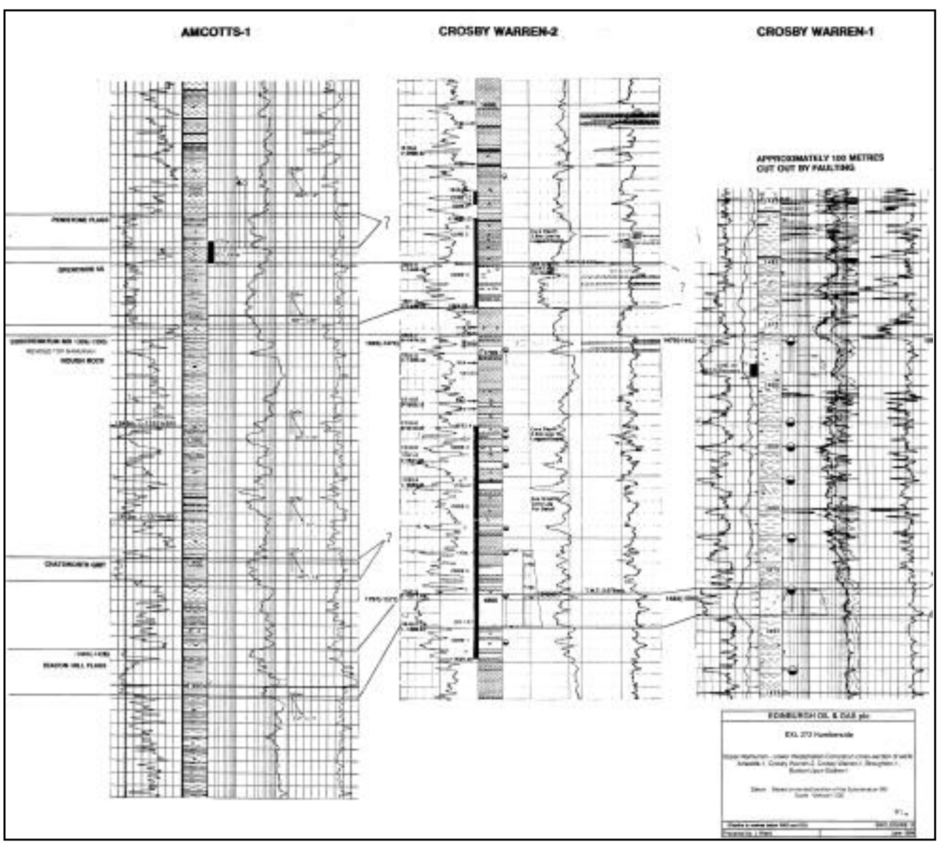


Figure 1.14: Crosby Warren correlation panel

The oil is relatively light, with an API gravity of 35 deg and a gas oil ratio of some 550 to 600 scf/bbl. The initial reservoir pressure was 2400 psi, whilst surveys in 2007 showed the reservoir pressure in Well CW-1 to be some 1175 psi.

1.3.3. Field Performance

Figure 1.15 shows that the monthly averaged oil production rate for the single Crosby Warren production well declined from an initial rate of 400 stb/d to under 50 stb/d when Europa acquired its interest in 2006. Europa installed a new pump and produced the well continuously (previously operations were run on a five-day week), resulting in an improvement in rate. The cumulative oil production to date, which includes a small contribution from Well CW-2ST2, is 739 Mstb.

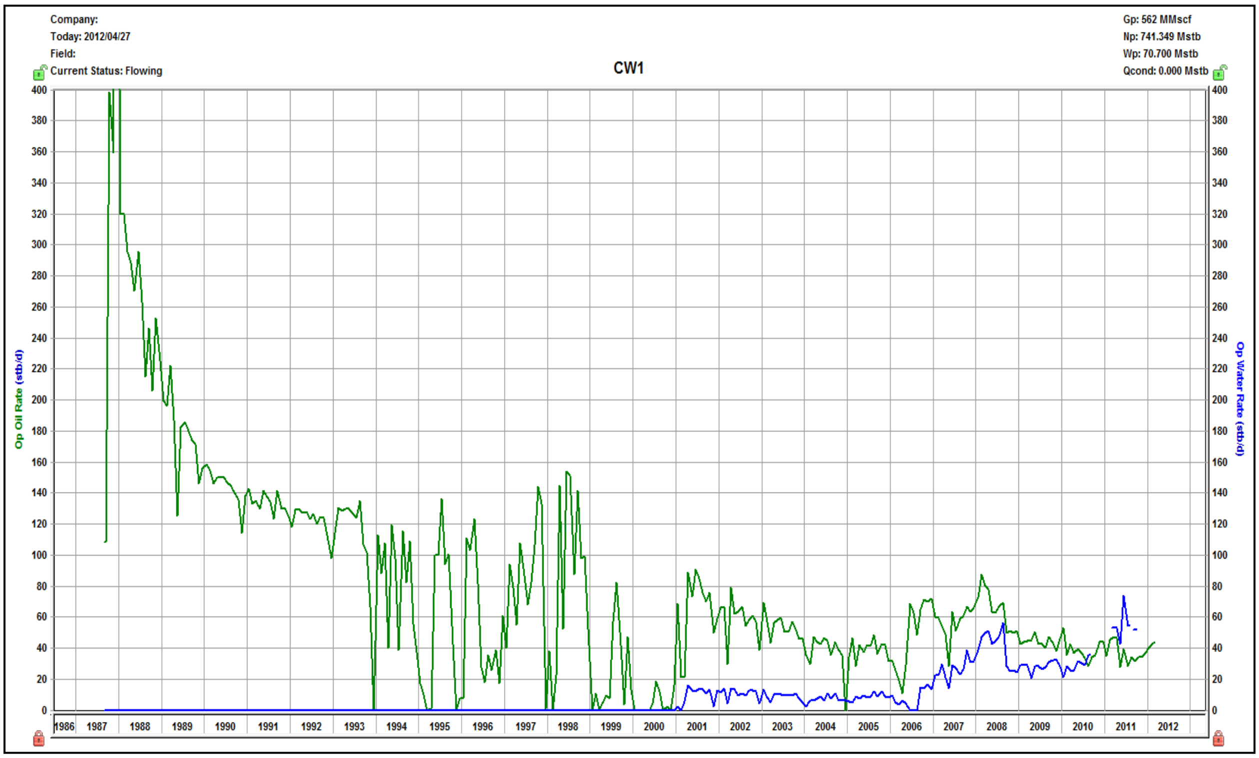


Figure 1.15: Crosby Warren oil production rate

The water cut of Well CW-1 has increased to some 50 per cent. The water is re-injected into the reservoir at Well CW-3.

Well CW-2 was sidetracked in mid-2007 targeting an undrained fault block in the west of the field. The initial hole encountered the formations deep to prognosis and the well had to be sidetracked again before reaching the reservoir. The Beacon Hills Flags sandstone was encountered almost entirely water bearing, other than a thin oil column over the top 2.5 m. The well was initially completed on this upper oil bearing interval and production was initiated in October 2007. A pressure survey carried out in

October 2007 showed a partially depleted reservoir pressure, indicating communication with Well CW-1. The performance of Well CW-2ST2 was disappointing, with an initial oil rate of 25 stb/d at a water cut of 50 per cent.

1.3.4. Oil in Place, Reserves and Production Forecasts

We have not prepared independent estimates of oil in place as our assessment of remaining reserves is based on decline curve analysis. Previous estimates of STOIIP, prepared before drilling Well CW-2ST2, have shown values ranging from 2.3 to 4.1 MMstb.

We have prepared estimates of remaining reserves for Crosby Warren based on decline analysis of the well's production performance. Figure 1.16 shows the monthly averaged oil rate plotted against cumulative oil production.

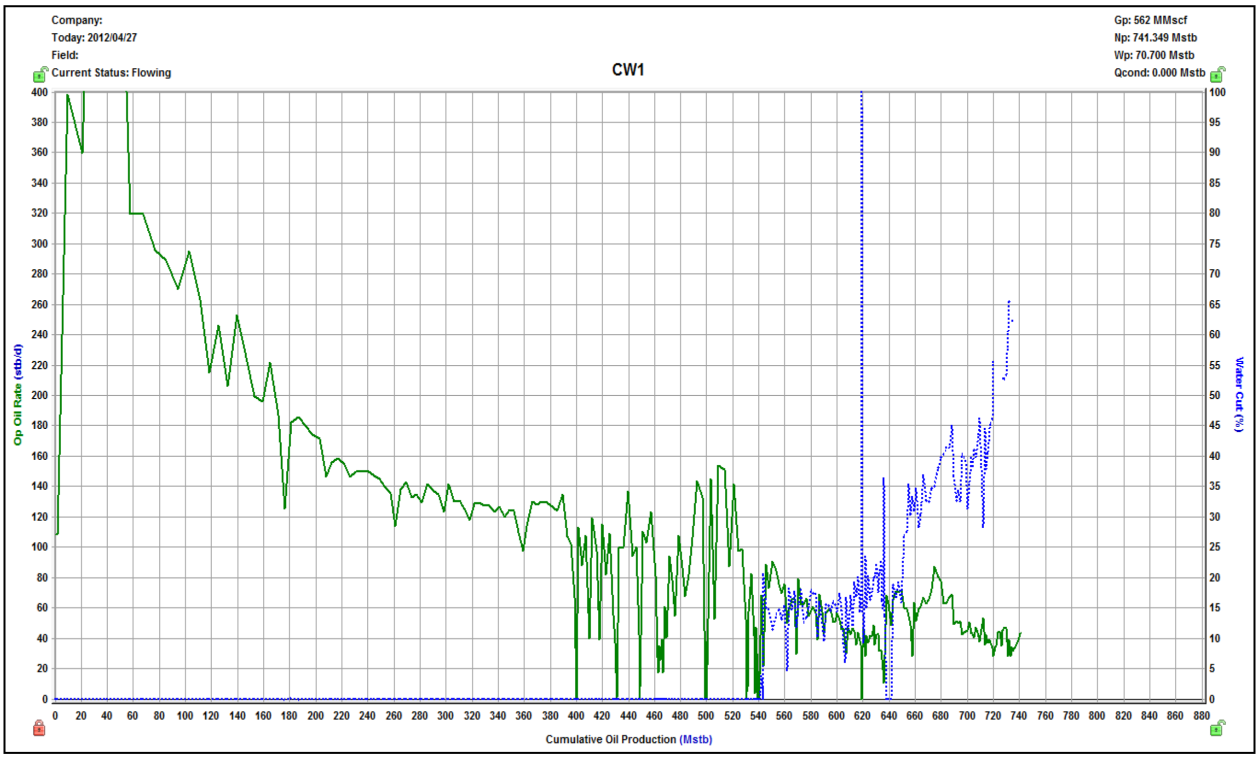


Figure 1.16 Crosby Warren oil rate and water cut versus cumulative oil production

A cut off of 10 stb/d has been used for the production forecasts, as advised by Europa based on its economic modelling.

Our estimates of ultimate and remaining oil reserves (Mstb) for Crosby Warren as at 31 December 2011 are as presented in Table 1.4.

	Proved	**Proved + Probable**	**Proved + Probable + Possible**
Remaining Reserves at 31 Dec 2011	33	80	127
Remaining Reserves Attributable to Europa at 31 Dec 2011	33	80	127

Table 1.4 Crosby Warren remaining oil reserves

Table 2 presents our forecasts of production.

2. Onshore UK - Prospects

2.1. Introduction

Europa has interests in several licence blocks onshore the United Kingdom. We have reviewed undrilled prospects in licences PEDL180/182 and 143.

Europa has a 33.33 per cent interest in licences PEDL 180 and 182, located in North Yorkshire and which contain the Wressle and Broughton undrilled prospects (Figure 2.1). The operator of both licences is Egdon Resources UK Ltd. The licences were awarded in July 2008 and have an initial exploration period of six years, with a commitment to drill one exploration well.

Europa has a 40.00 per cent interest in, and is operator of, licence PEDL143 in the south of England, which contains the Holmwood undrilled prospect (Figure 2.2). The licence was awarded in October 2004 with a six year exploration period, which has been extended to September 2013, with a commitment to drill an exploration well.

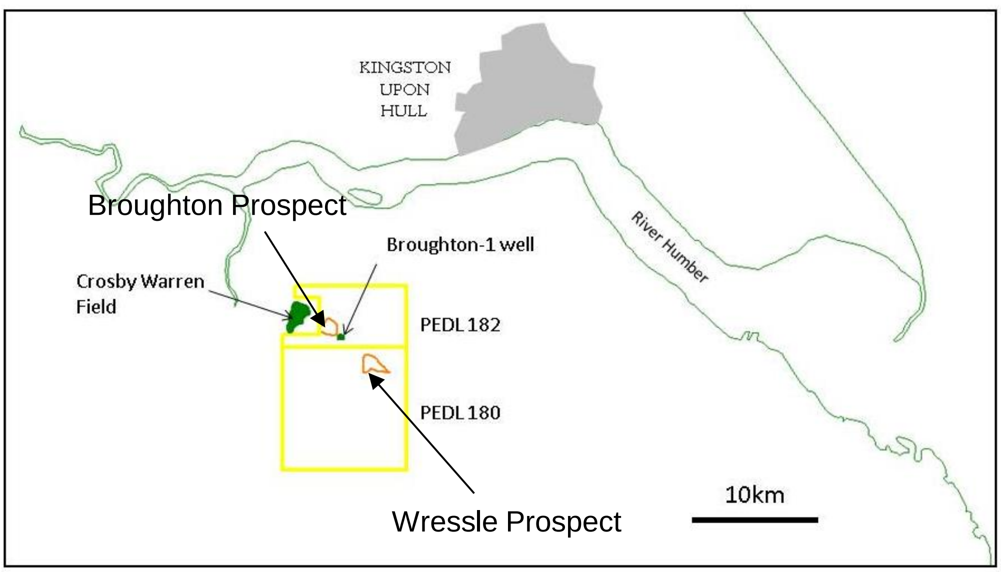


Figure 2.1: Location of licences PEDL 180 and PEDL182

Figure 2.2:

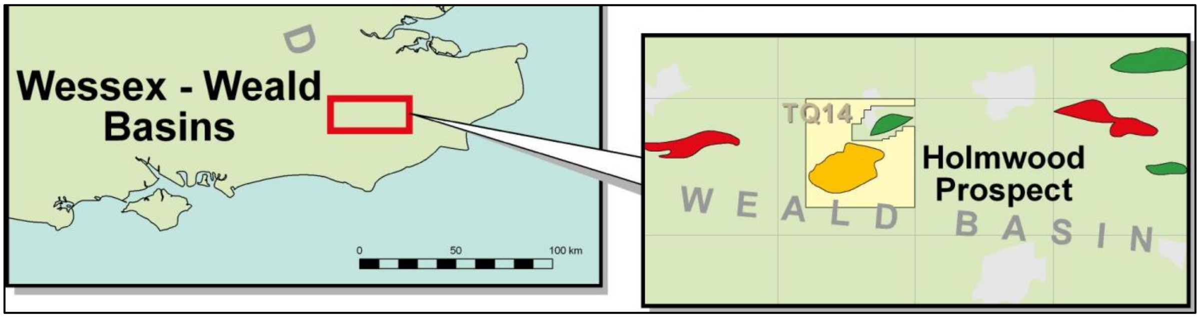


Figure 2.2: Location of licence PEDL 143

2.2. Data Base

The database covering Licence PEDL143 (Holmwood) consists of various vintages of 2D seismic data acquired between 1980 and 1985 (Figure 2.3). No information regarding acquisition or processing parameters were available. Data from Well Brockham-1 were the only well data available.

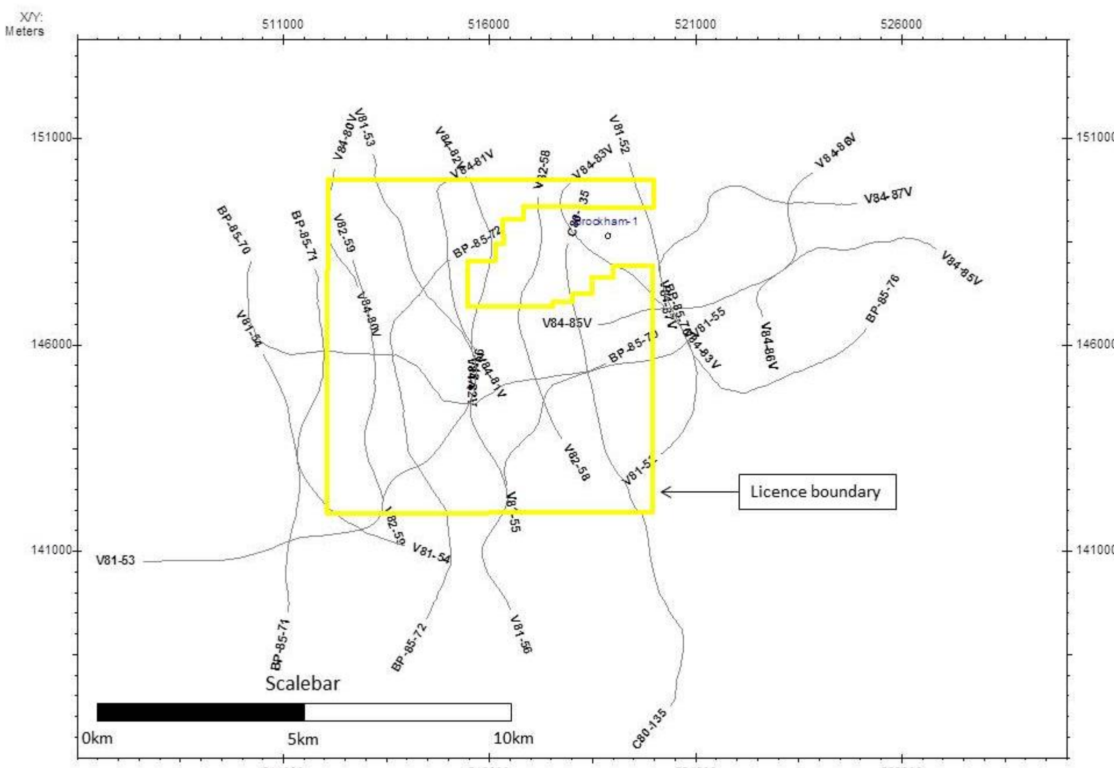


Figure 2.3: Seismic and well database over the Holmwood prospect

The seismic database over Licences PEDL180 and PEDL182 consists of various vintages of 2D lines acquired between 1977 and 1987 and two wells; Wells Crosby Warren -1 and Broughton -1 (Figure 2.4).

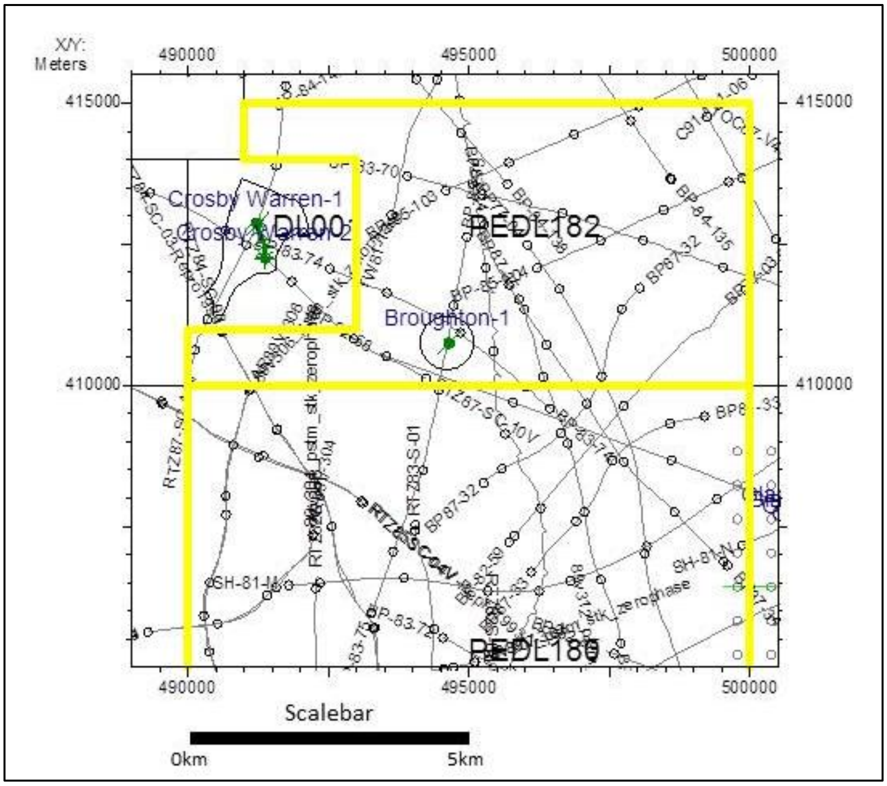


Figure 2.4: Seismic and well database over the Wressle and Broughton prospects

2.3. Geological Setting and Prospectivity

2.3.1. East Midlands Regional Geological Setting

The Broughton and Wressle prospects are located on the NE margin of the East Midlands oil (and gas) province, which is an area of block faulted Upper Namurian and Westphalian A – C sediments. The rocks comprise interbedded shales, coals and sandstones, deposited in a fluvial-deltaic environment, with marine incursions producing dateable marine bands which provide excellent markers to aid correlation of the sandstone reservoirs.

Sand body geometries are variable. The thicker sandstones are channel fills or mouth-bars, and are therefore discontinuous, whereas other usually thinner sandstones are more continuous overbank deposits. The sandstones tend to be clean and quartzose, but have rather low average porosities (12-16%), though there are individual core data points of >25%. Permeability averages 1 – 20 md, but there are individual core data points of greater than one darcy permeability.

Block faulting was active throughout the Namurian/Westphalian, and there is a tendency for sequences to be thicker on the downthrown side of normal faults, and for the contemporary structural growth to affect depositional patterns. Oil is sourced from the pro-delta shales, which are presumed to be particularly organic rich in areas such as the Widmerpool Gulf. Uplift and erosion at the end of the Westphalian produced a major unconformity, at which level the block faulting dies out. Subsidence during the deposition of the overlying Permo-Triassic produced further thermal maturity, and it is possible that oil generation is continuing at the present day. Although hydrocarbon accumulations in the East Midlands are predominantly of oil, coals could provide a gas charge, and there are gas fields to the west at Hatfield Moors and east at Saltfleetby.

Charging of sandstones appears to be direct from surrounding shales and migration does not appear to be an issue.

2.3.2. Weald Basin Regional Geological Setting

The Holmwood prospect lies near the northern margin of the Weald Basin. This basin consists of a number of E-W trending half graben formed during the Jurassic and Cretaceous. The basin was subject to strong regional and local scale inversion during the Tertiary as a result of Alpine movements. Reservoirs are present in the Middle Jurassic Great Oolite, Late Jurassic Corallian sandstones and Cretaceous Portland Sandstones. The main source rock in the basin is the Oxford Clay which became mature during Late Cretaceous thermal subsidence. Hydrocarbon expulsion ceased during Tertiary uplift and subsequent cooling. The Kimmeridge Clay Formation does not appear to have reached thermal maturity in the basin.

2.4. The Broughton Prospect

The Broughton Prospect is located between the Crosby Warren Field and Well Broughton-1. Mapping suggests it lies slightly up-dip of Well Broughton-1. The prospect is covered by two 2D seismic lines and the structure is formed by three-way dip closure and down-faulted closure against a NW-SE trending, down to the NE normal fault (Figure 2.5). It appears to be separated from Well Broughton-1 by a saddle. The main risk to the prospect is to trap/containment, as it requires side-seal across the bounding fault to the north. The orange contours on Figure 2.5 shows the low and high areas assigned to our volumetric cases.

The reservoir of the Crosby Warren field is the Beacon Hill Flags in the Upper Namurian (gross thickness 10-24 m, net to gross ratio of some 0.75 and average porosity of 14%). The Penistone Flags (Middle Westphalian A) and Chatsworth Grit (Upper Namurian) reservoirs are absent within the Crosby Warren field but present in Well Broughton-1. The Penistone flags and Chatsworth Grit are proposed as potential reservoirs in the Broughton prospect.

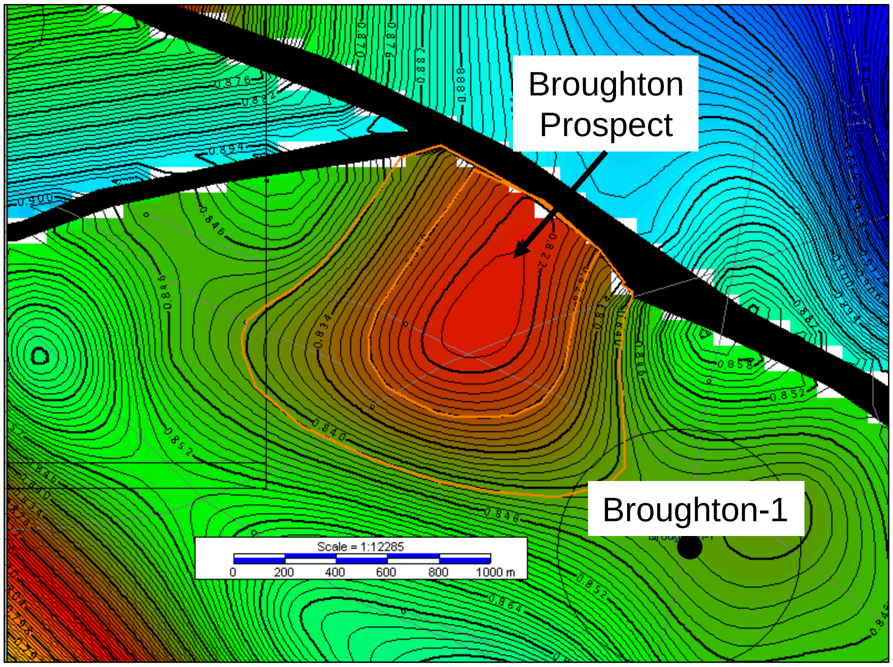


Figure 2.5: Top Westphalian A time structure map over the Broughton prospect

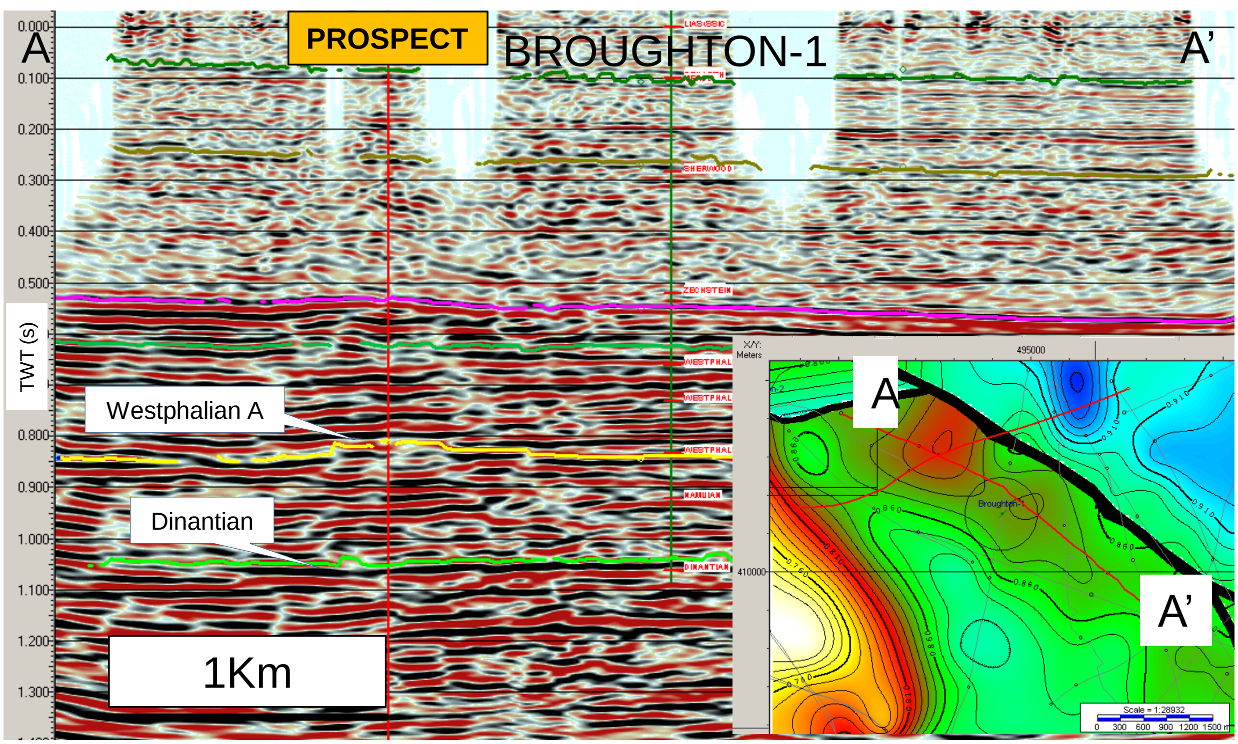


Figure 2.6: NW-SE Seismic Line (BP83-74) over the Broughton prospect & through Well Broughton-1.

For the Penistone Flags reservoir (Figure 2.7) the well completion report (WCR) for Well Broughton-1 notes a gross sand of 18.5 m, average porosity of 12%, and permeability 5.5 md. Review of core data from this interval shows averages of porosity 12.8% and permeability 4.2 md. The core shows mainly massive sand. This interval was tested in Well Broughton-1. DST 1 produced 15 bbl dry oil in 9 hrs, and DST 8A produced 9 bbl oil + 6 bbl water in 9.5 hrs.

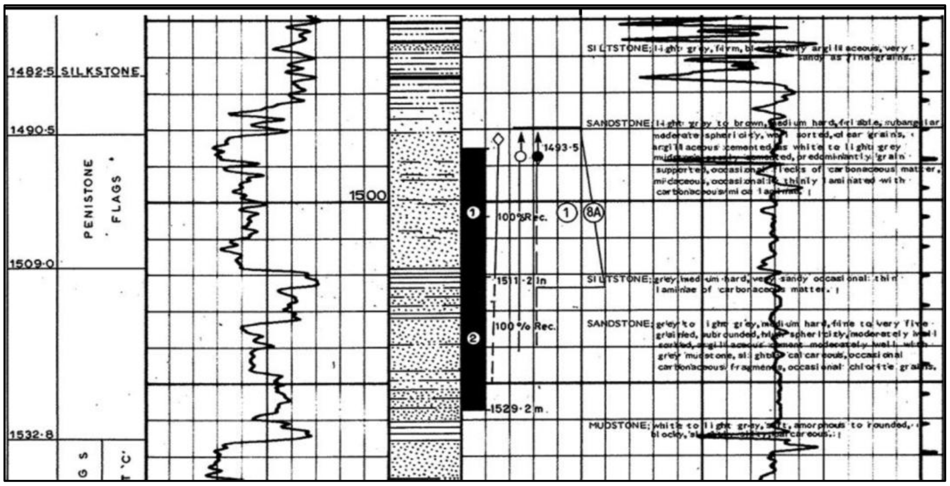


Figure 2.7: Penistone Flags reservoir, Well Broughton-1

For the Chatsworth Grit, (Figure 2.8), the Well Broughton-1 WCR notes the gross reservoir thickness is 14.2 m, but the main sand thickness is 10.9 m with an average porosity of 13%, and average permeability of 70 md. The average of the core data is 14% porosity and 40 md permeability. The core description shows a uniform sandstone with steep cross bedding. Permeabilities are uniformly better than the Penistone Flags. There is fluorescence but no oil stain in the core. A test in this interval, DST 6, flowed 138 bbl/d water.

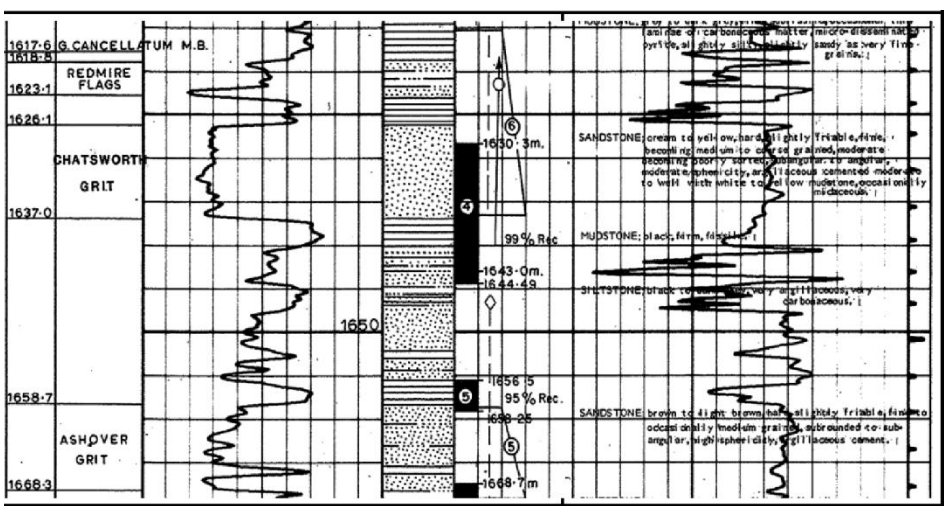


Figure 2.8: Chatsworth Grit reservoir, Well Broughton-1

2.4.1. HIIP, Prospective Resources and Risks

We have made estimates of STOIIP and resources for the Broughton prospect Penistone Flags and Chatstone Grit reservoirs using probabilistic methods. As seismic control is poor, we have used an area/net methodology, making low and high case estimates of area of closure, shape factor and gross reservoir thickness to define the P90 and P10 of a log normal distribution of gross rock volume in our probabilistic simulation. Other reservoir and fluid parameters, and recovery factors, are derived from Well Broughton-1, and offset producing fields. The input parameters to, and results from, our probabilistic simulation of STOIIP and resource for both reservoir targets are presented in Table 2.1 and Table 2.2.

Penistone Flags	**P90**	**P50**	**P10**
Area (km2)	0.57		1.42
Gross pay (m)	10		26
Shape factor	0.50		0.87
GRV MMm3)	2.9	9.6	32.1
N/G	0.50	0.70	0.90
Phi	0.10	0.12	0.14
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.20	1.30	1.40
STOIIP (MMstb)	**0.75**	**2.51**	**8.74**
Recovery Factor	0.15	0.23	0.30
Prospective Resource (MMstb)	**0.15**	**0.55**	**1.99**

Table 2.1: Input volumetric parameters and results, Broughton prospect, Penistone Flags reservoir

Chatsworth Grit	**P90**	**P50**	**P10**
Area (km2)	0.57		1.42
Gross pay (m)	9		18
Shape factor	0.50		0.92
GRV MMm3)	2.6	7.8	23.5
N/G	0.80	0.90	0.95
Phi	0.10	0.13	0.16
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.20	1.30	1.40
STOIIP (MMstb)	**0.88**	**2.79**	**8.66**
Recovery Factor	0.15	0.23	0.30
Prospective Resource (MMstb)	**0.18**	**0.60**	**1.94**

Table 2.2: Input volumetric parameters and results, Broughton prospect, Chatsworth Grit reservoir

We use a four component risk matrix to assign geological chance of success (COS) to the two prospective reservoirs of the Broughton prospect. The main risk with the Broughton prospect is to trap, as the structure is defined only on a sparse grid of 2D seismic lines and because of cross fault seal risk across the bounding fault, given the number of sandstone beds in the section. Reservoir presence and effectiveness is a lesser risk; both the Penistone Flags and Chatsworth Grit are present in Well Broughton-1 (although the latter was water bearing) but neither are present in the Crosby Warren field. We see a slightly higher risk to reservoir presence and quality in the deeper Chatsworth Grit relative to the Penistone Flags. Overall prospect risks are presented in Table 2.3 below.

Penistone Flags		Chatsworth Grit	
Source	1	Source	1
Reservoir	0.8	Reservoir	0.7
Seal	0.9	Seal	0.9
Trap	0.5	Trap	0.5
COS (%)	**36%**	**COS (%)**	**32%**

Table 2.3: Chance of success, Broughton prospect, Penistone Flags and Chatsworth Grit reservoirs

Enclosures 2.1 and 2.2 present the prospect summary sheets for Broughton.

2.5. The Wressle Prospect

The Wressle Prospect is located 3 km southeast of Well Broughton-1, and 7 km southeast of the Crosby Warren field (Figure 2.1). The prospect is covered by six 2D seismic lines and is formed by three-way dip closure and down-faulted closure against a NW-SE trending, down to the NE normal fault. Our High Case area is similar to the areal extent of the Crosby Warren Field.

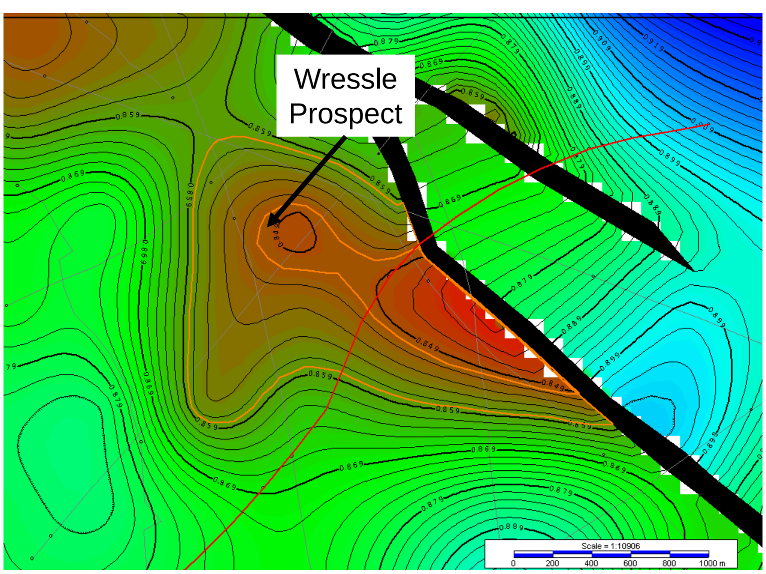


Figure 2.9: Top Westphalian A time structure map, Wressle prospect.

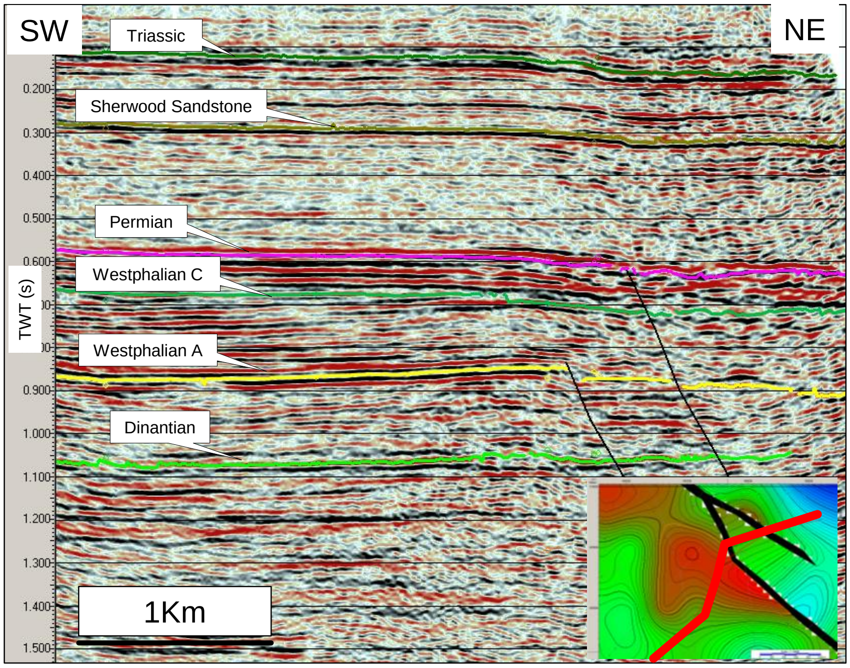


Figure 2.10: SW-NE seismic line 9BP87-33) over the Wressle prospect

The Penistone Flags (Middle Westphalian A) and Chatsworth Grit (Upper Namurian) reservoirs are absent at Crosby Warren but present in Well Broughton-1, as discussed in Section 2.4. We have taken the Penistone Flags and Chatsworth Grit as the prognosed reservoir targets in the Wressle prospect. A description of these reservoirs can be found in Section 2.4.

2.5.1. HIIP, Prospective Resources and Risks

We have made estimates of STOIIP and resources for the Wressle prospect Penistone Flags and Chatstone Grit reservoirs using probabilistic methods in a similar manner to our estimates for the Broughton prospect. As seismic control is poor, we have used an area/net methodology, making low and high case estimates of area of closure, shape factor and gross reservoir thickness to define the P90 and P10 of a log normal distribution of gross rock volume in our probabilistic simulation. Other reservoir and fluid parameters, and recovery factors, are derived from Well Broughton-1, and offset producing fields. The input parameters to, and results from, our probabilistic simulation of STOIIP and resource for both reservoir targets are presented in Table 2.4 and Table 2.5.

Penistone Flags	P90	P50	P10
Area (km2)	0.48		1.75
Gross pay (m)	10		26
Shape factor	0.83		0.85
GRV MMm3)	4.0	12.4	38.7
N/G	0.50	0.70	0.90
Phi	0.10	0.12	0.14
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.20	1.30	1.40
STOIIP (MMstb)	**0.95**	**3.53**	**12.50**
Recovery Factor	0.15	0.23	0.30
Prospective Resource (MMstb)	**0.20**	**0.77**	**2.89**

Table 2.4: Input volumetric parameters and results, Wressle prospect, Penistone Flags reservoir

Chatsworth Grit	P90	P50	P10
Area (km2)	0.48		1.75
Gross pay (m)	9		18
Shape factor	0.78		0.86
GRV MMm3)	3.4	9.6	27.1
N/G	0.8	0.9	0.95
Phi	0.1	0.13	0.16
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.2	1.3	1.4
STOIIP (MMstb)	**1.13**	**3.38**	**10.12**
Recovery Factor	0.15	0.225	0.3
Prospective Resource (MMstb)	**0.24**	**0.73**	**2.28**

Table 2.5: Input volumetric parameters and results, Wressle prospect, Chatsworth Grit reservoir

The main risk with the Broughton prospect is to trap, as the structure is defined only on a sparse grid of 2D seismic lines and because of cross fault seal risk across the bounding fault, given the number of sandstone beds in the section. Reservoir presence and effectiveness is a lesser risk; both the Penistone Flags and Chatsworth Grit are present in Well Broughton-1 (although the latter was water bearing) but neither are present in the Crosby Warren field. We see a slightly higher risk to reservoir presence and quality in the deeper Chatsworth Grit relative to the Penistone Flags. Overall prospect risks are presented in Table 2.6: Chance of success, Wressle prospect, Penistone Flags and Chatsworth Grit reservoirs Table 2.6.

Penistone Flags

Source	1
Reservoir	0.8
Seal	0.9
Trap	0.5
COS (%)	**36%**

Chatsworth Grit

Source	1
Reservoir	0.7
Seal	0.9
Trap	0.5
COS (%)	**32%**

Table 2.6: Chance of success, Wressle prospect, Penistone Flags and Chatsworth Grit reservoirs

Enclosures 2.3 and 2.4 present the prospect summary sheets for Wressle.

2.6. The Holmwood Prospect

The Holmwood Prospect (Figure 2.2) is a faulted hanging wall anticline south of the northern bounding fault to the Weald Basin. The well and seismic database used for our evaluation is shown in Figure 2.3. In all, around four to five seismic lines constrain the prospective structure. The nearest offset well is Well Brockham-1.

Two horizons have been mapped and are prognosed as potential reservoirs within the prospect: Near Top Portland (Figure 2.11) and near Top Corallian. Figure 2.12 shows a seismic section across the structure. At the Corallian level the trap consists of four way dip with normal faults at its crest, and at the overlying Portlandian level, the structure is a three way dip-closed fault bound high. Both are of low relief.

Prospective reservoir horizons identified from Well Brockham-1 are the Portland Sandstone and Corallian Sandstone Formations (Figure 2.13). Sealing facies for each reservoir are found in the Purbeck and Kimmeridge Clay Formations respectively.

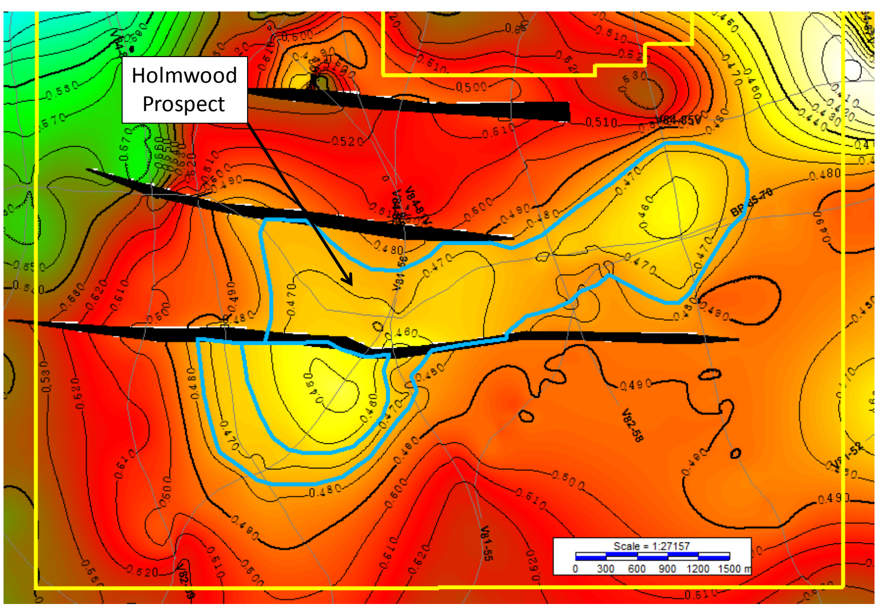


Figure 2.11: Top Portland Sandstone time structure map, Holmwood prospect.

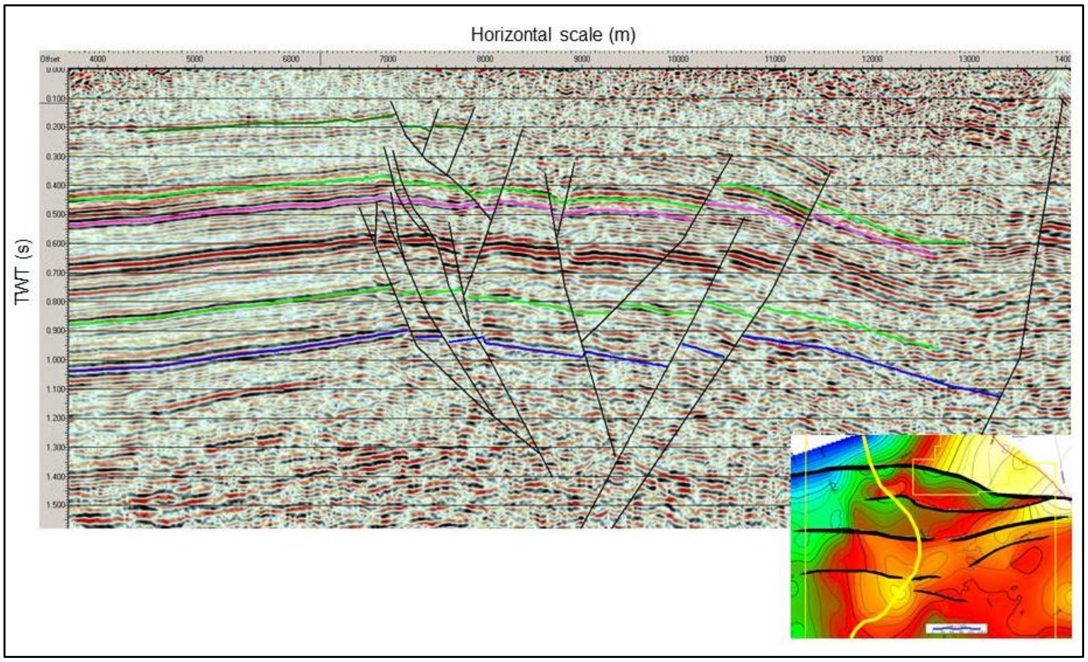


Figure 2.12: N-S seismic line (V81-53) over the Holmwood prospect

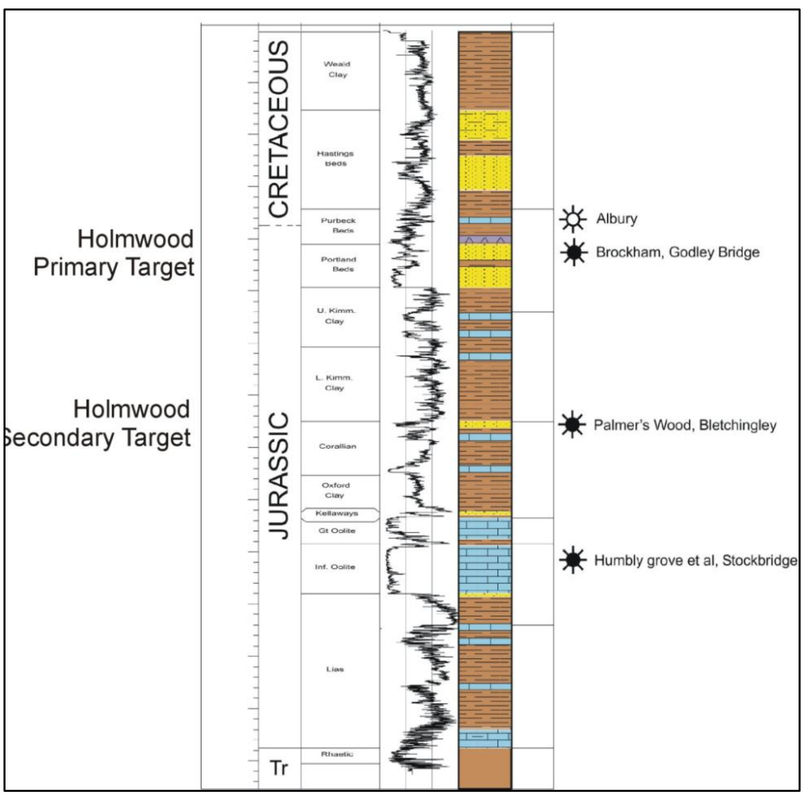


Figure 2.13: Stratigraphy, Holmwood prospect, (Well Brockham-1)

The Portland Sandstone is interpreted as a shallow marine sheet sand, shed off of the London Platform to the north, and gradually shaling out southwards. In the Brockham area it is vertically sealed by the Purbeck Anhydrite.

The Portland Sandstone in the Brockham field comprises a gross interval of c.12 m thickness (Figure 2.14), but only 2 m net oil pay is interpreted.

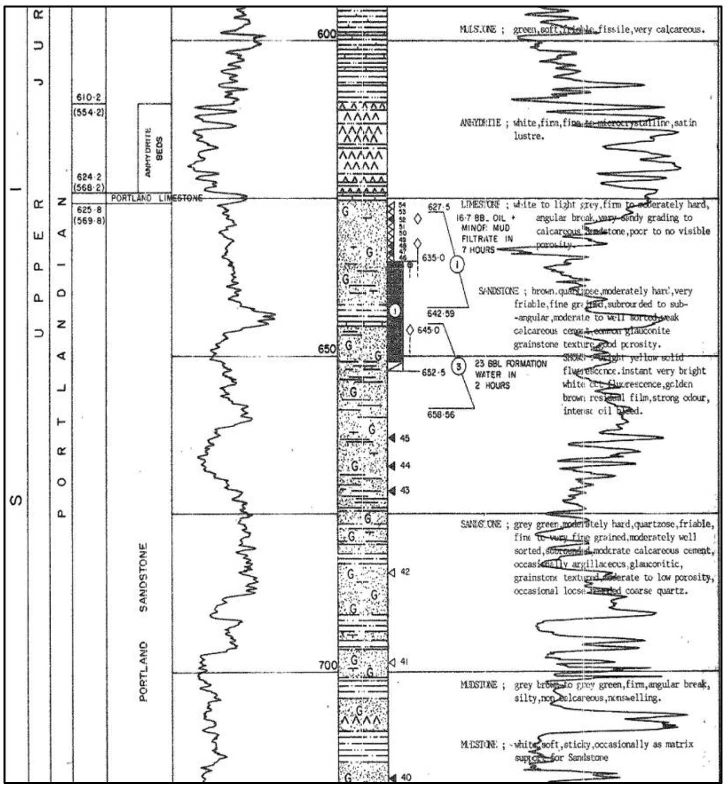


Figure 2.14: Portland Sandstone, Well Brockham-1

The Corallian reservoir is also present in Well Brockham-1. We have chosen this section and the correlative reservoir in the Palmers Wood field as our analogue for the Holmwood prospect. Like the Portland Sandstone, the Corallian is also composed of shallow marine sandstones. Porosity in the Palmers Wood reservoir averages 17%, with a range of 10 – 22%. Permeabilities are 5-7 md and oil saturation averages 65%, with a range of 25 – 70% (Trueman 2003). The Corallian appears to thicken southward from Palmers Wood to Well Brockham-1, where there is 15 m gross sandstone which has slight fluorescence Figure 2.15.

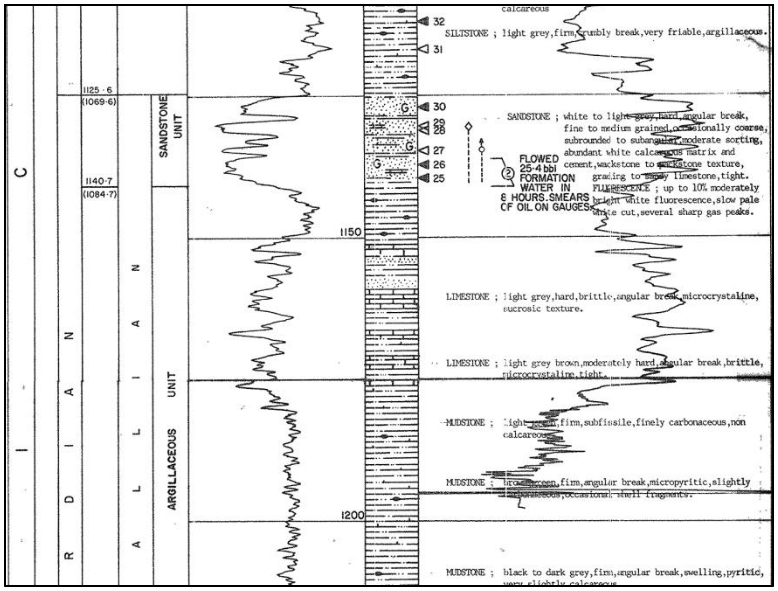


Figure 2.15: Corallian section, Well Brockham-1

Source for the oil is likely to be Lower Jurassic, which reached maturity prior to Tertiary inversion of the Wealden Basin. The Kimmeridge Clay does not appear to have entered the oil window in this area. There is a risk of gas charge, as fields to the south of the Holmwood prospect are of gas, rather than oil. The pre-inversion thermal maturity of the source rocks means that old structures are more prospective, unless oil can be spilled from pre-existing structures during inversion.

2.6.1. HIIP, Prospective Resources and Risks

We have made estimates of STOIIP and resources for the Holmwood prospect Portlandian Sandstone and Corallian reservoirs using probabilistic methods. As seismic control is poor, we have used an area/net methodology, making low and high case estimates of area of closure, shape factor and gross reservoir thickness to define the P90 and P10 of a log normal distribution of gross rock volume in our probabilistic simulation. Other reservoir and fluid parameters, and recovery factors, are derived from Well Brockham-1 and the Palmers Wood field. The input parameters to, and results from, our probabilistic simulation of STOIIP and oil prospective resource for both reservoir targets are presented in Table 2.7 and Table 2.8 .

Portland Sandstone	P90	P50	P10
Area (km2)	1.40		7.50
Gross pay (m)	10.00		20.00
Shape factor	0.80		0.60
GRV MMm3)	11.2	31.7	90.0
N/G	0.10	0.14	0.20
Phi	0.20	0.25	0.26
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.05	1.10	1.15
STOIIP (MMstb)	**1.23**	**3.75**	**11.42**
Recovery Factor	0.15	0.23	0.30
Prospective Resource (MMstb)	**0.26**	**0.82**	**2.61**

Table 2.7: Oil input parameters & results, Holmwood prospect, Portland Sandstone reservoir

Corallian Sandstone	P90	P50	P10
Area (km2)	1.63		7.70
Gross pay (m)	10.00		20.00
Shape factor	0.95		0.96
GRV MMm3)	15.49	47.85	147.84
N/G	0.20	0.50	0.70
Phi	0.10	0.17	0.22
So	0.55	0.65	0.75
FVF (res bbl/stb)	1.23	3.75	11.42
STOIIP (MMstb)	**2.60**	**11.63**	**43.96**
Recovery Factor	0.15	0.23	0.30
Prospective Resource (MMstb)	**0.55**	**2.54**	**9.90**

Table 2.8: Oil input parameters & results, Holmwood Prospect, Corallian Sandstone reservoir

The main risk with the prospect is to trap, as the structure is defined only on a sparse grid of 2D seismic lines and is low relief. Closure is therefore difficult to define, particularly to the east. We see an increased risk to trap definition at the deeper Corallian Sandstone level. Reservoir presence and effectiveness is a lesser risk; both the Portland Sandstone and Corallian Sandstone are present in Well Brockham-1 (although the latter was water bearing). Overall prospect risks are presented in Table 2.9.

Portland Sandstone	
Source	1
Reservoir	0.7
Seal	0.9
Trap	0.5
COS (%)	**32%**

Corralian Sandstone	
Source	1
Reservoir	0.7
Seal	0.9
Trap	0.4
COS (%)	**25%**

Table 2.9: Chance of success, Holmwood Prospect, Portland and Corallian Sandstone reservoirs

We note that due to the presence of gas fields to the south of the Holmwood prospect there is a risk to gas charge for the prospect, which we estimate at 50%. The input parameters to, and results from, our probabilistic simulation of GIIP and gas prospective resource for both reservoir targets are presented in Table 2.10 and Table 2.11.

Portland Sandstone	**P90**	**P50**	**P10**
Area (km2)	1.40		7.50
Gross pay (m)	10.00		20.00
Shape factor	0.80		0.60
GRV MMm3)	11.2	31.7	90.0
N/G	0.10	0.14	0.20
Phi	0.20	0.25	0.26
So	0.55	0.65	0.75
GEF (scf/rcf	61.2	64.4	67.6
GIIP (bcf)	**0.49**	**1.48**	**4.53**
Recovery Factor	55	65	75
Prospective Resource (bcf)	**0.31**	**0.95**	**2.96**

Table 2.10: Gas input parameters & results, Holmwood prospect, Portland Sandstone reservoir

Corallian Sandstone	**P90**	**P50**	**P10**
Area (km2)	1.63		7.70
Gross pay (m)	10.00		20.00
Shape factor	0.95		0.96
GRV MMm3)	15.49	47.85	147.84
N/G	0.20	0.50	0.70
Phi	0.10	0.17	0.22
So	0.55	0.65	0.75
GEF (scf/rcf	108.0	113.7	119.4
GIIP (bcf)	**1.83**	**8.31**	**30.12**
Recovery Factor	65	75	85
Prospective Resource (bcf)	**1.36**	**6.17**	**22.75**

Table 2.11: Gas input parameters & results, Holmwood prospect, Corallian Sandstone reservoir

Enclosures 2.5 and 2.6 present the prospect summary sheets for Holmwood.

A planning application to drill the Holmwood prospect has been refused. An appeal against this decision has been initiated by the licence owners, the result of which should become available later in 2012.

3. Onshore France

Europa has a 100% interest in two licences in the Aquitaine Basin of southwest France (Figure 3.1). The Béarn des Gaves licence contains the deep, high-pressure Berenx gas discovery and the Tarbes Val d'Adour contains two abandoned oil fields, Osmet and Jacque, which are being considered for re-development.

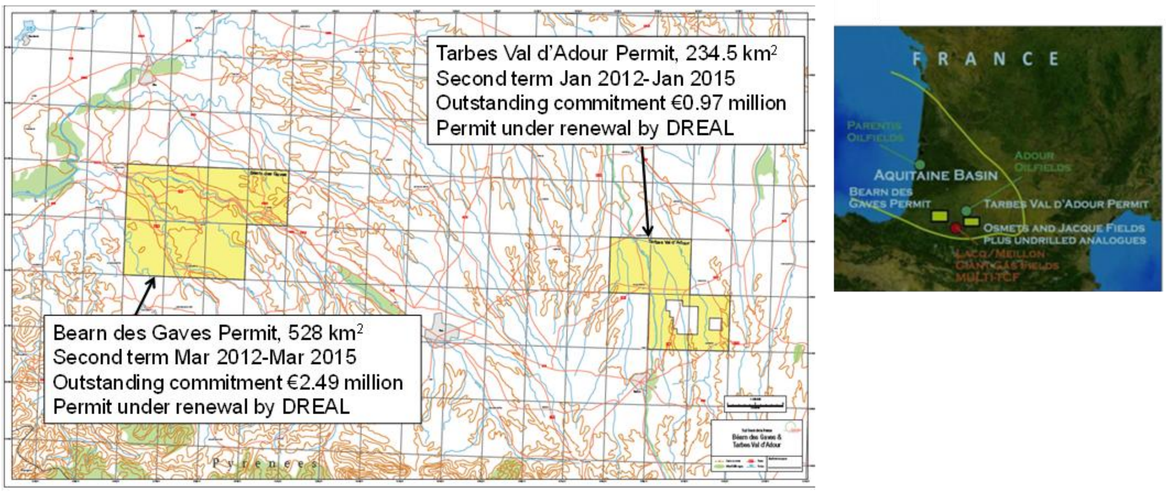


Figure 3.1 Béarn des Gaves & Tarbes Val d'Adour location map with anticipated renewal licence areas

3.1. Béarn des Gaves

3.1.1. Introduction

The Béarn des Gaves licence was acquired in March 2007 for an initial five year term which finished in March 2012. A three-year renewal of the licence has been applied for covering an area of 528 km^2. This renewal is under active discussion with the authorities (Bureau Exploration Production des Hydrocarbures (BEPH) and Directions Régionales de l'Environnement, de l'Aménagement et du Logement (DREAL)) but this process can take many months to finalise. Nevertheless, it is still possible to continue work through this time. Work to date has comprised seismic reprocessing and interpretation studies. Future expenditure of EUR 2.49 MM has been offered.

3.1.2. Geological Setting and Prospectivity

The licence contains a high pressure, very sour, gas accumulation near to the established gas production infrastructure of the Lacq and Meillon Fields (Figure 3.1). It has been drilled by two closely adjacent wells, Wells Berenx-1 and Berenx-2 in 1969 and 1972, both of which had gas shows over an interval of about 400 m of carbonate rocks below 5500 m. Testing of a single 12 m interval in Well Berenx-2 produced gas at 0.3 MMscf/d after acidisation.

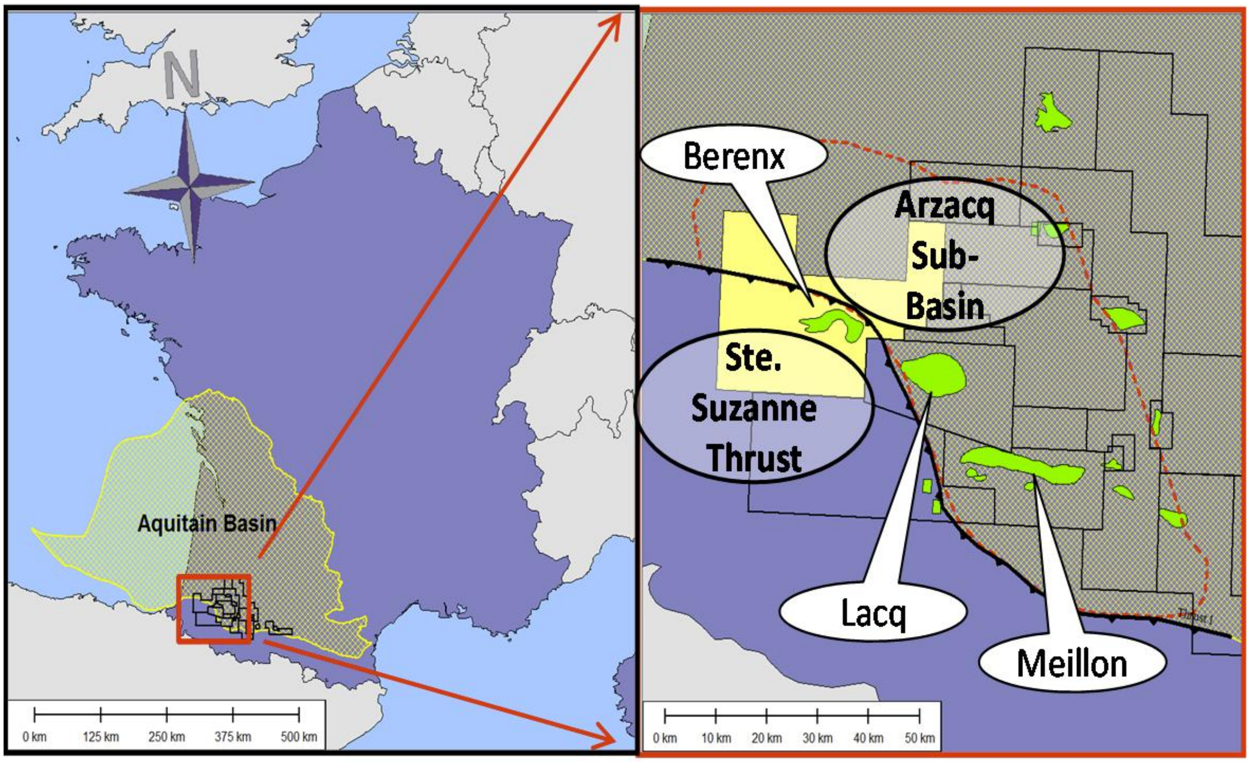


Figure 3.2 Location of Berenx discovery to the west of the Lacq and Meillon gas fields

Europa also recognises a separate shallower potential trap at 2100-2800 m which we call Berenx Shallow in this report and describe after our evaluation of the deep discovery.

The Berenx discovery is located in the Aquitaine Basin of south-west France and is associated with the interplay of the North Pyrenean front zone with its complex over-thrusts, and the Arzacq Sub-Basin to the north, where sedimentation was controlled by the overthrusting and which is partially overlapped by the thrusts (Figure 3.1 and Figure 3.3). Berenx lies underneath the Sainte Suzanne Thrust Unit and the Upper Jurassic to Middle Cretaceous autochtonous sequence is overlain by an allochtonous unit whose thrusting is facilitated by Triassic salt. The thrust is complex in detail and the Berenx well penetrations show inverted and repeated section (Figure 3.3). The Berenx Shallow lead lies in this over-thrust complex.

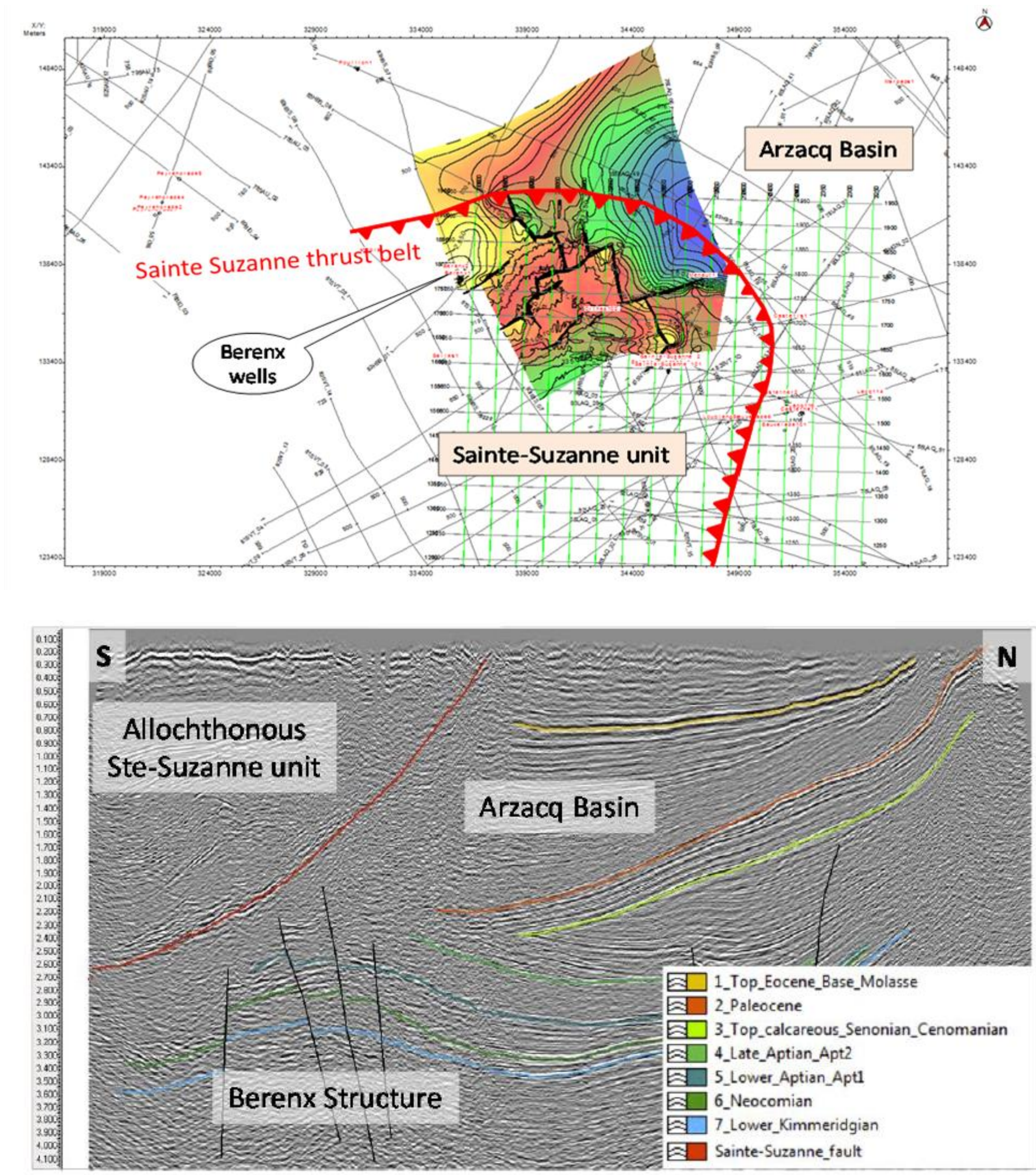


Figure 3.3 Time structure map at Kimmeridgian level and representative 2D seismic line

The structure is covered by 3D seismic to the east but only scattered 2D lines to the west (Figure 3.3). The most recent seismic time interpretation suggests that the structure is complex and the area of closure is not defined. Closure to the southwest is probably provided, in part, by the Ste Suzanne thrust fault. The seismic data are in time but the overthrust section contains high velocity sediments that make two way time (TWT) maps unreliable as an indicator of depth structure. Europa has recognised that additional 3D data and pre-stack depth migration are required to better image the structure and assist in depth conversion. This survey will go some way to achieving coverage of the structure but additional seismic acquisition may be necessary to complete the coverage.

The Upper Jurassic – Lower Cretaceous carbonate reservoir interval of the Berenx area is highly overpressured and deep (greater than 5500 m). Based on log interpretation from the Berenx wells, (Figure 3.4), the porosity is very low (only locally greater than 3%) and, despite strong gas shows over a long interval whilst drilling, a DST over a small interval in Well Berenx-2 flowed at 0.3 MMscf/d after acidisation. This zone had the best log porosity. The lithologies are mainly micritic limestones. Fracture porosity and permeability will be critical to commercial flow rates and to draining any gas held in the rock matrix. Whilst fracture development is likely its extent and effectiveness are yet to be established.

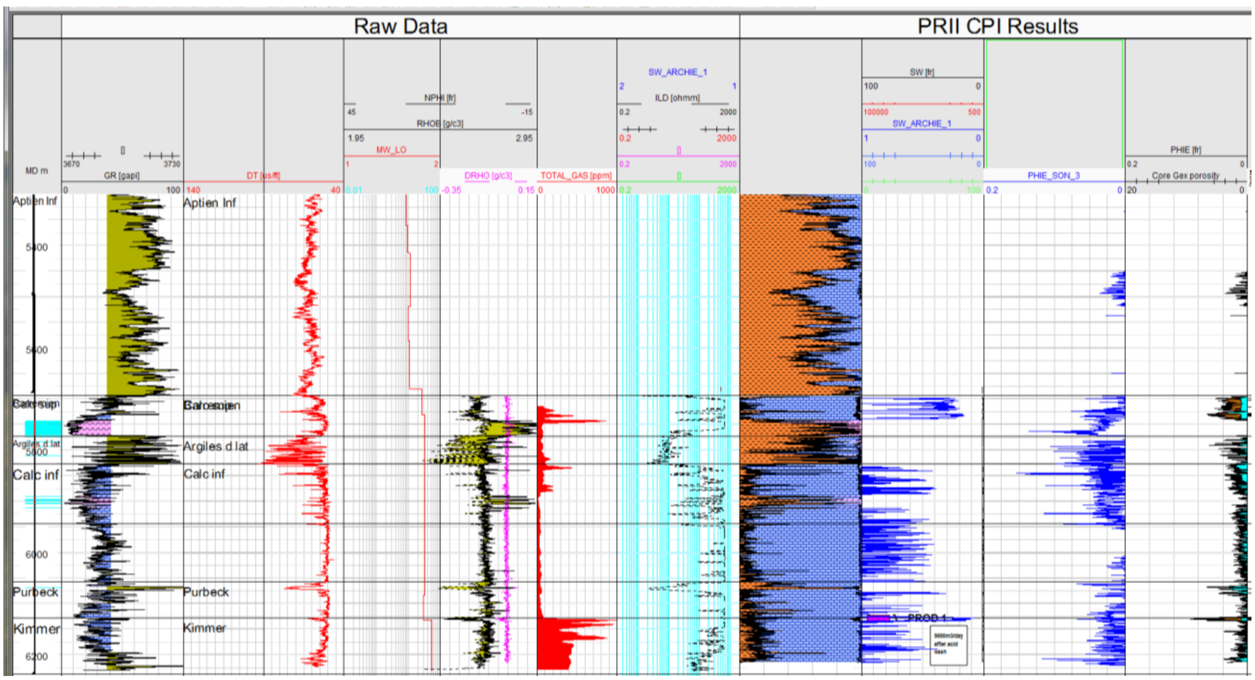


Figure 3.4 CPI log of Well Berenx-2 reservoir section

3.1.3. HIIP, Contingent Resources and Risk

Given the great uncertainty as to the Berenx discovery's size and shape our resource estimate range is necessarily very wide. There is also considerable uncertainty as to the reservoir characterization and potential productivity. As a result, we have used an area/net methodology, and made our estimates using probabilistic methods.

Given the lack of structural definition at the reservoir level it is hard to assign areas for volumetric purposes. There could be one large hydrocarbon column or multiple reservoirs or it could be an 'unconventional' reservoir whose productivity is unrelated to structural trapping. We have assigned a range of areas derived from the Kimmeridgian TWT map but this range is based more on our experience of the size of structure that is consistent with the possible vertical gas column seen in the wells than any objective depth structure mapping.

The logs are incapable of distinguishing gas and water-bearing intervals. We have estimated volumetrics for fracture and matrix porosity separately. We have used the Well Berenx-2 porosity log for guidance on the matrix porosity and the matrix net to gross ratio. For the fracture porosity range we have used our experience of fractured reservoirs worldwide. We have also assumed a range of gas saturations for the fracture and matrix cases based on our experience.

Most drilling gas indications suggest dry gas to be present, although no analysis of the DST gas was presented. There are indications of high H_2S from gas readings. The nearby Lacq field has 10% H_2S and 15% CO_2 and other nearby fields also have significant inert content. We assume a 14%-22%-29% range of inert gas for Berenx in the overall gas volume.

The input parameters for our probabilistic estimation of GIIP and contingent resource in the fractures and matrix are presented in Enclosures 3.1 and 3.2.

Production from existing fields is currently processed at the Lacq-Mourenx plant where sulphur and CO_2 are stripped and the gas and sulphur are processed for market. There is capacity in the plant to accept all gas produced from Berenx, and Europa advises it has already entered into discussion with the plant owners regarding potential gas processing and sales.

Table 3.1 presents our estimates of GIIP and contingent resources after removal of the assumed inert fraction, giving notional sales gas resource. The fracture and matrix volumes have been added probabilistically.

	GIIP			Unrisked Contingent Resource			
	Low (Bcf)	Best (Bcf)	High (Bcf)	Low (Bcf)	Best (Bcf)	High (Bcf)	Mean (Bcf)
Berenx Matrix	14	92	616	7	49	341	145
Berenx Fracture	10	74	534	5	40	292	132
TOTAL	58	245	1120	31	134	623	277

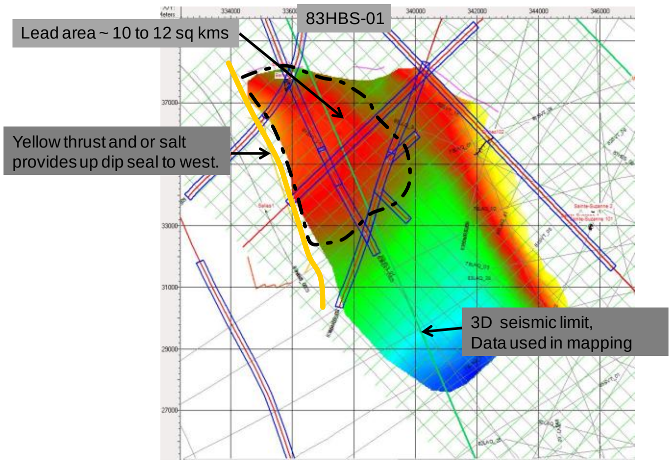
Table 3.1 GIIP and contingent gas resource estimates for the Berenx discovery

The key risk for the future development potential of Berenx will be demonstrating the presence of an efficient open fracture system which can sustain commercial flow rates. An appraisal well is required to test the potential reservoir zones using modern drilling, completion and testing techniques and also to sample the fluids to establish the gas composition. In addition, the acquisition and PSDM processing of a sizeable 3D seismic survey will be required in order to define the trap size and configuration.

Notwithstanding that the Berenx discovery is poorly defined at present, this is a productive basin with large gas fields and the wider area may be potentially interesting if depth imaging could be improved.

3.1.4. Berenx Shallow Lead

During the drilling of the Berenx wells there were also strong gas indications within the shallow allochtonous section in Well Berenx-1 over a 110 m interval, although not in Well Berenx-2, which is interpreted to be some 170 m downdip at this level. Gas shows were concentrated in the same Upper Jurassic to Middle Cretaceous carbonate interval that forms the deep reservoir that is repeated at 2100-2800 m in the over-thrust (Figure 3.5).



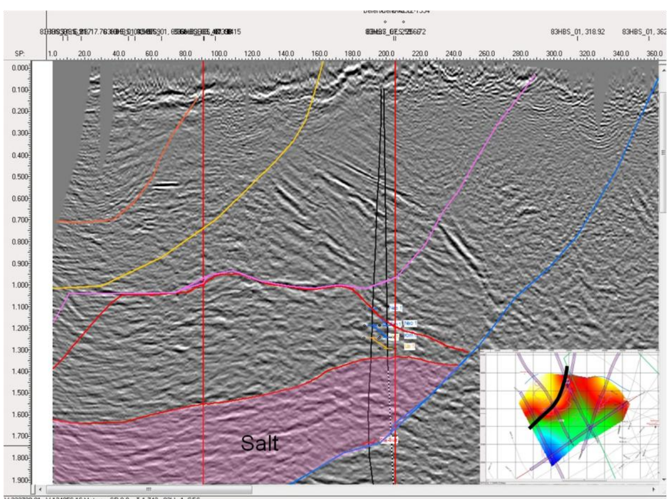


Figure 3.5 Schematic structure map and seismic section for the Berenx Shallow lead

This interval occurs just above the Triassic salt and the structural 'form' map is on the red horizon in Figure 3.5. Structural definition in the complex zone of imbricate thrusting is presently inadequate to understand the possible trapping mechanism. Also, closure to the west is not adequately defined. Europa plans to acquire some new 2D seismic lines to clarify the structure, which is currently assessed as having an area of some 10 to 12 km^2 and may contain some 75 bcf gas initially in place.

Evaluation of the reservoir quality at this level is hampered by a limited logging suite in both wells but reservoir parameters are not expected to be significantly different to the deeper section. Again, an efficient open fracture system will be vital to obtaining commercial flow rates for any gas present.

We consider that this shallow section carries more risk than the deep accumulation. Gas has not been proven by test, log coverage is poor and the trapping mechanism is not adequately defined. Nevertheless, we note that Gallic Energy is targeting a similar idea in the adjacent Ledeuix licence to the south and we consider this to be a valid play concept. We see the Berenx Shallow target as a lead at present, requiring further geotechnical data and work to develop into a prospect. As such, we have not undertaken a quantitative assessment of resources or risk

3.1. Tarbes Val d'Adour

3.1.1. Introduction

The Tarbes Val d'Adour licence was acquired by Europa (100%) in January 2007 for an initial five year term which finished in January 2012. A three-year renewal of the licence has been applied for covering an area of 234.5 km^2. This renewal is under active discussion with the authorities but, as mentioned earlier, this process can take many months to finalise. Work to date has comprised purchase of 1200 km of 2D seismic data, reprocessing of 600 km of 2D seismic, and interpretation studies. Future expenditure of EUR 0.97 MM has been offered.

3.1.2. Geological Setting and Prospectivity

The licence contains two abandoned oil fields, Osmets and Jacque (Figure 3.6). Both were discovered and produced by SNEA and both were shut-in in 1986.

Osmets Field

The Osmets field comprised two wells. Well Osmets-1 discovered 33^{o}API oil in the Upper Jurassic Meillon Dolomite in 1976 at a depth below 3500 m. Production was shut in after a few months but the well was re-opened in 1981 when the Well Osmets-2 discovered 27.5^{o}API oil in Aptian-Albian reefal carbonates at approximately 3000 m. Both wells were shut-in in 1986. Both wells had initial oil production rates of approximately 150 stb/d and the total production was approximately 45,000 bbl with a final water cut of 70%.

The area has a complex geological history with important unconformities at the Base Cretaceous and within the Cretaceous (the Austrian Unconformity). Although Well Osmets-2 is only 1 km NW of Well Osmets-1 it has a significantly thinner Upper Jurassic section and a greatly expanded Lower Cretaceous section (Figure 3.7). Moreover, although Well Osmets-2 is updip of Well Osmets-1 at the Meillon Dolomite level it is water-bearing in this zone despite the oil downdip. Seismic data are of limited quality and currently do not fully resolve the area's structural and stratigraphic complexity.

The Meillon Dolomite in Well Osmets-1 is 25-30 m in thickness and the average porosity is 3-5%. Production from Well Osmets-2 was only from the deepest of three pay zones in the Aptian Albian

Cretaceous reservoir interpreted by SNEA (Figure 3.8). The total interpreted pay is 13.6 m from a 44 m gross interval. Average porosity is estimated at 12%. No OWC was seen in the well.

The main potential for re-development of Osmets is thought to lie in the Cretaceous reservoir seen in Well Osmets-2. The Aptian-Albian carbonates appear to be regionally laterally continuous and could potentially be targeted updip of the discovery well, possibly with a horizontal well to maximise the production rate. Presently, there is significant uncertainty in the structural interpretation and the control on trapping.

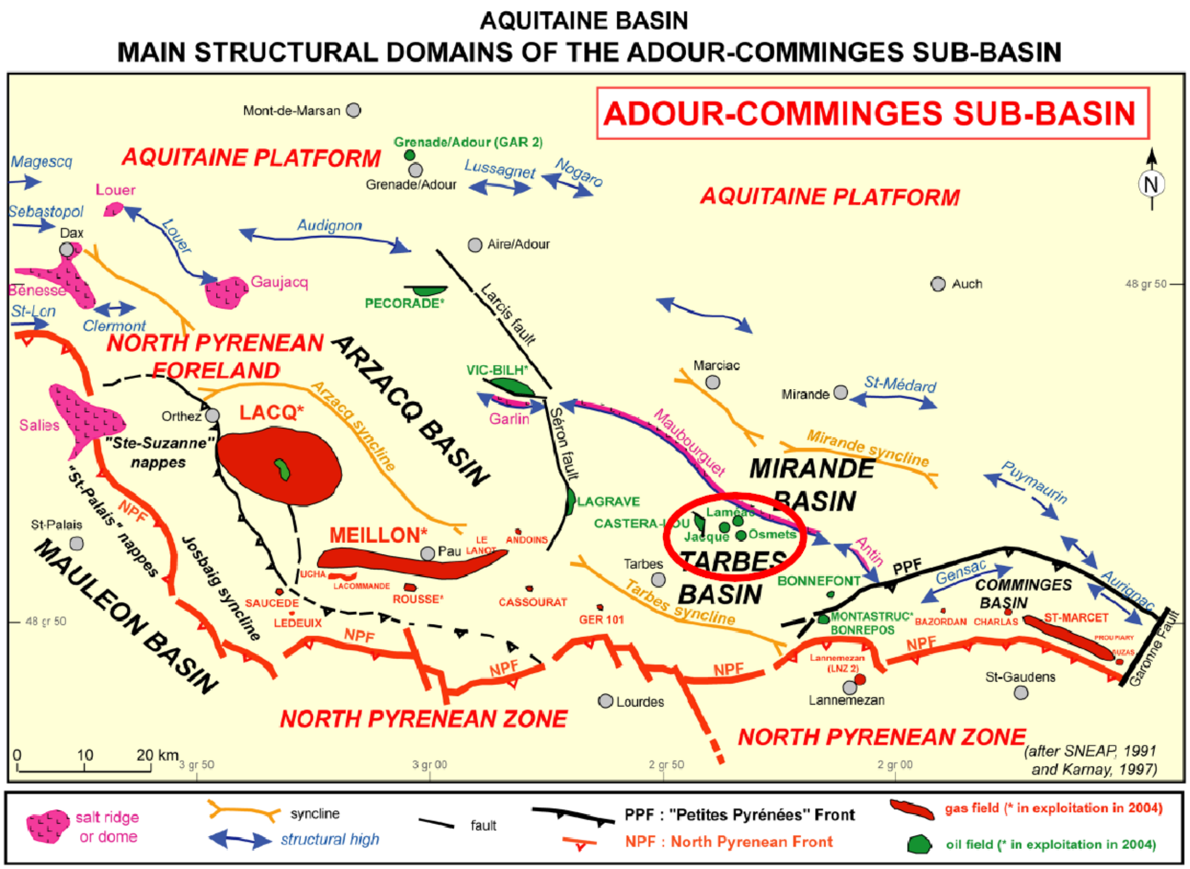


Figure 3.6 Location of Osmets and Jacque fields

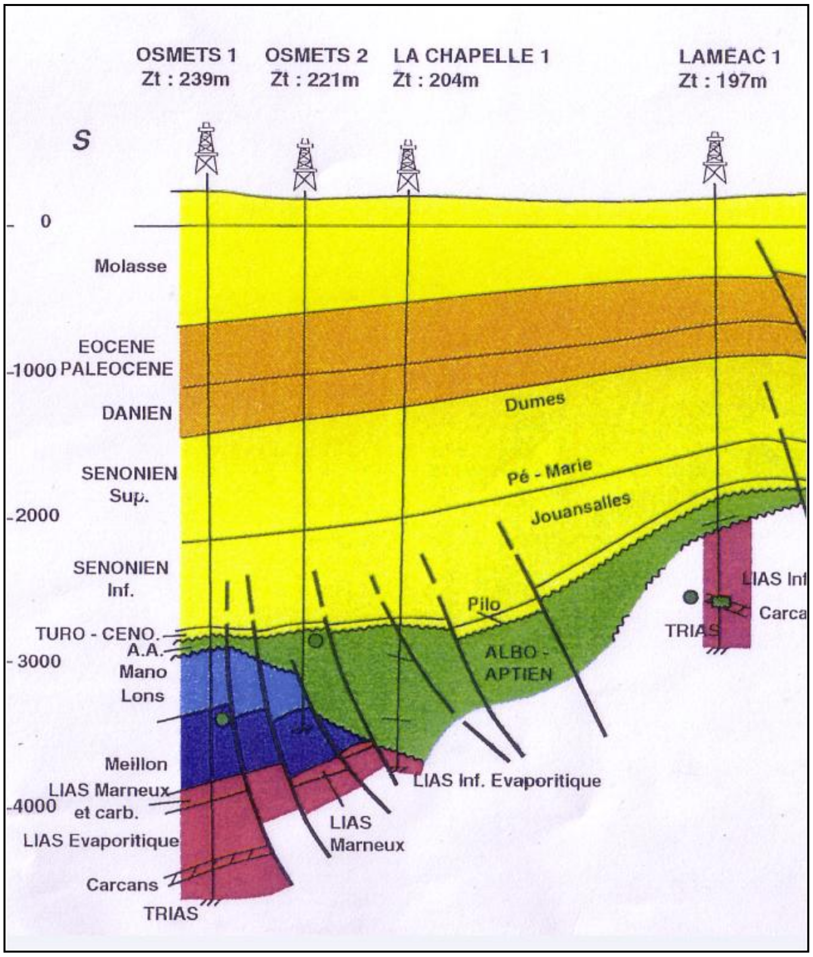


Figure 3.7 Structural cross-section through the Osmets wells showing the interpreted geology

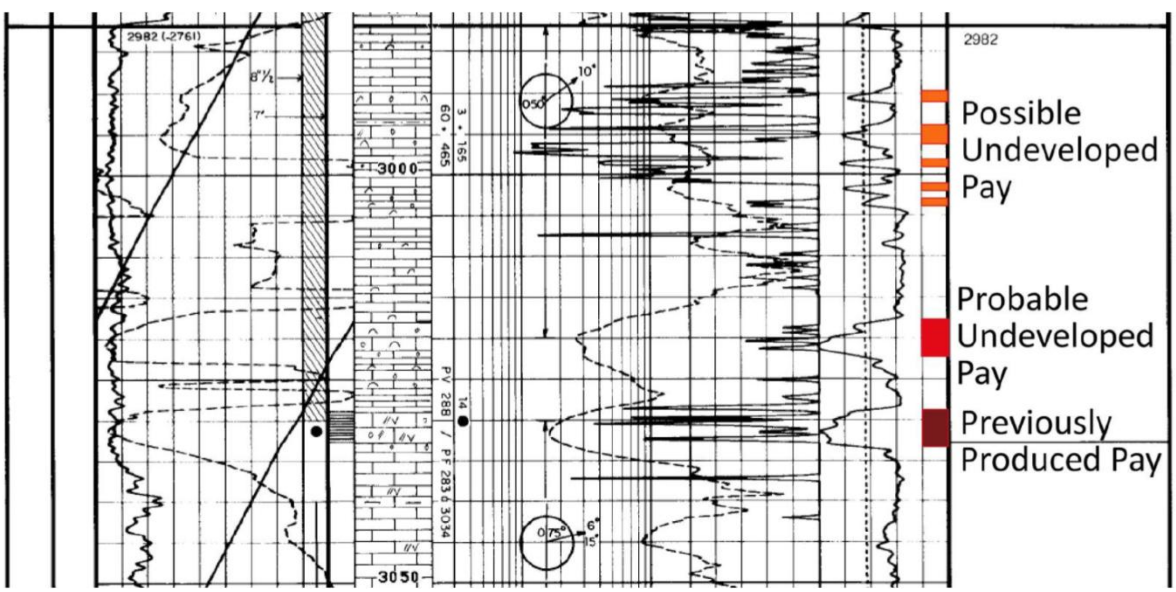


Figure 3.8 Log through the reservoir in Well Osmets-2 showing the interpreted pay

Jacque Field

The Jacque field consisted of one well located approximately 2 km WNW of Well Osmets-2. Well Jacque-1 was drilled by SNEA in 1981 on an interpreted south-westerly dipping structure bounded updip by faults. As with Well Osmets-2 it found oil in Aptian-Albian reef limestones. These were encountered at 3284 m MD depth, and contained oil down to an OWC at 3297 m MD. The oil zone was cored and showed an average porosity of 15% and a permeability averaging 50 md. During initial well testing, the well produced approximately 3700 stb of dry oil in two months. From 1981 to 1986 the well produced 32,000 stb of 26.2°API oil. At shut-in the water cut was approximately 80%.

This accumulation is clearly separate from that in Well Osmets-2 and could also have updip potential if this can be demonstrated seismically.

3.1.3. HIIP, Contingent Resources and Risk

Given the currently poorly structural understanding of the two of fields we have not attempted a quantitative estimate of the volumes either in place or recoverable.

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.

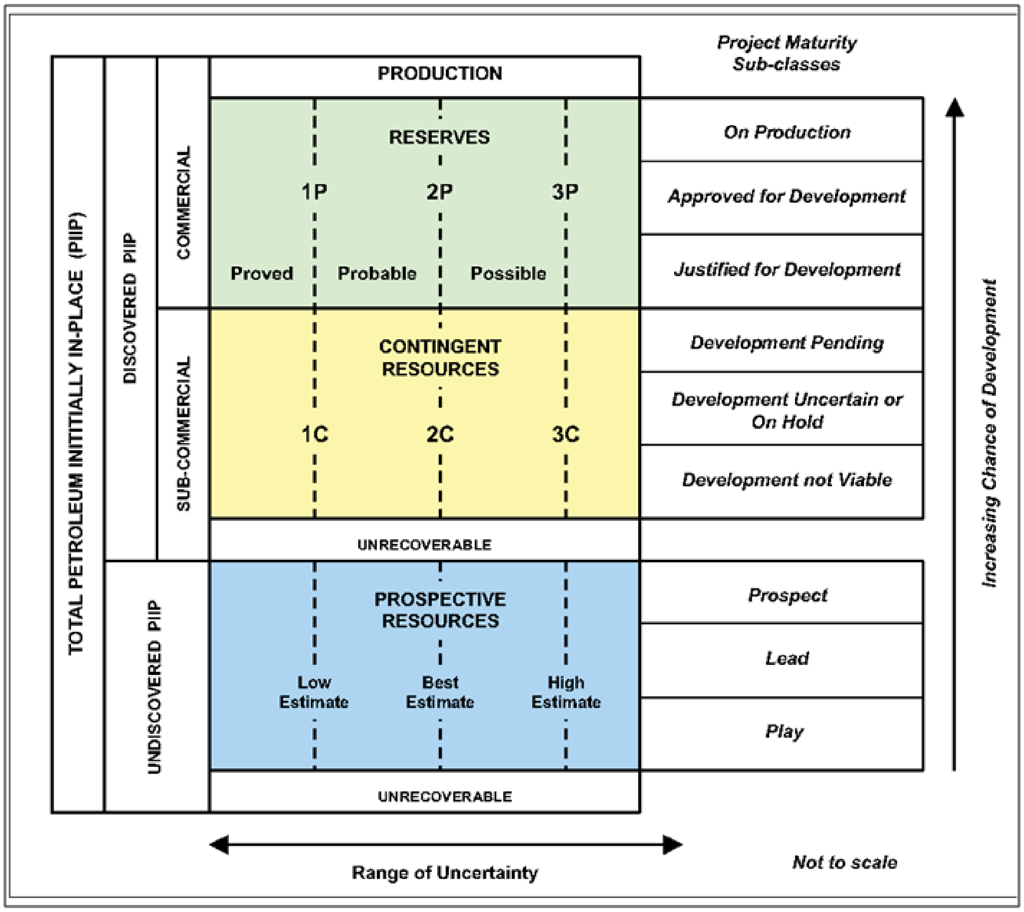


Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

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.

Appendix 2: Nomenclature

“bbl”	means barrels
“bcf”	means thousands of millions of standard cubic feet
“Bo”	means oil shrinkage factor or formation volume factor, in rb/stb
“1C”	means Low Estimate Contingent Resource, as defined in Appendix 1
“2C”	means Best Estimate Contingent Resource, as defined in Appendix 1
“3C”	means High Estimate Contingent Resource, as defined in Appendix 1
“cm”	means centimetre
“cp”	means centipoises
“CPI”	Computer Processed Information log
“3D”	means three dimensional
“Eg”	means gas expansion factor
“°F”	means degrees Fahrenheit
“ft”	means feet
“ ft ss”	means feet subsea
“FVF”	means formation volume factor
“g”	means gram
“GEF”	means gas expansion factor
“GIIP”	means gas initially in place
“GR”	means Gamma Ray
“GRV”	means gross rock volume
“GWC”	means gas water contact
“HIIP”	means hydrocarbons initially in place
“km”	means kilometers
“m”	means metres
“M” “MM”	means thousands and millions respectively
“md" or “mD”	means millidarcy
“MD”	means measured depth
“MDT”	means modular formation dynamic tester
“m/s”	means metres per second
"m ss"	means metres subsea
“N/G”	means net to gross ratio
“Np”	means cumulative oil production

"OWC"	means oil water contact
"Por" or "Phi"	means porosity
"Proved"	means Proved, as defined in Appendix 1
"Probable"	means Probable, as defined in Appendix 1
"Possible"	means Possible, as defined in Appendix 1
"1P" or "P"	means Proved
"2P" or "P+P"	means Proved + Probable
"3P" or P+P+P	means Proved + Probable +Possible
"P90"	means 90 per cent probability = Proved
"P50"	means 50 per cent probability = Proved + Probable
"P10"	means 10 per cent probability = Proved + Probable + Possible
"PSDM"	means prestack depth migration
"psia"	means pounds per square inch absolute
"psig"	means pounds per square inch gauge
"rcf"	means cubic feet at reservoir conditions
"res bbl"	means reservoir barrels
"scf"	means standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"Sg"	means gas saturation
"So"	means oil saturation
"Soi"	means initial oil saturation
"stb"	means a standard barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
"stb/d"	means standard barrels per day
"STOIIP"	means stock tank oil initially in place
"ss" or "TVDSS"	means true vertical depth sub-sea
"Sw"	means water saturation
"TD"	means total depth
"TVD"	means true vertical depth
"twt" or "TWT"	means two way time