6th January 2016

The Directors

Europa Oil & Gas plc
UK Office
6 Porter Street
W1U 6DD

Dear Sirs,

RE: January 2016 Competent Person's Report, Europa Oil and Gas plc

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has reviewed certain petroleum exploration interests of Europa Oil and Gas plc and its associated companies ("Europa"), and we have prepared independent estimates as of the date of this letter of the Prospective Resources associated with these interests. We have used information and data available up to 30th April 2015.

We have carried out this work using the March 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. A summary of the PRMS is found in Section 5 of this report. The full text can be downloaded from www.spe.org/spe-app/spe/industry/reserves/prms.html.

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.

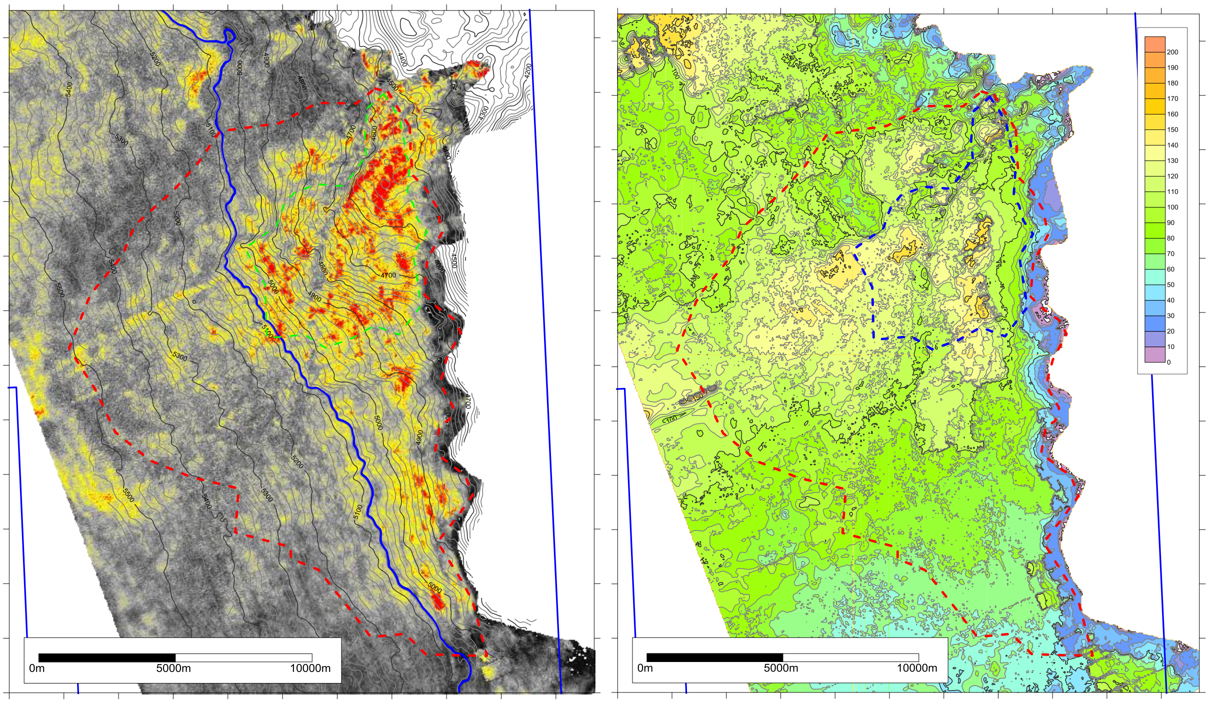
The work has been supervised by Dr Adam Law, Geoscience Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers. He has 20 years' relevant experience in the evaluation of oil and gas fields and exploration acreage, preparation of development plans and assessment of reserves and resources.

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

Yours faithfully,

Dr Adam Law
Geoscience Director, ERC Equipoise Limited

Competent Person's Report: Europa Oil and Gas plc



PREPARED FOR: Europa Oil and Gas plc

BY: ERC Equipoise Limited

January 2016

Approved by: Adam Law

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1. Summary

ERC Equipoise Limited (ERCE) has completed an audit of the Prospective Resources, (including estimates of Geological Chance of Success – COS), attributable to prospectivity within Frontier Exploration Licences (FELs) 2/13, and 3/13, offshore Ireland, in which Europa Oil and Gas plc or its subsidiaries (Europa) hold working or equity interests. Both FELs are operated by Kosmos Energy, which holds an 85% working interest. Europa holds the remaining 15%.

1.1. Data Provided

ERCE was provided with a comprehensive database for this audit, which included, amongst others:

- Estimates of Prospective Resources for all properties assessed
- Well data from offset wells within the Porcupine basin area
- Core and formation pressure data, where applicable
- Seismic data and associated interpretations and attribute analyses for all reviewed properties
- TCM and OCM documentation, where applicable, for all reviewed properties
- Licence documentation, including fiscal term information, where applicable

1.2. Work Completed

The dataset provided by Europa enabled ERCE to complete a comprehensive audit of the:

- Estimates of hydrocarbons initially in place
- Estimates of prospective oil and gas Resources at the Low, Best and High levels of confidence in FEL 3/13
- Estimates of Geological Chance of Success (COS) for the Prospective Resources assessed

We have reviewed the Prospective oil and gas Resources and Geological Chance of Success (COS) for exploration prospectivity. We make independent estimates of Prospective Resources and COS for identified prospectivity that can be classified as Prospects: that is features that have been sufficiently well defined through analysis of geological and geophysical data that they are considered drillable targets. In terms of Europa's Irish licences, identified prospectivity is classified as Prospects in FEL 3/13 only. In the case of undiscovered resources (Prospective Resources) presented in this report, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

1.3. Evaluation Methodology: Prospective Resources

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. We have estimated the degree of this uncertainty and determined ranges of estimates of petroleum initially in place and recoverable hydrocarbons. Our methodology adheres to the guidelines outlined in the SPE PRMS (Section 5).

Mapping of prospectivity within FEL 2/13 is at an early stage. Although leads have been identified by Europa and the operator, Kosmos, these need to be matured to prospect level, and we have not assessed any prospects or attributed Prospective Resources to FEL 2/13.

We have used probabilistic methods to evaluate selected prospects within FEL 3/13. We classify the results of our probabilistic simulation as Low, Best and High estimates of Prospective Resources following the Petroleum Resources Management System, or PRMS (Appendix 1). We have assigned a Geological Chance of Success to each of the prospects, using the methodology described below. Estimates are made for oil only, although we recognise that, due to the significant uncertainties in the available geological information, there is a possibility of gas charge in all licences.

Inputs to our probabilistic simulation are evaluated in a consistent manner. The three prospects evaluated (Beckett, Shaw and Wilde) have a stratigraphic trapping mechanism. We have made low and high estimates of area of closure, using depth mapping. We have then made low and high estimates of gross reservoir thickness, derived from regional observations and analogues. Amplitude support for the presence of reservoir and/or hydrocarbons is debatable in all three prospects. Where appropriate, a geological shape factor is used, depending on trap shape and structural relief relative to reservoir thickness.

Estimates of reservoir porosity and net to gross ratio are made with reference to regional data, offset wells and analogue data, and account for compaction and a degree of overpressure. We make low, mid and high deterministic estimates, and use these to constrain the P90, P50 and P10 inputs to a probabilistic simulation. Inputs for hydrocarbon saturation are constrained in a similar manner, with reference to regional porosity and permeability trends.

We have estimated oil formation volume factors for a range of gas oil ratios (GORs) (from an appropriate minimum to fully saturated) for each of the prospective intervals, assuming 4^{o}C at the mudline (seabed) and geothermal gradients between 2.5 and 3.5^{o}C per 100 m, consistent with regional observations and the available well data. We assume that the minimum GOR will increase with depth below the mudline. Some degree of overpressure is accounted for, as it has been in our estimates of porosity, but we assume that it is unlikely to exceed 500 psi over the depth range investigated.

Recovery factors are estimated with reference to published information from discoveries in similar reservoir types, presuming, because of water depth, that a low well count and tertiary recovery mechanism is employed, and taking into account the depth below sea bed of the prospects. Based on this, we estimate low, best and high recovery factors of 15%, 30% and 45% respectively. Again, these are used to constrain the P90, P50 and P10 values of our input distribution during probabilistic simulation.

Due to the early stage of exploration within Europa's licences in the Republic of Ireland, we have adopted a six component risk matrix to estimate Geological Chance of Success (COS), separated into play and prospect specific risks, (Table 1.1). We have adopted this form of presentation of COS to reflect the fact that exploration in the Southern Porcupine Basin is at an early stage, and also that some of the identified prospects have risk dependence, and thus can be grouped as a play.

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

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

Table 1.1: Play and prospect risk system

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

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

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

1.4. Summary of Results

Europa is currently maturing its prospect and lead portfolio for FEL 3/13. ERCE has made independent estimates of Prospective oil Resources and Geological Chance of Success (COS) for the prospective intervals identified in the Beckett, Shaw and Wilde structures. Our estimates of Prospective Resources and COS are summarised in Table 1.2 (Prospective oil Resources), Table 1.3 (associated gas Resources), and Table 1.4 (Prospective oil and associated gas Resources converted to oil using a conversion rate of one barrel of oil for each six thousand standard cubic feet of natural gas). In these tables, we list gross Prospective Resources, and the Prospective Resources net to Europa's working interest taking due consideration, where applicable, of any volumetric extension of the mapped prospect outside the licence in question. Risked Prospective Resources are also tabulated. Estimates are made for oil only, although we recognise that, due to the significant uncertainties in the available geological information, there is a possibility of gas charge in all licences. Gross and net estimates for the Shaw prospect are on-block only.

Prospect	STOIIP			Unrisked Prospective Resources				Interest (%)	Net Unrisked Prospective Resources				COS (%)	Net Risked Prospective Resources			
	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)
Beckett	378	1,336	4,718	97	373	1,441	651	15	15	56	216	98	15	2.2	8.4	32.4	14.6
Shaw [1]	203	622	1,911	51	174	590	274	15	8	26	89	41	13	1.0	3.4	11.5	5.3
Wilde	209	752	2,706	54	210	826	372	15	8	32	124	56	19	1.5	6.0	23.5	10.6
DETERMINISTIC TOTAL	790	2,710	9,335	202	757	2,857	1,297		30	114	429	195		5	18	67	31

[1] on-block volumes

Table 1.2: Summary of Prospective oil Resources, gross and attributable to Europa, and geological chance of success, FEL 3/13, offshore Ireland.

Prospect	Unrisked Prospective Resources				Interest (%)	Net Unrisked Prospective Resources				COS (%)	Net Risked Prospective Resources			
	Low (Bscf)	Best (Bscf)	High (Bscf)	Mean (Bscf)		Low (Bscf)	Best (Bscf)	High (Bscf)	Mean (Bscf)		Low (Bscf)	Best (Bscf)	High (Bscf)	Mean (Bscf)
Beckett	72	308	1,317	586	15	11	46	198	88	15	1.6	6.9	29.6	13.2
Shaw [1]	38	144	544	246	15	6	22	82	37	13	0.7	2.8	10.6	4.8
Wilde	40	174	753	335	15	6	26	113	50	19	1.1	5.0	21.5	9.5
DETERMINISTIC TOTAL	150	626	2,614	1,167		23	94	392	175		4	15	62	28

[1] on-block volumes

Table 1.3: Summary of Prospective Resources (associated gas), gross and attributable to Europa, and geological chance of success, FEL 3/13, offshore Ireland.

Prospect	Unrisked Prospective Resources				Interest (%)	Net Unrisked Prospective Resources				COS (%)	Net Risked Prospective Resources			
	Low (MMboe)	Best (MMboe)	High (MMboe)	Mean (MMboe)		Low (MMboe)	Best (MMboe)	High (MMboe)	Mean (MMboe)		Low (MMboe)	Best (MMboe)	High (MMboe)	Mean (MMboe)
Beckett	109	424	1,661	749	15	16	64	249	112	15	2.5	9.5	37.4	16.8
Shaw [1]	57	198	681	315	15	9	30	102	47	13	1.1	3.9	13.3	6.1
Wilde	61	239	952	428	15	9	36	143	64	19	1.7	6.8	27.1	12.2
DETERMINISTIC TOTAL	227	861	3,293	1,492		34	129	494	224		5	20	78	35

[1] on-block volumes

Table 1.4: Summary of Prospective oil and associated gas Resources, (as boe, converted to oil using a conversion rate of one barrel of oil for each six thousand standard cubic feet of natural gas), gross and attributable to Europa, and geological chance of success, FEL 3/13, offshore Ireland

2. Introduction

2.1. Republic of Ireland: Licence Overview

Licence options 11/7 and 11/8 were awarded to Europa (100%) in 2011. After identifying a series of leads within the Cretaceous section on the available 2D seismic data, Europa undertook a farm-out programme in January 2013. In April 2013 Kosmos entered into the blocks as operator (85%) in return for full funding of a 3D seismic survey over both licences and a carry through the first exploration well on each licence, subject to an investment cap of US$90 MM in FEL 2/13 and US$110 MM in FEL 3/13. Costs in excess of the cap would be shared between Kosmos (85%) and Europa (15%). In May 2013 a mandatory 25% relinquishment occurred, and the licences were converted to Frontier Exploration Licences (FEL) 2/13 and 3/13.

2.2. FEL 3/13

Frontier Exploration Licence 3/13 (Frontier) is operated by Kosmos Energy Ireland (85% working interest). Europa Oil and Gas (Ireland East) Limited has a 15% working interest in the licence. The licence contains blocks 54/1(p), 54/2, 54/6(p) and 54/7 and covers an area of 781.97 km^2. The licence term began on 5th July 2013 and continues until 4th July 2028; the term comprises four phases.

As of January 2016, the licence is in the first phase (5th July 2013 to 4th July 2016) of its exploration period. Commitments during this phase include the acquisition of a minimum of 740 km^2 of full-fold 3D seismic data together with marine gravity and magnetic data, processing of new seismic data to include Pre Stack Time Migration (PSTM) and if geological uncertainties require depth risk reduction then Pre Stack Depth Migration (PSDM) is to be undertaken. Other commitments include AVO and attribute analysis of seismic data, seismic inversion, frequency and spectral decomposition, integration and interpretation of new data with existing data, geological mapping, depositional facies analysis and prospect fairway analysis. Source rock maturity and hydrocarbon charge should be modelled. Leads and prospects should be mapped and prospect resource analysis performed as well as other geological and geophysical studies as necessary, with a play and prospect assessment for the full prospective section of the entire licence area being made available to the Irish Petroleum Affairs Division (PAD) in the form of a written report, three months before the end of the first phase of the licence.

As of January 2016, the licensees have acquired 1,584 km^2 of 3D seismic data (completed by October 2013) and the processed product has been available since May 2014. All other commitments of the work program have been performed except for reporting to the PAD, which must occur on or before 4th April 2016. A mandatory relinquishment of 25% of the licence area is required at the end of the first phase.

The second exploration phase of the licence has a four year term. The work programme for the second phase of the exploration licence has yet to be specified but will include an exploration well. Fifty percent of the licence area must be relinquished at the end of the second phase.

The third and fourth phases span the time frames 5th July 2020 to 4th July 2024 and 5th July 2024 to 4th July 2028 respectively. Work programs for these phases have not yet been defined.

Annual contributions of €87,361 per licence are to be made to the Petroleum Exploration and Production Promotion and Support programme through the Irish Shelf Petroleum Study Group. Further annual financial contributions are to be made to the Petroleum Exploration and Production Promotion and Support programme through the Expanded Offshore Support Group.

2.3. FEL 2/13

Frontier Exploration Licence 2/13 (Frontier) – formerly Licence Option 11/07- is operated by Kosmos Energy Ireland (85% working interest). Europa Oil and Gas (Ireland east) Limited have a 15% working interest in the licence area. The licence contains blocks 43/9, 43/10(p), 43/14 and 43/15(p) and covers an area of 768.029 km^2 (previously Licence Option 11/07 had an area of 1026.455 km^2). The licence term began 5th July 2013 and continues until 4th July 2028 (15 years); the term comprises four phases.

Licence terms for each phase are identical to those specified for FEL 3/13. To date the licensees have acquired 777 km^2 of 3D seismic data (completed in 2013). All other commitments of the work program have been performed except for reporting to the PAD, which must occur on or before 4th April 2016. A mandatory relinquishment of 25% of the licence area is required at the end of the first phase.

3. Republic of Ireland: Porcupine Basin Prospectivity and Plays

3.1. Introduction

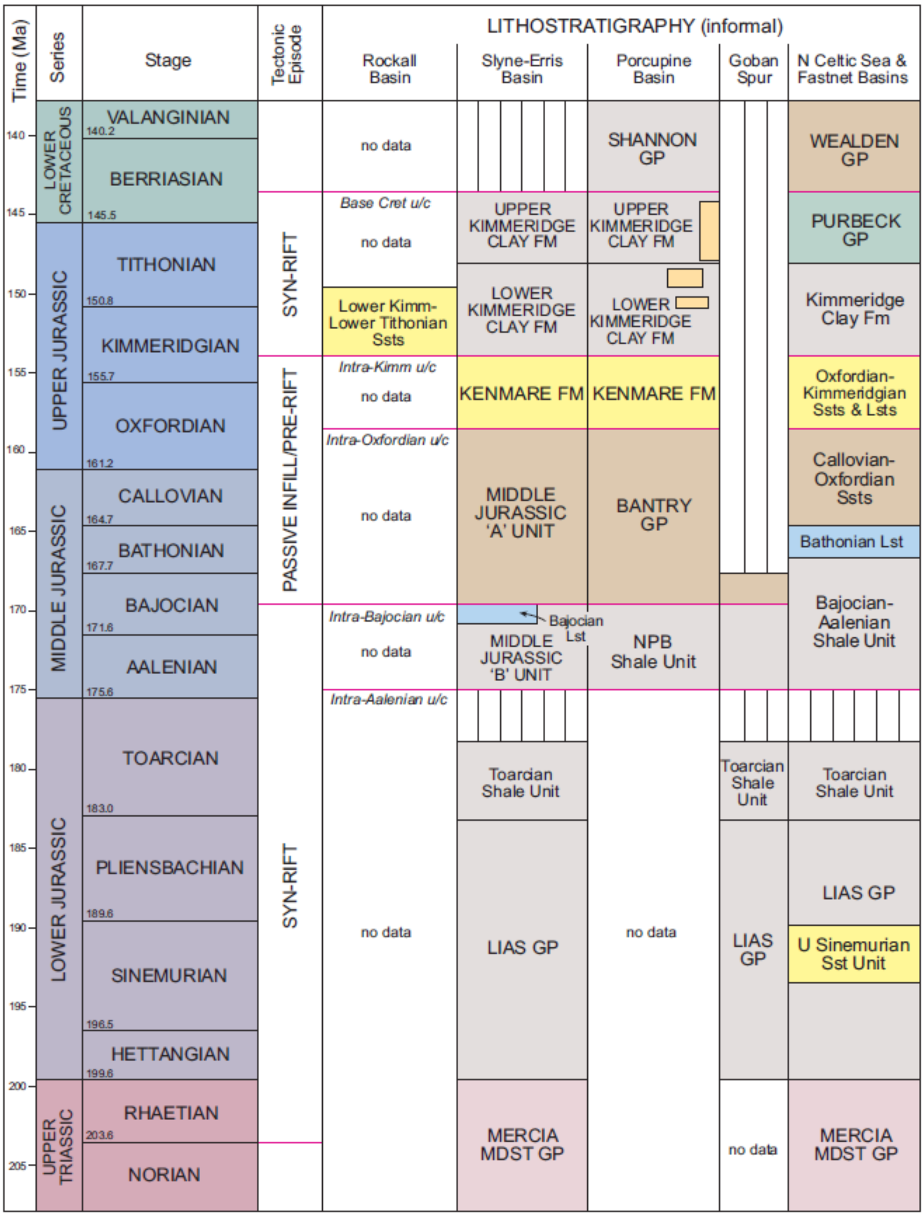

Figure 3.1: Atlantic Ireland lithostratigraphy (from PAD report)

The Porcupine Seabight Basin is a large and complex basin that is currently underexplored. It is located 150 km south-west of the southern coast of the Republic of Ireland. It is a large NNE-SSW oriented structure. Water depths range from 350 m in the north of the basin to 3500 m in the south where it opens in a southerly direction onto the abyssal plain.

The basin formed primarily as a failed rift during the various phases of the opening of the Atlantic Ocean. It contains up to 13 km of Mesozoic and Cenozoic sediments. The basin divided and now has two parts; the Main Porcupine Basin and the North Porcupine Basin. The Main Porcupine Basin formed as part of several rift episodes and recurrent subsidence and subsequent infill (Conliffe et al., 2010).

The three main periods of rifting that formed the basin were Permo-Triassic, Early Jurassic and Late Jurassic in age. A fourth rifting event occurred late in the early Cretaceous. These rifting events occurred across most of the Atlantic Margin basins (Conliffe et al., 2010).

The North Porcupine basin is separated from the Main Basin by a series of East-West trending structural highs starting at Finian's Spur in the west and extending to the eastern edge of the basin via the Connemara Ridge. In the central part of the Porcupine basin there is a buried but still prominent structural feature - the Porcupine Arch – which splits the basin into western and eastern parts. The Spanish Point Discovery is located in the middle of the Eastern Porcupine Sub-Basin (Conliffe et al., 2010).

Pre-rift sediments in the Porcupine basin are largely Upper Carboniferous in age and represent a deltaic to shallow marine succession (which includes sandstones, shales and thin coals) (Conliffe et al., 2010). Rifting in the Jurassic was accompanied by the deposition of further deltaic sands (Conliffe et al., 2010). Sub-marine fans comprising sandstones interbedded with occasional lacustrine silts and muds were deposited during a northward progressing marine transgression in the Upper Jurassic (Conliffe et al., 2010). Cretaceous and Cenozoic sediments that are unconformable to the Jurassic strata were deposited during significant thermal subsidence at the end of crustal extension. Cretaceous and Cenozoic sediments include shales, chalky limestones and deltaic sands (Conliffe et al., 2010).

Potential source rocks range from Carboniferous to Cenozoic shales. An Upper Jurassic marine shale and a Middle Jurassic marine shale are among the best quality oil and gas prone source rocks in the basin. Sandstones that may act as hydrocarbon migration pathways are present throughout the sedimentary section (Conliffe et al., 2010).

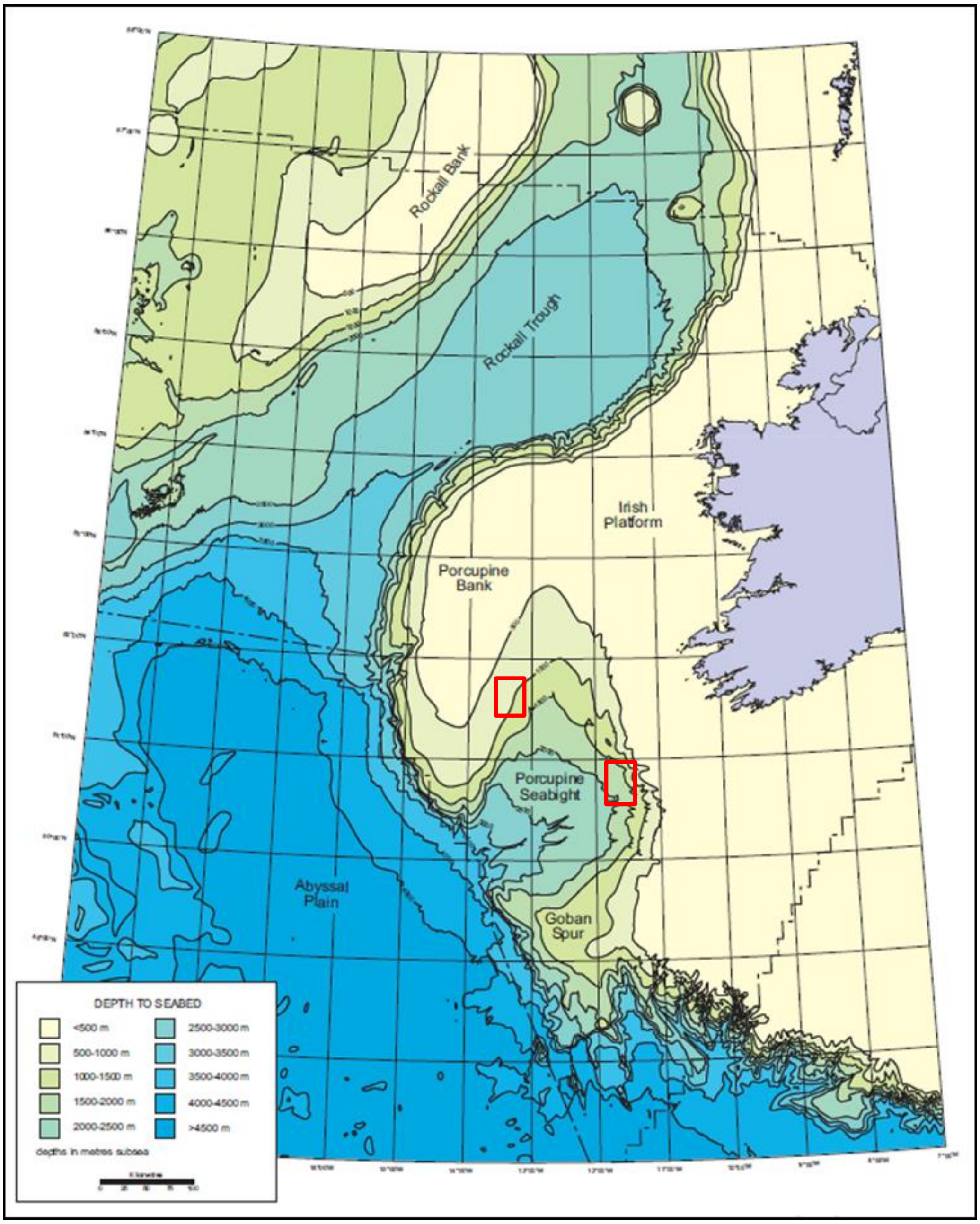

Figure 3.2: Bathymetric Map of Atlantic Ireland (PAD Special Publication 3/06)

(Approximate locations of blocks marked in red)

A number of petroleum play systems have been recognised in the Porcupine Basin. Hydrocarbon potential is identified within pre-Jurassic reservoirs located within tilted fault blocks developed along the margin of the basin. Additional potential is predicted in post-rift and structural and stratigraphic plays in Cretaceous and Tertiary sediments. The most likely source of any hydrocarbons within these plays is predicted to be Upper Jurassic Kimmeridge Clay equivalent mudstones that are proven to be present and mature within the basin.

Since 1977 thirty-one wells have been drilled across the basin. Of all the wells drilled, three flowed hydrocarbons, making the Burren (1978), Connemara (1979) and Spanish Point (1981) discoveries. Only one well (44/23-1), on the Dunquin prospect, has been drilled in the last twelve years.

3.2. Well and Seismic Database

The well and seismic database for the licences evaluated is shown in Figure 3.3.

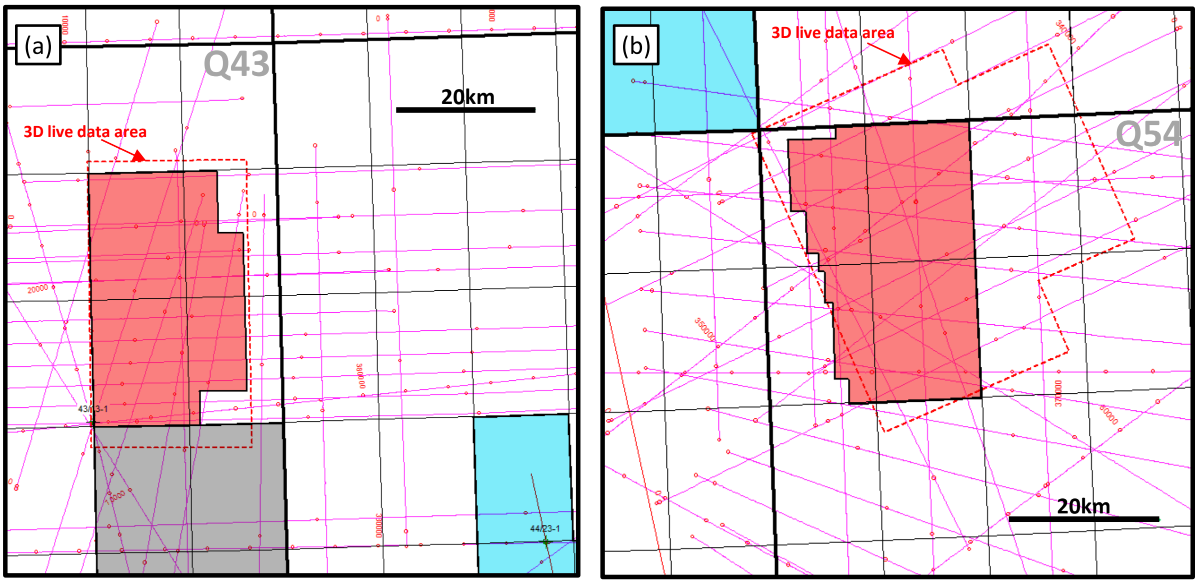

Figure 3.3: (a) Well and seismic data available for review of FEL 2/13 (b) Well and seismic data available for review of FEL 3/13

There are no wells within either FEL 2/13 or FEL 3/13, but offset wells were made available for our review, (43/13-1, 62/7-1 and 44/23-1). The primary seismic dataset used is the 2013/14 Kosmos acquired 3D seismic data, although we have made reference to the PAD regional 2D seismic data held by Europa to determine the closure of the Shaw prospect as this is not fully covered by the available 3D.

3.3. Plays and Petroleum Geology: FEL 3/13 and 2/13

Play maturation within FEL 2/13 is at an early stage. Currently Europa and Kosmos identify a number of leads within the post rift section (Figure 3.4). These include traps within slope channel-fan systems of probable Cretaceous age (the 'Doyle' leads) and within younger slope apron deposits of Tertiary age (the 'Joyce' lead). These leads, along with others in the syn and pre-rift section, are being matured to prospect status. We have therefore not attributed Prospective Resources to FEL 2/13.

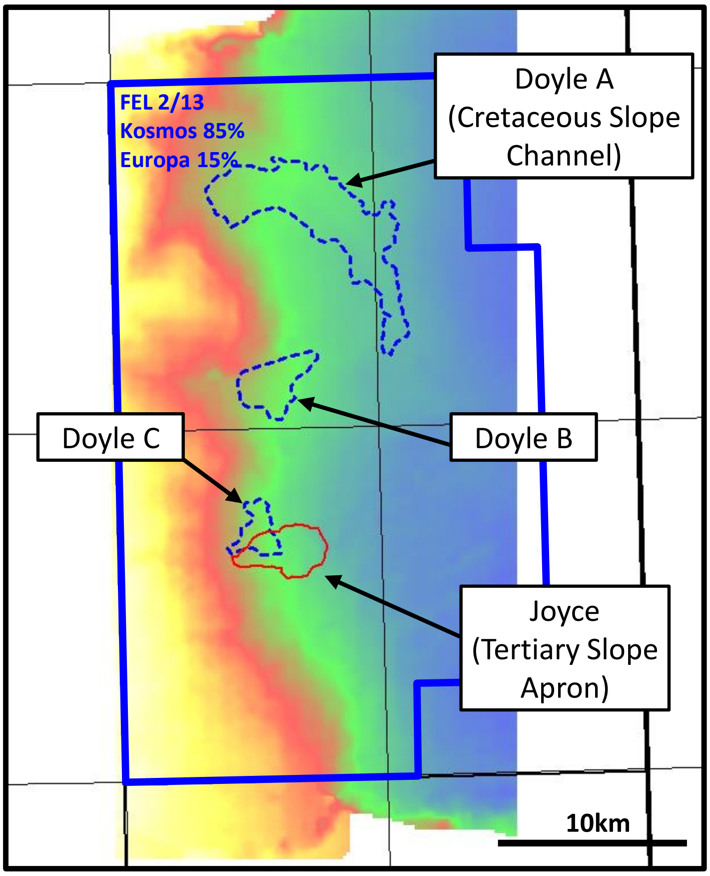

Figure 3.4: Leads, FEL 2/13

Similar plays are identified by Kosmos and Europa within FEL 3/13. The most significant play is that of deep-marine channel-fan systems, as structural and stratigraphic traps, identified within a section of probably Lower Cretaceous age. Hydrocarbons are prognosed as being sourced from coeval source rocks, but primarily from a deeper Upper Jurassic source. Seals are interpreted to have been deposited within the shallower Cretaceous section as the system was drowned.

There is some seismic evidence, largely geomorphological, for the presence of a number of fan systems within the Lower Cretaceous interval. Of these, three have been matured by Kosmos and Europa to prospect status: Beckett, Shaw and a deeper Wilde prospect. We have made independent estimates of Prospective oil and gas Resources, and Geological Chance of Success, for these three prospects.

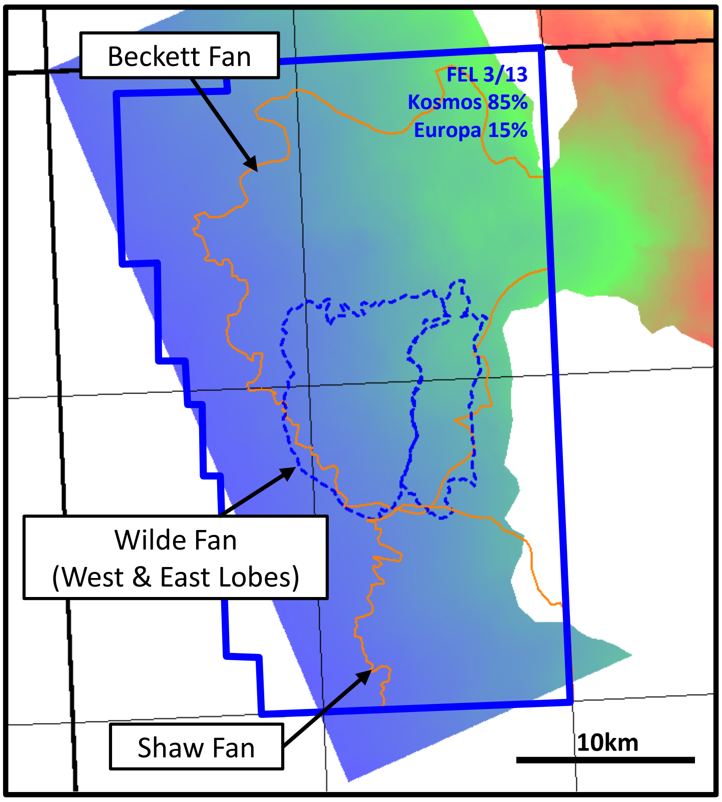

Figure 3.5: Leads and prospects, FEL 3/13

3.4. Play and Prospect Risk: FEL 3/13

The Beckett, Shaw and Wilde prospects are identified within Lower Cretaceous channel-fan plays. With no wells within the play, we have used a Play and Prospect risking system for these three prospects, as described in Section 1.3. The results are presented in Table 3.1.

Prospect	Play Risk				Prospect Risk				COS (frac)
	Source	Reservoir	Seal	Total	Containment	Charge	Reservoir	Total	
Beckett	0.80	0.80	0.80	0.51	0.60	0.70	0.70	0.29	0.15
Shaw	0.80	0.80	0.80	0.51	0.50	0.70	0.70	0.25	0.13
Wilde	0.80	0.90	0.80	0.58	0.60	0.80	0.70	0.34	0.19

Table 3.1: Prospect risk within Licence Block 3/13

We see a favourable play risk for all three prospects, due to the presence of seismic anomalies such as gas chimneys within the 3D seismic area proximal to the prospects. Basin modelling, although uncertain, also suggests that Jurassic source rocks, if present, will be mature for hydrocarbon generation. There is also geomorphological evidence within the mapped seismic data that would indicate deep water depositional systems, and the prognosed sediment source area at this time to the east would suggest plentiful clastic supply. The deeper Wilde prospect also shows some evidence of differential compaction.

Prospect specific risk is discussed in the relevant section for each prospect.

3.5. Prospective Resources: FEL 3/13

3.5.1. The Beckett Prospect

The Beckett prospect is located in the north-west of Block FEL 3/13. The prospect is mapped as a deep water unconfined channel-fan system with sediment supply being fed through remnant pre-rift topography. A single reservoir unit has been mapped within the probable Lower Cretaceous sediments between 3500 ms TWT and 4530 ms TWT (Figure 3.6). The crestal depth of the structure is approximately 4850 m TVDSS with a water depth of 1725 m.

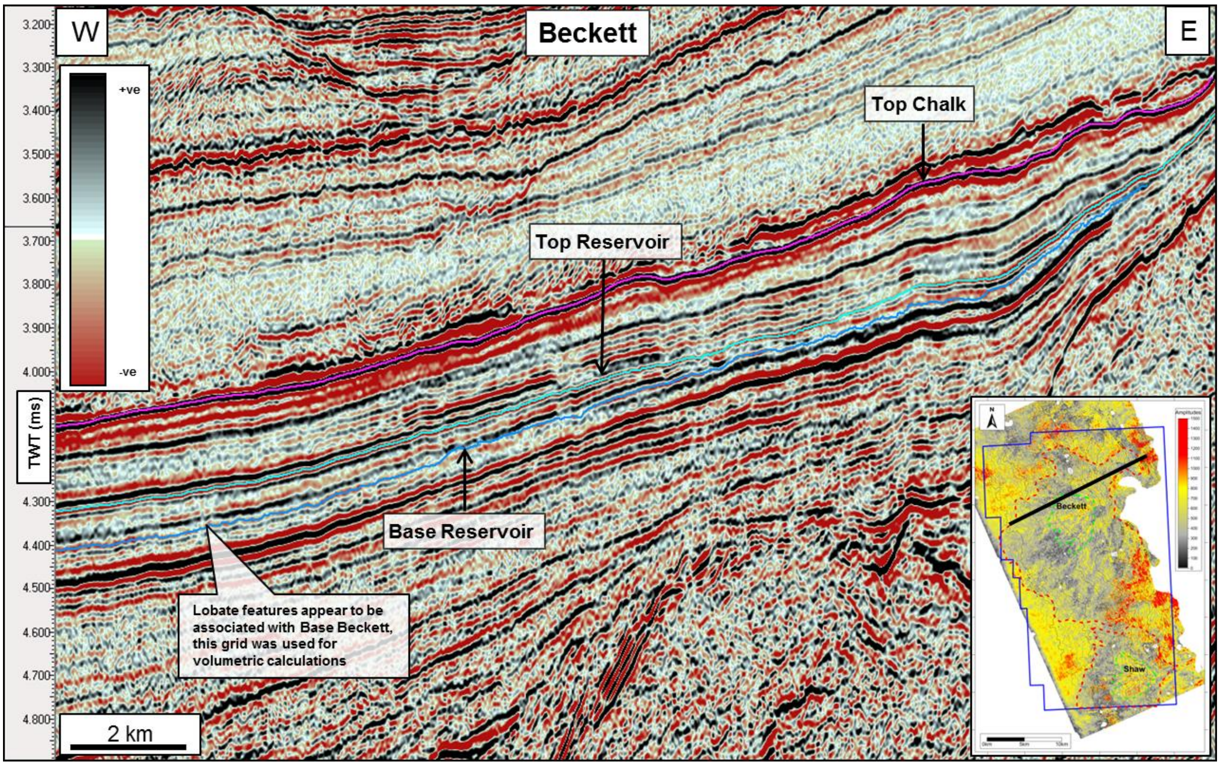

Figure 3.6: Dip seismic line across the Beckett prospect.

As described in Section 1.3, we use an area net approach to constrain the areal extent. We estimate net reservoir thickness using analogues with a similar structural and depositional environment (Richards et al., 1998 and Hodgson et al., 2006). In our low case, we restrict the area of the accumulation to the brightest anomalous amplitudes and a column height of 200 m. Our high case extends the prospect down-dip to a column height of 600 m and laterally to incorporate the whole mapped fan structure (Figure 3.7). These polygons are used to constrain P90 and P10 area inputs of our probabilistic simulation.

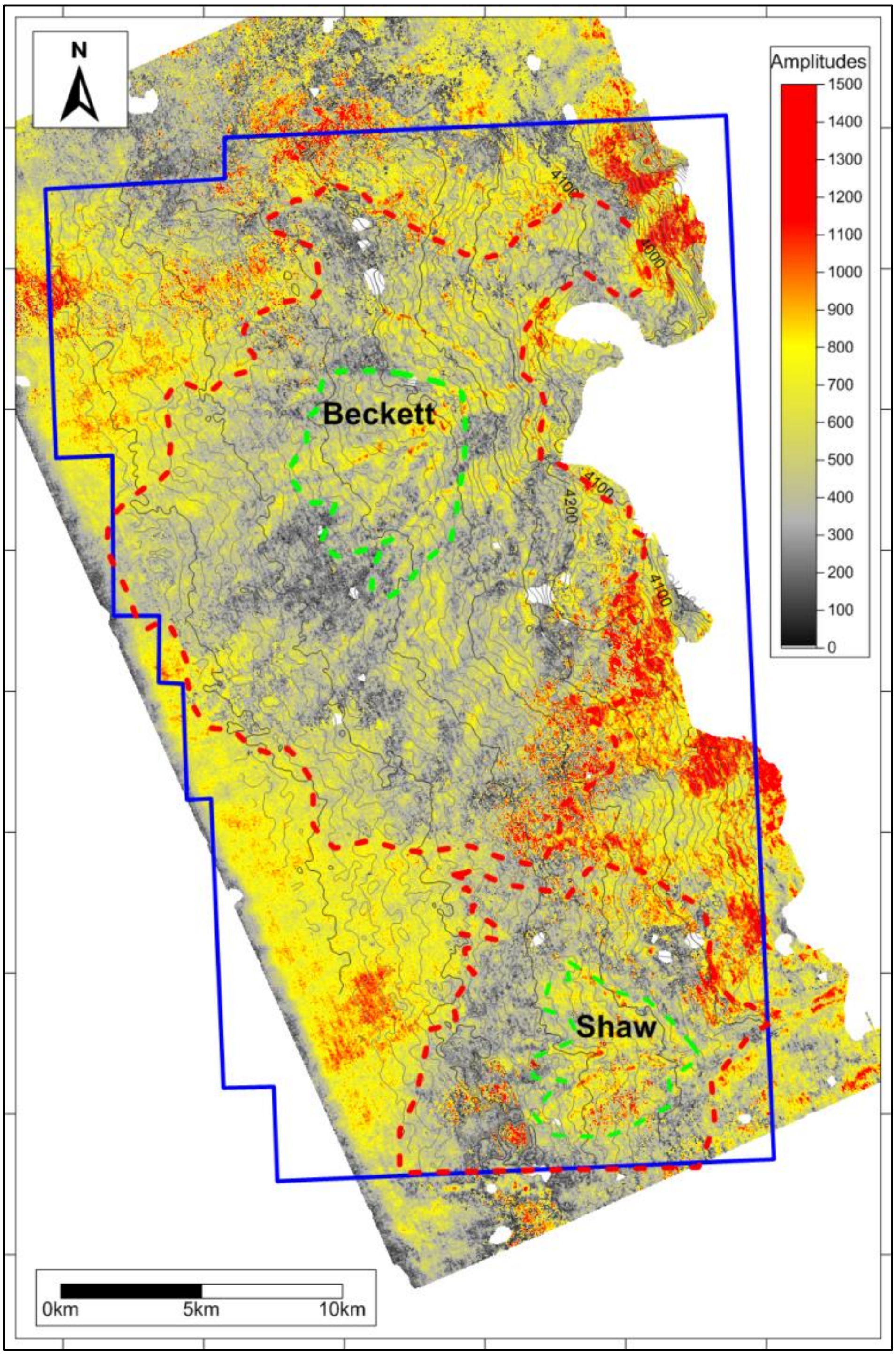

Figure 3.7: Hate amplitude extraction; Beckett and Shaw prospects.

(Low and high case volumetric polygons are displayed as green and red polygons respectively. Block boundary in blue)

Porosities and fluid properties are estimated as described in Section 1.3.

Inputs to and results of our probabilistic simulation of Prospective oil and gas Resources are given in Table 3.2. and Table 3.3 respectively. Gas volumes are associated gas for an oil charge.

Block	Reservoir	Area (Km^2)			Net (m)			Porosity (frac)			HC Saturation (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Beckett	25.7	79.0	243.0	9.0	21.0	66.5	0.13	0.17	0.21	0.56	0.77	0.97

Block	Reservoir	Bo (stb/rb)			Recovery Factor (frac)			GOR (scf/stb)			Associated Gas RF (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Beckett	1.2	1.4	1.7	0.15	0.30	0.45	400	900	1400	0.15	0.30	0.45

Table 3.2: Volumetric input parameters, Beckett prospect

Reservoir	Unrisked STOIIP (MMstb)				Gross Unrisked Resource (MMstb)			
	Low	Mid	High	Mean	Low	Best	High	Mean
Beckett	378	1336	4718	2169	97	373	1441	651

Table 3.3: Gross Unrisked STOIIP and Prospective Resources, Beckett prospect

Key risk to the Becket prospect is containment (trap integrity), with a subsidiary risk to reservoir quality, due to the depth of burial of the prospect below mud line. We estimate an overall COS for the prospect of 15%.

3.5.2. The Shaw Prospect

The Shaw prospect is located in the south of Block FEL 3/13, and extends off-block to the south. Our volumetric estimates are therefore constrained to the block boundary in all cases. The prospect is mapped at the same stratigraphic level as the Beckett prospect, and is of similar morphology, with a single reservoir unit mapped within probable Lower Cretaceous sediments (Figure 3.8).

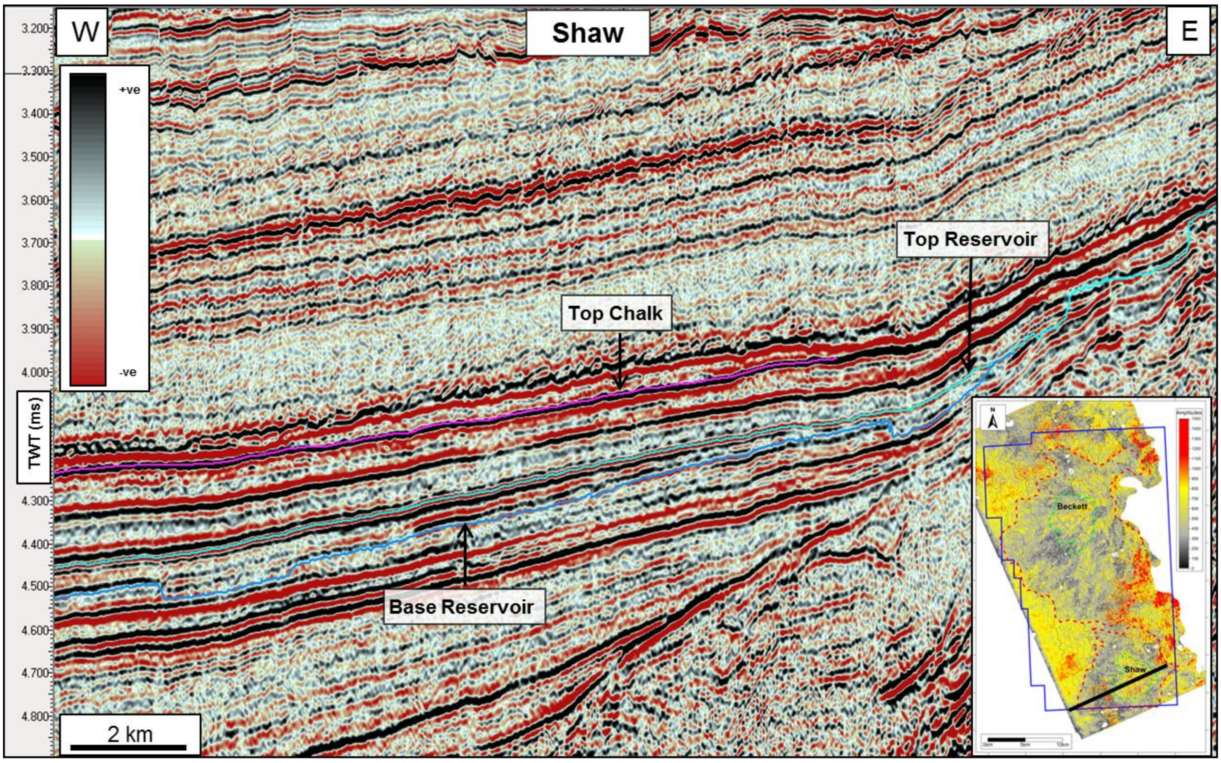

Figure 3.8: Dip seismic line across the Shaw prospect.

As described in Section 1.3, we use an area net approach to constrain the areal extent. We estimate net reservoir thickness using analogues with a similar structural and depositional environment (Richards et al., 1998 and Hodgson et al., 2006). In our low case, we restrict the area of the accumulation to the brightest anomalous amplitudes and a column height of 200 m. Our high case extends the prospect down-dip to a column height of 600 m and laterally to incorporate the whole mapped fan structure. These polygons are used to constrain P90 and P10 area inputs of our probabilistic simulation.

Porosities and fluid properties are estimated as described in Section 1.3.

Inputs to and results of our probabilistic simulation of Prospective oil and gas Resources are given in Table 3.4 and Table 3.5 respectively. Gas volumes are associated gas for an oil charge.

Block	Reservoir	Area (Km^2)			Net (m)			Porosity (frac)			HC Saturation (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Shaw	14.7	38.1	99.0	9.0	21.0	66.5	0.12	0.17	0.21	0.56	0.77	0.97

Block	Reservoir	Bo (stb/rb)			Recovery Factor (frac)			GOR (scf/stb)			Associated Gas RF (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Shaw	1.2	1.4	1.7	0.15	0.30	0.45	400	900	1400	0.15	0.30	0.45

Table 3.4: Volumetric input parameters, Shaw prospect

Reservoir	Unrisked STOIIP (MMstb)				Gross Unrisked Resource (MMstb)			
	Low	Mid	High	Mean	Low	Best	High	Mean
Shaw	203	622	1911	913	51	174	590	274

Table 3.5: Gross Unrisked STOIIP and Prospective oil and gas Resources, Shaw prospect

Key risk to the Becket prospect is containment (trap integrity), which we see as higher than the Beckett prospect, due to the lack of full 3D coverage over Shaw. We see a subsidiary risk to reservoir quality, due to the depth of burial of the prospect below mud line. We estimate an overall COS for the prospect of 13%.

3.5.3. The Wilde Prospect

The Wilde prospect is located in the central portion of Block FEL 3/13. The prospect is interpreted as a deep water semi-confined channel-fan system with sediment supply being fed through remnant pre-rift topography. It is mapped at a deeper (older) stratigraphic level than the Beckett and Shaw prospects, but is still prognosed as being of Lower Cretaceous age. Two lobes are mapped; a Western Lobe and an Eastern Lobe (Figure 3.9). The prospect also shows evidence on seismic of differential compaction. Depth to crest is approximately 4500 m TVDSS in a water depth of 1725 m.

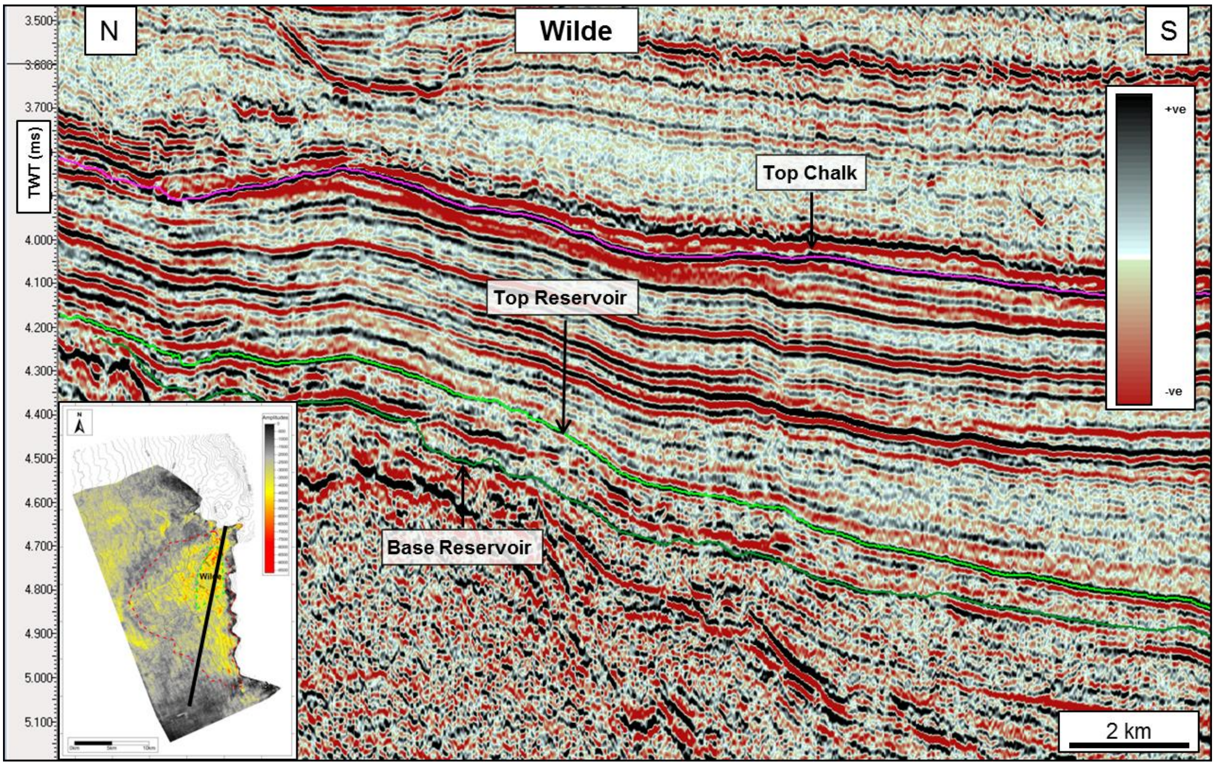

Figure 3.9: Dip seismic line; Wilde prospect, Eastern Lobe.

As with the Beckett and Shaw prospects, an area net approach has been used to estimate hydrocarbons in place and Prospective Resources. Net reservoir thickness has been estimated using analogues (Richards et al., 1998 and Hodgson et al., 2006). Differential compaction across the prospect has also been used to help define the limits of closure, and estimates of reservoir net.

Our low case area is restricted to the brightest anomalous amplitudes in the core of the Eastern Lobe, and a column height of 200 m. Our high case extends the prospect down-dip to a column height of 600 m, and laterally to incorporate the mapped compactional high (Figure 3.10). These polygons are used to constrain P90 and P10 area inputs of our probabilistic simulation.

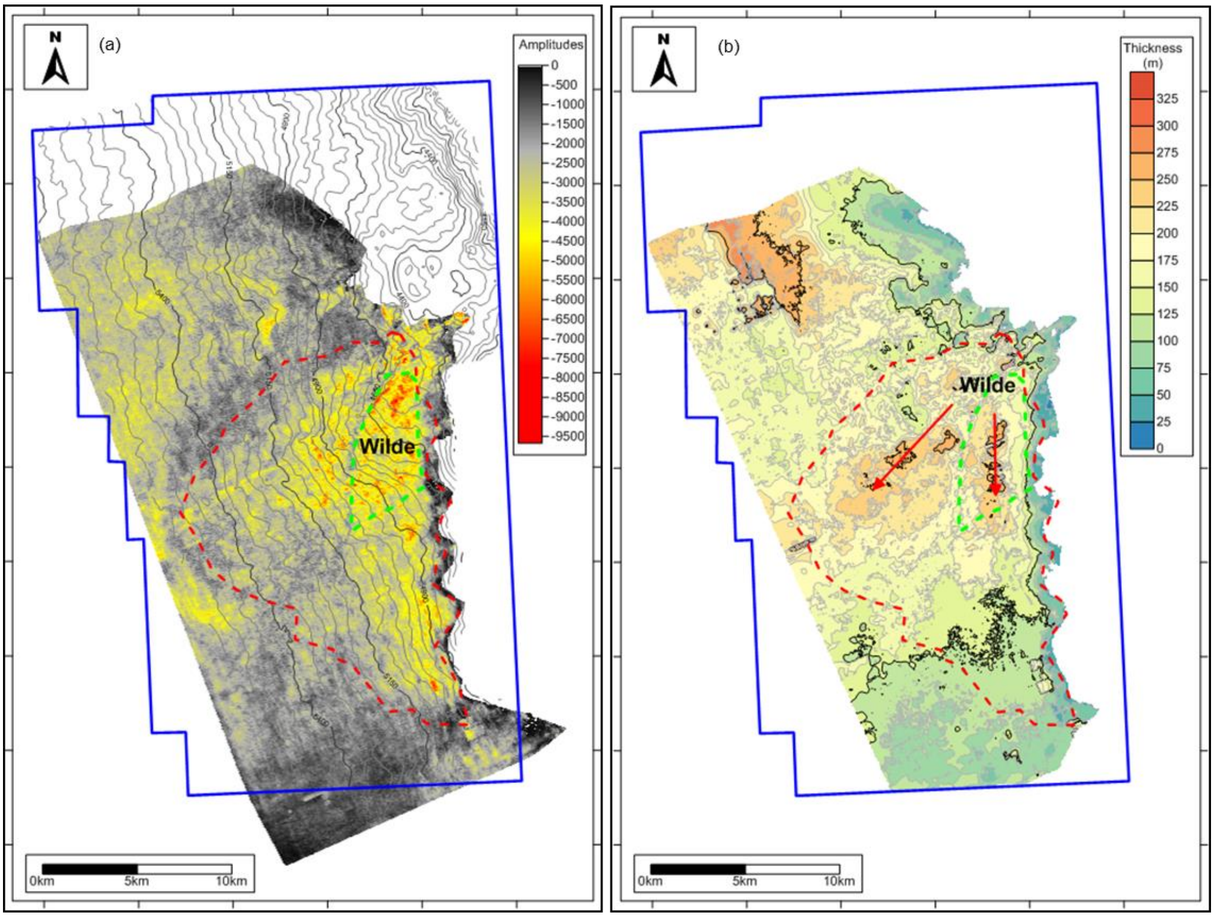

Figure 3.10: (a) HATE amplitude extraction and depth structure map (m TVDSS); Wilde Prospect (b) Isopach (m) top to base Wilde prospect

(Low and high case volumetric polygons are displayed as green and red polygons respectively. Block boundary in blue. Red arrows indicate the position of the western and eastern lobes of the prospect.)

Gross reservoir thickness estimates have been computed from the mapped seismic interval. Net pay is approximated from the mapped seismic interval and regional analogues with porosities and fluid properties estimated as described in Section 1.3.

Inputs to and results of our probabilistic simulation of Prospective oil and gas Resources are given in Table 3.6 and Table 3.7 respectively. Gas volumes are associated gas for an oil charge.

Block	Reservoir	Area (Km^2)			Net (m)			Porosity (frac)			HC Saturation (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Wilde	13.4	36.9	101.8	20.0	40.0	80.0	0.11	0.16	0.20	0.56	0.77	0.97

Block	Reservoir	Bo (stb/rb)			Recovery Factor (frac)			GOR (scf/stb)			Associated Gas RF (frac)		
		Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Block 13-3	Wilde	1.2	1.4	1.7	0.15	0.30	0.45	400	900	1400	0.15	0.30	0.45

Table 3.6: Volumetric input parameters, Wilde prospect

Reservoir	Unrisked STOIIP (MMstb)				Gross Unrisked Resource (MMstb)			
	Low	Mid	High	Mean	Low	Best	High	Mean
Wilde	209	752	2706	1239	54	210	826	372

Table 3.7: Gross Unrisked STOIIP and Prospective oil and gas Resources, Wilde prospect

Key risk to the Wilde prospect is containment (trap integrity). We see a subsidiary risk to reservoir quality, due to the depth of burial of the prospect below mud line. Charge risk is slightly lower than for the shallower Beckett and Shaw Prospects, as Wilde is stratigraphically closer to the prognosed source rock interval. We estimate an overall COS for the prospect of 19%.

4. References

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5. 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 5.1 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.

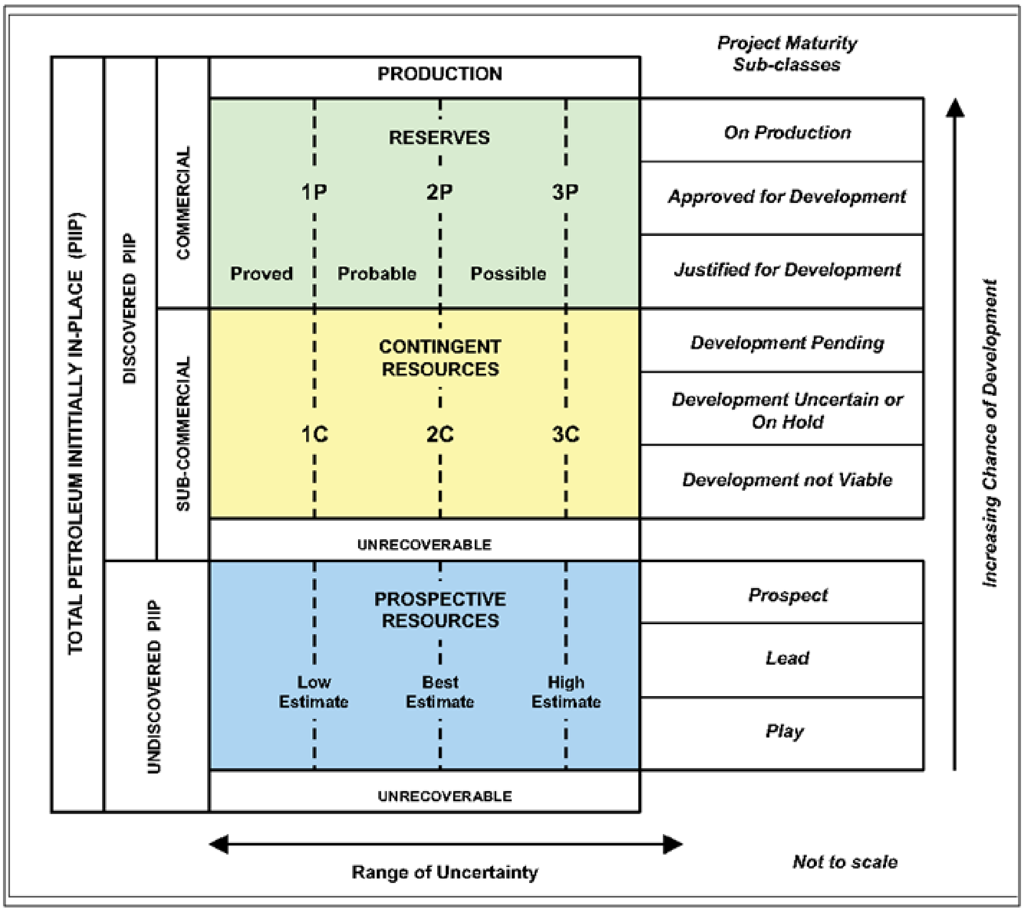

Figure 1-1: SPE/AAPG/WPC/SPEE Resources Classification System

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.

6. Appendix 2: Nomenclature

6.1. Units

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

6.2. Reserves and Resources Classifications

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

6.3. Abbreviations

AvO	amplitude variation with offset

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