

**SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT
ON ATLANTIC PETROLEUM INTERESTS
AS AT 31ST AUGUST, 2013**

**Prepared for
ATLANTIC PETROLEUM LIMITED
NOVEMBER 2013**

www.gaffney-cline.com

INTRODUCTION	1
BASIS OF OPINION	2
EXECUTIVE SUMMARY	5

Tables

0.1 AP Licences in the Moray Firth Area (UK) as at 31 st August, 2013	6
0.2 AP Licences in UK Sector, Northern North Sea as at 31 st August, 2013	7
0.3 AP Licences in UK Sector, Central North Sea as at 31 st August, 2013.....	8
0.4 AP Licences in UK Sector, Southern North Sea as at 31 st August, 2013.....	9
0.5 AP Licences in the UK West of Shetland as at 31 st August, 2013	11
0.6 AP Licences in the Faroe Islands as at 31 st August, 2013.....	12
0.7 AP Licences in Ireland as at 31 st August, 2013	14
0.8 AP Licences in The Netherlands as at 31 st August, 2013.....	14
0.9 AP Licences in Norway as at 31 st August, 2013.....	15
0.10 Oil Reserves as at 31 st August, 2013	17
0.11 Gas Reserves as at 31 st August, 2013.....	17
0.12 Post-Tax Net Present Values of Reserves, Net to AP, as at 31 st August, 2013	18
0.13 Oil Contingent Resources as at 31 st August, 2013.....	19
0.14 Gas Contingent Resources as at 31 st August, 2013.....	19
0.15 Oil Prospective Resources (Prospects) as at 31 st August, 2013.....	20
0.16 Gas Prospective Resources (Prospects) as at 31 st August, 2013	21

Figures

0.1 Location of AP Licences in the Moray Firth Area	5
0.2 Location of AP Licences in UK Sector, Northern North Sea	7
0.3 Location of AP Licences in UK Sector, Central North Sea	8
0.4 Location of AP Licences in UK Sector, Southern North Sea	10
0.5 Location of AP Licences in the UK West of Shetland	11
0.6 Location of AP Licences in the Faroe Islands	13
0.7 Location of AP Licences in Ireland.....	13
0.8 Location of AP Licences in The Netherlands	15
0.9 Location of AP Licences in Norway.....	16

Appendices

- I. Glossary
- II. Abbreviated form of SPE PRMS

MIH/kab/EL-13-206200/0588

8th November, 2013

The Directors
Atlantic Petroleum Limited.,
26/28 Hammersmith Grove,
London,
W6 7BA.

**SUMMARY VERSION OF THE COMPETENT PERSON'S REPORT
ON ATLANTIC PETROLEUM INTERESTS
AS AT 31ST AUGUST, 2013**

INTRODUCTION

Atlantic Petroleum Limited (AP) requested Gaffney, Cline & Associates (GCA) to provide an independent assessment of its oil and gas Reserves and Resources, and the net present value (NPV) of the Reserves on its assets in UK, Norwegian, Faroese, Irish and Dutch waters, in the form of a Competent Person's Report (CPR). GCA understands that this CPR is now to be initially dated as of 31st August, 2013, and will then be updated as of 31st December, 2013. The CPR is to fulfil the Copenhagen Stock Exchange requirements and for AP to use for its Annual Report, and also for possible use in raising finance. This report is a summary version of the CPR, as requested by AP

AP has made available to GCA a data-set of technical information, including geological, geophysical, and engineering data and reports, together with financial data and the fiscal and contractual terms applicable to each of the assets. GCA has also had meetings and discussions with AP technical and managerial personnel. In carrying out this review GCA has relied on the accuracy and completeness of the information received from AP.

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

No person or company other than those for whom it is intended may directly or indirectly rely upon its contents. GCA is acting in an advisory capacity only and, to the fullest extent permitted by law, disclaims all liability for actions or losses derived from any actual or purported reliance on this document (or any other statements or opinions of GCA) by the Client or by any other person or entity.

A glossary of abbreviations and terms, used in this report, is attached as Appendix I.

BASIS OF OPINION

This document must be considered in its entirety. It reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by AP and obtained from other sources e.g. public domain, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by or at the direction of AP and obtained from other sources e.g. public domain, and has accepted the accuracy and completeness of these data. GCA has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geological, geophysical, and engineering data and reports, together with financial data and the fiscal and contractual data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights including environmental and abandonment obligations, and any necessary licenses and consents including planning permission, financial interest relationships or encumbrances thereon for any part of the appraised properties.

In carrying out this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report. In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with AP. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis carried out as part of this report.

Staff members who prepared this report are professionally-qualified with appropriate educational qualifications and levels of experience and expertise to perform the scope of work set out in the Proposal for Services.

GCA has not undertaken a site visit and inspection as it is considered unnecessary for the purposes of this CPR. As such, GCA is not in a position to comment on the operations or facilities in place, their appropriateness and condition and whether they are in compliance with the regulations pertaining to such operations. Further, GCA is not in a position to comment on any aspect of health, safety or environment of such operation.

In the preparation of this report GCA has used The Petroleum Resources Management System approved by the Society of Petroleum Engineers, the World Petroleum Council,

the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in March, 2007 (see Appendix II).

Oil volumes appearing in this report have been quoted at stock tank conditions. Typically these volumes have been referred to in million barrel increments (MMBbl). Natural gas volumes have been quoted in billions of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60° Fahrenheit.

It is GCA's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes at 31st August, 2103 are, in the aggregate, reasonable and the reserves and resources classification and categorization is appropriate and consistent with the definitions and guidelines for reserves and resources.

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further 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 development and production status. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test (pre-tax and exclusive of accumulated depreciation amounts) assessment prior to any NPV analysis.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident 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.

It must be appreciated that the Contingent Resources reported herein are unrisks in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resource volumes are presented as unrisks. It must be appreciated that Prospective Resources are risk assessed only in the context of identifying the stated 'Geological Chance of Success', a percentage which pertains to the percentage probability of achieving the status of a Contingent Resource (where the Geological Chance of Success is unity). This dimension of risk assessment does not incorporate the considerations of economic uncertainty and commerciality.

Reserves, Contingent Resources and Prospective Resources net to AP are based on AP's working interest equity.

It should be clearly noted that the Net Present Values (NPVs) contained herein do not represent a GCA opinion as to the market value of the subject property, nor any interest in it. In assessing a likely market value, it would be necessary to take into account a number of additional factors including: reserves risk (i.e. that Proved and/or Probable and/or Possible Reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk; potential upside, such as in this case exploitation of reserves beyond the Proved and the Probable level; other benefits, encumbrances or charges that may pertain to a particular interest; and the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the reference NPVs presented herein.

EXECUTIVE SUMMARY

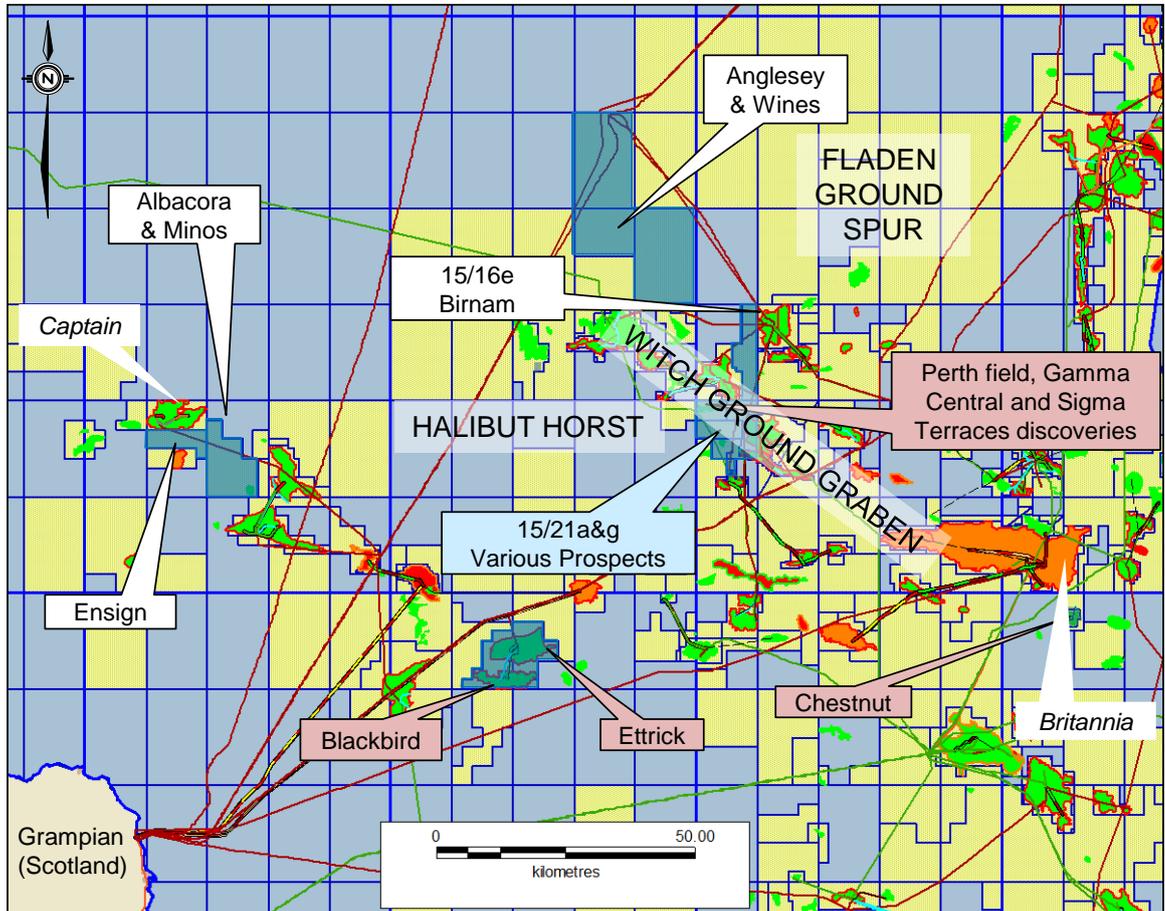
AP was formed in February, 1998 as an independent Faroese upstream oil and gas company. Since that time it has been awarded exploration licences in the Faroe Islands, the Netherlands and the UK. Additionally the company has completed several UK asset acquisitions and farmed into exploration and appraisal acreage in the UK and Ireland. In November, 2012 AP entered Norway through the acquisition of the Norwegian company Emery Exploration AS. AP listed on the Nasdaq OMX in Iceland (2005) and in Copenhagen (2007).

AP's UK North Sea assets can be divided into 4 groups: Moray Firth, Northern North Sea, Central North Sea and Southern North Sea. AP's interests in the Moray Firth area are described in Table 0.1 and illustrated in the location map in Figure 0.1.

AP has interests in two discoveries in the UK sector of the Northern North Sea. These assets are being developed. Orlando is a new development, and Kells (previously known as Staffa) is being redeveloped. Their locations are given in Figure 0.2. Both assets are operated by Iona, AP having the interest documented in Table 0.2.

FIGURE 0.1

LOCATION OF AP LICENCES IN THE MORAY FIRTH AREA



Source: GCA after Deloitte

TABLE 0.1

**AP LICENCES IN THE MORAY FIRTH AREA (UK)
AS AT 31st AUGUST, 2013**

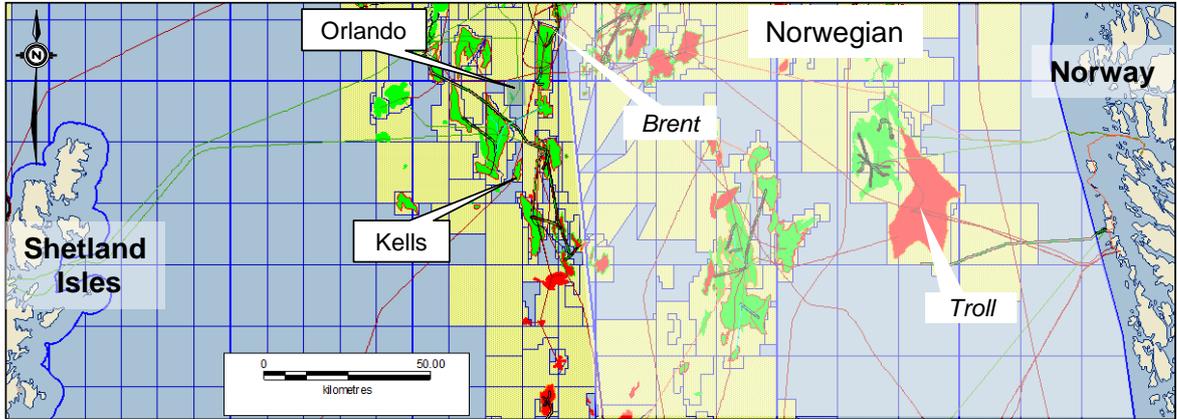
Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Ettrick	P273 & P317	20/2a & 20/3a	Field	Nexen (79.73)* Dana Petroleum Plc (12)	8.27	None	14/02/2015 (to be extended if still producing)
Blackbird (& Blackbird extension) ¹	P273, P317 & P1580	20/2a, 20/3a & 20/3f	Field	Nexen (90.60227)*	9.39	None	01/11/2016
Chestnut	P354	22/2	Field	Centrica (69.875)*, KNOC (15.125)	15.00	None	16/12/2016
Perth	P588	15/21b & 5/21c	Discovery	Parkmead (52.13)* Faroe Petroleum (34.62)	13.35	Drill 13/21a-P1	31/12/13
Sigma Terraces and Dolphin	P218	15/21b	Discovery	Parkmead (52.13)* Faroe Petroleum (34.62)	13.35	None	15/03/2018
Gamma Central/ Spaniards West	P218 & P1655	15/21a & 15/21f & 15/21g	Discovery	Premier Oil UK Ltd (28)*, Serica Energy (21), Cairn (21), Parkmead (12.624), Faroe Petroleum (8.4), Maersk Oil (5.736)	3.24	None	11/02/17
Birnam & Kinross	P1993	15/16e	Discovery & Exploration	Parkmead (application as DEO) (34)*, Faroe Petroleum (33)	33.00	Seismic reprocessing. Drill or drop	31/12/14
Magnolia, Albacora, Minos	P1610	13/23a	Exploration	Dana/KNOC (45)*, Summit (25), Trap Oil (10)	20.00	none	11/2/17
Magnolia, Ensign	P1766	13/22d	Exploration	Dana/KNOC (50)*, Summit (30)	20.00	Drill or drop	9/1/15
Anglesey & Wines	P1767	14/9, 14/14a & 14/15	Exploration	Bridge Energy (70)*	30.00	Reprocess 100 km 3D or 150 km ² 3D seismic. Drill to 2,500 m or drop	9/1/15

Note:

1. For P1580, Block 20/3f equities are Nexen Petroleum UK Ltd & Nexen Ettrick UK Ltd 79.73%, Korea National Oil Corporation (KNOC) 12% and AP 8.27% and the expiry date is 11/02/2017

FIGURE 0.2

LOCATION OF AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA



Source: GCA after Deloitte

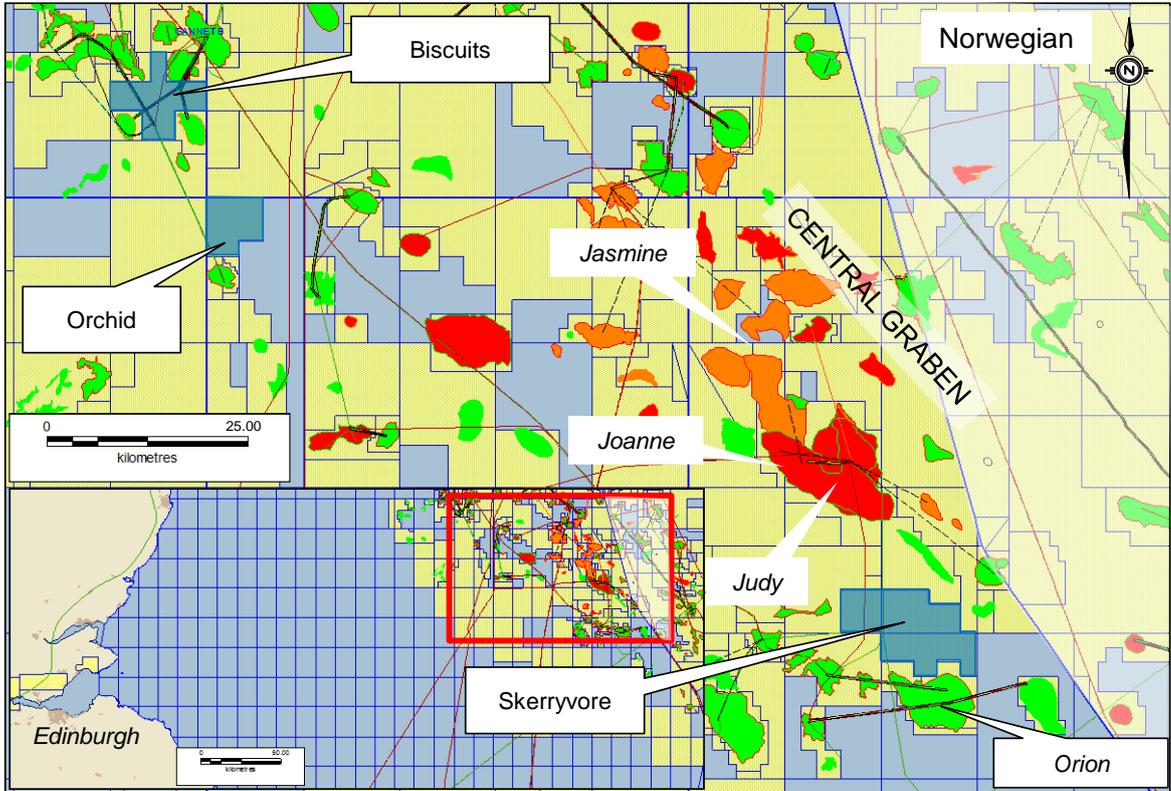
TABLE 0.2

**AP LICENCES IN UK SECTOR, NORTHERN NORTH SEA
AS AT 31st AUGUST, 2013**

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orlando	P1606	3/3b	Field	Iona (75)*	25.00	None	11/02/2017
Kells	P1607	3/8b	Field	Iona (75)*	25.00	None (FDP to be Resubmitted to DECC)	11/02/2017

Within the area of the Central Graben of the North Sea, AP has interests in three licences, as shown in the Figure 0.3. Orchid is an existing discovery, Skerryvore and Biscuits are exploration assets as described in Table 0.3.

FIGURE 0.3
LOCATION OF AP LICENCES IN UK SECTOR,
CENTRAL NORTH SEA



Source: GCA after Deloitte

TABLE 0.3
AP LICENCES IN UK SECTOR, CENTRAL NORTH SEA
AS AT 31st AUGUST, 2013

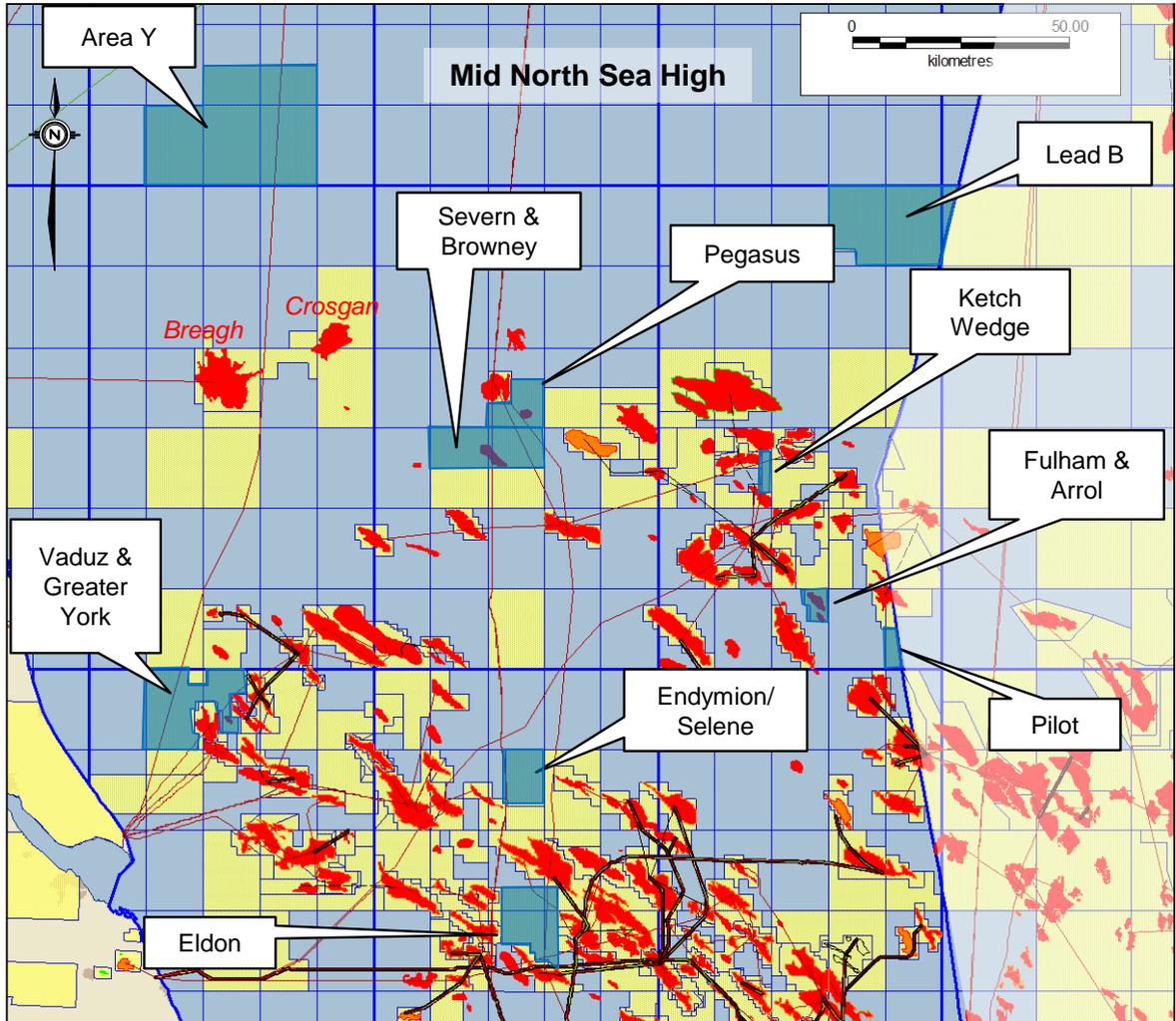
Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Orchid	P1556	29/1c	Discovery & Exploration	Trap Oil (60)* Valiant Exploration Ltd (30)	10.00	None	12/02/17
Skerryvore	P2082	30/12c, 30/13c, 30/18c	Exploration	Parkmead (30.5)* Bridge Energy (25) Dyas (14)	30.50	Firm well to 3,500 m TVDss or 200 m into Chalk, reprocessing, rock physics	31/12/16
Biscuits	P1791	21/30e	Exploration	Bridge Energy (40)* Idemitsu Petroleum (40)	20.00	None	Jan 2015

AP has interests in many assets in the UK sector of the Southern North Sea; both discoveries and exploration acreage. These can be considered as ten assets, although some licences contain multiple discoveries or prospects. The location of the assets and AP's interest are shown in Table 0.4 and Figure 0.4.

TABLE 0.4
AP LICENCES IN UK SECTOR, SOUTHERN NORTH SEA
AS AT 31st AUGUST, 2013

Asset Name	Licence	Blocks	Status	Partners (% (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Fulham & Arrol	P1673	44/28a	Discovery	Centrica (95)*	5.00	None	11/2/17
Pegasus	P1724	43/13b	Discovery & Exploration	Centrica (55)* Viking UK Gas (Third Energy) (35)	10.00 (5% carry)	None	30/4/18
Severn & Browney	P1727	43/17b, 43/18b	Exploration	Centrica (55)* Viking UK Gas (Third Energy) (35)	10.00 (5% carry)	Well by Apr 2014	30/4/14
Greater York	P1906	47/2b, 47/3g 47/7a, 47/8d	Exploration	Centrica (52.5)* Serica (37.5)	10.00 (5% carry)	Reprocess 180 km ² , G&G	31/1/16
Endymion/ Selene	P1734	48/8c	Exploration	Centrica (90)*	10.00 (5% carry)	Contingent Well	30/4/14
Area Y	P1828	36/23a, 36/24a,36/27, 36/28 & 36/29	Exploration	Centrica (90)*	10.00 (5% carry)	G&G studies, Drill or drop in 4 years	9/1/15
Lead B	P1899	44/4a, 44/5 & 45/1	Exploration	Centrica (45)* GDF (45)	10.00 (5% carry)	None	31/1/16
Pilot	P1905	44/30b	Exploration	Centrica (90)*	10.00 (5% carry)	Drill or drop	31/1/16
Ketch Wedge	P1924	44/17e	Exploration	AP (100)*	100.00	Drill or drop	31/1/16
Eldon	P1927	48/13c, 48/14b, 48/18e & 48/19d	Exploration	AP (100)*	100.00	Drill or drop	31/1/16

FIGURE 0.4
LOCATION OF AP LICENCES IN UK SECTOR,
SOUTHERN NORTH SEA

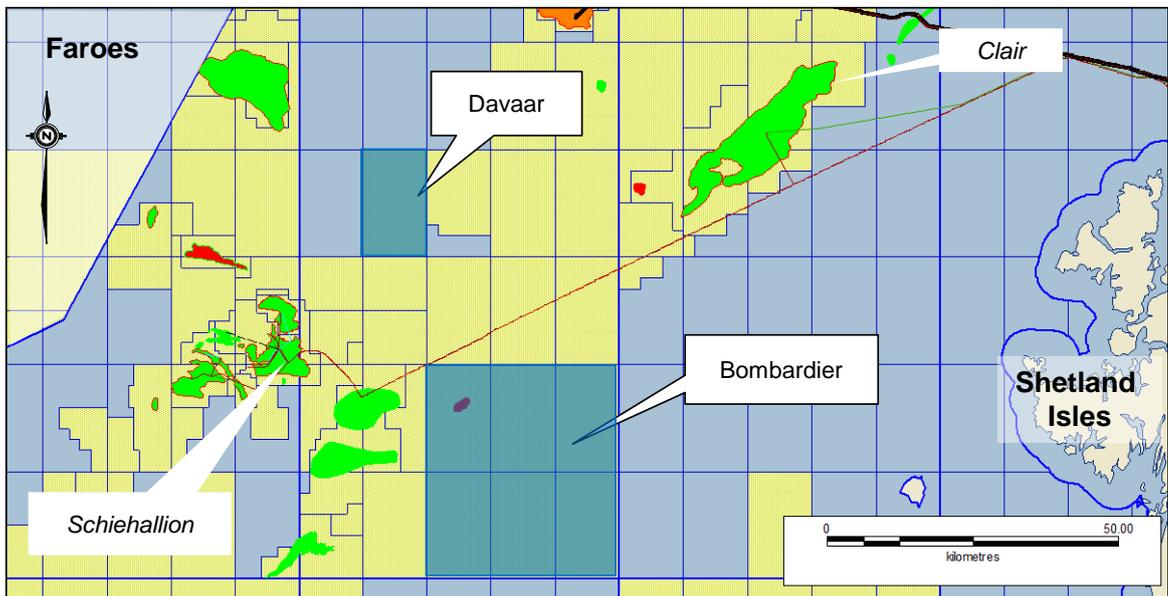


Source: GCA after Deloitte

AP also has interests in two licences in the UK sector of the Faroe-Shetland Basin, herein termed UK West of Shetland. Licence UK P1933 comprises Blocks 205/23, 205/24, 205/25, 205/28, 205/29 and 205/30 and contains the Bombardier discovery, the Eddystone Prospect and the Bell Rock Lead. Licence UKP2069 comprises Block 205/12 containing the Davaar Prospect. The location of the assets and AP's interest are shown in Figure 0.5 and Table 0.5.

FIGURE 0.5

LOCATION OF AP LICENCES IN THE UK WEST OF SHETLAND



Source: GCA after Deloitte

TABLE 0.5

**AP LICENCES IN THE UK WEST OF SHETLAND
AS AT 31ST AUGUST, 2013**

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Bombardier, Eddystone & Bell Rock	P1933	205/23, 205/24, 205/25, 205/28, 205/29, 205/30	Discovery & Exploration	Parkmead (43)* Dyas (14)	43.00	Drill or drop, obtain 2D seismic studies	31/12/18
Davaar	P2069	205/12	Exploration	Parkmead (30)* Summit (26) Dyas (14)	30.00	Drill or drop, reprocessing, studies	31/12/16

Table 0.6 and Figure 0.6 show AP's interests in two licences in the Faroe Islands sector of the Faroe-Shetland Basin. Licence L006 comprises Blocks 6104/16a, 6104/21 and 6105/25 and contains the Brugdan Prospect. Licence L016 comprises multiple Blocks containing the Kúlubøkan Prospect.

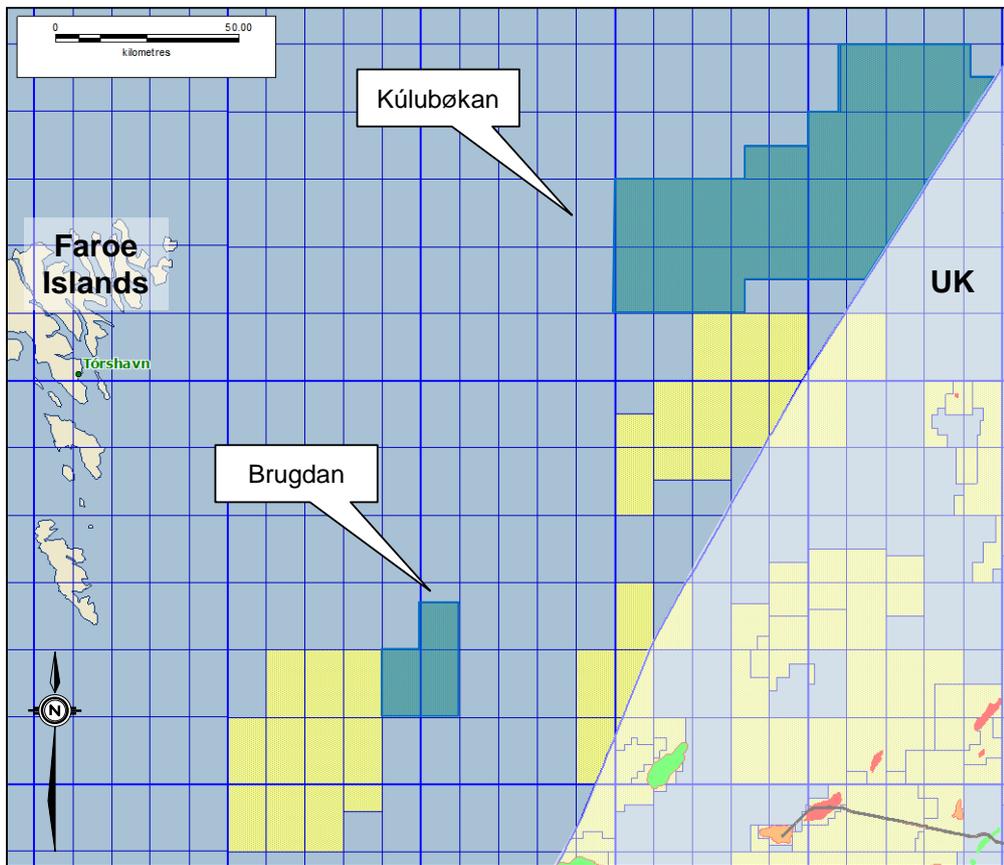
TABLE 0.6

**AP LICENCES IN THE FAROE ISLANDS
AS AT 31st AUGUST, 2013**

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Brugdan	L006	6104/16a, 6104/21, 6105/25	Exploration	Statoil (50)* ExxonMobil (49)	1.00	1 well to Vaila Reservoir or 4,756 m ss whichever is shallower (re-entry in 2014)	07/12/14
Kúlubøkan	L016	6202/6a, 6202/7, 6202/8, 6202/9, 6202/10a, 6202/11, 6202/12, 6202/13, 6202/14, 6202/15, 6202/16, 6202/17, 6202/18, 6202/21a, 6202/22a, 6203/14a, 6203/15a, 6203/16, 6203/17, 6203/18, 6203/19, 6203/20, 6203/21, 6203/22, 6203/23, 6203/24a, 6203/25a	Exploration	Statoil (40)* DONG (30) ExxonMobil (26)	4.00	None	08/12/14

FIGURE 0.6

LOCATION OF AP LICENCES IN THE FAROE ISLANDS

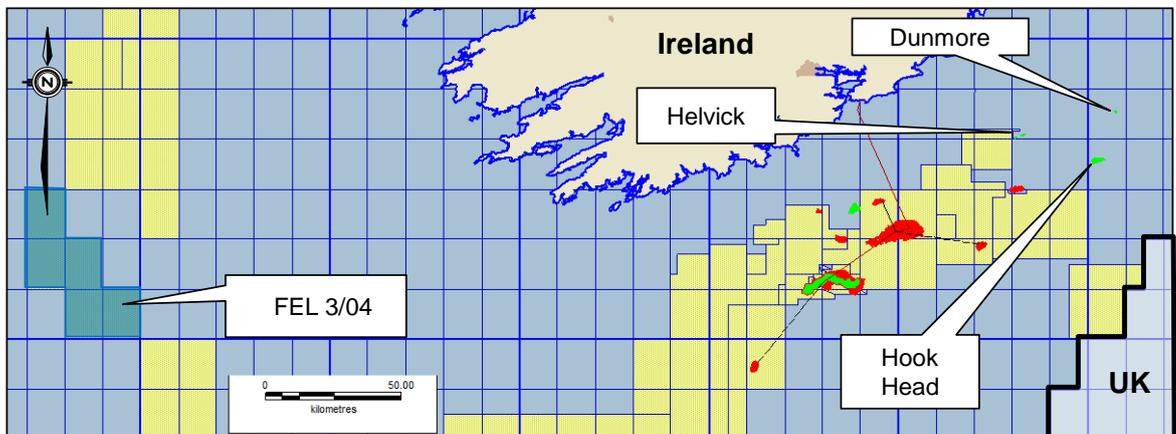


Source: GCA after Deloitte

AP's interests in Irish waters (see Figure 0.7), include four assets; three discoveries in the North Celtic Sea Basin and an exploration opportunity in the Porcupine Basin (Table 0.7).

FIGURE 0.7

LOCATION OF AP LICENCES IN IRELAND



Source: GCA after Deloitte

TABLE 0.7

**AP LICENCES IN IRELAND
AS AT 31st AUGUST, 2013**

Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
SEL 2/07	50/11, 49/9, 50/6 & 50/7	Requested to convert to Lease Undertakings	Providence (72.5)* ¹ Sosina (9.167)	18.33	None	31/1/2013 ²
FEL 3/04	44/18, 44/23, 44/24, 44/29, 44/30	Exploration	Exxon Mobil (25.5), ENI (27.5), Repsol (25), Providence (16), Sosina (2)	4.00	None	14/11/2103

Notes:

1. For Helvick only the partnership is: Providence (62.5%), AP (18.333%), Sosina (9.167%), Landsowne (10%)
2. An extension for FEL 3/04 has been requested in order to decide the next step based on the results of the well 44/23-1.

AP's interests in four blocks in Dutch waters; E1, E2, E4 and E5 is demonstrated in Table 0.8 and Figure 0.8. These are all frontier exploration blocks clustered together against the international boundary line. Note that AP also has interests in the adjacent blocks on the UK side of the international boundary, namely blocks 44/4a, 44/5 and 45/1 which form the UK licence P1899.

TABLE 0.8

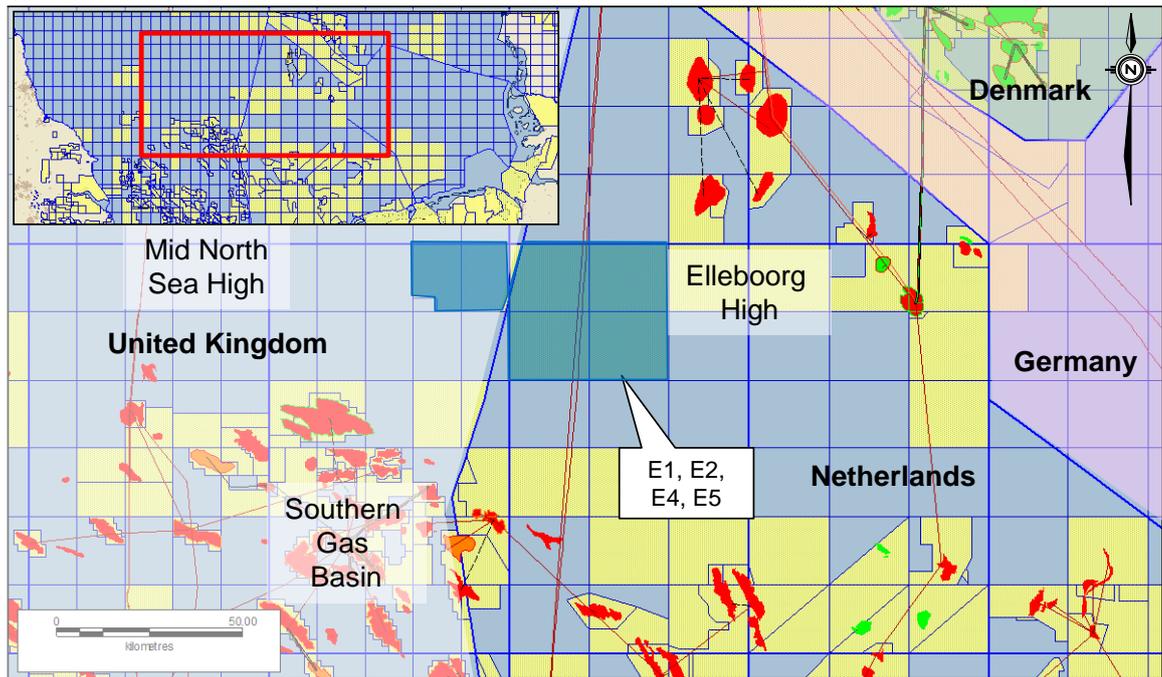
**AP LICENCES IN THE NETHERLANDS
AS AT 31st AUGUST, 2013**

Asset Name	Licence	Blocks	Status	Partners (%)	AP Interest (%)	Outstanding Commitments	Expiry Date
Quad E	E1, E2, E4, E5	E1, E2, E3, E4	Exploration	Centrica (54) EBN (40)	6.00	Acquire long cable 3D (215 km ² per block), acquire gravity/magnetics. Drill or drop within 2 years	21/11/13

Note: A two year extension has been sought to allow for integration with new adjoining data

FIGURE 0.8

LOCATION OF AP LICENCES IN THE NETHERLANDS



Source: GCA after Deloitte

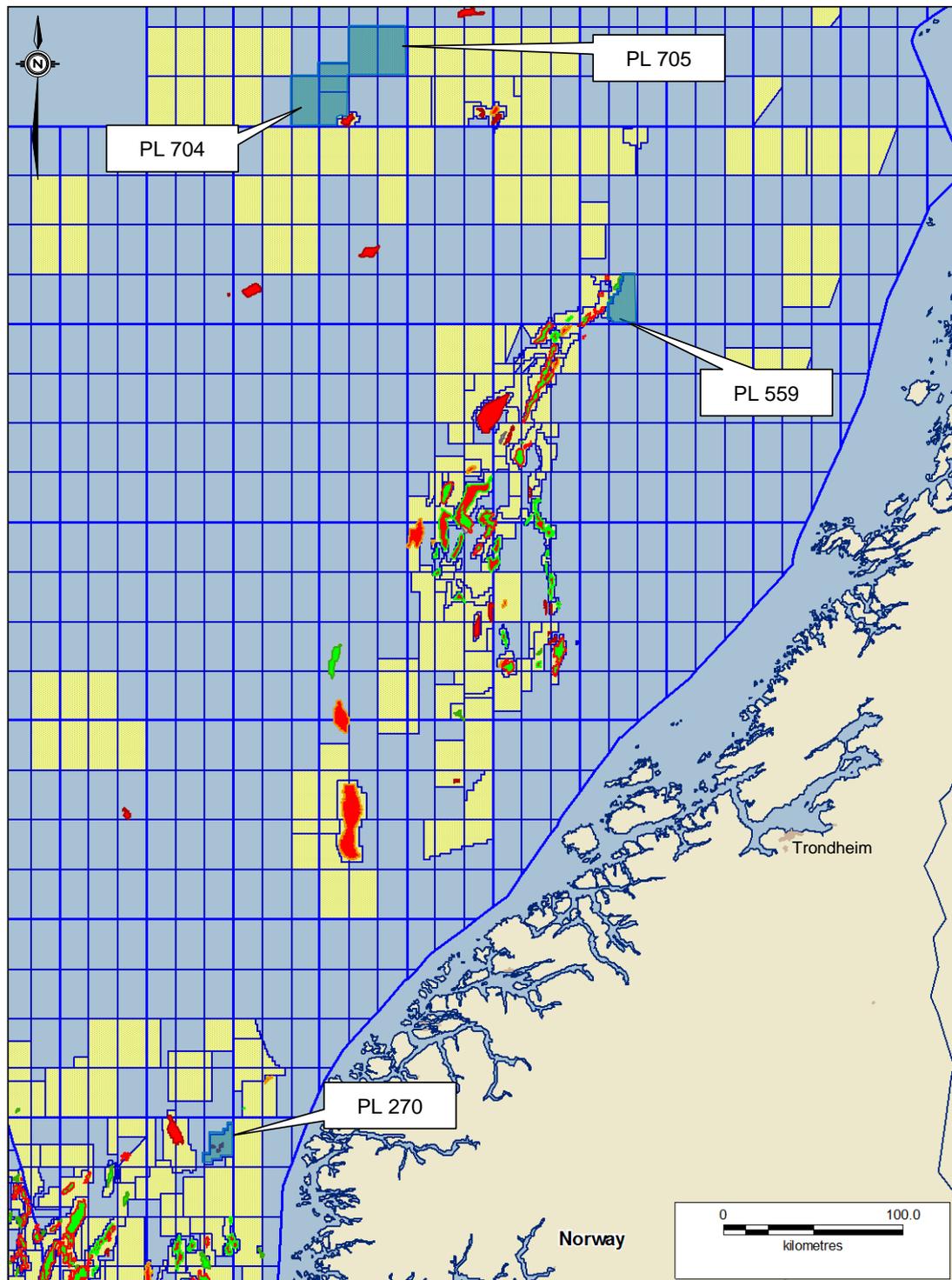
AP's interests in four licences in Norway are shown in Table 0.9 and Figure 0.9. Licence PL270 is located at the northern end of the Maløy Slope in the Norwegian sector of the North Sea, comprises Block 35/3 and contains the Agat discovery and additional prospectivity. Licences PL559, PL704 and PL705 are located in the Norwegian Sea and contain multiple Prospects.

TABLE 0.9

AP LICENCES IN NORWAY
AS AT 31st AUGUST, 2013

Asset Name	Licence	Blocks	Status	Partners (%) (*Operator)	AP Interest (%)	Outstanding Commitments	Expiry Date
Agat	PL270	35/3	Discovery & Exploration	VNG (85)*	15.00	Drill or drop in 2013, Potential new well in 2014, Decide possible development in 2014 after next well	2035
Nordland Ridge	PL559	6608/10 & 6608/11	Exploration	Rocksource (60)* VNG (20) Skagen 44 (10)	10.00	Plan for Development	19/02/16
St Helen	PL704	6704/12-1 & 6705/10 (part)	Exploration	Eon (40)* Repsol (30)	30.00	Years 1-2, Decide on 3D purchase or drop, Years 3-5 Drill exploration well	June, 2019
Napoleon	PL705	6705/7 (part), 6705/8, 6705/9, 6705/10 (part)	Exploration	Repsol (40)*, Eon (30)	30.00	Years 1-2 Acquire 3D seismic and decide to drill or drop, Years 5-7 Drill exploration well	June, 2019

FIGURE 0.9
LOCATION OF AP LICENCES IN NORWAY



The Proved, Proved plus Probable and Proved plus Probable plus Possible oil and gas Reserves attributed to AP's interests in the Ettrick, Blackbird, Chestnut, Orlando and Kells Fields as at 31st August, 2013 are summarised in Tables 0.10 and 0.11. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test.

TABLE 0.10
OIL RESERVES
AS AT 31st AUGUST, 2013

Field	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)		
	Total Proved	Proved plus Probable	Proved plus Probable plus Possible		Total Proved	Proved plus Probable	Proved plus Probable plus Possible
Ettrick	10.1	13.1	17.8	8.3	0.8	1.1	1.5
Blackbird	1.1	4.4	6.2	9.4	0.1	0.4	0.6
Chestnut	6.3	7.7	10.3	15.0	0.9	1.2	1.5
Orlando	7.8	15.4	21.6	25.0	2.0	3.8	5.4
Kells	1.9	4.2	5.2	25.0	0.5	1.1	1.3
Total	27.2	44.8	61.1		4.3	7.6	10.3

Note:

1. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st August, 2013 onwards.

TABLE 0.11
GAS RESERVES
AS AT 31st AUGUST, 2013

Field	Gross (Bscf)			WI (%)	Net to AP (Bscf)		
	Total Proved	Proved plus Probable	Proved plus Probable plus Possible		Total Proved	Proved plus Probable	Proved plus Probable plus Possible
Ettrick	4.9	6.4	8.7	8.3	0.4	0.5	0.7
Blackbird	0.5	2.2	3.1	9.4	0.1	0.2	0.3
Kells	19.7	27.5	33.1	25.0	4.9	6.9	8.3
Total	25.1	38.3	44.9		5.4	7.6	9.3

Note:

1. Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st August, 2013 onwards.

Net Present Values (NPVs) have been attributed to the Proved, the Proved plus Probable and the Proved plus Probable plus Possible Reserves. Post-Tax NPVs at discount rates of 8%, 10% and 12% are summarised in Table 0.12 based on GCA's third quarter 2013 Brent price scenario and applicable North Sea gas prices, as shown below, and the applicable fiscal regime of the UK (Reserves are currently only attributable to properties in UK waters). All NPVs quoted are those attributable to AP's net entitlement interests in the properties reviewed.

OIL PRICE SCENARIO

Year	Oil Price (US\$/Bbl)
2013 (Remainder)	101.29
2014	98.23
2015	94.39
2016	93.37
2017	99.71
2018	101.61
2019+	+2% p.a.

GAS PRICE SCENARIO

Year	Gas Price (pence/therm)
2013 (Remainder)	68.19
2014	66.21
2015	64.81
2016	63.24
2017	62.54
2018	62.34
Thereafter	+2.0% pa

TABLE 0.12

POST-TAX NET PRESENT VALUES OF RESERVES, NET TO AP, AS AT 31st AUGUST, 2013

Field	WI (%)	Reserves Category	NPV (US\$ MM)		
			8%	10%	12%
Ettrick	8.3	Proved	20.93	20.62	20.31
		Proved plus Probable	26.63	26.13	25.63
		Proved plus Probable plus Possible	37.60	36.27	35.02
Blackbird	9.4	Proved	1.63	1.70	1.77
		Proved plus Probable	9.95	9.82	9.68
		Proved plus Probable plus Possible	16.35	15.75	15.18
Chestnut	15.0	Proved	15.30	15.02	14.75
		Proved plus Probable	18.68	18.23	17.80
		Proved plus Probable plus Possible	22.68	21.97	21.30
Orlando	25.0	Proved	43.54	39.43	35.74
		Proved plus Probable	80.55	72.85	66.03
		Proved plus Probable plus Possible	112.94	101.38	91.31
Kells	25.0	Proved	10.42	8.89	7.52
		Proved plus Probable	30.35	27.25	24.45
		Proved plus Probable plus Possible	37.89	34.18	30.82
Total		Proved	91.82	85.66	80.09
		Proved plus Probable	166.16	154.28	143.59
		Proved plus Probable plus Possible	227.46	209.55	193.63

Notes:

1. The Net Present Values are calculated from discounted cash flows incorporating the fiscal terms governing each license block.
2. The values shown in this table are Net to AP.

The oil and gas Contingent Resources attributed to AP's interests, as at 31st August, 2013, are summarised in Tables 0.13 and 0.14 respectively.

TABLE 0.13

**OIL CONTINGENT RESOURCES
AS AT 31st AUGUST, 2013**

Area	Discovery	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)		
		1C	2C	3C		1C	2C	3C
Moray Firth, UK	Perth	28.7	38.0	48.4	13.35	3.8	5.1	6.5
	NE Perth	6.8	13.0	21.3	13.35	0.9	1.7	2.8
	Bright	12.3	18.6	27.2	8.27	1.0	1.5	2.2
	Dolphin	2.0	6.0	14.0	13.35	0.3	0.8	1.9
	Spaniards	8.1	18.9	33.6	3.24	0.3	0.6	1.1
Central North Sea, UK	Orchid	4.0	5.0	8.0	10.00	0.4	0.5	0.8
North Celtic Sea, Ireland	Helvick	1.5	2.1	2.6	18.33	0.3	0.4	0.5
	Hook Head	25.2	35.0	47.2	18.33	4.6	6.4	8.6
	Coral/Dunmore	0.5	0.7	1.0	18.33	0.1	0.1	0.2
Total		89.1	137.3	203.3		11.7	17.1	24.6

Notes:

1. "Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field and "Net" are those pertaining to AP's working interest, both without any economic cut-off being applied.
2. The volumes reported here are "Unrisked" in the sense that "Chance of Development" values have not been arithmetically applied to the designated volumes within this assessment. "Chance of Development", which is not stated herein, represents the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
3. The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

TABLE 0.14

**GAS CONTINGENT RESOURCES
AS AT 31st AUGUST, 2013**

Area	Discovery	Gross (Bscf)			WI (%)	Net to AP (Bscf)		
		1C	2C	3C		1C	2C	3C
Southern North Sea, UK	Fulham & Arrol	17.0	42.0	63.0	5.0	0.9	2.1	3.2
	Pegasus North	30.1	103.7	310.1	10.0	3.0	10.4	31.0
Norway	NW Agat	5.2	14.6	39.7	15.0	0.8	2.2	6.0
	Bloody Basin	11.7	43.9	161.1	15.0	1.7	6.6	24.2
Total		63.9	204.2	573.9		6.4	21.3	64.3

Notes:

1. "Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field and "Net" are those pertaining to AP's working interest, both without any economic cut-off being applied.
2. The volumes reported here are "Unrisked" in the sense that "Chance of Development" values have not been arithmetically applied to the designated volumes within this assessment. "Chance of Development", which is not stated herein, represents the probability that the Contingent Resource will be developed, which would warrant the re-classification of that volume as a Reserve.
3. The primary Contingent Resource volume reported here is the 2C, or 'Best Estimate', value.

Oil and Gas Prospective Resources attributed to a number of undrilled Prospects, together with the associated geological chance of success (GCoS), are summarised in Tables 0.15 and 0.16. Further, a significant number of Leads have been acknowledged in many of AP's licences areas. These are listed and discussed within the relevant sections of GCA's full report.

TABLE 0.15
OIL PROSPECTIVE RESOURCES (PROSPECTS)
AS AT 31st AUGUST, 2013

Area	Prospect	Gross (MMBbl)			WI (%)	Net to AP (MMBbl)			GCoS (%)
		Low	Best	High		Low	Best	High	
Moray Firth, UK	Perth NW Terrace	10.0	18.6	29.2	13.35	1.3	2.5	3.9	24
	Perth East	1.8	3.6	6.8	13.35	0.2	0.5	0.9	24
	Birnam	5.1	23.7	106.1	33.00	1.7	7.8	35.0	22
	Anglesey North	4.5	13.8	36.0	30.00	1.4	4.1	10.8	19
	Anglesey Central	5.8	27.9	80.0	30.00	1.7	8.4	24.0	19
	Anglesey South	3.3	9.3	23.6	30.00	1.0	2.8	7.1	19
	Chenas	2.5	7.8	25.2	30.00	0.8	2.3	7.6	17
	Fleurie	4.5	11.1	29.2	30.00	1.4	3.3	8.8	17
	Brouilly	1.3	4.2	14.4	30.00	0.4	1.3	4.3	17
Morgon	3.5	8.7	24.0	30.00	1.1	2.6	7.2	17	
Central North Sea, UK	Orchid West	4.0	8.1	17.2	10.00	0.4	0.8	1.7	40
	Skerryvore	9.0	16.0	27.0	30.50	2.7	4.9	8.2	26
	Skerryvore Chalk	31.0	66.0	119.0	30.50	9.5	20.1	36.3	30
West of Shetland, UK	Eddystone	71.0	166.0	328.0	43.00	30.5	71.4	141.0	9
	Davaar	75.0	159.0	285.0	30.00	22.5	47.7	85.5	15
Norway	Hendricks	64.0	132.0	233.0	10.00	6.4	13.2	23.3	18

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered viable drilling targets.
2. "Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from the field.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked"
4. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

TABLE 0.16
GAS PROSPECTIVE RESOURCES (PROSPECTS)
AS AT 31st AUGUST, 2013

Area	Prospect	Gross (Bscf)			WI (%)	Net To AP (Bscf)			GCoS (%)
		Low	Best	High		Low	Best	High	
Southern North Sea, UK	Pegasus West	39.0	135.6	447.3	10.0	3.9	13.6	44.7	45
	Pegasus South/ East	11.0	34.2	100.1	10.0	1.1	3.4	10.0	39
	Endymion	16.0	36.0	74.2	10.0	1.6	3.6	7.4	24
	Selene	18.0	66.6	239.4	10.0	1.8	6.7	23.9	24
Faroe Islands	Brugdan	1,134.9	3,481.3	8,448.5	4.0	45.4	139.3	337.9	15
	Kúlubøkan	1,300.0	4,400.0	13,500.0	4.0	52.0	176.0	540.0	11
Porcupine Basin, Ireland	Dunquin South	343.0	2,059.2	5,390.0	4.0	13.7	82.4	215.6	12
Southern North Sea, Netherlands	Maes	13.1	65.0	280.8	6.0	0.8	3.9	16.8	21
	Hals	9.8	50.0	224.9	6.0	0.6	3.0	13.5	14
	Metsu	5.6	21.0	61.1	6.0	0.3	1.3	3.7	21
	Van Goyen	8.8	28.5	70.9	6.0	0.5	1.7	4.3	19
	Cuyp	13.3	73.0	365.3	6.0	0.8	4.4	21.9	25
Norway	Agat (Turitella)	15.4	66.8	280.8	15.0	2.3	10.0	42.1	52
	Napoleon North	146.7	370.5	772.7	30.0	44.0	111.2	231.8	28
	Napoleon South	117.2	282.7	554.9	30.0	35.2	84.8	166.5	28

Notes:

1. Prospects are features that have been sufficiently well defined, on the basis of geological and geophysical data, to the point that they are considered viable drilling targets.
2. "Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from the field.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect would result in a discovery, which would warrant the re-classification of that volume as a Contingent Resource. The GCoS value for Contingent Resource is, by definition, unity. These GCoS values have not been arithmetically applied to the designated volumes within this assessment. Thus the volumes are "Unrisked"
4. It is inappropriate to aggregate Prospective Resources without due consideration of the different levels of risk associated with each Prospect/Lead and the potential dependencies between them. Similarly, it is inappropriate to aggregate Prospective Resources with Reserves or Contingent Resources.

Yours sincerely,
GAFFNEY, CLINE & ASSOCIATES



Brian Rhodes
Global Director - Corporate Advisory Services

APPENDIX I

Glossary

GLOSSARY
List of Standard Oil Industry Terms and Abbreviations

B	Billion (10 ⁹)
Bbl	Barrels
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
DECC	Department of Energy and Climate Change
G&G	Geology & Geophysics
km	Kilometres
km ²	Square kilometres
m	Metres
Mcf or Mscf	Thousand standard cubic feet
MMcf or MMscf	Million standard cubic feet
MM	Million
MMBbl	Millions of barrels
NPV	Net Present Value
psia	Pounds per square inch absolute
SPE	Society of Petroleum Engineers
ss	Subsea
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
US\$	United States Dollar
WI	Working Interest
2D	Two dimensional
3D	Three dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage

APPENDIX II

Abbreviated form of SPE PRMS

Petroleum Resources Management System

Definitions and Guidelines ⁽¹⁾

March 2007

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 management 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 definition 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 document 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 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 PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

¹ These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

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 5 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.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

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:

- (1) the area delineated by drilling and defined by fluid contacts, if any, and
- (2) 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. 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.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

- (1) completion intervals which are open at the time of the estimate but which have not yet started producing,
- (2) wells which were shut-in for market conditions or pipeline connections, or
- (3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

- (1) from new wells on undrilled acreage in known accumulations,
- (2) from deepening existing wells to a different (but known) reservoir,
- (3) from infill wells that will increase recovery, or
- (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
 - (a) recomplete an existing well or
 - (b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources 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.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclassified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

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.

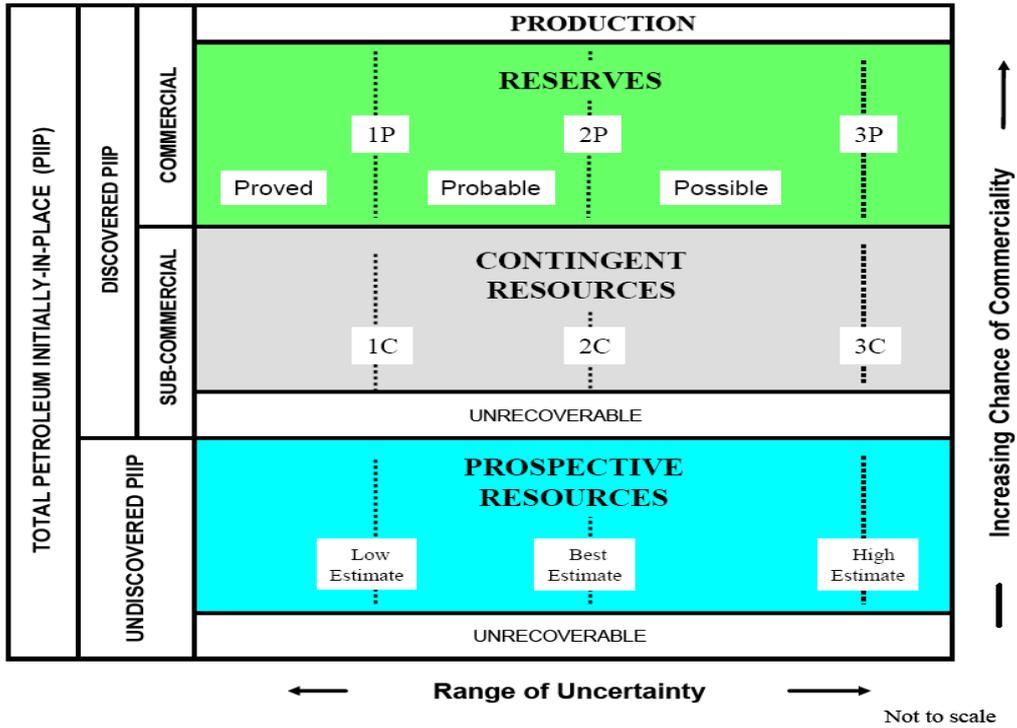
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under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

RESOURCES CLASSIFICATION



PROJECT MATURITY

