EDISON

Exploration watch

2018 exploration wells

Worldwide exploration levels remain low compared to the 2014 peak and in 2018 are not expected to increase significantly from 2017. Latin America dominated 2017 in terms of both discovery numbers and size, mainly due to ExxonMobil's continuing success offshore Guyana, but also with the 400-800mmbbl Zama discovery offshore Mexico. Activity in the region is set to continue in 2018, with further drilling in Guyana and renewed efforts to prove an extension of the basin into Suriname. The largest discovery in 2017 was the 15tcf Yakaar offshore Senegal, but in 2018 the exploration focus offshore West Africa switches to Morocco and Namibia. In this Exploration watch, we highlight these wells and more that are due to be drilled in 2018 involving independent companies, and with resource estimates greater than 100mmboe.

Frontier basins dominate

Of the nine wells highlighted in this report, six are located in frontier basins. These wells include the **Anapai** and **Aurora/Apetina** prospects offshore Suriname and to the east of the seven discoveries in the Stabroek block offshore Guyana. On the other side of the Atlantic and offshore West Africa, drilling is already underway offshore Morocco in **Rabat Deep-1**, while two wells, **Cormorant** and **Prospect S** are due to be drilled in Namibia. These are all deepwater wells, but our final frontier prospect, **Wild Horse**, in Mongolia is the only onshore well featured in this report.

The remaining three wells featured are located in the established areas of the UK and Norway but in relatively less explored or in technically specialist areas. **Lyon** will be drilled West of Shetland and **Rowallan** is an HPHT well in the Central North Sea, while **Shenzhou** is in the underexplored Barents Sea.

Investment still low, but opportunity in lower costs

Global investment in conventional exploration is expected to dip below 2017 levels, with Wood Mackenzie estimating oil and gas exploration expenditure of US$37bn in 2018, down by 7% from 2017 and over 60% from the 2014 peak of US$100bn. However, companies with drill-ready targets are now seeing significantly reduced exploration costs (with rates for state-of-the-art deep water drillships in the region of $150,000/day down from the 2014 level of $650,000/day). Those companies that have effectively reset their portfolios and worked to de-risk and high-grade prospects should now benefit.

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*Hurricane Energy and Petro Matad are research clients of Edison Investment Research

EXPLORATION WATCH
A periodic look ahead from our in-house petroleum engineer, Elaine Reynolds, focusing on interesting exploration activities with significant potential impact on E&P equities.

Wells to watch in 2018

Exhibit 1: Summary of wells in report

Prospect	Region	Operator	Operator resource estimate	Chance of Success	Estimated spud 2018
RD-1	Morocco	ENI	768mmbbl	24%	In progress
Anapai-1	Suriname	Kosmos Energy	700mmbbl	20 – 25%	In progress
Lyon	North Sea	Siccar Point	1.4tcf	NA	Q2
Rowallan	North Sea	ENI	130mmboe	NA	Q2
Wild Horse	Mongolia	Petro Matad	290mmbbl	NA	Q3
Aurora/Apetina	Suriname	Kosmos Energy	500mmbbl+	20 -25%	Q3
Cormorant	Namibia	Tullow Oil	125mmbbl	15%	September
Prospect S	Namibia	Chariot Oil & Gas	459mmbbl	29%	October
Shenzhou	Barents Sea	Statoil	138mmbbl Triassic 229mmbbls Permian (Partner Lundin estimate)	23% Triassic 8% Permian (Partner Lundin estimate)	Q4

Source: Edison Investment Research

West Africa: Focus on Morocco and Namibia

Recent successes offshore West Africa have been concentrated in the Mauritania/Senegal/Gambia/Bissau/Conakry (MSGBC) basin, with BP/Kosmos Energy's Tortue gas development project straddling Mauritania and Senegal and Cairn Energy's appraisal of its 473mmbbl SNE oil field offshore Senegal.

In 2017, BP/Kosmos entered the second phase of exploration in Mauritania, and targeted the outboard basin fan play fairway with four exploration wells. One well, Lamantin, tested the northern Mauritania oil trend and the remaining three wells, Yakaar, Hippocampe and Requin Tigre, tested the southern Mauritania/northern Senegal gas trend. Only Yakaar was successful, although it was the largest find in the world in 2017 with estimated Pmean resources of 15tcf. The well encountered 45m of net pay in thick stacked reservoir sands over a large area, with very good porosity and permeability.

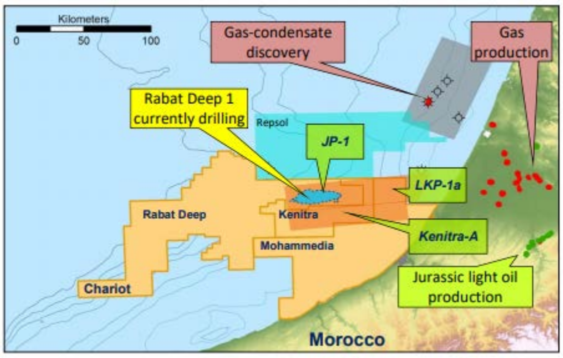
In 2018, West African exploration moves away from Senegal/Mauritania and shifts to Morocco and Namibia.

Morocco: Rabat Deep-1 results imminent for Chariot

Offshore Morocco emerged as an exploration hotspot in 2013/14 as part of the increased interest in Atlantic Margin acreage, and attracted companies such as Kosmos Energy, Genel Energy and Cairn Energy to drill in the region. However, none of the resulting seven exploration wells was considered to be a success, and the region remains underexplored with only 43 wells drilled offshore and only one discovery, the 1969 Cap Juby heavy oil discovery in the Jurassic carbonate play.

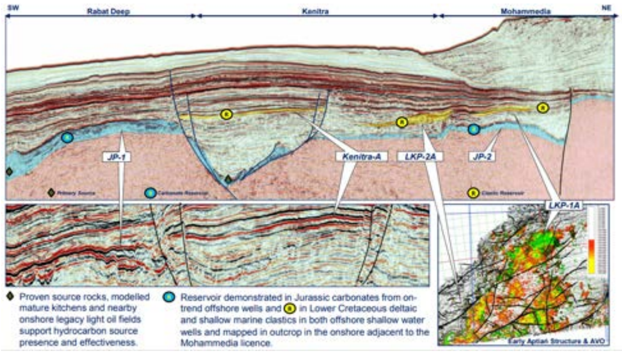
Chariot Oil & Gas holds three exploration licences offshore Northern Morocco, covering an area of around 12,800km^2: Rabat Deep, Kenitra and Mohammedia. The company holds a 10% WI in the Rabat Deep licence, having farmed out to Woodside (25% WI) in 2014 and operator Eni in 2016 (40% and operator). The company also holds a 75% WI and is operator in both Kenitra and Mohammedia (the Office National des Hydrocarbures et des Mines (ONHYM) holds a 25% carried interest in all licence areas). Chariot is currently drilling the Rabat Deep-1 (RD-1) well on its JP-1 prospect in the Rabat Deep licence and results are due in May if drilling goes to schedule. Chariot is carried for its share of the cost of the well under the terms of its farm-out deal with Eni, with an unspecified agreed cap.

Exhibit 2: Map of Chariot's Moroccan portfolio with Rabat Deep-1 location



Source: Chariot Oil & Gas

Exhibit 3: Seismic covering JP-1 prospect



Source: Chariot Oil & Gas

The JP-1 prospect was originally identified on 2D seismic and de-risked on c 1,075km^2 3D seismic acquired in 2014. The structure sits in 1,115m of water and is a four-way dip closure with faulting towards the southern edge, with a structural closure of around 200km^2. RD-1 is targeting a Jurassic carbonate reservoir. The well is located on the southern margin of the prospect where it can penetrate the mound and wedge of the structure in an area of major faulting, thereby optimising the information that can be gained from one well. The prospect has been independently assessed by Netherland Sewell & Associates (NSAI) to hold gross mean prospective resources of 768mmbbls.

Evidence for the presence of hydrocarbons in this area can be seen from the light oil produced onshore Morocco (Exhibit 2). There are very few offshore wells in the region and the closest, Repsol's RSC-1 well, around 50km to the north-west of JP-1, did not encounter Jurassic reservoir. However, cuttings from the well do contain traces of hydrocarbons, indicating that a charge has existed at this location. Further evidence can be found in the clusters of sea pockmarks to the south-east of JP-1. Sea bed cores taken by Chariot from these pockmarks have been found to have a high-incidence hydrocarbon signature. The company has modelled hydrocarbon charge into the prospect from the Northwest Outboard kitchen that is believed to be mature for hydrocarbons.

The success of the well also relies on the Lower Cretaceous providing a top seal, but the company sees the key risk as reservoir development. The well has a 24% COS, which is reasonably high for such a frontier well. Success would de-risk an additional six Jurassic leads in Rabat Deep.

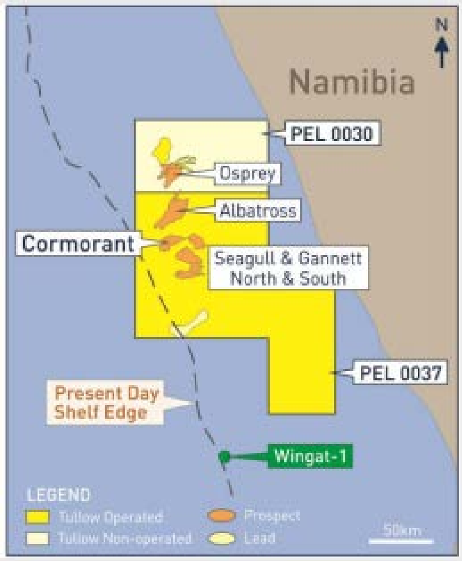
Namibia: Two high-profile wells in 2018

Namibia remains a frontier exploration area, with only 15 wells drilled offshore to date, of which six have been drilled since 2012. The 1.4tcf Kudu gas field, discovered by Chevron in 1974, remains the country's only commercial discovery. The breakthrough well for the presence of oil in the region was the HRT-operated Wingat-1 well drilled in 2013, which encountered two high-quality Aptian source rocks and the presence of light 38 - 42^o API oil in thin bed reservoirs, though not in commercial quantities. HRT's follow-up well, Murombe, found 39m of water wet reservoir with good porosity in the secondary Santonian target. Between them, these wells demonstrated that all the elements required for a working petroleum system are present in Namibia, although not yet found together in one well. Wingat and Murombe sit in PEL 82 in the central Walvis Basin, operated since 2016 by Galp Energia (40%) and partnered by ExxonMobil (40%) after it farmed into the licence in 2017. In 2018, drilling will return to Namibia with two wells planned in the central Walvis Basin: the Cormorant prospect, operated by Tullow, and Chariot's Prospect S.

Cormorant: Potential gateway to >1bnbbls

The Cormorant prospect is located in PEL 37, the licence to the north of Wingat and Murombe. Tullow is operator and holds a 35% WI, and is partnered by ONGC Videsh (30%), Pancontinental (20%), Africa Energy (10%) and Paragon (5%). Cormorant is a basin slope Cenomanian Cretaceous fan covering 120km^2 and sitting in 550m of water. Tullow is targeting resources of 125mmbbls and expects to spud the well on 1 September 2018 with the sixth-generation Ocean Rig Poseidon drillship.

Exhibit 4: Cormorant prospect map



Source: Tullow Oil

The well will be Tullow's only exploration well to be drilled in 2018, in line with its efforts to limit its exposure to high-cost, high-risk offshore drilling in recent years. Cormorant is a simple play in that it is expected to be simple drilling, with minimal casing strings required and, as such, together with current lower deepwater rig rates, is expected to cost between $35m and $45m. Geologically the well is higher risk at 15% COS. The prospect is a single loop turbidite identified on 3D seismic acquired in 2013, but is at the limit of the amplitude variation with offset (AVO) window and cannot be de-risked further without drilling. As Cormorant is a stratigraphic trap, the company is looking for a stratigraphic pinch out at the feeder suggested by stratigraphic attenuation updip on seismic, and supported by evidence of some shelf edge faulting. The larger goal is to open up the region and other fans with a potential of 1bnbbls if Cormorant is successful.

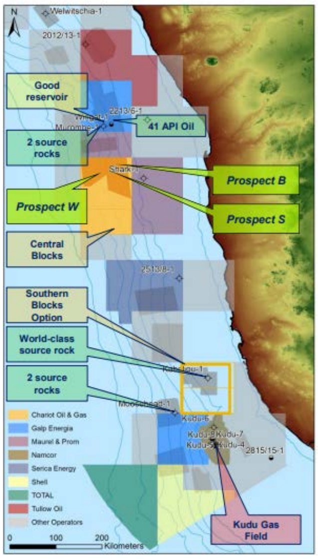
One such fan that would be de-risked is the Osprey fan in PEL 30 immediately to the north of PEL 37 and in which Tullow holds a 15% WI. The licence is operated by Eco Atlantic (32.5%) and partnered by AziNam (32.5%), ONGC Videsh (15%) and NAMCOR (10%). Osprey was independently assessed by Gustavson in 2016 for Eco Atlantic to hold P50 gross prospective resources of 245.5mmbbls with a COS of 17.9%.

Prospect S: One of five Upper Cretaceous structures

Prospect S sits in 1,650m of water in PEL 71 to the south of Wingat and Murombe. It is due to be drilled from mid-October 2018 by operator Chariot (65%) and partners AziNam (20%), NAMCOR (10%) and a Namibian BEE component of 5%. The well will target gross mean prospective resource of 459mmbbls independently assessed by NSAI, and is one of five, four-way, dip-closed structures identified by Chariot in the Upper Cretaceous turbidite fairway. Chariot has not yet secured a rig and is continuing to look for a farm-in partner for the well, although it can fund its share of drilling costs after raising US$15m through a placing and an additional US$2.5m through an open offer in March 2018.

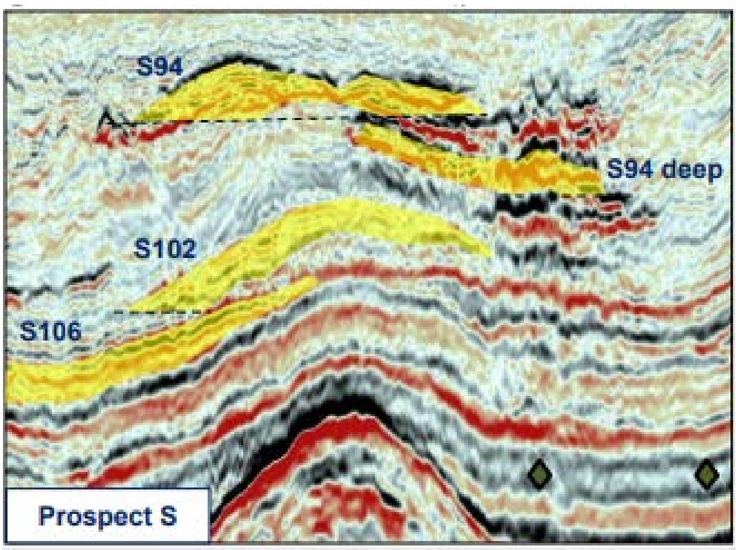
The licence area footprint is 16,000km^2, of which 6,100km^2 has 3D seismic coverage. The Murombe well encountered good-quality sands above the primary target and Prospect S will target these Cretaceous sands, which are draped over a volcanic structure at this location. The well has been designed to penetrate three separate sand bodies, S94, S102 and S106 (Exhibit 6).The thick, rich and mature Aptian source rock found in Wingat and Murombe has a characteristic seismic signature, which Chariot sees in its own licence at the same depth and so has inferred to be mature here. Prospect S has the lowest risk of the five identified four-way dip closures with a COS of 29% (the COS of remaining prospects T,U,V and W ranges between 22% and 25%). The key risks are in the source and reservoir, which have been established in Wingat and Murombe, but uncertainty remains as to how this may have changed across the area.

Exhibit 5: Namibia acreage with Prospects S and W



Source: Chariot Oil & Gas

Exhibit 6: Prospect S seismic



Source: Chariot Oil & Gas

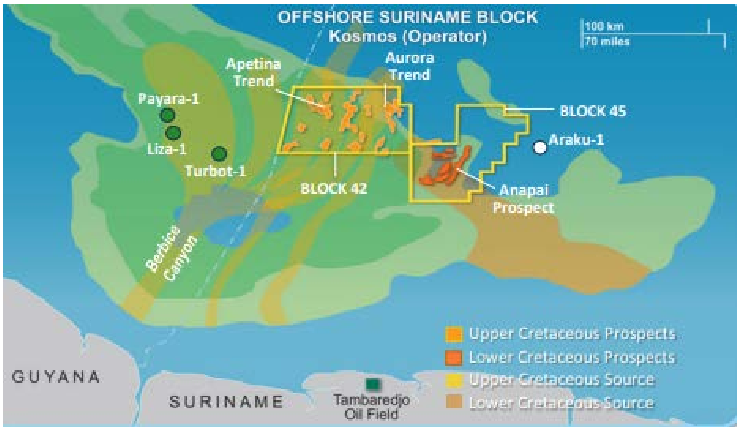
If Prospect S is successful, Chariot plans to move the rig to drill Prospect W back to back. Since the modelled charge for Prospects S, T and U is from the east, but from the west in Prospects V and W, this sequence of wells would allow the presence of charge in both areas to be tested. Prospect W is estimated to hold gross mean prospective resources of 284mmbbls with a COS of 25%.

Suriname: Looking to extend success from Guyana in 2018

In 2017 ExxonMobil continued its run of success in Guyana since its 2015 Liza discovery in the Stabroek block. To date there have been seven discoveries on the block and gross recoverable resources are now estimated at over 3.2bnboe, with the final two discoveries, Ranger and Pacora, not yet included in the estimate. In 2018 Exxon will drill four exploration wells and have identified 20 further prospects.

Efforts to prove an extension of the Cretaceous fan play into Suriname have so far proved unsuccessful. In 2017, Apache's Kolibri-1 exploration well in Block 53 was deemed non-commercial and followed on from the failure of the company's Popokai-1 well in Block 58 in 2015. Tullow did establish the presence of gas condensate in its 2017 Araku well in Block 54, but did not find a significant quantity of reservoir rocks.

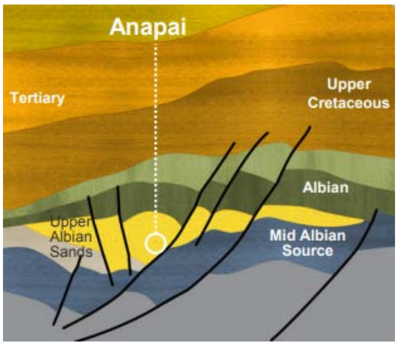
Exhibit 7: Kosmos Suriname prospects map



Source: Kosmos Energy

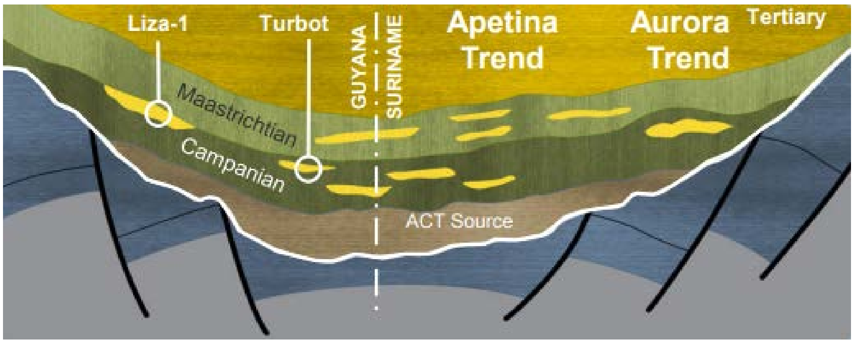
In 2018, operator Kosmos Energy is planning to drill two exploration wells offshore Suriname: Anapai -1 in Block 45 and Aurora or Apetina in Block 42. The wells will test two separate Cretaceous plays, with a further three plays identified across the acreage, and both blocks have full 3D seismic coverage, acquired in 2016.

Exhibit 8: Anapai schematic



Source: Kosmos Energy

Exhibit 9: Apetina and Aurora trends schematic



Source: Kosmos Energy

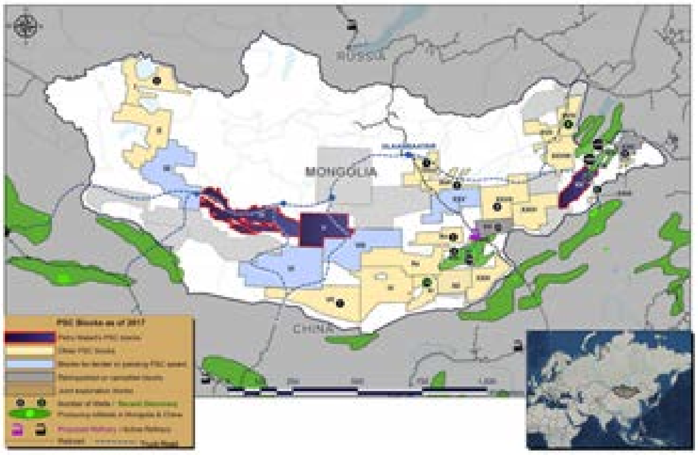
Drilling is already underway at Anapai-1 with the Ensco DS-12 drillship. Kosmos holds a 50% WI in Block 45 where it is partnered by Chevron. The prospect sits in 1,500m of water and is targeting gross unrisked resources of 700mmbbls in a Lower Cretaceous structural/stratigraphic trap. It was selected to be drilled first since it was the most mature in the company's portfolio and so drill ready. The company has modelled Anapai as being fed by a feeder system from the east, and so a different system to that seen in Liza. The key risk is considered to be the trap, due to the combination stratigraphic element of the prospect.

In Block 42, Kosmos has yet to decide whether to drill in Aurora or Apetina and is working through multiple prospect options. Aurora and Apetina are both located in the same Upper Cretaceous play and partly fed by the same feeder system as seen in Liza**.** Kosmos holds a 33.3% WI in Block 42, together with Chevron (33.3%) and Hess (33.3%). Hess is a partner (30%) in the Guyana discoveries with ExxonMobil and brings its in-depth knowledge of the region to Block 42. Kosmos has access to non-proprietary seismic over Liza and sees a positive calibration in its seismic over Block 42. The company is targeting gross estimated resources here of over 500mmbbls. Drilling is expected to commence in Q318, as the drillship will drill one well elsewhere between Anapai-1 and Aurora/Apetina. The company believes the COS for both wells is in the range of 1 in 4 to 1 in 5.

Mongolia: Wild Horse targeting 290mmbbls

Oil was first discovered in Mongolia in 1941, and proven and producing fields sit in analogous and adjacent basins across the border in China, but the country's petroleum potential has yet to be developed. Production reached an average of 21mbopd in 2017 from three producing fields, with the bulk coming from the Petro China-operated Tamsag field in Block XIX in eastern Mongolia. Meanwhile, only three wells have been drilled in Western Mongolia. Petro Matad holds a 100% WI in three blocks, making it one of the largest concession holders in the region alongside Australia-listed Wolf Petroleum. The company's acreage covers more than 60,000km^2 and is spread over multiple basins including low-cost targets close to existing infrastructure in Block XX in the east and high-impact frontier exploration in Blocks IV and V in Western Mongolia. Petro Matad is planning to drill two exploration wells in Block IV and V in 2018, with the Wild Horse prospect targeting 290mmbbls. The company will also drill the Snow Leopard prospect in Block V targeting 90mmbbls across two targets. Snow Leopard will be drilled first in Q218 and is expected to take around 70 days to drill and log, and will be followed by Wild Horse.

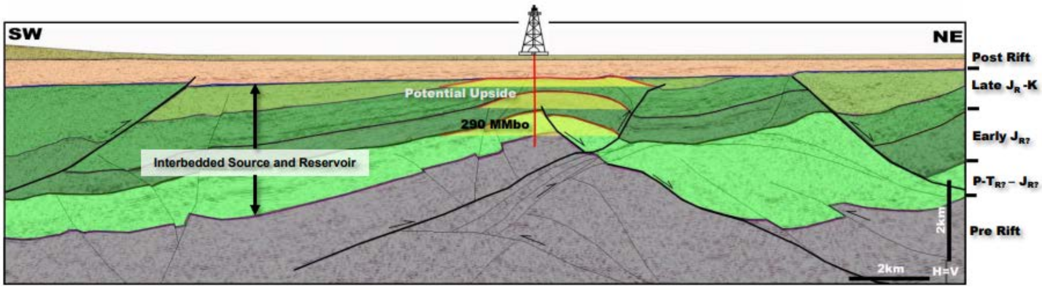
Exhibit 10: PSC blocks in Mongolia with Petro Matad's blocks shown in dark blue



Source: Petro Matad

Wild Horse sits in the Baatsagaan Basin in Block IV, updip of the two largest and deepest identified potential kitchen areas mapped in Petro Matad's acreage. The prospect is a four-way dip closure with a fault-bounded component and contains stacked pay potential. It is estimated to hold mid-case recoverable resources of 290mmbbls in the primary structural target. The well will be drilled to a TD of 1,850m and is expected to cost $4m. Although this is a frontier area, studies on outcrop sections here indicate clean continuous sands so that reservoir porosities are expected to be between 10% and 30%. This is in contrast to the reservoirs in eastern Mongolia that exhibit low permeability due to the presence of volcanic debris in the sediment that clogs the pore space. Wild Horse has a closure area of 22km^2. The prospect is supported by a 'soft' (ie not volcanic) amplitude anomaly that conforms to structure, which could be an indication of hydrocarbon fluid charge. A migration pathway has been identified from the south-west and success will rely on the migration of hydrocarbons into the structural high. As Wild Horse sits in a lacustrine basin, any discovered oil is expected to be of a waxy nature. In the case of success, a further 13 prospects and leads in the Baatsagaan Basin will be de-risked with an estimated combined 750mmbbls of recoverable resources in the mid-case.

Exhibit 11: Wild Horse



Source: Petro Matad

UKCS: Exploration remains at low level

Exploration in the mature UK North Sea has been at historically low levels, and the number of exploration wells drilled in 2017 remained at the 2016 level of 14, while current forecasts indicate that this will drop to around 10-12 wells in 2018. 350mmboe proven and probable reserves were discovered in 2017 (although not all well results have been announced to date), compared to the current UKCS annual production rate of around 600mmboe. Notable successes in 2017 were Statoil's Verbier in the Moray Firth and BP's Achmelvich and Hurricane Energy's Halifax discoveries West of Shetland. The latter region remains a key focus for the UKCS into 2018. BP will bring its 640mmbbls Clair Ridge development on stream this year, and Hurricane is continuing to progress the development of its 523mmbbl (2P +2C) Lancaster field to first oil from its Early Production System (EPS) in H119. In April 2018, Shell farmed into a 30% WI in licences P1028 and P1108 and, together with operator Siccar Point Energy, will drill the fifth and final appraisal well in the Cambo field. Meanwhile, Nexen will drill an appraisal well in Cragganmore, which is part of the Lyon cluster. Here we take a closer look at the Lyon exploration well to be drilled West of Shetland by Siccar Point, and the high-pressure, high-temperature (HPHT) well Rowallan, operated by Eni in the Central North Sea (CNS) where independent Serica Energy is a partner.

Lyon: Potential for new West of Shetland gas hub if successful

The Lyon prospect is operated by private E & P company Siccar Point (WI 33.33%) and partnered by INEOS (66.66%). Siccar Point entered the region in January 2017 when it took over OMV, and subsequently farmed out P1854 and P1935 to INEOS in November 2017. The prospect sits in the P1854 licence, located around 150km north of the Shetland Islands, and both companies also hold a share in the Total-operated Tobermory and Bunnehaven discoveries to the west of P1854 (Total 30%, INEOS 32.5%, SSE 20%, Siccar Point 17.5%)

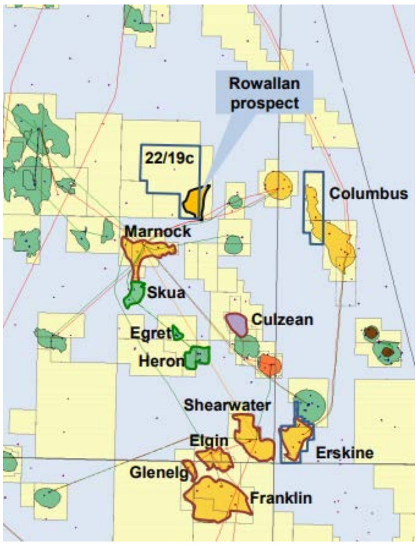
Lyon is estimated to contain mean recoverable resources of 1.4tcf in the Tertiary Flett sandstones. It was identified based on a strong seismic amplitude anomaly seen on 3D seismic and the geometry is a combination of structural with a stratigraphic pinch out. 3D is particularly crucial here as the presence of basalts in the region can make the identification of reservoir sands challenging (the Flett sands in Bunnehaven and Rosebank were interlaced with basalt). If successful, Lyon would be large enough to operate as a new gas hub in the region and allow existing smaller discoveries such as Tobermory, Bunnehaven and Cragganmore to be developed. An appraisal well is planned by Nexen on the Cragganmore discovery in 2018.

P1935 sits 30km north of Lyon and contains a number of Tertiary gas leads. However, these have been identified on 2D seismic and would need 3D seismic data to be matured into prospects.

Rowallan: HPHT exploration close to existing infrastructure

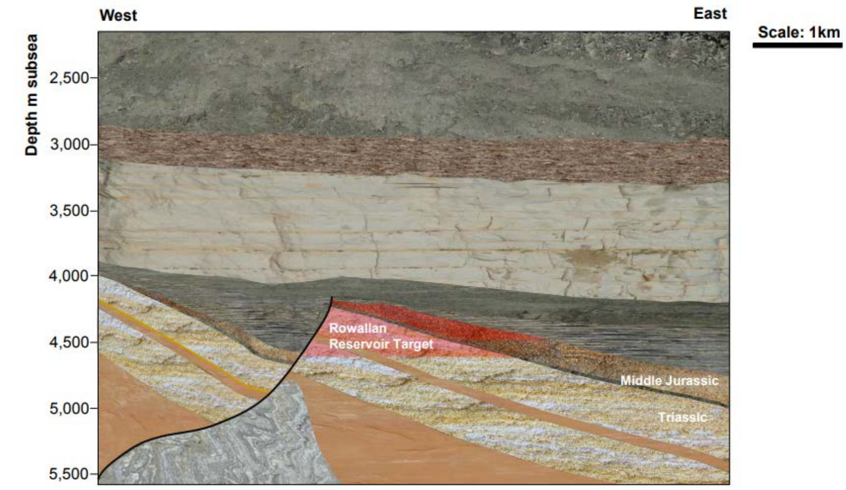
The HPHT Rowallan prospect is located in the east of Block 22/19c in the Central North Sea and not far from an area of existing HPHT production. It sits 20km to the NNE of Total's Culzean development, due on stream in 2019, while existing HPHT fields Shearwater, Erskine, Elgin, Franklin and Glenelg sit to the south of Culzean. The Rowallan exploration well is due to be drilled in Q318 and will be operated by Eni (40% WI), together with partners JX Nippon (25%), Mitsui (20%) and Serica (15%). Serica is already active in the area as operator of the Columbus gas condensate field (50% WI) to the east of Rowallan, and as a partner in Erskine (18% WI).

Exhibit 12: Rowallan location map



Source: Serica Energy

Exhibit 13: Rowallan prospect cross-section



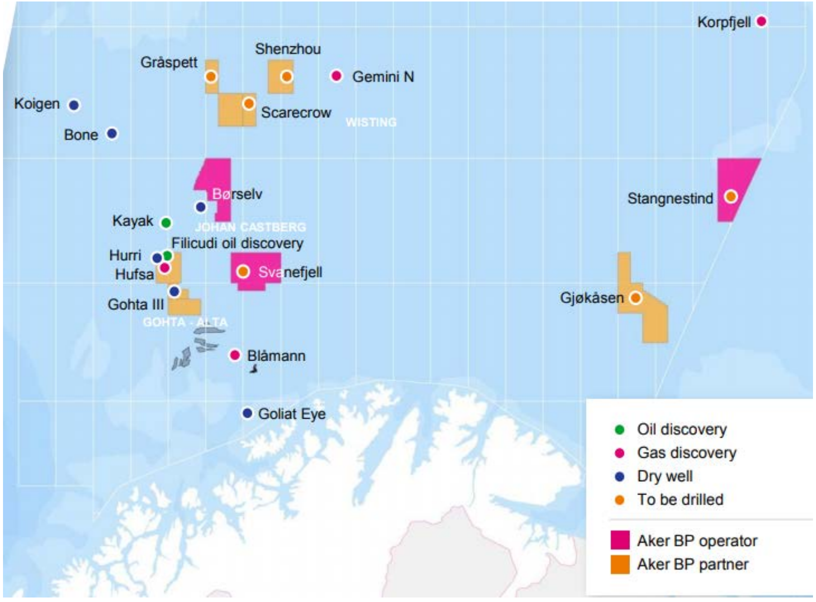
Source: Serica Energy

The well is targeting gas condensate in the Triassic Skagerrak and Middle Jurassic Pentland formations. The structure is a structural fault and dip-closed trap and is considered to be similar to and analogous with Culzean. Serica believes that it is optimally located to be charged from the direction of the Mungo and Monan oil fields to the east. Rowallan has been independently assessed to contain gross P50 resources of over 130mmboe. Technology has advanced for the drilling of HPHT wells, although it is more technically demanding than for a typical North Sea exploration well, particularly as the difference in these wells between pore pressure and fracture pressure is usually quite small, resulting in a narrow drilling window. A cost estimate for the well is not publicly available, although Serica is fully carried for the cost of the well. Success in Rowallan would de-risk the Dundonald and Sundrum prospects, which also sit in Block 22/19c.

Barents Sea: Seven confirmed exploration wells in 2018

One of the most high-profile wells to be drilled in 2017 was Statoil's Korpfjell exploration well in the Barents Sea, offshore Norway. The well found only a small non-commercial volume of gas, contributing to a year of disappointing results for the region. Despite this, exploration continues in the Barents in 2018, with seven exploration wells confirmed and options for a further five wells announced to date. Statoil and Lundin remain as key explorers in the region, but Aker BP will also make a major contribution to the number of wells drilled, as it plans to operate or partner in six wells in the Barents, out of its total Norwegian exploration programme of 12 wells in 2018. UK independent Cairn Energy has exposure to the region this year with its 15% share in the Shenzhou well, due to be drilled in Q4.

Exhibit 14: Barents map with 2018 exploration well locations



Source: Aker BP

Shenzhou is located in PL722 to the west of the Wisting oil field and will be operated by Statoil (45%WI). Shenzhou is described by partner Lundin (20%) as a four-way dip closure targeting 138mmbbls in the Triassic sandstone and 229mmbbls in Permian carbonates. Lundin assigns a COS of 23% to the Triassic and 8% to the Permian, while Aker BP (20%) gives a pre-drill range of 40-295mmboe.

To the west of Shenzhou, DEA will drill the Gråspett prospect in PL721 in Q4. Partner Aker BP estimates that the prospect holds between 32 and 263mmboe. Spirit Energy will drill the Scarecrow prospect in PL852 and is also partnered here by Aker BP with estimated volumes of 83-245mmboe.

Three wells are planned in the frontier Southeastern Barents, where Korpfjell is located. Statoil is expected to return to the PL859 licence in 2018 targeting the Korpfjell Deep prospect and the Gjøkåsen shallow prospect around 300km south of Korpfjell. While Statoil has not given details for these prospects, Lundin estimates that Gjøkåsen holds gross prospective resources of 768mmbbls and Korpfjell Deep holds 201mmbbls. COS for both prospects is low, however, at 10% and 8% respectively, highlighting the frontier nature of the south-eastern region. Nevertheless, partner Aker BP gives a pre-drill range of 26-1427mmboe for Gjøkåsen, so that the well has the highest potential impact of all the wells currently planned in the region in 2018. Aker BP will also drill here for the first time in 2018 as operator on the Stangnestind prospect in PL858, located between Korpfell and Gjøkåsen. The well is expected to be drilled in the second half of the year and is targeting an estimated preliminary gross volume of 30-190mmboe.

Finally, the remaining well, Svanefjell in PL659, is likely to be the first of the wells to be drilled in 2018. Planned for Q2, the well sits 93km to the north of Goliat and will be operated by Aker BP. The company estimates volumes of 17-331mmboe, while partner Lundin estimates that the Triassic target will hold 268mmboe, although it assigns a COS of only 12%.

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