Finding Petroleum

Why onshore fracking probably won't work in UK

But North Sea fracking might

Finding oil in basement rock

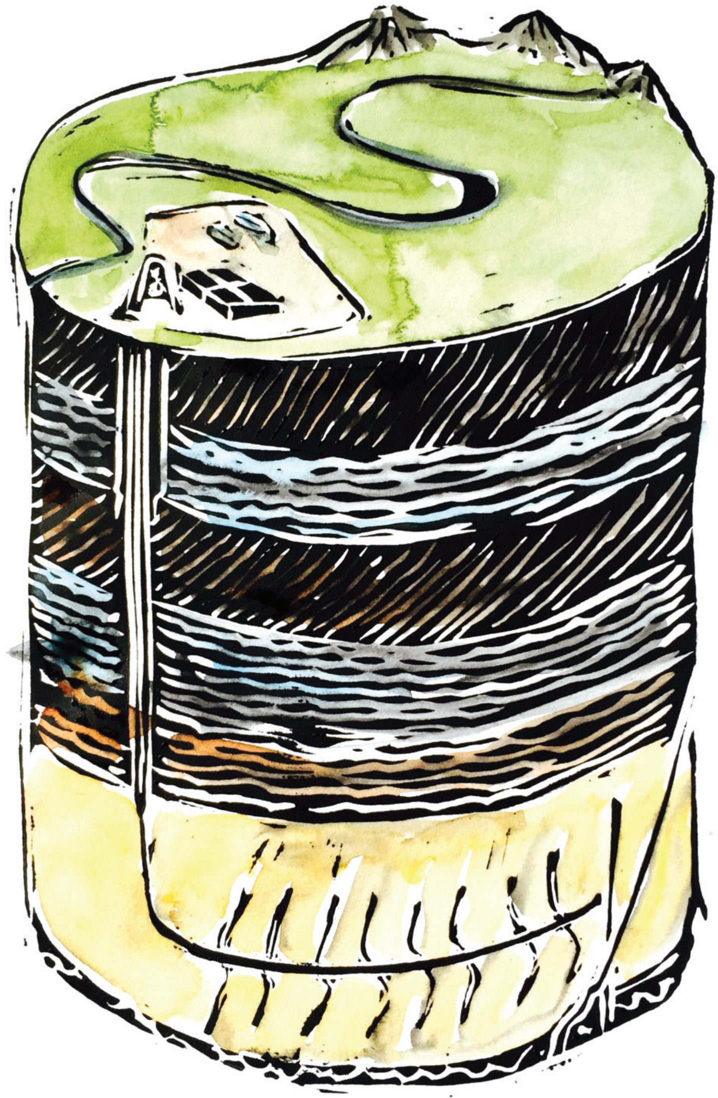
Steam flood - 80 per cent recovery?

Event Report, Finding & Exploiting new petroleum resources in Europe, March 10 2016, London

Special report

Finding & Exploiting new petroleum resources in Europe

The Geological Society, London, March 10 2016



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Finding and Exploiting New Resources in Europe

Shale oil in Germany and in the North Sea, steam flood in the North Sea, basement oil West of Shetland, and shale oil in Siberia – some of the ideas for new resources in and around Europe we covered in our Finding Petroleum March 10 London forum "Finding and Exploiting New Resources in Europe"

By using steam flood, you can get recovery of as much as 80 per cent. Could this work in the North Sea? Could you frack in the North Sea? Are there any workable locations in Europe for onshore fracking? Can we find oil and gas by looking for source rock and tracking where the oil has migrated to, rather than looking for structures which might hold oil?

These are some of the interesting themes we explored in our March 10 London Finding Petroleum conference, "Finding and Exploiting New Resources in Europe".

Opening the conference, Neil McMahon, Managing Director of Kimmeridge Energy, said that there are many interesting exploration opportunities in Europe which may not work at $30 oil prices, but could work in an oil price environment which is "slightly better", he said.

If the oil price rises, "we will have many companies that have not done any exploration for the last few years, especially those outside US unconventional space, looking for new opportunities."

As a starting idea, Dr McMahon suggested that the best places to develop unconventional (tight) oil and gas is probably places which are already successful conventional oil and gas fields, rather than look for somewhere new.

For tight oil to work, you need to see a large active petroleum system, which will probably have also driven conventional oil and gas discoveries. Otherwise there is probably something wrong with your source rock and the entire petroleum system, Dr McMahon believes.

"I look at the world in a very simplistic way – you find good unconventional projects where you find a lot of conventional oil, it's not rocket science," Dr McMahon said. That's the number one thing we look for. You need to see an area that has produced large amounts of O+G conventionally."

"We believe in vertical percolation as the most prominent method of migration in a petroleum system, it helps saturate areas around the source rock."

For example, Kimmeridge did not consider developing unconventional fields in Lancashire (UK) because there hasn't been any gas fields there.

On this basis, a list of the latest potential shale plays in the world outside the US might include the Russia's Bazhenov and Domanik, Germany's Posidonia, the UK's Kimmeridge Clay, and shale of North Africa, and perhaps Romania, Dr McMahon said.

Limited discoveries

On the down side, the number of significant discoveries over the past decade is getting very low, Dr McMahon said.

Dr McMahon presented data taken from the American Association of Petroleum Geologists "Explorer" magazine, where it publishes what it considers to be 'significant discoveries of the previous year" worldwide.

The criteria for 'significant' is a subjective one, and can include very large discoveries, or opening up new basins.

"I've added up the number of significant discoveries they have mentioned," he said. "Since 2009, new discoveries have dropped significantly, they've bumbled along at 60 to 70 discoveries a year. Looking at 2015 compared to previous years, the numbers look like they are flat lining."

Some of the offshore wells counted as 'significant discoveries' have similar production rates to individual unconventional wells in the US onshore Permian basin, he said.

One oil discovery rated as 'significant' was a well in Lincolnshire, UK, which had flow rates in the initial testing phase of 80 barrels of oil per day. "You think, is this it?" Dr McMahon said. "You start to worry what the future for oil supply is."

However, there have been some very large gas discoveries in the past 6-7 years, he said.

Note – the conference included a talk from Emily Rees, geoscientist with Landmark Exploration Insights (formerly known as Neftex) on Carboniferous Basin Fill and Systems Tract Evolution: A Model for Source Rock Development.

Videos and slides from the conference can be downloaded from the event agenda page **http://www.findingpetroleum.com/event/d08e9.aspx**

This special edition of Finding Petroleum is an event report from our forum in London on March 10, 2016, "Finding & Exploiting new petroleum resources in Europe".

Event website
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Hurricane Energy – finding oil in the basement

Basement rock, the oldest rock of all, lying below sediment, can develop many fractures over its long life, which can make good traps for oil. Hurricane Energy believes that it might be possible to produce it West of Shetland

UK oil company Hurricane Energy is looking at four basement prospects in the North Sea West of the Shetland Islands, known as Whirlwind, Lancaster, Typhoon and Lincoln, in a region known as "Rona Ridge."

In 2014, Hurricane Energy drilled its first horizontal production well in the "Lancaster" fractured basement rock, and the well test showed an oil flow rate of 9,800 stock tank barrels of oil per day, and flow was limited by the capacity of the test equipment, not the well.

It will take more than one oil well to fully develop the field – so the big question is, is this well a one-off, or is there an extended oil province West of Shetland with many opportunities in it? Said Dr Robert Trice, CEO of Hurricane Energy, speaking at the Finding Petroleum forum in London on Mar 10, "Finding and Exploiting New Resources in Europe."

The 2014 Horizontal well's "productivity index" (a commonly used measure of the well's ability to produce) was 160 stock tank barrels / day / psi, which "demonstrates a very good quality reservoir pressure and indicates that under production conditions and a moderate 120 psi draw-down, the basement reservoir could deliver 20,000 STB/d from a single well," the company said.

Basement rock, the oldest rock of all (lying below sediment) could be holding viable oil and gas reservoirs – it has so many faults in it, because it is so old and has so many stresses on it. This means that there are many places for oil to lie, flowing down from source rock above.

There are three other producing fields in the region – Foinaven, Schiehallion and Clair. Foinaven, Schiehallion and Clair are clastic reservoirs (composed of fragments of minerals and rocks moved from somewhere else). However some of their oil might be coming from reservoirs in basement rock, for example with clastic sands just above basement rock.

Hurricane's reservoir analysis was made by a third party consultancy company, to Society of Petroleum Engineers (SPE) standards, as part of Hurricane's submission to the Alternative Investment Market (AIM), he said.

The analysis concluded that the Lancaster and Whirlwind reservoirs have "about 200m barrels of 2C contingent resource," Dr Trice said. "So it's very clear that there's potentially a lot of oil – and accessible oil – if Lancaster is anything to go by in this part of the ridge."

Lincoln basement has not yet been drilled, and Typhoon has been drilled to the basement encountering oil.

Exploration dream

"The exploration dream is to drill a well through the basement," he said. "We are ready, we've identified four clear seismic faults and want to establish their properties.

"The whole Atlantic margin has the correct elements for the basement to be effective," he said. "I do not think Lancaster is one–off. I do believe there's an extensive fractured province West of Shetland."

There may be basement reservoirs in the nearby Rockall basin, where the UK government has recently financed a seismic survey.

"If Lancaster proves to be a proven field, it is likely to be the tip of the iceberg. Basement is a global phenomenon."

"Two discoveries and additional basement prospectivity indicate significant resource base in shallow water and an area much needing infrastructure."

However, there will need to be a period of long term production before industry accepts this as a 'proven play', he said.

It will take a few more wells to try to get a better understanding of fracture network's drainage characteristics.

"The UK has failed to bring a fractured basement play into production, which is pathetic considering the age of our industry and the fact that we've got a world class source rock, phenomenal data and very high well counts," he concluded. "We do believe we're close to achieving a reversal of that, bringing Lancaster to field development."

Ocean bottom seismic

One audience member noted that BP has made big advances in mapping the subsurface structure and defining the trap on its nearby Clair field, partly through the use of Ocean Bottom Cable (OBC) seismic data. So perhaps OBC could also be very helpful in Lancaster, to map the basement.

Dr Trice replied that the biggest challenge was not finding oil volumes, it is "demonstrating oil will come out of the ground at commercial rates for a sustainable period of time."

In order to get investment, you need to prove 'productivity', a measure of the well's potential or ability to produce.

The seismic might help better understand the reservoir dimensions, but "We don't consider mapping the top reflector to be major challenge," he said. "There's potential for down dip thickening of sands North of Lancaster, additional seismic may bring into focus."

Could steam flooding in the North Sea be viable?

By flooding a reservoir with steam, you can get up to 80 per cent recovery. The revenues from that could justify the cost of putting in the steam, said Steve Brown, of Steam Oil Production Company

Could it be viable to use steam flood in the North Sea? Steve Brown, CEO of the Steam Oil Production Company, notes that steam flood can achieve over 80 per cent recovery factor, compared to about 45 per cent with water flood – which could generate more than enough revenue to cover the cost of creating the steam.

Recovery factor is a measure of the amount of oil removed from a reservoir, divided by the amount of oil in place to begin with. A reservoir will naturally only produce about 30 per cent of its oil – so to increase recovery beyond that, you need to use special techniques.

Oil companies commonly use water to improve oil recovery, pumping in the water in one well, so it pushes oil through the reservoir to a production well nearby. With careful 'water flood' for 20 or 30 years, you can get up to 40 to 50 per cent of the oil out, Mr Brown said.

But by using steam, you can get much more oil out, and get it out much faster.

He was speaking at the Finding Petroleum forum in London on March 10 2016, "Finding & Exploiting new petroleum resources in Europe."

Steam heats the oil, which will increase recovery in two ways. Warmer oil has a lower viscosity, so it flows out of the rock more easily. The steam also lowers the residual oil saturation (so less gets left behind in the rock pores).

"It turns out that residual oil saturation is highly temperature dependent," Mr Brown said. "For steam it can be as low as 5 per cent. It is hard to believe."

So far, steam flooding has been widely used onshore to improve production, but only once offshore.

Onshore, about 2m barrels of oil are produced per day using steam, Mr Brown said, including in fields in California, the Middle East, Indonesia and in Europe.

There is only one offshore steam flood, in the Congo, operated by Perenco, in 65m of water.

The reservoir is proving a "very difficult reservoir to steam flood," with interbedded limestones and siltstones, he said. Sandstones are better for steam flooding.

In the North Sea, the reservoirs are much better. But because no-one has yet used steam flood successfully offshore it is hard to find people willing to try it, Mr Brown said.

Ways to use steam

There are three ways to use steam to improve production.

Steam flood is similar to water flood, when you send steam into a reservoir via an injection well, and it both warms the oil, which makes it flow more easily into a production well, and displaces the oil towards a production well. Leading companies in this sort of steam flooding are Chevron and Occidental Petroleum, he said. This is for oil which will flow cold, but will use steam to increase production.

Steam flooding is known for being used in Canada, California and Indonesia. It is used by Shell in the Netherlands and by Wintershall in Germany, for steam flooding a field known in the Netherlands as Schoonebeek and in Germany as Emlichheim. That is the biggest steam flood in Europe.

A variant on this is 'huff and puff', where you just have a single well which you use to put steam into a reservoir, then you turn the well around to allow the oil to flow back into the well.

A third variant is "steam assisted gravity drainage", which is used for oil which is so heavy "you can walk on it without your boots getting sticky". You have a horizontal injection well about 5m above the horizontal production well.

Chevron uses steam flood on its Kern River Field, in California. The field was discovered in 1899, and produced at a rate of 30 to 40,000 bopd of primary production before slowly declining for 50-60 years. The company tried putting heaters at the bottom of the oil wells in the 1950s, and found that production doubled, he said.

Chevron then moved to steam flooding, and increased production to 120,000 bopd, so three times as much as their primary production levels. The company is achieving recovery factors approaching 80 per cent.

As another example, Mr Brown showed photos of cores from the Duri Duri field in Indonesia. One core was from a reservoir which had seen water flood, yet there was still a 55 per cent residual oil saturation. Another core was from a reservoir which had seen a steam flood, and had a residual oil saturation of 8 per cent. "There's nothing like steam for getting oil out of clastic reservoirs," he said.

Many people see steam flood as something to do at the end of the reservoir life, when you have tried every other possible way to get oil out of the reservoir. But there's no reason why steam flood should only be used at the end of a reservoir's life. For example, imagine what production the Kern River Field might have seen, if it had used steam flood right from the start, he said. "Why wait 50 years doing water flood when you can have twice as much oil, in half the time, if you steam flood?"

Horizontal wells

If you were trying to steam flood offshore, you can reduce your heat losses by using horizontal wells, he said.

Even with insulation, a lot of the heat can be lost as the steam travels through the riser to the seabed, and through the subsurface to get to the reservoir.

For a typical vertical well you might be injecting 500 barrels a day into the well. If the reservoir is at about 3,000 feet below the surface you would expect to lose 300 barrels of steam per day due to heat losses (that steam condenses back to water). That's a big problem, but if you have a horizontal well in a high quality reservoir you can inject 10,000 barrels of steam per day into the well, but the heat loss, measured in barrels of steam per day is just the same. If you are injecting 10,000 bbls, the 300 barrels of losses don't matter.

100m is about the right distance to have between injector and producer wells. Kern River has 40m and Schoonebeek has 150m, Mr Brown said. On the North Sea Pilot Field, Steam Oil plans to drill horizontal wells 1500m long and 100m apart.

Steam Oil

In the North Sea UK Continental Shelf, Steam Oil has licenses on blocks 21/27b and 28/2a (the blocks are joined together). It bid for the blocks in the 28th license round for the UK North Sea (2014). There are two discoveries on it, known as Pilot and Harbour.

It's a really well appraised field, with very good 3D seismic, he said. There are 6 cored wells and 3 tested wells. This includes a horizontal well which could flow 1800 bopd in the most viscous part of the reservoir.

In the license round, Steam Oil was the only company which applied for the blocks. Previous owners had relinquished this block because the oil was heavy and they didn't believe they could get a recovery factor high enough to make it viable, he said.

Steam Oil's plan is to drill 42 horizontal wells across the block, between 1000m and 1800m long, alternating producers and injectors.

The steam flow will be carefully controlled in the injection wells, and the production wells will be designed to automatically shut off the relevant zone if the steam is 'breaking through' to the production well. This is known as "conformance control", he said.

The steam flood gradually creates a steam chamber at the top of the reservoir, which gives a path for steam to find its way directly to the production well. So it helps to get the well as close to the bottom of the reservoir as possible, he said. "The lower you set the well, the higher the recovery factor."

Reservoir simulation models showed that the production profile for steam flood wells is very different to water flood wells, he said.

With steam flood as in water flood, you start with a high production rate, which goes down as water (coning up from below) starts entering the production well.

In a waterflood the production rate continues steadily at a low rate, but in a steam flood after a while then oil production rate increases substantially as the reservoir gets heated by the steam. Once steam breaks through into the production well you stop producing as it is wasteful to circulate steam through the reservoir. In a waterflood you keep going for many years to try and eke out oil from the reservoir.

If you do steam flood for many different wells at the same time, but adjust the timings so each section is at a different point in the cycle, then stack all the production together at the end, you can get a 'fairly flat production profile', he said.

In the Pilot field, Steam Oil is currently expecting a 57 per cent recovery factor based on the reservoir simulation.

There's a further 33m boe in place in another field to the south, called Pilot South. So altogether, Steam Oil expects to produce 152m barrels from the one license block, he said.

Steam Oil has made an agreement with oil company Enquest to purchase its nearby Narwhal and Elke discoveries, thought to have 226m barrels of oil in place. "We think we can get a 50 per cent recovery factor on those," he said.

Economics

"You're probably wondering, surely this is far too expensive, you can't do this in today's environment," Mr Brown said.

"Maybe if the oil price is 30 something you really struggle."

But Steam Oil has worked out ways to reduce the cost of steam flooding, which could make it viable.

The wellheads will probably need to be on a platform (above the water level), because you probably can't do steam injecting from a subsea well head or using flexible flow lines.

But platform production is very feasible, with relatively shallow water depths of 80m.

These depths mean that the well can be drilled with a jack-up rig, rather than a more expensive floating rig.

For taking the oil away, you can't use a pipeline for heavy oil (since it will clog), so Steam Oil plans to use a Floating Production Storage and Offloading vessel (FPSO), and it has picked the cylindrical Sevan Marine design. The accommodation block can also be on this vessel, rather than the wellhead platform.

The steam must be generated close to the injection wells, so you don't lose heat as it travels down a longer pipeline. The steam making processes can be built on the FPSO.

The water used to make the steam must be as pure as possible, to maximise the efficiency of the boiler. Steam Oil 'plans to take seawater, which has 35,000 ppm dissolved solids, and put it through 2 passes of reverse osmosis (pushing the water through a membrane under pressure). After a final stage called electro-deionisation, you can reduce the solids to 10 ppm. BP is using a similar technique on its Clair Ridge field, where it is creating low salinity water to use in water floods.

For fuel, Steam Oil plans to use gas. It will need 200 bcf of gas in total to get the 152m barrels of oil out.

To source the gas, "you lay a pipeline to a gas system and say 'I'll pay national balancing point price," [the price which gas is exchanged between the UK and other countries] he said. "That's the commercial assumption that we make."

Taking all of this into account, Steam Oil expects to pay $10 a barrel for the facilities, $6.50 for drilling, and just under $10 for operational cost, and $11.5 to $12 for fuel, leading to a cost of around $37.5. So if the oil price is $50, Steam Oil can break even and make a 10% rate of return, taking tax into account.

The pricing work was made when the oil price actually was $50. Since then, the oil price has gone down. "We've set ourselves a target to get our costs down, we don't think it's going to be that hard," he said.

With plans to extend the steam flooding to include the nearby Elke and Narwhal fields, the capital expenditure can be spread over more barrels of production, so the facilities cost and operational expenditure per barrel will also come down.

The company is looking for ways to reduce the fuel cost, possibility by importing propane or ethane from the US.

It is also possible to reduce the ratio of barrels of steam injected: barrels of oil produced.

It might be possible to bring it down by injecting a non-condensable gas with the steam – for example one company has reduced the steam oil ratio to 1:1 by co-injecting methane.

"We think there's a real possibility to get that cost down, and to get the cost base to $30 a barrel, which gives us a breakeven at $40 Brent," he said. "We think there's a real project here, and it ranks pretty well when we compare it to other projects in the North Sea," he said. "For maximising economic recovery in the UK – we think steam flooding is really important," he said.

There are also other projects in the North Sea with around 200m barrels of reserves, which could produce twice as much if they were steam flooded.

The steam flood capex and opex costs don't look particularly high compared to other North Sea oil and gas projects being planned, particularly as the Steam Oil project will produce oil at a higher rate, he said.

The capex is linked to the fluid handling capability (what volume of fluids you expect to handle) and how many wells you plan to drill.

The opex is linked to how long you plan to operate the field for. So with the lower and slower recovery rates, conventional projects need to operate for much longer, increasing their opex per barrel.

"We're expecting about 60 per cent recovery factor, these other heavy oilfields are getting about 30 per cent with water flood," he said.

"Our strategy is to try to attract a major oil company to come into the project and move it forward," he said.

To get the project moving, Steam Oil needs $2.4bn for capital expenditure. "We've come a long way on our resources, but frankly, I don't have $2.4bn," he said.

"So we're trying to get people's attention. It's a little hard just now, people are so busy putting projects back on the shelf, and this industry is the most conservative industry in the world."

"We're always asked, 'where a steam flood has happened offshore before'. We say, there is one in the Congo.' They say, 'it's not really working'. We say, 'look at the reservoir, it's completely different'. They say 'it's not really working;'."

Perhaps Steam Oil will need to do a pilot project on the Pilot Field. We think that it is possible to produce 5m barrels in 500 days, at costs which break even at $40 to $50.

"If we could just accelerate that a little bit and get some of the costs down, use some of the rigs sitting around doing nothing, that might be an exciting thing to do, that might get the industry's attention," he said.

Shale in the North Sea and Germany?

UK / US oil and gas company Kimmeridge Energy is taking a heavily analytical approach to working out the best place for shale oil – and believes it could work in the North Sea and in Germany

UK / US oil and gas company Kimmeridge Energy takes a very analytical approach to its investments, with two of its three managing directors, and both of its vice presidents being formerly with research and analysis company Bernstein Research, according to the company's website.

Most of the company's assets are in US unconventionals, including in the Paradox Basin (Utah / Colorado), the Illinois Basin, the Las Animas Arch (Eastern Colorado). It also has an investment in the Permian Basin through its holding in Arris Petroleum.

In Europe it has two positions, one in the UK North Sea, the other in the Lower Saxony Basin in onshore Northwest Germany.

Managing Director Neil McMahon explained some of the analysis which has led to the positions which the company has taken, speaking at the Finding Petroleum forum in London in March "Finding and Exploiting New Resources in Europe," raising the question of how it might be possible to identify viable shale oil reserves in Europe.

Analysing US tight oil

The company's analysis of tight oil wells in the Bakken (crossing Montana and North Dakota in the Northern US), showed that there is enormous variability in what different wells in the same region have produced.

There is a 'sweet spot' within the Bakken, and many wells drilled in the Bakken which have not been successful.

So it isn't enough for someone to say 'we're in the Bakken' to know how good their wells are. You need to know what townships they are in, he said.

The geological core of the Bakken has a variable depth and organic content, among other factors.

If you work out which of the wells are viable at $40 oil price, you come up with a core area which is "quite a sharp reduction from the entire extent of the Bakken," he said.

"A lot of the core areas of these unconventional plays are rather small indeed, especially when you look at the economics behind them."

The companies who have wells in the 'core' are usually the companies which started in the region first, which means they get the longest lease terms and the lowest royalty rates, and of course the highest production rates. All of these magnify the argument of why being in the core is better.

Over 2015, the industry pretty much stopped drilling new wells in the fringe areas, and also drilled less wells in the core, he said.

All of this means that US oil supply is starting to plummet fast. "The only places worth drilling are in the best areas, and the best areas aren't actually as big."

Even in the core, the production is not very predictable. Some formations can give you a 1,000 bopd initial production rate from one section, and the next section will give you just 200 to 300 bopd.

Kimmeridge estimates that the only areas of the US tight oil currently viable are "the Delaware part of the Permian basin, the Midland basin of the Permian basin, the Eagleford, parts of the Niobrara, and three sections of the Bakken, plus the Woodford. There is a play in Oklahoma called Scoop and Stack which "also works," he said.

"All the rest of this is really struggling at this point in time."

And this is in the US, where "you've got absolutely fantastic geology, you've got the technology, you can drill where you want to drill."

So it indicates that finding good shale reservoirs outside the US will probably be extremely hard. There are "very few unconventional plays outside the US and Europe that are going to work, largely because the geology just isn't there," he said.

However the technology for drilling unconventional wells is getting better, with the latest wells having 20 to 30 stage frac, with a 7,500 foot lateral length, producing about 1000 barrels a day, with drilling and completion costs of under £7m.

Europe

In Europe, Kimmeridge Energy is trying a different approach to exploration to most oil companies. It is keen to start in shale oil, but thinks it might be too risky doing a pure shale oil play. So it would like to find a region where it can start producing oil conventionally, and then add shale oil later. "It is a bit aggressive to look for an unconventional play that can be developed straight away," he said.

It is also looking for opportunities by starting by identifying where good source rock is, and where that oil might have gone to, rather than starting with oil seeps and seismic, as other companies do.

The Kimmeridge Clay, which is found offshore around the North Sea is "probably the best source rock in the world – if you look at a number of different characteristics put together," Dr McMahon said.

"It is a relatively easy one to model, and in places it has got incredibly high total organic content (TOC), even at very significant depths. In some places you've got TOCs over 25 per cent at 13,000 feet depth. The original TOCs were over 35 per cent, they've matured and expelled hydrocarbons.

So you could probably frack the Kimmeridge Clay directly and get oil out. If the Kimmeridge Clay was on land, "it would probably be the number one unconventional source rock play on the planet," he said.

But the Kimmeridge Clay is mainly offshore, and not many people think it will be possible to frack offshore. "Perhaps you could, if it was in shallow enough water, and close enough to infrastructure and pipelines," Dr McMahon said.

"Hardly anyone has fracked anything in the North Sea. I think that's astonishing given where the technology has taken the industry elsewhere. "I feel very strongly, the North Sea has to evolve," he said. "They need to take new ideas from outside."

In the UK's 28th license round (2014), Kimmeridge was awarded 4 blocks under 1 license - 14/30b, 15/26d, 21/12b and 21/13b.

Two blocks to the North of these blocks are two existing discoveries, Kildare and Finlay. The Finlay is the most robust conventional play and relatively close to infrastructure. The Kildare field is shallower, sitting in the middle of the Kimmeridge Clay. They should both be viable developments, Dr McMahon said.

The Kildare field is in Ettrick Sands, which are normally too thin to work in a conventional development, but because they spread over a wide area laterally, the total production volume is high enough.

It might be possible to do 'semi unconventional' plays, fracking existing wells to see what happens, he said.

"If this was in the Permian basin we would frack this immediately because it looks so good," he said. "We'd frack the main resource and try to tag all of the sands in one area with a horizontal well."

Trying to create a fracture of more than 100-1500 feet is very hard, when you are in a reservoir under 10,000 feet of rock, he said. "I think you'd need a nuclear bomb down there."

A frack could be used to extend field life and get old wells going again, or new wells piggy-backing on another development, he said.

Germany

The company did a big screening of possibilities in Europe (not including Russia), looking mainly for where there is already a successful conventional play.

There is some potential in the Paris Basin (France), although France currently has a moratorium on fracking. Six years ago it was the "epicentre of Europe for tight oil", he said.

As a result of the analysis, Kimmeridge Energy bought acreage in the lower Saxony Basin of Germany.

The region has produced 1.5 to 2bn barrels of oil already, although most oil exploration stopped in the mid-1960s in Germany. "This area has not been worked extensively," he said.

There are two main source rocks, Posidonia and Wealden. The Posidonia source rock has been itself a conventional reservoir rock, with one well producing 300 bopd unstimulated in the 1950s in Germany, "which would be pretty impressive today," he said.

"There are multiple conventional reservoirs. Because the source rock generated so much oil, it spread vertically as well as laterally. You've got multiple places that oil has found its way into. It has found its way into the tightest pore spaces," he said.

Kimmeridge sponsored a study into the basin at Aachen University, to try to learn more.

For good reservoirs, "you want to see a high carbonate content, high quartz content, not nasty sticky muds," he said.

The study showed that the theoretical volume of rock, which is classified according to a petroleum system study method as "S2 component", is "very similar to the Bakken," he said. "It looks fantastic from a source rock point of view".

The Posidonia source rock is well deposited across the basin.

Petroleum systems

Kimmeridge Energy is evaluating prospects by working through all the petroleum systems, considering redeveloping some of the abandoned oil fields and testing what the Posidonia source rock can do.

Hardly any geochemistry has been done over the past 20 years. "Geochemistry was killed off in the mid-90s," he said. Like biostratigraphera, you were expelled to same damp dark place in Aberdeen never to see the light of day."

Most geoscientists were trained to look for spaces which could hold oil using seismic data, and hope that there would be some oil and gas in them. "You didn't really care where it came from and it either worked or didn't work."

Kimmeridge by contrast will "only look at an area if we know the source rock works. There's very limited work that's been done in this area."

The source rock will allow the oil to leave as the pressure from rock above builds, to the point where natural fractures form in the rock itself. So you need to look for source rock in a certain 'maturity range'.

"You want to find source rocks in that exact position and if possible find conventional targets sitting right above them," he said.

Examining resistivity data from well logs, and looking at how resistivity changes with depth, can give you a useful indication, he said.

If there have been seeps that is also a useful indication. "We know there's mobile oil."

"We try to high-grade places where it looks exceptional and in that maturity range where we know it should expel oil," he said. "You start to high-grade areas that start to become significant drilling locations," he said

"So our focus on this area is looking for conventional targets siting right above the unconventional play," he said.

"There are two abandoned oilfields sitting directly above the source rock, each with 6 or 7 reservoir intervals. One was produced for 20-30 years up to 1990s and then abandoned."

"We think this is a tremendous resource play that has been misunderstood and not focussed on for quite some while."

"We think Kimmeridge clay offshore is something that can work, if tagged along with a conventional development, part of a conventional plan in an existing field."

Questions

Dr McMahon was asked how fast he thinks the US can get going again if the oil price goes to $60 to $70.

Perhaps the answer is about whether the capital will be there, not the crews or the drilling rigs, Dr McMahon said. "The question is when will the banks start lending to public companies again – when will investors start lending to companies again."

"The only game in town out there at the moment is private equity capital, because banks aren't lending, the investors aren't [investing]. I think that's going to be the big issue."

"Wells Fargo according to analysts and press reports has got massive amounts of debt associated with companies that may nor may not be in business for very long.

"We're going to have to see oil prices come back up, stabilise at 40 -50 dollars. It is only then that you'll start getting people come back into the industry. It will take oil prices probably in the $60 range before you'll get the capital markets to open up."

"I think this time around you'll see people taking a more aggressive stance on leasing."

In terms of getting drilling rigs and crew into operation, there are yards in the US full of rigs not being used. And "I'm not so much worried about getting the crews back, that's a few phone calls," he said.

Over the past few years, drilling costs in the US dropped from $28,000 a day to $17,000 a day, with a better quality rig and a better crew, and drilling time dropped from 42 days to 20 days.

But costs to enter in the Permian on Delaware side are $20,000 per acre, on the Midland side is $40,000 per acre. "Those are pretty chunky numbers now," he said.

Seismic and tight oil

Dr McMahon was asked if the company is doing seismic surveys, particularly because seismic data can show density, which can correlate with organic content, as a means of determining the best places for tight oil.

"We'd rather spend our money drilling wells and showing commercial production than spending money on seismic," he replied.

"I know this is not what geophysicists want to hear."

The hard part is finding the exact right 'landing zone' for the well within a certain interval, within 10 feet, something which seismic won't usually show. "If you can link your perfect landing spot to some signature on seismic, I think then it becomes worthwhile," he said.

However the company uses seismic in the Permian to see if there are any basin bounding faults, which can have a big impact on fracking.

Poland

Dr McMahon was asked about why he thinks Germany could be better than Poland, considering that the oil and gas industry tried hard at unconventional wells in Poland but has now largely given up.

"In Poland, the main problem was not enough gas," he replied. "But also consider that there was never a conventional gas play in Poland. As a gas producing region, "It has always been on the fringes, it has never been something you would have focused on."

The oil and gas industry is still embryonic in Germany in comparison with onshore Romania and Bulgaria, where there have been large conventional oil plays in the 1950s and 1960s. But Germany has got "better characteristics than in Poland."

Learning rate

Dr McMahon was asked how many wells you have to drill before you figure out the optimum way to do it.

"We're 13 wells into a program into the Permian basin, one of the best onshore basins in the planet, we're learning on every single well," he said.

"[the question is] whether or not people will have the patience to do that in the UK, when its $20m per well not $7m. [will people have] the patience to say, I need to drill 15 of those things to get comfortable with what I've got in my block."

"It's going to take a huge amount of wells in the UK before we can get close to any of those figures (for unconventional wall potential) BGS has come up with – it's totally unproven."

Lukoil – developing shale oil in Russia

Russian oil and gas company Lukoil is looking at developing shale oil in the Domanik shale and the Bazhenov shale, both in mid-West Russia, north of Kazakhstan.

"I can just show you some numbers and you will understand the quality of Russian shales," said Aleksei Gabnasyrov, Oil and Gas Content Team Leader with Lukoil, speaking at the finding Petroleum forum in London on March 10, "Finding & Exploiting new petroleum resources in Europe".

To compare the Bazhenov and Domanik, the Bazhenov is larger, but the Domanik is easier to understand, he said.

Starting with the Domanik deposits, Mr Gabnasyrov looked at areas of unconventional potential within PJSC Lukoil's leasehold and licenses in Volga – Ural and Timan-Pechora provinces.

The company only just started looking at unconventionals in the region a few years ago, until then it was mainly concerned with conventionals, he said.

The total area is about 1 billion square km, with reservoir thickness of between 10 and 40m. Over 330 targets have been evaluated.

By volumetric calculation, Lukoil estimates that the Domanik has 0.78 bn tonnes (approx. 5.7bn barrels) of P90 probability oil, he said.

"We can see the TOC [total organic content] and thermal maturity of Domanik shale is as good as commercial shale deposits in the US," he said.

"The prevalent mineral composition of Domanik shale is similar to one of the US largest shale deposits."

There are many faults in the basement rock, which are good for unconventional production.

The most important parameters for developing the shales are total organic content, thermal maturity, natural fractures, and favourable geomechanical conditions (so a frack will work), he said.

Geochemical core analysis shows total organic content of up to 23 per cent. The organic matter is predominantly type II kerogen.

The company has planned a program of future wells, although it won't be drilling wells at the current low oil prices, he said.

It has a conventional resources exploration program, where it can look for unconventionals at the same time.

"Domanik deposits are understudied as a source of unconventional resources," he said. "Maybe at the end of a year, we'll go on the next step."

Looking now at the Bazhenov Shale further South, Lukoil's company AO Ritek has a license to develop 2 fields.

The potential is estimated to be 140m tonnes (1bn barrels) of oil.

The Bazhenov shale has been actively studied with a range of approaches, but currently has no commercial production.

Lukoil is undertaking studies to find the most productive area, identifying the most promising naturally fractured zone.

It has drilling a well to determine the potential, with a 1000m horizontal leg. It pumped in about 200t of proppant.

There is a very rapid decline in production, so the most important task is maintaining reservoir pressure, he said.

To try to main pressure, the company is experimenting with using warm gas as a method of enhanced oil recovery. It injected over 7m cubic metres of hot air. The technology has been gradually developed from a first pilot test in 2009, with commercial implementation expected in 2019.

Air "fracking" is used because there is a lot of organic content (clay) in the Bazhenov, which doesn't really work with hydraulic fracturing, he said.

List of attendees Finding & Exploiting new petroleum resources in Europe, London, March 10 2016

Pasha Morozov, VP Business Development, 3esi-Enersight

Christian Bukovics, Partner, Adamant Ventures

Duncan McSorland, Business Development Manager, Aker Solutions

Geoffrey Boyd, Field Development Consultant, Antium Frontfield

Henry Lang, Partner Oil and Gas, Arcadis

Richard Hulf, Artemis Funds

Paul Mullarkey, Managing Director, Auriga Energy

Tim Papworth, General Manager Armenia, Blackstairs Energy Armenia LLC

Peter Farrington, Geophysicist, Consultant Geophysicist

Hugh Ebbutt, Associated Director, CRA Marakon

Andrey Panna, MD, Crestline Investors

Azzurra Cillari, Regional Geologist, Currently on Maternity

Alexandra McKenzie, Artist, Digital Energy Journal

David Jackson, Global Manager G&G New Ventures, Dolphin Geophysical

David Trapp, Data Analyst, DrillingInfo

Martin Riddle, Technical Manager, Envoi

Richard McIntyre, Sales Manager, Finding Petroleum

Karl Jeffery, Editor, Finding Petroleum

Avinga Pallangyo, Conference Coordinator, Finding Petroleum

Tom Whittington, Associate, FirstEnergy Capital

Nick Norton, Senior Energy Advisor, Foreign Office

Aleksey Vashkevich, Exploration Director, Gazprom Neft

Nick Stronach, Senior Geoscientist, GCA

Faouzi Khene, GXT

Simon Berkeley, Principal Halliburton

Amy Taylor, Sr. Product Specialist, Halliburton

Emily Rees, Geophysicist, Halliburton

Mike Simmons, Technology Fellow (Geosciences), Halliburton/Neftex

Wally Jakubowicz, Managing Director, Hampton Data Services

Hywel John, Haven Energy

Norman Hempstead, Director, Hempstead Geophysical Svcs

Robert Trice, CEO, Hurricane Energy

Alastair Reid, Consultant, IHS

Rhydian Williams, BD Manager EAME Ikon Science

Neil Dyer, Independent

John Griffith, Upstream Advisor, JJG Consulting International Ltd

Joe Staffurth, Director, JSI Services

Tue Larsen, Senior Exploration Geophysicist, JX Nippon Exploration and Production (U.K.) Limited

Jonathan Bedford, Director, JXT

Neil McMahon, Managing Director, Kimmeridge Energy

Mark Hornett, COO Europe, Kimmeridge Energy

Ewan Whyte, Business Development Manager, LR Senergy

Sergei Pokrovsky Manager, Unconventional Resources, Lukoil

Kai Gruschwitz, Senior Geophysical Advisor, Lukoil

Aleksei Gabnasyrov, Oil and Gas Content Team Leader, Lukoil

Vladimir Plotnikov, Head of Department, Lukoil Engineering

Amrit Brar, Marketing and Sales Manager Lynx Information Systems

Douglas Snell, Director, M,Carta Management Services Ltd

Brian McCleery, Director, M2C Energy Advisers

Amanda Turner, Head of Sales & Marketing, Merlin Energy

Tara Lapsley, Assistant Underwriter, Navigators

David Buddery, Consultant, Neoseismic Ltd

David Bamford, Director, New Eyes Exploration Ltd

Ramesh Shukla, Shareholder of Exploration Companies

Jodie Cocker, Remote Sensing Geologist, NPA Satellite Mapping

Tim Jones, Director, Global Business Development, OneSubsea

Toby Walker, Account Manager, OneSubsea

Paul Binns, Consultant, P E Binns

Mark Enfield, Managing Director, P.D.F. Limited

Robert Parker, Consultant, Parker

Vincent Sheppard, Chief Geophysicist, Petrofac

Greg Coleman, MD, Petromall Ltd

Sergey Palenov, Sales, PGS

Valeriy Karpov, Chief Geologist, PJSC "RITEK"

Tim Davies, Global Portfolio & NV Manager, Premier Oil

Andrei Belopolsky, Brazil Exploration Manager, Premier Oil

Josh King, Analyst, RAB Capital

Robert Snashall, Consultant, RGSConsult

Alastair Bee, Partner, Richmond Energy Partners

Andreas Exarheas, Assistant Editor, Rigzone

Patrick Taylor, Director, RISC (UK) Limited

Andrew Webb, Deputy General Manager, Robertson Limited

Norrie Stanley, Consultant, RPS Energy

Rob Naylor, Seismic Project Manager, RPS Ltd

David Webber, Seismic Operations Supervisor, Sceptre Oil & Gas

Glyn Roberts, Director, Spec Partners Ltd

Karyna Rodriguez, Director of Geoscience Spectrum

Daniel Barnes, Consultant, StrategicFit

James Bull, Geologist, Taipan Resources

Daniel Plant, Business Director, Terrabotics

Rosemary Johnson Sabine, VP Exploration Tethys Petroleum

John Weston, Managing Director, Thalweg Energy Ltd

Andrew Scutter, Midstream Analyst, The EIC

Simon Bradbury, Chief Operating Officer, The Steam Oil Production Company Ltd

Greg Harding, Technical Director, The Steam Oil Production Company Ltd

Steve Brown, CEO, The Steam Oil Production Company Ltd

Steve Bottomley, Director, Upstream Consultants Limited

John Wood, Consultant Geophysicist-Geosciencetist, Wood Geoscience Limited

Deirdre ODonnell Managing Director Working Smart

Michael Simioni, Technical Director, WSS Energy Consulting Ltd

Andrew Zolnai, Owner, zolnai.ca

What did you enjoy most about the event?

Neil Mc Mahon's talk - very informative and interesting debate.
Deirdre O'Donnell, Working Smart

Surprised by the quality of the presentations - all very thought provoking. The networking opportunity was also excellent and I now have 3-4 good leads as investment opportunities. Keep up the quality and relevance.
John Weston, Thalweg Energy Ltd.

The ability to network with the industry colleagues and meet new people without having to pay over priced conference fees.

There was a particularly good mix of attendees and the discussions (during the breaks) were good.
Ritchie Wayland, JKX Oil & Gas plc

Learning from others how tough it is in the job market to find work; and also how companies are finding new investors by turning to China for capital investment.
John Wood, Wood Geoscience Limited

Listening to new methods of oil extraction such as Steam extraction using a high density (of horizontal wells PI/1000ft).

Met the artist Alexandra McKenzie, whose work partly reminds me of Norwegian art on the walls in the NPD offices in Stavanger.

Took the opportunity, to talk to Robert Trice about fractured basement and to open discussion as to why is the PI 160 STB/D/PSI: possibly build the case where the basement is in dynamic communication to new YTF onlapping reservoirs.

Hearing more detail on some new and potentially large ideas and plays. In particular Robert Trice on West Shetland and Neil McMahon's US data and the comparisons with Europe. Emily Rees was also an impressive presenter.
Paul Binns, P E Binns

Quality presentations. Candid and professional.
Ramesh Shukla

The broad range of subjects presented and the opportunity to discuss key aspects with interested parties.
Robert Trice, Hurricane Energy

Networking, geology talk from Neftex and detailed info from E & W (US & Russia).
Andrew Zolnai, zolnai.ca

Excellent talks (good speakers and content) and a well engaged audience.

Very informative presentations at play and field level, as well as global overviews, given by oil company representatives, much lower share of "advertisements" by contractors/consultants than usual.

Excellent talks with a diverse yet coherent content.

The shale oil presentation.

I like the format as it is. 9 to 2 pm is a good time frame.