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INSIGHTS

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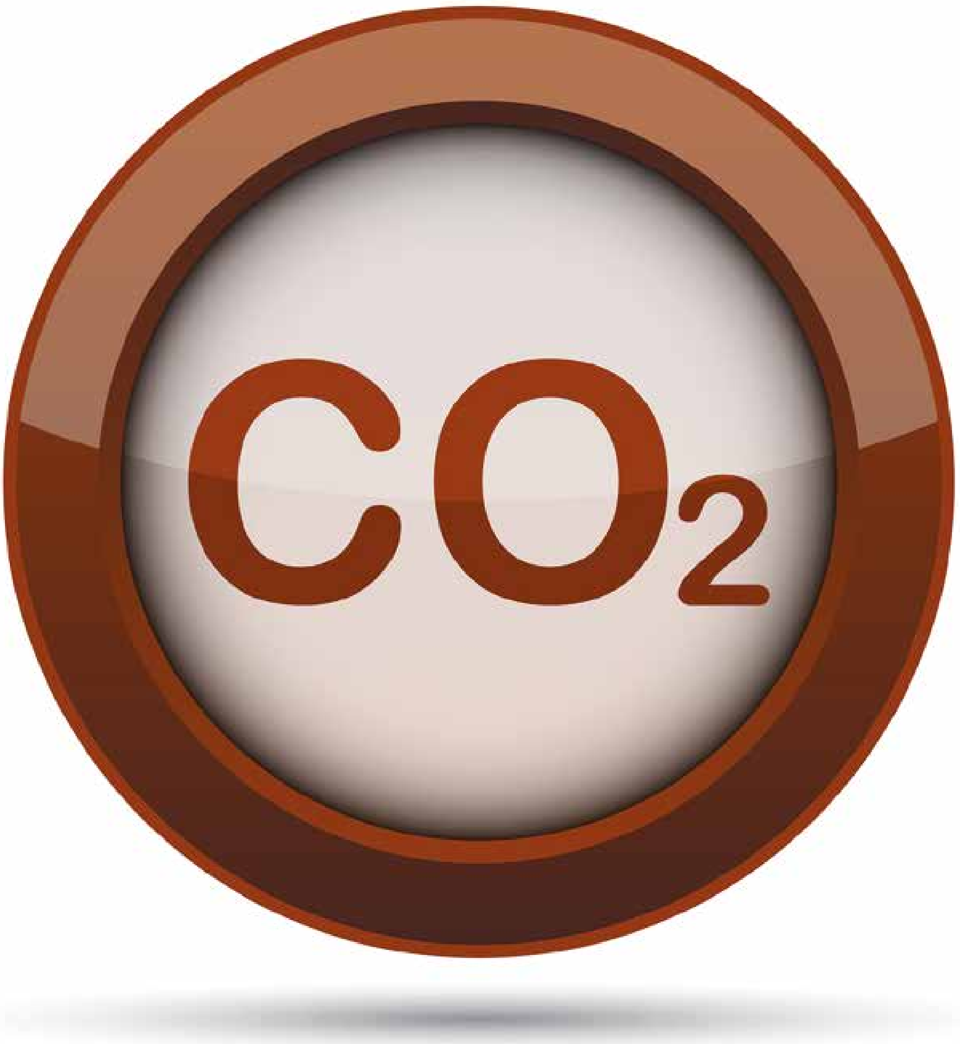
Making CO2 storage a viable business for oil and gas companies



Making CO2 storage a viable business for oil and gas companies

CO2 geological storage costs money. Oil companies have the expertise to do it, and are under pressure to do it. But if it was added to the cost of oil and gas production, it would make their costs more expensive than their competitors in other parts of the world who are not mandated to store their CO2. How can this be resolved?

International/western oil and gas companies are coming under pressure from shareholders, regulators, environmentalists, and their own employees in some cases, to find ways to reduce CO_2 emissions to the atmosphere from consumption of their own fuels in addition to emissions form their operated assets. Many are being forced to consider at least offset their emissions by removing emissions elsewhere.

They have the expertise to develop and manage geological storage of CO_2. But it costs a great deal of money. Companies are willing to invest money in business models which might give them a return, but not to agree to incur costs which would make their operations uncompetitive compared to operations in other parts of the world.

Governments could create legislation or a subsidy which would make CO_2 storage a viable business proposition – a carbon price, a requirement, a subsidy on top of the carbon price. But as of July 2019, the incentive schemes are not big enough. This may change, but it would be better if a need to rely on government could be avoided.

There are a few examples where CO_2 storage can work commercially. There are around 100 CO_2 enhanced oil recovery (EOR) projects, mainly in the US, where CO_2 injected in the ground helps improve oil production, and the extra production pays for it. There are projects in Australia and Norway where an oil company wants to produce a gas reservoir rich in CO_2, and it is viable to separate and sequester the CO_2 as a condition of running the project, or to avoid paying carbon taxes. But carbon capture and storage still does not operate as a mainstream business.

Some people argue that oil companies should be required to do CO_2 capture and storage. This would increase their own costs of operation by incurring CO_2 disposal costs. This would make their companies uncompetitive compared to national oil companies (NOCs), which, with the exception of Equinor, have shown barely any interest in sequestering CO_2, and generally do not have any pressure to sequester CO_2.

If these costs mean that western/internationally owned oil companies cannot continue their business, any gap in oil supply could ultimately be filled by a national oil company unencumbered by climate regulations, leading to no net reduction in CO_2 emissions to the atmosphere, and a big loss of jobs and government revenue in countries which have publically traded oil companies.

An international carbon trading scheme would impose the same costs on companies everywhere, but would require international support to achieve, which is currently absent.

Governments are reluctant to impose rules which would increase the cost of fuel which their voters pay, if the government is obviously to blame for the increase.

So how do we move forward? This report looks at three options. Firstly improved government incentive schemes, secondly ways to strengthen the business case for CO_2 + enhanced oil recovery, and thirdly how we can find innovative ways to combine public (government) support, engineering and private investment to make it all work.

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Petromall was founded by 4 senior industry and academic practitioners who consider the challenges faced by today's oil and gas environment are going to require herculean acts of leadership and technical skill in the high cost provinces of the world, in order to maintain an industry that is sustainable and even recognisable compared to recent history.

Similarly nations developing an oil and gas industry face related challenges as they seek to maximise the benefits of this new wealth-creating opportunity - in a responsible manner.

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This edition of Petromall Insights was written by:
Karl Jeffery, editor,
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Laura Jones, Very Vermilion Ltd

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c/o Future Energy Publishing
39-41 North Road,
London, N7 9DP, UK
United Kingdom

Email david.bamford@petromall.org
+44 208 150 5292
www.petromall.org

Industry perspectives from EAGE

We heard perspectives on how the oil and gas industry should tackle their impact on climate change from senior oil industry representatives, including BP, Total, Wood Mackenzie and OMV, speaking at panel sessions at the June 2019 EAGE forum in London

The 81st Conference and Exhibition for the European Association of Geophysicists and Engineers (EAGE), a major oil and gas industry event, included a great deal of high level discussion about how the oil and gas industry should handle CO_2 issues.

In the opening session, Angela Strank, Head of Technology and Chief Geoscientist Downstream, BP, listed BP's current CO_2 related projects.

Angela Strank, Head of Technology and Chief Geoscientist Downstream, BP.

It is developing its gas production, which is less CO_2 intensive than oil. It is reducing greenhouse gas emissions from its own operations, including by reducing flaring, improving pump efficiency, optimising supply vessels, improving leak detection, she said. It is improving the efficiency of products supplied to customers, including power generators. It has technologies which reduce engine wear, so engines run more efficiently.

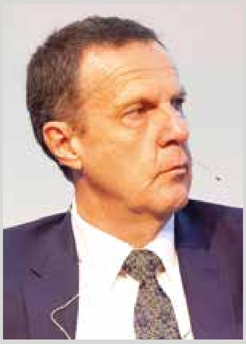
BP is investing in wind, solar, and methanol from biofuels. It is building refineries which process vegetable oils and fats. It is offering aviation fuels made with recycled cooking oil.

It is investing in vehicle charging systems and battery technology, and technologies to charge batteries much faster. It is investing in a feasibility study for a carbon capture project in Teesside together with the Oil and Gas Climate Initiative, a group of 13 oil majors.

Also in the discussion, Gary Ingram, VP Exploration & Appraisal, OMV, noted that New Zealand has banned oil and gas exploration for CO_2 reasons, saying, "they are trying to be a front runner, putting pressure on the world to see how they can solve it."

Wood Mackenzie

Also at EAGE, in a session titled "Delivering the World's Low Carbon Energy Needs", Neal Anderson, CEO of energy consultancy Wood Mackenzie, said that the "energy transition", a move to zero carbon fuels, is happening today whether oil companies like or not.



Neal Anderson, CEO of energy consultancy Wood Mackenzie.

"The oil and gas business has a critical role to play [in reducing CO_2]. I would like to see us, as a business, to be much more proactive and involved in this debate," he said.

Mr Anderson said that he has worked in the US for the past 14 years, "continually talking to clients about the energy transition, and got very little traction until about six months ago". But here (UK), "everyone wants to talk about it. Companies understand there's a potential about revoking the industry's license to operate."

On carbon issues, the oil and gas industry is often seen as bad, and the renewables sector good. "That does no-one any good at all," he said.

The industry needs to get much better at communicating how it can contribute positively to climate problems. "We're really good at solving complex problems. I've never heard anyone make that argument," he said.

The low public opinion of the oil and gas industry can cause real problems, as we saw with fracking, which in the UK was "effectively shut down by public opinion".

"The perception is we're dragged, kicking and screaming by investors."

More focus on climate could help companies attract younger people. "Young people care passionately about this. "Everyone who comes to WoodMac asks me, 'what's your position on the energy transition,'" he said. "We need to be better at attracting young folks to the business."

Mr Anderson said that carbon prices can disadvantage companies in the EU, if they are uncompetitive with suppliers outside the EU which don't have carbon prices. One answer could be "something like a carbon tariff applied on imports to the EU".

Jon Erik Reinhardsen, chairman of Equinor (formerly Statoil).

"People say it's a 'WTO issue', but look at the Trump Administration [and its unilateral tariffs]," he said.

A concern is that oil majors stepping back from projects for climate reasons may see their place taken up by national oil companies (NOCs). So there is no net reduction in CO_2. "I haven't seen any NOCs asking, 'how do we respond to the climate debate,' except Equinor," Mr Anderson said.

Equinor

Investors are now having significant influence on aligning oil companies with the Paris agreement," said Jon Erik Reinhardsen, chairman of Equinor (formerly Statoil), speaking at the opening session of the European Association of Geophysicists and Engineers (EAGE) annual meeting in London in June 2019.

A group of investors with $33tn under management called Climate Action 100+ "has had a material impact on oil companies," he said.

Equinor sees the ground changing so much that it changed its name in summer 2018, after being Statoil for 45 years. The Statoil name "represented certainty the world needed oil and gas and Statoil provided it as safely and efficiently as possible," he said. The name change reflects the fact that this is no longer the case.

Factors weighing into the decision included that Equinor "accepts climate change is real and it will make an impact on how we do business," he said. "We support the Paris agreement and we want to be part of the solution for a cleaner energy supply to the world."

"Under the new strategy we are becoming a broad energy company [also selling renewables]," he said.

Equinor "has ambitions" to invest 15 to 20 per cent of its capital into renewable energy from 2030 (although the remainder will still be oil and gas).

"We believe demand for oil and gas will eventually start flattening out – first for oil and later for gas. That is a necessary thing to happen to meet Paris agreement goals," he said.

Mr Reinhardsen sees a carbon tax as a very important measure to drive change in emissions. "From an international perspective we don't have a legislative framework. But we do have Paris agreement and UN sustainable development goals," he said. "Both accords have become widely accepted among societies, investors and companies as targets to strive for improve climate."

Oil companies will increasingly compete based on their carbon efficiency, so Equinor will look for 'low carbon' resources and energy efficient solutions.

Carbon taxes "will play an important role driving this development," he said.

There will be increased focus on how to mitigate CO_2 emissions, which can be from natural carbon sinks (such as forestation), Carbon Capture and Utilisation and Storage (CCUS), and generating hydrogen from natural gas (with CCS).

There will be increasing expectations and demands from society and investors to deal with our impact on climate change and to contribute to sustainability.

Equinor's new Johannes Sverdrup development will produce 660,000 bopd at maximum production, with CO_2 emissions from operations at under 1kg CO_2 per barrel, 5% of the industry average. This is possible because the hydrocarbons are of high quality, and because the field will be powered by electricity generated by hydroelectric power onshore.

Mr Reinhardsen was asked how CO_2 emissions could be incentivised, after we have seen the carbon trading system not really functioning properly in Europe. "I think we have to keep working on this," he said. "One of the elements that come into play is the degree we are successful with CCS. That could create space for some of these industries."

"It is always about technology and developing new solutions."

"We have to realise climate change is for real and we have to work towards a zero carbon profile, and put the effort in to find out how we're going to get there.

CCSA

Luke Warren, chief executive of the Carbon Capture and Storage Association (CCSA), says he believes that the future of the oil and gas industry will be tied intimately with CCUS (carbon capture, utilisation and storage).

Looking at carbon capture overall, we see that today there are 23 large industrial carbon capture projects, operating or under construction. We want to see costs coming down as business grows, just as we saw with renewables.

However, the oil and gas industry is not yet "wholeheartedly getting behind CCUS," he said. And "it is the oil and gas industry which has the capacity to develop this technology."

Mr. Warren believes that one way or another, the energy transition "will happen" – and there will be restrictions on CO_2 emissions – although there are doubts about whether the Paris agreement will be adhered to.

Carbon capture was initially focussed on the coal power sector. Now, "in a lot of markets – [coal has] lost its future," with governments withdrawing support for coal power stations due to carbon concerns. The same could happen to the oil and gas industry now.

In terms of the cost of storing CO_2, this depends largely on how expensive it is to obtain the CO_2. "There's pure CO_2 being vented to the atmosphere in Teesside. Sequestering it is very cheap," he said.

It is perhaps a bad idea for oil and gas companies to be too fixated on the carbon price as a way to make carbon capture commercially viable, he said.

Mr Warren said he did not envisage that a carbon price will drive investment in carbon capture and storage "this side of 2030".

"I think we need a price on carbon to send a signal to the market. But we can't rely on carbon pricing," he said. The carbon price is currently low while the costs of technology are high.

Instead, we are likely to see a range of policies focussing on supporting CCS, focused on different sectors, just as we saw with wind and solar.

Looking over the longer term, a possible business model could be for oil companies to make hydrogen from reforming natural gas offshore, sequester the CO_2 offshore (so no need to pipe it long distances), and then bring hydrogen onshore, where it might be sold at a premium as a zero carbon fuel.

Hydrogen has "gone up on everyone's radar," Mr Warren said. "It can be stored. It can be used in applications which require high heat (industry, domestic), and used to power heavier vehicles such as ships and trucks, where batteries are challenging. "The question is how to create some early markets."

Finding the right government incentives

Governments have many options to incentivise oil companies to capture and store CO2, as well as power companies and other energy intensive industries. But companies have not done much so far, because governments don't want to lose jobs or be blamed for high oil prices. More sophisticated schemes are needed

Governments can make it commercially viable for oil companies to do carbon capture and storage, by putting a charge on CO_2 emitted – as Norway has done with the Sleipner project, which involved producing a CO_2-rich gas stream.

This charge did not lead to any obvious increased price in fuel to any voters, and it did not make any existing business obviously uncompetitive, so there was nothing for voters to blame governments for. The economics worked such that it was viable for the wells and carbon capture system to be developed, and carbon tax paid, and still sell the gas at the commodity price and make a margin.

But governments have not yet done much to make it viable, or required, for oil companies to do carbon capture and storage to offset the CO_2 released when their products are used. This is more likely to lead to higher oil prices (and governments being blamed), or local industries becoming uneconomic (and governments blamed for loss of jobs).

So more sophisticated schemes must be developed which make it more viable to invest in CCS projects, without governments being blamed for anything.

This means that investors must have confidence that the project will make competitive returns over a long enough time scale to pay back the development costs.

The principal mechanism, the carbon price, is not motivating much commercial activity, and would not do so, even if it was high, says Emrah Durusut from UK consultancy Element Energy.

"We talk to some of the investors and banks, they say 'we can't really rely on uncertain carbon prices,'" he said. "Investors are looking for some additional reassurance."

The US tax credit system, by putting a fixed number of dollars per tonne available, gives much more certainty to investors. "That type of certainty definitely helps in terms of putting the money on CO_2 storage," he said.

One idea is a kind of carbon contract with the government, where investors would receive a certain payment based on the CO_2 they sequester or abate. Or perhaps a 'contract for difference' with guaranteed payments based on the difference between a certain price and the carbon price. Oil companies could see a long-term contract at fixed returns to them. A very similar system already works for certain UK power projects, Mr Durusut says.

There are no mechanisms yet for achieving negative emissions with CCS using bio-energy, which could happen together with a plant which already has a contract for difference for CCS, he said.

There are also difference phases in the CCS market, which need different treatment in terms of incentives. Mr Durusut suggests specific definitions for terms like "scale-up phase" (when priority is to improve cost certainty and deliverability, and to provide learnings for follow-on projects) and "roll-up phase" (when the focus increasingly turns towards cost effectiveness and significant rollout).

The level of government support required changes in each phase. However, it does not help if the business evolves so it is dependent on government funding, because then the business is not viable when that support is removed.

"In my opinion it is really important to introduce the policy or market mechanisms the government will use in the longer term even in the scale–up phase," he says.

Direct government funding/grant "can't be the underlying business model for everything forever."

Direct government funding could be feasible for the first projects to be funded completely by grant funding, on the basis of the technical learning it would provide – although that would not provide any commercial learning as a basis for the next phase, he said.

An alternative structure is for the government to pay for the CO_2 transport and storage infrastructure and own it, he suggests, and then charge companies for its use, thus taking over the burden of the initial investment. It could be either owned by government, or treated as a "regulated asset base." Companies would still pay the cost of capture.

Element Energy has looked hard at financing options for CCS projects. Certain loan guarantees and risk mitigation instruments from governments can unlock cheap loans and financing options even in the short-term.

If the CO_2 storage is built with government funding, it may be difficult to subsequently switch the system to enhanced oil recovery, because of complaints from environmentalists that government money has ultimately been spent on improving oil production, he said.

"Probably a project that wants to do EOR may get a lot of push back from the public, while CCS is being promoted as a key net zero technology," he said. "But I personally think it makes commercial sense in the short term to combine oil production with CCS as long as it displaces other EOR options."

The main missing element is for the government to make a decision, he concludes.

US tax credits

The US has a tax credit called "45Q", available to companies which store CO_2 permanently. There is a deadline of 2023 for CCS projects to begin construction in order to receive 45Q payments.

A study published in February 2019 by the US Clean Air Task Force estimated that there could be 49m tonnes CO_2 per year sequestered from power plants by 2030, following the tax credit.

It is based on a model from Charles River Associates, looking at 45 power plants which are close to EOR friendly oil production sites, three quarters coal and a quarter gas.

Enhanced oil and gas recovery with CO2

CO2 can be used for enhanced oil and gas recovery, using CO2 to get more out of oil and gas reservoirs. The extra hydrocarbon production can pay for the capture. It works commercially in many places of the US. But there are many reasons why it is hard to make it work elsewhere.

CO_2 Enhanced oil recovery (CO_2 EOR) means using carbon dioxide to improve oil production from a reservoir. The CO_2 is injected into the reservoir through a well. The CO_2 mixes with the oil, reduces its viscosity so it flows more easily, and so less oil gets left in the pores, and the oil flows out of another well.

There are around 100 US projects using CO_2 to get more oil out of reservoirs in this way.

The same method can work with gas, where it is called Enhanced Gas Recovery (EGR).

The business case, as it works in the US, is that the CO_2 is readily available, including from natural CO_2 sources. The extra revenue from oil production pays for any cost of capturing CO_2 and injecting it into the well, with a margin to make it worth doing. There is one objective – improving oil production with minimum cost.

The question is whether the same system might be used as part of a carbon capture scheme, with the additional revenue from oil being used to pay the costs of carbon capture.

This would mean a scheme with two different objectives at once – improving oil production and sequestering CO_2. This would makes the project much more complex.

It is easier to get CO_2 EOR started onshore, where wells are usually cheaper, more closely spaced, and more accessible. If there is a readily available CO_2 supply, experiments can be conducted at very low cost.

Offshore, CO_2 competes with seawater as a means of maintaining reservoir pressure (but not reducing the viscosity of oil). But there is no unsurmountable obstacle to doing it offshore.

After the US, it may be most viable in India, where there is a large onshore oil and gas production, and growing concerns about CO_2 emissions.

Is CO_2 EOR good for the environment? It depends how you calculate it. If you count the number of carbon atoms sequestered and the amount of additional carbon atoms produced in new oil production, the answer is probably no. But if you calculate on the basis that oil consumption is driven by the consumer, not the supplier, then the additional oil production from the EOR is not causing any increase in oil consumption, just displacing more expensive oil production elsewhere. And at the same time CO_2 is being permanently stored, which must be good for the environment.

"CO_2 EOR can work nicely together with CO_2 storage (without EOR). Perhaps EOR would make the business case for the initial capital investment work, but at some point in the future, the CO_2 stream could be diverted to a storage site rather than an oil reservoir. Or a CO_2 storage system could be set up, and then the CO_2 could be diverted to an oil reservoir as needed, initially as an experiment, without the oil company paying the capital costs.

The problem with both of these examples is that there is no-one willing to pay for the initial investment to start them.

India enhanced oil recovery

India's Oil and Natural Gas Corporation (ONGC) has been exploring using CO_2 for enhanced oil recovery.

The company has been using technologies to improve oil recovery since 1956, when it started using thermal processes to produce heavy oil. Then it came to improved oil recovery and enhanced oil recovery, for offshore and onshore operations in 2000.

Shri Omkar Nath Gyani, GM-Head of the Institute of Reservoir Studies at ONGC

It started with using polymers, and then water alternating gas techniques.

It is looking at "slowly shifting to CO_2", explained Shri Omkar Nath Gyani, GM-Head of the Institute of Reservoir Studies at ONGC, talking at the Carbon Capture Journal forum in Mumbai in October 2018.

India's Prime Minister Narendra Modi has set targets to both reduce oil imports and reduce coal use, and CO_2 EOR is a method of achieving both of these, he said.

So far ONGC have done a number of trials with CO_2 EOR in Indian oil fields around the country, particularly in the Southwest and Northeast, where there is CO_2 sources and sinks close to each other. "I think it is working technically."

ONGC has signed two memoranda of understanding with power companies, to provide CO_2.

The costs being quoted for CO_2 separation has dropped over recent years from \$60 to \$35 per tonne, which makes it more viable, he said.

The critical factor is making sure that the CO_2 reaches the miscibility pressure, where it will mix with oil and lower its viscosity.

This miscibility pressure must be lower than the reservoir pressure, or you risk reservoir damage, compressing CO_2 you are injecting to a higher pressure than the reservoir it is injected into. But this is usually the case in ONGC's trials, showing miscibility pressures which are lower than the initial reservoir pressure.

Another important factor is the CO_2 replacement factor, how many barrels of oil additionally you provide per tonne CO_2 injected. The average is 3-4, and the maximum seen is 6-7 barrels of oil per tonne CO_2, he said.

When the CO_2 breaks through into the production oil, you need a system to capture the CO_2 from oil and inject it back to the reservoir, he said.

With one exercise, the company estimated that the overall project could work with an oil price of around £85, he said. If this cost can be brought down to \$60 a barrel, it could be a sustainable business.

Note that an average 3 barrels per tonne CO_2 injected, and at a cost of capturing CO_2 of \$30 per tonne, the CO_2 cost works out at \$10 per barrel.

Enhanced coalbed methane (ECBM) recovery

One strategy has been developed to capture, utilise and store CO_2, using oxygen combustion to capture CO_2 from coal-fired power plants in order to inject CO_2 at high pressure into coal seams located more than 600m below surface.

Jupiter Oxygen Corporation (JOC) of Chicago is exploring business cases using CO_2 for enhanced coalbed methane (ECBM) recovery in Eastern India, using the company's oxy-combustion based carbon capture technology.

JOC's high flame-temperature oxy-combustion (burning coal in a boiler with nearly pure oxygen) maximises fuel efficiency and enables cost-effective carbon capture.

This oxy-combustion process produces both CO_2 and nitrogen, which, when injected at high pressure into deep, unmineable coal seams, significantly increases unconventional domestic gas production.

The freed coal-bed methane is collected and used, acting as an important bridge fuel in the transition to clean energy. (Enhanced coal-bed methane recovery has been field tested in the USA, Canada and China).

It would be necessary to establish a CBM/ECBM market, so that the captured CO_2 and nitrogen can be sold to ECBM operators.

Revenues from the sale of CO_2, nitrogen and other by-products will offset the higher costs of operating power plants with CCUS.

In addition, co-benefits of this advanced coal power plant operation are 95% of CO_2 emission reduction, air pollutant control (SOx, NOx, PM and mercury removal), as well as heat recovery and water recovery.

In India, the company is looking initially at projects in West Bengal, but it could be applied to other states.

A first step is identifying where the biggest business opportunities might be geographically. CO_2 sources such as coal-fired boilers need to be located close to CO_2 sinks such as ECBM sites.

The potential looks particularly good in West Bengal, which has significant CO_2 ECBM potential, many CO_2 sources in proximity, and an established oil and gas industry which can provide the necessary infrastructure and competence, the company says.

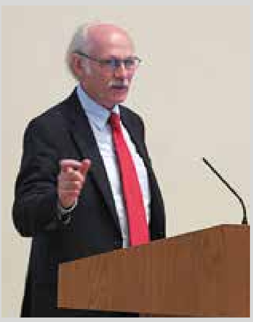
There is an estimated 2.0 to 2.6 trillion cubic metres of methane resources in India, of which 25 per cent is recoverable from coal bed methane, and an additional 20 per cent recoverable via enhanced coal bed methane (using CO_2).

There are 275 billion cubic metres of methane in coal bed methane basins currently producing or planned to produce. And at the same time, approximately 800m tonnes of CO_2 could be stored via ECBM at those sites. The overall CO_2 storage potential via ECBM in India is probably several billion tons of CO_2.

Jupiter Oxygen is seeking funding from one of the development banks to pay for research to better understand the viability of the concept.

CO2 EOR in the Caribbean

Neil Ritson, a former CEO of Regal Petroleum, Columbus Energy and Solo Oil and business unit leader for BP Norway (among other roles), is exploring a project in the Caribbean involving CO_2 EOR.



Neil Ritson, a former CEO of Regal Petroleum, Columbus Energy and Solo Oil and business unit leader for BP Norway.

The proposed CO_2 source is an LNG project in Trinidad, Atlantic LNG, which is generating about 1m tonnes of carbon a year, from burning methane to power the compression / cooling systems.

While details of the project cannot be revealed at this stage, the project illustrates what sort of project may work commercially.

A CO_2 EOR project makes sense in Trinidad because it would be onshore, so be a similar project to the nearby US, and could apply expertise developed on similar US EOR projects.

"I work on the basis that it's usually easier to do something where it's already been done. It hasn't yet been done in the Caribbean, but the characteristics are the same as onshore US which helps," he says.

The project economics could work if the CO_2 leads to an incremental increase in oil production, generating revenue which you can offset against the cost of removing CO_2 from flue gases. "It really is no more complicated than that, all the technologies are proven," he says.

"A lot of the US projects, which are successfully running, are exactly of that sort. They take CO_2, however generated, and re-inject it in to the oil production process," he said.

So you could start at that point and ask, if you had a million tonnes of CO_2 available, what could be done with it, looking for a route which would ideally make a return, not just incur costs.

If the CO_2 was captured without any EOR, it would add substantially to the cost of the LNG, and may make the LNG project globally uncompetitive, he said.

The US business began with the discovery of actual CO_2 fields, which companies thought they could use for EOR. Then the network extended to capturing CO_2 from a number of processes and today there is a large network of CO_2 pipelines which allows companies to buy CO_2, so reward companies who remove CO_2, CO_2 that would otherwise reach the atmosphere, he says.

With EOR, it is not "storage in the simplest sense" – because some of the CO_2 will come out of the ground with the oil, and needs to be captured again, re-compressed and put back in the ground, perhaps several times.

The project will finish when any oil left in the ground is fully saturated with CO_2. Some CO_2 in the ground will also react with water in the subsurface and form carbonates. And therefore overall CO_2 will ultimately be removed from the atmosphere.

There are a number of "rules of thumb" which people in the EOR industry have developed about how much oil can be generated per tonne of CO_2 under different circumstances.

One estimate could be that 1m tonnes of CO_2 per year will enable you to increase oil production by say 50,000 bopd. "This is easily enough economic return to justify the cost of sequestering the carbon, piping it to the nearby fields and re-injecting it," he said.

CO_2 pipelines are not cheap, because CO_2 is very corrosive in its liquid state. This means that oil wells which are onshore or relatively close offshore will initially be preferred.

But as time goes on, people will see the economic returns from their fields, and gain more confidence in it.

"Those CO_2 pipeline networks will expand and there will be more opportunity for people to use the infrastructure as opposed to having dedicated infrastructure that they have to build," he said.

With the cost of building infrastructure in mind, then of course the less you have to build the better.

Onshore EOR tends to be simpler than offshore, because it is easier to access the reservoir, and also onshore fields tend to have more wells, due to the lower drilling costs. But "inherently there's no reason why this can't be done offshore," he said.

A new major offshore EOR project would be "a whole different ballgame in terms of cost," he says. This includes maintenance of the pipelines.

But perhaps there is a way to get there incrementally. "Things happen and spread because they make economic sense. They will continue to spread as long as people can see they get a return on their investment by doing it," he said.

So there is no inherent reason why CO_2 EOR cannot be viable in an offshore oilfield – you just need to start somewhere.

Tax breaks

Investors would be very cautious about any business model which is dependent on financial support in some form from a regulator, after a number of experiences where government support has been offered and then withdrawn.

"If you can encourage a government to give you some kind of tax break – that's icing on the cake," he says. "But you can't assume anything will stay for very long".

It is better not to build an economic model which pays back in 20 years – then find the tax relief only lasts five."

So in the US, there are some tax breaks, but without a long term commitment, it is hard to factor them into a project, which might provide returns over decades.

Can EOR + CCS work in the North Sea?

Two Heriot-Watt researchers have been studying what it might take to get CO2 EOR working in the North Sea, based on US experiences.

Two researchers at Heriot-Watt University in Edinburgh, Prof Eric Mackay, the Energi Simulation Chair in Reactive Flow Simulation, and Dr Saeed Ghanbari, a post-doctoral researcher, have been looking at whether it would be possible to get a CO_2 EOR business working in the North Sea.

More specifically, they have been looking at differences between CO_2 EOR in the US, where it works as a business, and in other parts of the world, where it is yet to start.

Fundamentally, rock will exhibit the same behaviour in fundamental processes with CO_2 or water flooding whether onshore or offshore, Dr Ghanbari said.

But because of various constraints described below, the only way Dr Ghanbari imagines CO_2 EOR could work in the North Sea is if it is combined with CO_2 storage – and the CO_2 storage system is built first. "I don't think CO_2 EOR will be implemented in the North Sea without storage," he said.

CO_2 flooding in the North Sea has to compete with cheap, flexible and efficient secondary waterflooding, Dr Ghanbari said. Waterflooding is much more expensive on US onshore wells.

And CO_2 EOR in the United States has the advantage of being an onshore business, characterised with reduced costs, risk and complexity. The offshore nature of North Sea creates challenges for CO_2EOR implementation.

Due to more expensive drilling costs in the North Sea, perhaps by a factor of 10 compared to United States, there is much wider spacing between wells. This may limit understanding of critical reservoir properties required prior to designing the tertiary CO_2 flood in the North Sea, said Dr Ghanbari.

Offshore North Sea, the negative impact of CO_2 associated production problems, such as wax and asphaltene precipitation, could be much drastic due to the already restricted number of wells. The loss of even one single well could not be tolerated in this region.

The additional space required for CO_2 EOR facilities may not also be readily available in many North Sea developments. Logistical constrains coupled with limited number of wells may also restrict implementing pilot CO_2 projects in the North Sea aimed to reduce CO_2 EOR uncertainties.

But lack of CO_2 sources is perhaps the most serious constrain for implementing CO_2 EOR North Sea. No such abundant CO_2 sources are available in the North Sea. Although if the problem of CO_2 supply is resolved in the North Sea, e.g. by carbon capture and storage, we could hope seeing CO_2 EOR projects in this region despite other technical barriers, Dr Ghanbari said.

Professor Mackay said that people from a number of North Sea oil and gas companies have told him they would happily use CO_2 for EOR if someone else would deliver it to their reservoir, and guarantee a steady supply for the next 15 years.

On the plus side, the Acorn CCS project plans to use the Goldeneye pipeline to carry CO_2 offshore. This pipeline runs very close to various existing oilfields.

For example, the Buzzard field "could really benefit from CO_2 EOR" from a purely commercial perspective, Professor Mackay said. The Miller field, where seawater had been used to maintain pressure and sweep oil towards production wells, could be redeveloped to use

CO_2 instead and be more effective. "If an operator saw a steady and adequate supply of CO_2 passing nearby their field, they would take notice."

Perhaps the supply would need to be as much as 5-10 million tonnes per year of CO_2 for companies to consider it.

By comparison, the North Sea Acorn project is planning to initially sequester 200,000 tonnes CO_2 per year, with capacity to handle 6m tonnes if the supply of CO_2 was supplemented by deliveries to the onshore terminal by ship or pipeline.

Also, a supply commitment might need to apply in the other direction, i.e. the oil company might be required to continually accept CO_2. This creates additional complexity if for example a production system was closed for maintenance. Also European legislation would apply penalties to any CO_2 released into the atmosphere, something which would not happen in the US.

"This is another level of complexity which has to be considered," Dr Ghanbari said.

An advantage of US CO_2 EOR is that the CO_2 comes from natural supplies. There is no discussion about spending money on carbon capture schemes, and no restrictions on how much is consumed – well operators have flexibility to use as much CO_2 as they can, or use none at all.

CO2 vs water

Operators everywhere typically use water to maintain reservoir pressure when the production depletes to a certain level. Seawater is of course easily obtained for an offshore well.

The seawater will not do more than maintain pressure – CO_2 will go further, because, if its pressure is high enough, it mixes with the actual hydrocarbons, making gas and oil less viscous, and reducing the surface tension which attracts it to the rock pores. Oil and water do not mix.

Typically companies will use water flood as a 'secondary' recovery, and then perhaps bring in another method such as CO_2 for a 'tertiary' recovery. Other methods of tertiary recovery can include gas injection, chemical injection and thermal injection (heating).

In the US, water flooding will typically get to 35-45 per cent recovery, while in the North Sea it is possible to get to 50-70 per ecnt, Dr Ghanbari said.

CO_2 in the North Sea might typically provide an additional 5-15 per cent recovery compared / beyond water flooding, (defined as % oil produced divided by total amount of oil in the reservoir).

Steady supply

The need for a steady supply is also an issue. If the CO_2 comes from a power station which is intermittently turned off, and there is no intermediate buffer storage, the supply will not be steady.

CO_2 EOR does not technically require a steady supply of CO_2 in order to work, but the reservoir modelling and economics would have been made on the basis of a steady supply. Ensuring overall project viability is much harder if the supply is intermittent.

One possibility is to have CO_2 storage and CO_2 EOR in the same network. If there was an interruption in the CO_2 supply, the EOR project could draw CO_2 from the storage system.

Objectives and risk appetites

A further complexity of North Sea CO_2 EOR, compared to US EOR, is that many more companies are involved, with different objectives and risk appetites.

In US EOR, the oil company can purchase CO_2 from a CO_2 source as it is required. With North Sea EOR, a power company would be intimately involved in the project, providing CO_2 from a coal or gas power station. Or the CO_2 could be supplied from a big industrial emitter.

Oil companies typically work on high risk, big margin projects, while power companies (and probably most industrial emitters) typically work on smaller margins but lower risk, Professor Mackay said.

And while oil companies may be happy to take on projects which have high risk from a reservoir point of view, they are typically much less comfortable trying out new technology, with the industry's culture often characterised as a "race to be second".

The North Sea culture is slowly changing with a move from big operators to smaller ones, who may be less comfortable with high reservoir risk but more comfortable with technology risk.

A challenge with CO_2 EOR projects is the mixed motivations – reducing CO_2 for climate reasons, and making use of an available resource for a useful result (incremental improvements to production).

In the US, the climate arguments have not played a role – just looking for ways to use available CO_2 to increase production. There was an availability of many natural sources of CO_2.

This means that the measurement criteria are different. In the US you might want to measure the additional cost (in CO_2) per extra barrel produced and see if it is worthwhile. In the North Sea it might be the amount of CO_2 sequestered as well as the oil produced, and look to maximise both.

The US operations targets mean that efforts are made to keep the CO_2 "miscibility pressure" as low as possible, to minimise CO_2 use. But in the North Sea, operators may want to have a higher pressure CO_2 to maximise the storage.

So the process design of CO_2 flooding might be "fundamentally different," Dr Ghanbari said.

Rotterdam – when CCS combines innovative engineering, investment and public support.

The CATO "CCUS developments in the North Sea region" event in Rotterdam on June 26 showed how innovative engineering, investment and public support might be combined to make carbon capture and storage viable.

John Browne, former CEO of BP, has said that the way to make carbon and capture and storage commercially viable is to get "the right combination of innovative engineering, private investment and public support", which also proved to be transformational for wind and solar power. Mr Browne is largely credited with turning BP from a small civil service type company into an oil major, and so has a track record building enormous businesses.

At the CATO event in Rotterdam on June 26, "CCUS developments in the North Sea region", we saw what it might look like when these elements come together. CATO is the Dutch national R&D programme for CO_2 capture, transport and storage.

For "public support" (government financial support), the Dutch government is developing a scheme called "SDE++", which will enable companies investing in CO_2 capture to receive a guaranteed return, based around the carbon price plus a top-up where necessary (like the UK's "Contract for Difference" scheme). Conversely, if they emit to the atmosphere, they may need to pay an additional tax on top of the carbon price, until the carbon price reaches a certain level.

To get "private investment", the companies emitting the most CO_2 in the Port of Rotterdam are being invited to join PORTHOS, a scheme to build a CO_2 pipeline along the length of the port, leading to capture offshore. The members will need to pay for their own capture and pay PORTHOS for transport and storage. The Dutch government is developing a subsidy / support scheme called SDE++ (see below).

For "innovative engineering", engineers and academics are carefully modelling the pressures and temperatures the pipeline can safely operate under and how to achieve them. One concern is the cooling the CO_2 will undergo as it reduces pressure from the pipeline to the reservoir, and whether this might lead to hydrates (CO_2 and water freezing) or damage to the materials. This might be mitigated by having CO_2 at low pressure (in pipelines and ships) to begin with, and then increasing the delivery pressure as the reservoir pressure increases.

Public support

The Dutch government is one of the proactive in the world on carbon issues, but also shows a willingness to listen to environmental groups, who have not been much in favour of carbon capture in the past seeing it as way to lock in use of fossil fuels.

But environmental groups are showing more support to the SDE++ subsidy scheme for carbon capture, planned for 2020, pacified by promises that it will be applied only to industrial emissions, because there is an expectation that all power will come from renewables. There may also be a cap on the maximum amount of subsidy for carbon capture which the Netherlands will ever do. (Proposals for a cap are not yet definite but a figure of 7 MT/y CO_2 was quoted). The first SDE scheme was for renewables only.

The Dutch government also has a subsidy scheme for carbon capture, utilisation and storage feasibility studies.

According to Keith Whiriskey of environmental group Bellona, which has always been in favour of carbon capture, perhaps some of the credit in the change of stance of other environmental groups could be credited to 16 year old Greta Thunberg, and her message that something needs to be done urgently about climate. People increasingly recognise that waiting for renewables to supply all energy may take too long, he said.

Private investment - PORTHOS

The PORTHOS project, is a scheme to build a CO_2 pipeline along the Port of Rotterdam, which roughly follows the Maas River, with a compressor site at the coast, then a pipeline to offshore storage. It is operated by 3 companies, the Port of Rotterdam, EBN, an organisation owned by the Dutch government which takes a non-operating ownership in oil and gas projects, and Gasunie, the national gas transport system operator. The name stands for "Port Of Rotterdam Transport Hub and Offshore Storage."

PORTHOS is planning to make its final investment decision in late 2020 / early 2021. The plan is to store 2 MT/year CO_2 from 2023, climbing to 4MT / year.

Mark Driessen from the Port of Rotterdam Authority pointed out that Rotterdam is the ideal location for a CCUS hub, with enormous CO_2 emissions (16 per cent of total CO_2 emissions for the country), a large industrial cluster in a relatively small area, and the potential for storage in nearby empty gas fields offshore. It is hard to think of a better place in the world to do CCUS.

Mark Driessen from the Port of Rotterdam Authority.

95 per cent of the emissions in the port come from 15 emitters, of which 3 are power plants, expecting to be phased out due to the move to renewable power. Of the remaining 12, five have been "very supportive" of PORTHOS. But the contracts have not yet been signed and negotiations continue, Mr Driessen said.

For the project to get a final investment decision, at least three of the large emitters in the port must at the same time commit to working with the project. And there is a chicken-and-egg reluctance to do detailed technical studies before the project is fully confirmed, he said.

But as a shared project, the contribution required from individual companies is much lower than if they were building their own scheme with a single emitter and single injection source. There is both pressure and support from the Dutch government. There are also plans to bring in CO_2 from other industrial sites nearby, growing the scheme into a major CO_2 hub.

The PORTHOS pipeline will be 90cm or 108cm in diameter, running the length of the port, with a compressor station on the Maasvlaakte in the western end. The project team have 'booked' the one remaining slot on an existing pipeline corridor. The pipeline will be able to take up to 5MT / year of CO_2, but this is envisaged as a maximum flowrate not steady state flowrate.

The compressor station will take 6 hectares of space, and require electricity and cooling.

The pipeline will then go beneath the Maas river, and then under the seabed out under the North Sea. It will use existing offshore platforms and wells, taking the CO_2 to storage in depleted gas fields at around 3.3km depth.

A longer term plan could be to bring in CO_2 from other industrial sites – including the Chemelot industrial cluster in South East Netherlands, the Zeeland cluster in South West Netherlands, and Antwerp (Belgium), together providing up to 10 MT/y CO_2.

There are "ten thousand" challenges to work through, because "it has never been done before the way we want to do it". In particular with flow assurance, he says.

It may make more financial sense to use shipping rather than a pipeline initially to take CO_2 to the offshore location – some financial models show that pipelines are only viable at flow-rates of above 5 MT/y. The operational and energy costs of operating a pipeline are lower than shipping, but the capital costs of a pipeline are much bigger. But the project team has decided that for the Rotterdam area it definitely wants to build a pipeline, he said.

Innovative engineering

Filip Neele, senior project manager CO_2 storage with TNO discussed how engineers are identifying and resolving storage challenges with CO_2 associated with the rapid depressurisation and cooling.

Filip Neele, senior project manager CO2 storage with TNO.

The CO_2 is planned to be stored in depleted gas reservoirs, typically at 20 bar or lower, but with temperatures above 100 degrees C, at 2.5 to 5km depth. But the CO_2 transport is planned to carry 80 to 100 bar pressure, at seawater temperatures of 5 to 10 degrees C.

The CO_2 pressure would normally be reduced with a choke valve at the well head. But a 1 bar pressure decrease will typically lead to a 1 degree temperature drop. Meanwhile CO_2 has the possibility of forming (frozen) hydrates at anything below 15 degrees C, which would block the well and cause a shut down in flow.

Also, the wells were designed to carry hot gas from oil reservoirs, not cold CO_2.

So the engineering is based on ensuring the bottomhole temperature is never below 15 degrees C.

Achieving this is easier with a higher injection rate, which also means a lower pressure drop at the choke. The minimum injection rate may be as much as 2 MT / year. But it depends on the tubing and the reservoir properties.

It could be possible to heat the CO_2 and avoid it being so cold at the bottom of the well, but this would require a lot of energy. Another option would be to only use higher pressure reservoirs (e.g. above 50 bar), or have a CO_2 pipeline at lower pressure.

Perhaps there would be an initial low pressure pipeline phase, and then increase pressure or switch to liquid injection as the reservoir pressurises, he said.

Developing CCS in the UK and Norway

The UK and Norway have big efforts to try to get carbon capture moving – which should lead to projects being developed in the next few years.

In the UK, the government has announced plans to reach "net zero" CO2 emissions by 2050. Modelling projects show that it will require between 75 and 175 MT CO_2 of storage per year, including CO_2 from industry, power generation, hydrogen generation, bio-energy CCS, and air capture, said Jon Gibbins, director of the UK Carbon Capture and Storage Research Centre (UKCCSRC).

But the UK is still struggling to develop business models for carbon capture. One obstacle is that people take the price of offshore wind power and compare it with the price of coal + CCS, without taking into account the intermittency of wind. So people are focussing on the price rather than the value.

Plans have been developed to build five CO_2 clusters around the UK, in Scotland, Teesside, Humberside, South Wales and Merseyside. The South East of England / London is yet to see any CO_2 planning – although it could involve CO_2 carried to a storage site by ship.

The Humber project is based around the Drax biomass power station and nearby offshore storage. The Merseyside project is based on storage in gas fields offshore North West England, and this works out "one of the least cost projects", with a total development cost of £1bn, according to reports.

South Wales has the "highest concentration of heavy industry in the UK" as a fraction of regional emissions, but would require shipping to take CO_2 to a storage site. Meanwhile Scotland has about half the storage capacity of the entire European Union, but relatively little CO_2 emission, mainly from the Grangemouth industrial cluster.

The Teesside project is based around a potential project by the Oil and Gas Climate Initiative (OGCI), a gas power station with post combustion capture, generating 5m tonnes of CO_2 a year. There are also ideas to generate 125 GW of hydrogen fuel, with an estimated £22.7bn capital cost, feeding hydrogen into industry and the domestic gas grid. The CO_2 transport and storage component of this project is a relatively small amount, £1.34bn.

The UK government recently announced £170m funding for CCUS projects, which should lay the groundwork to put together clusters, with an aspiration to have at least one cluster running by 2030. There would be larger amounts of money anticipated from the overall UK government spending on low carbon.

There is still no financial mechanism to reward doing BECCS (bio energy carbon capture and storage), he said. But perhaps after UK leaves the EU, agricultural subsidy schemes could be reconfigured to reward companies which produce energy crops and guarantee them a long term market.

Norway

Michael Drescher, principal researcher CO_2 transport with Equinor, gave an update on the "Northern Lights CCS Project", involving Equinor, Total and Shell. The project is part of the Norway's national CO_2 capture and storage project and contains the transport and storage part of the value chain.

The plan is to collect CO_2 from two sites, Fortum's waste to energy plant in Oslo and Norcem's cement factory in Brevik. The CO_2 is carried by ship to a receiving terminal near Bergen, where it would be further transported by pipeline to offshore storage.

The project would scale up gradually, with initially CO_2 from one or two sources from Fortum and Brevik with a volume of approximately 0.4 Mio tonnes/year each but seeking to add additional third-party volumes in the future. The project plans to install a pipeline with a maximum capacity of 5M tonnes/year.

The project is partly funded by the Norwegian State, which plans a final investment decision later in 2020. The project team is currently mid-way through FEED (front end engineering and design), planning to finish at the end of 2019, with drilling a confirmation well in Q1 of 2020.

Mr Drescher is confident it can go ahead. "We don't see any technical showstoppers for the facilities, but the well is needed to confirm acceptable subsurface storage," he said.

Injection of the first CO_2 is planned to be in Q1 of 2024.

The initial design is taking into account existing operational experience and latest technology. However, the included safety margins for the design could be further challenged in future projects being able to bring down the costs in later projects.

For example, Equinor is investigating the possibility of using lower pressures for CO_2 ship transport at later stages to enable larger CO_2 carriers.

In addition, Equinor is looking into the practice of establishing cost-effective CO_2-specificiations for CO_2 value chains. Necessary CO_2-specifications will vary from chain to chain. For example, a cost-effective CO_2-specification will be very different if it would be a ship-based chain, like the Norwegian CCS value chain project (very pure) or a pipeline-based chain, like the Porthos CCS project, where higher amounts of impurities could be tolerated. In addition, there are other important factors which influence a cost-effective CO_2-specification such as the CO_2 source, capture and purification technology, safety and thermodynamic considerations, material integrity, etc.

Furthermore, Equinor is evaluating more radical cost cutting concepts such as injecting CO_2 directly offshore, omitting a necessary receiving terminal in the future. However, this could bring other types of challenges. If the CO_2 would be injected directly by each CO_2 carrier, it would likely be batch-wise injection which would lead to strain on the equipment and reservoir. Another solution could be to have a floating CO_2 receiving ship at the wellhead, providing a buffer and thus enabling continuous CO_2 injection.

CO2 capture – costs, technology and business models

A critical element of a CO2 storage project is obtaining the CO2, the technology for separating it from a flue gas, and the business model of who pays

A critical element of discussions about carbon capture and storage projects is where the CO_2 is going to come from and how much this will cost.

An oil company seeking (or being obliged) to do carbon capture and storage will look for the cheapest way to obtain CO_2 which would otherwise be vented to the atmosphere.

Natural CO_2 subsurface reservoirs would not count for this purpose, because the CO_2 is in the ground, not the atmosphere. Gas wells which are high in CO_2 would not count, because they would normally not be produced at all.

So the most likely source is flue gases from power stations and energy intensive industries, particularly concrete, steel and oil refining.

The original assumption for carbon capture and storage was that they would mainly work on coal power station flue gases. This is no longer a proposition in the UK and Netherlands, which now have an expectation that they will stop using coal power. The UK anticipates continuing to use gas power, the Netherlands anticipates all power generation coming from renewables. So that shifts the focus to flue gases from energy intensive industries.

These flue gases are typically 20 per cent CO_2, so the CO_2 needs to be separated from the 80 per cent of other gases. There is a reasonably mature technology called amine separation – the amine molecule attaches to the CO_2 in one column, and the amine is separated from the CO_2 in a second column. The technology is expensive. We heard a 2019 estimate of \$35 per tonne CO_2 captured from a coal power flue gas in India in this way. This cost estimate reduced from around \$65 a tonne.

There have been many efforts over the past 10 years or so to find ways to reduce these costs. One idea is for fuel to be combusted in pure oxygen, with an air separation unit upstream of the combustion unit, also a mature technology. Then the flue gas is nearly entirely CO_2. Another idea is to have CO_2 circulating in the combustion system instead of air, again resulting in a much higher CO_2 level.

A great deal of research is going into carbon capture technology, particularly with new solvents. But today's carbon capture project managers, with the task of building ever bigger CO_2 capture units, are generally putting a preference on tried and tested, easily available, non proprietary technology, rather than using advanced proprietary technology, says Earl Goetheer, principal scientist with Dutch research organisation TNO. This is MEA, which has been in use since the 1930s.

However there are downsides to MEA which are not apparent in energy figures, he warned. The solvent loss rates of MEA is high, 1.5 to 2.5kg per tonne CO_2. This is not expensive in financial terms, but damages the overall CO_2 performance, because a lot of CO_2 is emitted in its manufacture.

The emission rates to air can also be high, in the range of grams (of MEA) per m3 of CO_2. This could be due to amines condensing onto tiny (sub-micron) particles present in the flue gas of a typical coal power plant or refinery. These particles are too small to separate with a typical water wash or demister.

This problem was not observed in the first CO_2 capture projects, because they were mainly on removing CO_2 from natural gas fired combustion, which did not contain such tiny particles and the focus was on the CO_2 as a product, he said.

On the subject of CO_2 air capture, Mr Goetheer said he was sceptical that it could work at costs he has seen quoted of \$80 per tonne. It costs at least \$40 to capture CO_2 from flue gas, which can be up to 25 per cent C02 in case of cement production. But air is just 400 parts per million of CO_2. To illustrate the difficulty of this separation, he suggested an analogy of trying to find the 400 people who have one leg in a city of a million people.

Covering costs with CO_2 utilisation

Mr Goetheer is also highly sceptical about ideas that CO_2 capture might be paid for by turning CO_2 into useful products.

There are many molecules which can be synthesised technically from CO_2 molecules, including methane and ethanol. But this makes no commercial sense if the cost of energy to make the molecule is more than the product is worth. For example, if you make methane from CO_2, you use an enormous amount of energy to create a very low value molecule.

Many people talk about making formic acid in this way, since this product has a high (but fluctuating) value, but it also has very small market volumes.

Mr Goetheer said that using CO_2 to make algae may be overrated, when you consider that algae contains 1 to 2 g of solid per litre of water. So sequestering a small amount of CO2 would require a massive quantity of water.

Some areas which may make sense are using electricity to make hydrogen and using this hydrogen for CO_2 activation towards methanol or methane. "Methanol makes a bit more sense, it has a higher mass, higher value and is a liquid," he said. "You can use methanol to make ethylene, propylene and gasoline."

Other interesting options could be converting CO_2 into polymers and permanently storing CO_2 in minerals, perhaps to make cement. Electrochemistry could as well be a mean to produce value added chemicals such as formaldehyde or CO from CO_2. TNO has already seen it would be possible to integrate an electrochemical conversion process with CO_2 capture in an integrated process.

Who pays the capture costs?

In Europe, emitters of CO_2 are being hit by ever increasing regulatory pressure and costs to dis-incentivise emitting CO_2 to the atmosphere. So perhaps the costs of CO_2 separation from flue gases would be paid for by emitters.

This is the plan of the Rotterdam PORTHOS project, which envisages that energy intensive industries in the Port of Rotterdam would pay themselves for CO_2 capture and storage.

In Europe, the emissions trading scheme covers all land based emissions (not shipping and aviation). But the cost of emitting is not yet close to the cost of CO_2 capture and storage, and is not a stable price, so does not provide enough incentive by itself.

Governments are looking for ways to fill this gap. The Netherlands is mooting an extension to its "SDE" scheme, to be called "SDE++", which will provide a subsidy or additional tax, between the carbon price and the cost of carbon capture. The UK is considering a similar scheme, which may be a tax credit.