carbon capture journal

Sept / Oct 2011 Issue 23

Sulzer - improving CO2 capture efficiency

CCS public consultation outside the tick box

CCS-EOR for global energy security

Gas dehydration for pipeline safety

Study finds CO2 storage poses no significant risk to human health

University of Regina Hydrogen pilot plant with CO2 capture

'Crunch time for UK CCS policy' AND the CCSA's new UK CCS strategy

Altona - diesel from coal with carbon capture for $53 a barrel

UK Energy Technologies Institute launches new projects


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Contents

Leaders

Sulzer - reducing the energy penalty for post-combustion CO2 capture
Sulzer has developed a new structured packing for absorbing carbon dioxide more efficiently from the flue gas stream of fossil-fueled power plants — 2

CCS public perception - consultation outside the tick box
Gaining public consent for CCS projects is vital for the success of the technology as a future component of UK energy infrastructure. Whilst good consultation cannot guarantee consent, poor consultation can almost certainly guarantee failure, says Leander Clarke at communications consultancy PPS — 6

Legal Column

The UK Electricity Market Reform White Paper was published in July. There has now been sufficient time to ponder the ramifications for CCS of the proposed reforms. Calum Hughes, principal consultant in CCS regulation and policy at Yellow Wood Energy, discusses a few of the issues — 8

Projects and policy

University of Regina Hydrogen pilot plant
Researchers in the University of Regina's Faculty of Engineering and Applied Science have developed a new catalyst capable of converting multiple feedstocks into Hydrogen while capturing the CO2 produced — 10

Crunch time for UK CCS policy
Chris Littlecott, senior policy adviser at the environmental thinktank Green Alliance, looks at the progress so far of the UK's coalition government, and highlights the top priorities for action in the coming months — 12

CCSA launches new UK CCS strategy
The Carbon Capture and Storage Association (CCSA) has launched its new plan, "A Strategy for CCS in the UK and Beyond" — 13

Capture

Diesel from CTL with carbon capture at a cost of $53 / barrel
UK company Altona Energy believes it can supply vehicle ready diesel at $53 a barrel (33¢ a litre), with a coal to liquids plant, incorporating carbon capture for underground carbon storage, with financial support from China — 16

U.S. DOE invests $41m in 16 post combustion projects
The U.S. Department of Energy has selected 16 projects aimed at developing advanced post-combustion technologies for capturing CO2 from coal–fired power plants — 18

Transport and storage

Using CCS to improve U.S. and global energy supply security
Combining carbon capture and storage with enhanced oil recovery using CO2 injection (CO2-EOR) can help produce more oil from mature oil fields while economically sequestering CO2 — 19

CO2 dehydration for pipeline safety
Failing to dehydrate carbon dioxide, for most applications, can result in the costly formation of hydrates and the very rapid corrosion of normal pipe. Wayne McKay at U.S. company Gas Liquids Engineering Ltd. explains DexPro, their patent-pending gas dehydration method — 22

Health fears over CO2 storage are unfounded, study shows
A University of Edinburgh study had concluded that capturing CO2 from power stations and storing it deep underground carries no significant threat to human health — 25

Status of CCS project database

The status of 78 large-scale integrated projects data courtesy of the Global CCS Institute — 28

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Sept/Oct 2011 Issue 23

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Front cover: Dry CO2 Seep - Rome Ciampino CO2 dry gas seep, located in a populated area in Rome. Photo taken from domestic flight landing into Rome Ciampino airport. Red ellipse outlines the extent of degassing. (See page 25)

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Sulzer - reducing the energy penalty for post-combustion CO2 capture

Sulzer has developed a new structured packing for absorbing carbon dioxide more efficiently from the flue gas stream of fossil-fueled power plants. The new MellapakCC™ structured packing significantly reduces the column size and the pressure drop across the CO2 Absorber—thus reducing capital and operational expenses for the customer.

By Dr. Abhilash Menon and Markus Duss, Sulzer Chemtech Ltd.

Power plant fitted with a pilot CO2 capture unit at Niederaussem, Germany

Carbon capture and storage (CCS) involves the responsible utilization of fossil fuels without endangering the planet. CO2 emissions from fossil fuel combustion (particularly from coal-fired and gas-fired power plants) are considered the primary contributor to this problem.

Due to the significant interest in mitigating this problem, there has been an unprecedented surge in activity to prove the techno-economic viability of CO2 capture technologies from flue gas streams from power plants (see Figure 1). Capturing CO2 requires a lot of energy (e.g. solvent regeneration) hence, the focus of every single technology provider is to reduce this energy cost wherever possible.

Another challenge stems from the need to remove CO2 (typically between 3.5 vol% and 14 vol%) from very large volume gas streams that therefore require very large column sizes. The pressure drop inside the absorber also presents a significant cost. If this expense can be well managed, large savings can be made. In this context, the right choice of mass transfer equipment is of great importance, and structured packing offers an excellent solution because it reduces the column dimensions (capital expenses, CAPEX) and provides low pressure drop (operational expenses, OPEX) over the CO2 absorber.

Specifically for post-combustion CO2 capture, Sulzer Chemtech has developed a new Mellapak™ structured packing (Sulzer MellapakCC™), to fit the individual, process-specific requirements. It targets process intensification by significantly reduced pressure drop to reduce OPEX and aims for maximum separation performance to reduce CAPEX. This article presents a significant step in further reducing the costs associated with CO2 capture in post-combustion plants.

State-of-the-art design of a CO2 absorber

Figure 2 provides a schematic overview of the amine-based scrubbing process for CO2

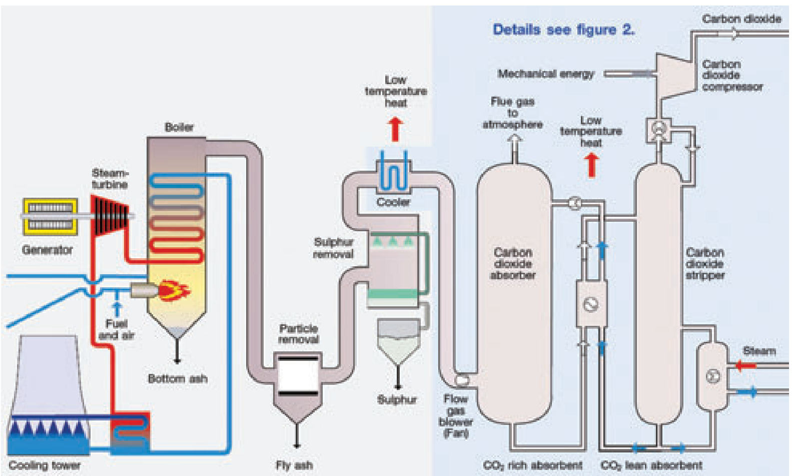

Figure 1 - Typical example of a CO2 capture unit fitted into an existing post-combustion power plant

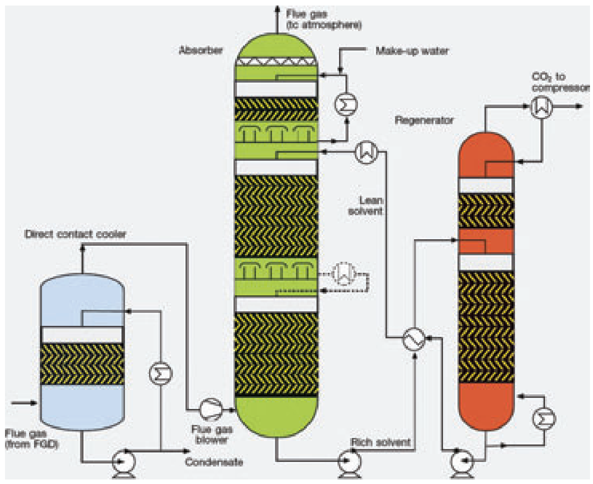

Figure 2 - Schematic of CO2 capture plant based on amine-scrubbing process

Process parameter	Value
Flue gas rate, G	3 000 000 m³/h
Pressure drop reduction, Δp	5 mbar
Fan efficiency, η	0.75
Operating time, t	8100 h/yr
Electrical costs[1], c	0.05 EUR /kWh
Energy per year, E = G • Δp • t / η	4.5 • 10⁶ kWh / year
Electrical costs, C = E • c	EUR 225 000 /year

[1] Average electrical cost in EU25 countries (Eurostat, 2007)

Figure 3 - Electricity cost savings for the flue gas blower for a medium-sized 800 MW European power plant

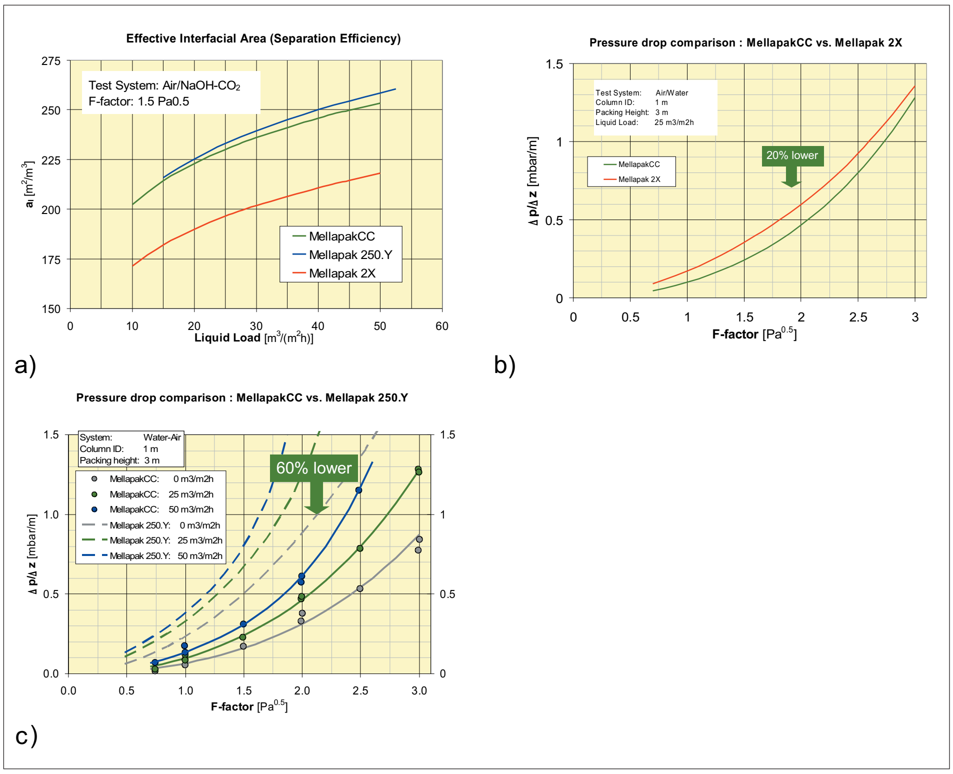

Figure 4 - Hydraulic and mass transfer performance of MellapakCC vs Mellapak

capture from a flue gas stream which could, e.g., come from a coal-fired power plant. All three columns shown have the potential for process intensification, but this article refers exclusively to the large CO2 absorber column. A typical 800 MW coal-fired power plant can emit up to 3 000 000 m3/hr of flue gas, corresponding to some 6 000 000 t/yr of CO2 emitted. Assuming a superficial gas velocity of 2.1 m/s, an indicative value for the required cross-sectional area for the absorber would be about 400 m2 (column inner diameter approx. 23m).

A previous study performed by Sulzer Chemtech (Menon, et.al. (2009)) showed that Mellapak structured packing in the CO2 absorber offers better mass transfer performance than random packing. Up to 15% savings in CAPEX (column bed heights) can be achieved here. In addition, Mellapak structured packing offers significantly lower pressure drop than random packing (up to a factor of 2). This improvement allows engineers either to reduce the column internal diameter (up to 10% CAPEX savings) or to save significant OPEX (reduced electricity demand due to reduced pressure drop across the flue gas blower upstream of the absorber). Another advantage of using Mellapak structured packing is the reduced amount of material required per unit geometrical area as compared to random packing, that positively influences the total investment costs (CAPEX).

Presented below is an analysis of the impact of pressure drop on the economics of this process. The new Sulzer MellapakCC structured packing has the potential to reduce the pressure drop in the CO2 absorber by up to 60% over the already efficient conventional Mellapak structured packing.

It is important to bear in mind that unlike the chemical and hydrocarbon processing plants, which are designed for a life-time of 10 to 15 years, power plants are typically designed for an operational life-span of 30 to 40 years. A simple life-cycle cost analysis for a typical 800MW power plant over a 30 to 40-year span clearly demonstrates the potential savings in electrical costs (by reducing pressure drop). Each mbar of pressure drop saved represents considerable savings in operating cost. In Figure 03, the annual savings in electricity costs are calculated, assuming a reduction of 5 mbar in pressure drop over the CO2 absorber column.

The savings calculated amount to EUR 225 000 per year (see Figure 3) in electricity costs for the flue gas blower. Hence, a savings in pressure drop of even 5 mbar over a 40-year life-time operation of the power plant, could save up to EUR 9 000 000 in electricity costs. Such costs need to be evaluated during the absorber design and when choosing the type of packing and associated internals.

Process intensification: Development of MellapakCC structured packing

Pressure drop was found to have a profound impact on the plant OPEX. Therefore, Sulzer Chemtech started an R&D program to find the 'sweet spot' with respect to mass transfer efficiency and hydraulic performance of the structured packing. The target was to maximize or maintain the effective interfacial area (or wetting), while simultaneously minimizing the pressure drop. To further optimize the geometry of Mellapak structured packing, it was necessary to fix the regime of operation and select a benchmark Mellapak packing type.

Mellapak types Mellapak™ 2X (200 m2/m3) and Mellapak™ 250.Y (250 m2/m3) were the candidates selected for further optimization. A systematic parametric study looked into the influence of the microstructure, hole size, numbers of holes, and angle of corrugation. This study resulted in a new structured packing, MellapakCC, with special geometrical features. MellapakCC was developed by optimizing the packing geometry in terms of the material requirement (lower CAPEX), the pressure drop (lower OPEX), and the high effective interfacial area (lower CAPEX and OPEX).

Performance of MellapakCC

The separation performance of MellapakCC was measured by experiments wherein CO2 (from air) was absorbed in an NaOH solution. This is a liquid-side controlled system and falls under the fast-reaction regime. Since all relevant physical properties are known for the CO2-NaOH system, it is possible to back-calculate the effectively available mass transfer area that determines the mass transfer efficiency of the packing.

The mass transfer performance (figure 4a) shows the efficiency (required packing height) of MellapakCC in terms of the effectively available mass transfer area at a constant gas flow rate and varying liquid loads. MellapakCC and Mellapak 250.Y have nearly the same mass transfer performance, whereas MellapakCC provides up to 20% higher separation efficiency compared to Mellapak 2X. This implies that compared with conventional Mellapak 2X, the new

MellapakCC will require approximately 20% less packing height.

Figures 4b and 4c show the hydraulic performance of MellapakCC against conventional structured packing. The hydraulic performance was measured using an air-water system in a 1000mm column at various liquid loads typically seen in post-combustion capture applications. First of all, the measurements confirmed the significant reduction in pressure drop when comparing the new MellapakCC structure with conventional Mellapak structured packing. Using MellapakCC instead of Mellapak 2X results in up to 20% lower pressure drop (see figure 4b). This impact becomes even more significant (as seen in figure 4c) where up to 60% reduction in pressure drop is possible when using the MellapakCC instead of Mellapak 250.Y.

What is important to note is that the relative benefit gained from the MellapakCC packing compared with the conventional Mellapak packing will also be applicable to any system that belongs to the fast-reaction regime (like the CO2 absorbers in post-combustion capture). In other words, if the packing height using a particular solvent is known for Mellapak 250.Y, then MellapakCC will require the same packing height for mass transfer for that same solvent, but will have 60% less pressure drop.

Deployment of MellapakCC in pilot and demo plants

MellapakCC is now ready for deployment in pilot and demo plants in the near future. The above comparisons with measured data demonstrate the importance of the selection of the right packing, which will become a key for the competitive design of post combustion capture units. The new MellapakCC is a step forward to the energy and cost effective realization of this technology.

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CCS public perception - consultation outside the tick box

Gaining public consent for CCS projects is vital for the success of the technology as a future component of UK energy infrastructure. Whilst good consultation cannot guarantee consent, poor consultation can almost certainly guarantee failure, says Leander Clarke at communications consultancy PPS

The potential for Carbon Capture Storage (CCS) in the UK is exciting but must be tempered by real concerns over the cost, commercial feasibility and associated infrastructure required to take this technology beyond theory into large-scale deployment.

As government and industry work together to try to solve some of these challenges, there is yet one more hurdle that developers will be required to jump in order to realise the potential of CCS as part of the low-carbon energy mix.

Public perception, engagement and support of any new infrastructure project can be a mixed bag, with energy infrastructure seeming to fair worse despite recognition that without new generation the lights are likely to start going out at some point in the next two decades.

Onshore wind for example, one of the most established low-carbon technologies in the UK has only a 50% success rate when it comes to gaining planning consent; likewise offshore wind continues to spark vociferous objection, particularly for the onshore connection and associated connection route, as well as the impact of costs on consumer energy bills. This objection is likely to have a major impact on the success of these two industries going forward. It is therefore realistic to assume given the immaturity of CCS technology, the cost, transport and storage requirements, that there is also likely to be significant objection once CCS projects start to be realised.

This has been compounded by recent changes in policy; the introduction of the localism agenda and the formalisation of planning for major infrastructure projects through the rigorous and process driven IPC/MIPU as two examples.

Public consultation therefore has become a much sought after skill-set and for something so vital to the success of the planning process, it is one of the easiest (and normally the most consistent) process to get wrong. Even with the greatest intention and rigorous application of tried and tested consultation methodology, developers can and often do fail.

Whilst good consultation cannot guarantee consent, poor consultation can almost certainly guarantee failure. The following are some of the common mistakes made even when following established consultation methodology.

Who are you consulting?

The most common mistake is for developers and those instructed to support consultation to assume they know who their audience is without thoroughly doing their homework. This might be obvious in terms of statutory consultees but when it comes to the community it is not always so clear who that is.

Communities can be defined in many ways depending on the scale, type and location of the proposed energy infrastructure project and the types of developments existing or already proposed within an area.

For CCS projects the local community is likely to span those within view of the actual development, those along the planned transport route and those with an interest in the proposed area for storage. Given that the UK has committed to storage offshore only this might include vociferous groups such as the fishing and surfing communities. For most CCS developments infrastructure work will be attached to previous development sites and therefore may only require an extension; however the perceived impact on the local community should not be underestimated.

How each of these communities will receive proposals depends on many factors tied in to the political, economical, social, historical and environmental connections with a site. These factors must be identified alongside the communities and stakeholders a developer actually wishes to consult with.

Finally, communities might also include neighbouring areas where impacts are perceived in terms of environmental impact or where a local community or council area feels that there has been overdevelopment. Take for instance a region that has seen proposals for a number of energy infrastructure projects over a short period of time. Whilst a CCS project individually might only impact visually on a very small number of people within a region, taken collectively the region might feel it is shouldering disproportionate impacts compared to other places in the UK. This must be accounted for in any future consultation work.

Identifying early on who your community might be, their motivations and drivers and importantly the expectations they might have of you as a developer is key to ensuring your consultation hits the mark and not a brick wall of opposition.

Who holds the power?

The next opportunity for consultation to flounder is failing to adequately explain the parameters of the consultation and the level of influence actually held by the communities and stakeholders being consulted.

In the case of proposed CCS projects there is little scope for negotiation in terms of the development site as initially these will be attached to existing power stations. Some developers therefore might be tempted to take a 'decide, announce, defend' approach to consultation, presenting communities with what feels like a fait accompli. Whilst in the past this might have done no more damage than to provide ammunition for the local objection group, localism has changed this with even the smallest of communities expecting some influence over an infrastructure or land use project that they perceive will affect their day-to-day life.

That is not to say that developers should hand power to consultees to make decisions beyond their level of understanding and experience of the project or technology. Often however, communities have a level of knowledge and understanding of the site that can actually improve the project being proposed – remember, it's their community.

If consultees feel they are genuinely being asked to participate and influence, and understand the nature of that influence, even at the smallest level such as landscaping or how a community benefits package might be managed, a community is more likely to engage with a developer and consultation begins from a more positive stand-point.

Listening not telling

Most developers understand the importance of being able to demonstrate that they have listened to consultee concerns. This is usually presented as a log of concerns and the (often stock) responses from the developer to show that these concerns have been 'listened too'. A community helpline is cited as a tool enabling consultees to really be listened to, as are public exhibitions and town hall meetings. However the perception of being listened to is far harder to engender than merely evidencing that you have provided a forum for, and responded to consultee feedback.

If you have been thorough with your stakeholder and community mapping and have adequately set the parameters for consultation it is very easy to plan how you will respond to common and expected concerns and issues, with stock responses and consultation materials that contain the answers your preparation has identified as being needed.

This is a valid form of consultation and will perhaps satisfy the majority of those being consulted. However, do not let this planned approach prevent you from really listening to those with unexpected or unique concerns or requests; responses that do not adequately deal with the matter being raised and feel as if they have come from a stock of prepared answers will only reinforce a communities' perception that the proposal is a done deal and they are not really being consulted.

Community help lines work well when those answering the phones actually listen properly to the person who has taken the time to call. Offering an individual response to the concerns raised will pay dividends in terms of developer trust and perception. This will inevitably require a call back or a letter sent but in the spirit of really listening, the right response, even if delayed, is better than a knee-jerk response based on what you think is being said.

Misunderstanding expectations

One of the biggest benefits of getting all of the above right is that you are more likely to meet or manage the expectations of your consultees and therefore garner trust and support (or at least ambivalence) to your proposed CCS development.

These expectations might, as previously suggested, be a simple case of the level of influence a community actually has over a proposal but might also include an expectation of benefits on offer, timescales in which a development will operate, the associated infrastructure required and the impact of these plans. This will be significant for CCS development as transportation routes will have to be retrofitted to connect current sites to proposed storage facilities out to sea. This might impact on local transport levels or might even require additional road infrastructure depending on the transportation scenario chosen by the developer.

CCS is also unlikely to provide any long-term financial benefits to a community including employment. However, if the community is expecting this form of payback for further development, then failure to manage expectations from the start will only fuel the fire of opposition.

Understanding and matching, or at least managing the expectations of your consultees is just one part of the expectation equation. Developers must also consider what they are expecting from consultees – NIMBY-style opposition or a genuine exchange of ideas and opinions?

Consultation has to involve a two-way dialogue about a proposed development. Developers should always prepare for views and opinions that do not match their own. This does not mean that consultees are merely demonstrating a 'NIMBY' attitude or are being difficult. By making that assumption developers will base responses on the idea that a community is misguided or uneducated rather than welcoming the participation of those being consulted.

Good consultation for the right result

Good consultation, properly conducted is now a prerequisite for helping ensure that developments get a fair hearing, and, in due course, a planning consent. There are any number of concerns that can be raised about a development and in order to get the right decision taken for the right reasons, time spent on good consultation is time well spent.

There are many tried and tested method than can – and should be used, but more important is to ensure that you try to answer the genuine concerns of affected residents and communities. Most people care passionately about where they live, and they want to know that your project will bring benefits and improvements, but certainly not make things materially worse. Listen hard and work hard to answer any concerns as quickly and fully as possible.

Good consultation well carried out is your best defence from a CCS development falling at the hurdle of public opinion. Play your cards right and rather than your proposals being fought and refused, you will give yourself the best chances of seeing your development given consent and being built.

With the methodology in place the only aspect left to decide is the format and delivery of your consultation. We have touched upon tried and tested methods such as community hotlines and public exhibitions and these, along with community newsletters and leaflets are cited as best practice. However, with all of the insight gained from understanding your consultees, setting the parameters of consultation, listening and managing expectations, CCS developers and those supporting the consultation process are in an excellent position to try new and less tired methods of consultation that match the way your consultees expect to be, wish to be and are most comfortable with being engaged.

This is the point at which you can be creative, using all the information you have gathered thus far, from social media through to conversations at the local pub; get this final piece of the jigsaw in place and you have ensured that your consultation at least will not stand in the way of development.

More information

Leander Clarke joined PPS in 2011, having previously been head of energy and environment for a large Bristol based PR consultancy.

She has spent the last 11 years working within the energy sector; in the private sector as a consultant for the likes of Envirowise, WRAP and E.ON, and as a civil servant for the Department for Environment, Food and Rural Affairs and the Energy Saving Trust.

She joined PPS to head up its energy team and provide expert and coordinated consultancy advice on a range of energy technologies.

PPS is the market leader in the field of contentious land use communications and has specialised in public consultation as part of the planning process for 20 years. PPS has an unrivalled track record of securing permissions on complex schemes through effective community consultation and stakeholder engagement.

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CCS legal and policy – Sept / Oct 2011

The UK Electricity Market Reform White Paper was published in July. There has now been sufficient time to ponder the ramifications for CCS of the proposed reforms. Calum Hughes, principal consultant in CCS regulation and policy at Yellow Wood Energy, discusses a few of the issues.

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A high level inspection of the reforms in the White Paper reveals the following. Firstly, that the stated raison d'etre of the combined schemes is to address the three-pronged energy conundrum (sometimes designated the 'Trilemma') currently facing the UK Government, i.e. how to ensure security of supply whilst meeting CO2 emissions abatement targets and keeping energy bills as low as possible. Secondly that the package as a whole rests on four pillar mechanisms: a Carbon Floor Price (CFP); a Feed in Tariff for low carbon generation operating via Contracts for Difference (FiT CfDs); some species of Capacity Mechanism; and an Emissions Performance Standard.

It is also worth mentioning what is not in the reforms, to wit, there are no major amendments to the prevailing electricity trading and transmission arrangements. Some alterations may soon be forthcoming as part of Ofgem's attempt to increase market liquidity (these are vital if the EMR reforms, especially FiTs, are to operate efficiently), but electricity in GB will continue to be generated and supplied via a trading system based upon open-market principles.

It is notable therefore that the mechanisms that make up the reforms would provide the executive with the regulatory levers necessary to set market conditions (and alter them from time to time) in order to obtain a centrally planned energy generation mix which it considers will best deal with the Trilemma it faces. In some cases these regulatory levers will, despite a number of assurances to instil confidence in the long term nature of the measures being adopted, introduce uncertainty and therefore risk into the commercial models of would be CCS developers.

Divining how the combination of existing schemes and the ERM measures will impact upon the development of CCS is currently very difficult for two main reasons: firstly, the labyrinthine nature of the possible interrelations between the various mechanisms in the reform package, existing incentive schemes and the EU ETS; and, secondly, the fact that, with the possible exception of the CFP, the key details of the schemes are as yet to be decided.

In the case of the FiT CfD it is currently unclear who the contracting counterparty will be, how the CfD strike price will be set for CCS is yet to be decided and what form of CfD might apply to CCS fitted plant that could operate in a way which DECC consider to be 'flexible' is in abeyance. With regard to the Capacity Mechanism there is very little certainty; the form that the proposed mechanism might take will be the subject of a further consultation.

The Carbon Floor Price

The Carbon Floor Price (CFP) is misleadingly labelled; it does not, as the name suggests, set an absolute minimum carbon price but instead adds a fixed level tax (Carbon Price Support) on top of the prevailing EUA price. Thus, for those caught by the CFP scheme, the carbon price will be equal to the EUA price plus the Carbon Price Support.

Whilst the Carbon Price Support is set at a level intended to generate a carbon price equal to the 'carbon floor price' targeted by Government, the eventual carbon price may fall well below this level depending upon the prevailing EUA price. This means that the scheme does not give low carbon generation project developers a minimum carbon price benefit over their CO2 emitting competitors as it was intended to do at its inception. A cynical observer might point out that one thing the scheme does do is provide a predictable level of tax revenue to the Treasury, by whom it was designed.

The White Paper remains silent on whether generation plant fitted with CCS will be exempt from the CPS. This is concerning as the Treasury's CFP Consultation response stated unequivocally that 'The Government intends to introduce legislation at the earliest practical opportunity to ensure that both demonstration projects and commercial CCS plants receive relief from carbon price support rates equivalent to the proportion of CO2 captured and stored'. Given the silence on the matter in the White Paper, the phrase of concern appears to be 'earliest practical opportunity'. Again, there is regulatory uncertainty here for potential investors in CCS.

The Emissions Performance Standard

The Emissions Performance Standard (EPS) has long been vaunted by many as an essential part of any regulatory system intended to encourage renewable energy generation. There are a number of variations on the EPS theme but the central concept is the application of a maximum emission level for a defined category of plant over a given time scale. The currently proposed EPS would limit the average annual emissions of any new fossil fuelled plant to 450g/kWh; a level at which gas plant can operate unabated but coal plant cannot.

Calum Hughes, Yellow Wood Energy

There are a number of uncertainties regarding important detail of the proposed EPS scheme. The emission standard will be applied to each plant separately (i.e. not to a generator's portfolio as some called for) but it is not defined whether each unit within a plant could have different emissions characteristics i.e. whether a combination of abated / non-abated / biomass across separate units in a single plant would be permissible.

The EPS will not affect plants which are already consented and projects receiving funding under DECC's demonstration programme or the EU schemes will be exempted from the EPS but the timescales over which plants yet to be consented will be able to retain the EPS level at the time of receiving their consent is still to be decided. What criteria will be used to assess when 'energy supply emergencies' will allow plants to derogate from the scheme and what limits will apply when plants are operating flexibly, as opposed to at baseload, are also yet to be elucidated.

The EPS has been designed as an annual average to allow CCS abated plant operators to have some flexibility to run without CCS when electricity demand (and prices) are high and the value of the parasitic energy load of CO2 capture and export is higher than the CO2 emissions penalty. This has the potential to improve the economics of the

power plant as well as helping to ensure security of electricity supply.

However, unlike absolute emissions limited mechanisms (e.g. the LCPD scheme) a limit based on average emissions per unit of energy exported does not allow a generator who's emissions levels are too high to come back within its limit by simply shutting down for a while. Therefore, depending upon how the annual average calculation is made, a generator is likely to operate differently at different times of the emission assessment period. If the plant's average emissions exceed the limit early in the period then the generator may not be able to capture high electricity prices later and still be able to economically reduce its average emissions by the end of the period.

This may make generators reluctant to build up high emission averages, or to try to build up a 'war chest' low average, early in the assessment period. Equally, towards the end of the assessment period, the inability to recover a high average position due to lack of time may restrict a generator's ability to supply to peak demand by ceasing to abate.

The value which the annual average EPS places on the ability to operate CO2 capture and export plant flexibly, as well as the impact that this will have on transport and storage systems, is also likely to have a important impact on the development of, and preference for, the various available technology options for these parts of the CCS chain.

It is increasingly clear that the flexibility offered by gas fired plants will be an essential part of the UK's electricity provision over the next couple of decades and that the EMR proposals must not deter the development of these plants. For this reason the EPS has been set at a level at which unabated gas plants can meet the emission limit without fitting CCS and plants receiving development consent before 2016 will be subject to the 450 g/kWh limit for a 'grandfathering' period regardless of reductions in the generally applicable EPS rate during that period. The length of the grandfathering period, which is critical, is yet to be decided. It must be long enough to allow proposed projects to receive financial sanction but not so long that the plant is able to run unabated for a longer period than is absolutely necessary.

The delay in the installation of CCS to gas plant created by EPS grandfathering has been interpreted by many as being detrimental to the development of CCS in general. Although this may be true to some degree, it may also have an up-side. If it results in the development of gas plants that are susceptible to a reduced EPS after their grandfathering period has elapsed, then this may attract early investment in the CO2 transport and storage infrastructure capacity that those plants will need in order to continue running once their EPS level has been tightened.

Hurdles to deploying CCS in developing countries high, but not insurmountable

Emissions of CO2 in developing countries in 2010 surpassed those released by developed countries – a problem worrying for environmentalists due to the vast energy needs of these countries to grow out of poverty. Bellona reports on a seminar in Washington, DC.

Because of the abundance of fossil fuels in developing countries, the need to deploy CCS technologies in these countries is urgent, a problem that was discussed at "Addressing barriers to CCS in developing countries," a seminar in Washington DC on September 7 and 8.

The seminar was arranged by The World Bank, in cooperation with the Global CCS Institute, the International Energy Agency, the Carbon Storage Leadership Forum and the Norwegian Government.

Countries such as Botswana, South Africa, Mexico, Algeria, China, Egypt, Jordan, Kosovo and other countries in South East Asia presented plans to develop and deploy CCS.

Though many plans were only preliminary, countries such as Mexico and South Africa forwarded concrete strategies for introducing CCS with a demonstration project to be built by 2020.

Challenges common to all the developing countries present were the lack of a regulatory framework for the development of CCS, as well as a lack of resources to fund demonstration projects. Many of those gathered called for the creation of a global CCS fund that would support development of demonstration projects.

Dr. Edward Rubin, professor of engineering and public policy at Carnegie Mellon University laid out the reasons why developing countries should start preparing for CCS development.

Rubin underscored that while other energy sources will be important, CCS is the only way to achieve large CO2 reductions from the use of fossil fuels for energy production. It also offers the best potential for providing a bridge between fossil fuel energy economies to a fully sustainable energy future.

A transformation of the transportation sector to cars running on electricity and hydrogen is also needed.

As costly as these efforts may seem, Rubin contended that the expenditures the world will face to meet the climate challenge will be far higher without CSS technology.

Many delegates raised the issue of introducing CCS technologies into the Kyoto Protocol's Clean development mechanism (CDM) and noted the important signal that would send to the market in emissions trading.

Bellona was invited to the seminar to present its projections for developing CCS deployment, specifically its Polish Road Map entitled "Insuring energy independence."

Poland, while far from being a developing country, is nonetheless heavily dependent on coal for over 90 percent of its electricity generation needs. Poland will need to update a large portion of its power plants in the coming decade.

With its vast coal resources and CO2 storage in geological formations, Poland is especially well placed for making investments in CCS.

In the Polish Road Map, Bellona looks at the future energy trajectory of Poland to until 2050 and identifies the costs and benefits of deploying CCS on a wide scale.

As the EU Emission Trading Scheme will put a price on CO2 emissions, Poland has an economic incentive that will be reinforced as the price of emitting CO2 increases over time.

Under all three trajectories, and across a wide range of possible EU climate and energy policies, it is clear that activities to commercialize and deploy CCS in Poland will result in lower costs of producing electricity, lower prices to the Polish consumers and a vast reduction in CO2 emissions.

University of Regina Hydrogen pilot plant

Researchers in the University of Regina's Faculty of Engineering and Applied Science have developed a new catalyst capable of converting multiple feedstocks into Hydrogen while capturing the CO2 produced

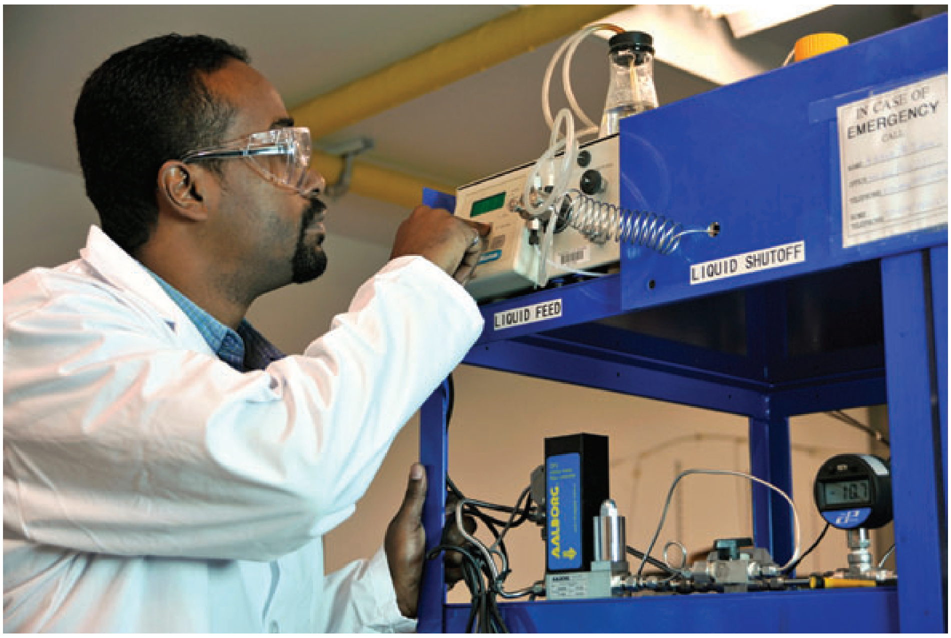
By Heidi Smithson, Technical Writer, Faculty of Engineering and Applied Science, University of Regina

Three must-have keys to successfully implement hydrogen production as a strong alternative energy resource are: scalability, feedstock flexibility, and incorporation of carbon capture. Researchers in the University of Regina's Faculty of Engineering and Applied Science believe they've found a single solution to providing all three keys.

"We have developed, for the first time, a single, cost-effective catalyst capable of converting multiple feedstocks into hydrogen," explains Dr. Raphael Idem, lead researcher of the University's hydrogen production team. "We have coupled this revolutionary catalyst with breakthroughs in process design that incorporate carbon capture and allow switching between feedstocks without disruption to process operations."

The newly patented catalyst was developed by graduate students and senior researchers in the laboratories of the University of Regina's Greenhouse Gas Technology Centre (GHGTC).

"We have a lab devoted specifically to catalyst development, a bench-scale hydrogen production test facility, and one of the most comprehensive arrays of analytical equipment available in North America," describes Dr. Hussameldin Ibrahim, who received his Ph.D. in Process Systems Engineering working on the development of novel hydrogen technology. Ibrahim continues his research on hydrogen production as a professor at the University of Regina and one of the lead researchers on the team.



Dr. Hussameldin Ibrahim adjusts settings on the University of Regina's bench-scale hydrogen production testing unit. Research using this unit led to the catalyst and process breakthroughs that supported the design and commissioning of a new pre-commercial hydrogen production pilot plant currently under construction. Photo: University of Regina Photography

Pilot plant

Based on the success of the new catalyst and process developments made at the bench-scale level, construction has recently begun on a new feed-flexible and process-flexible hydrogen production pilot plant, also to be housed in the Greenhouse Gas Technology Centre.

The pilot-scale plant is designed to demonstrate the commercial viability of the new catalyst and process, but a key feature of the new pilot facility will be a catalyst production plant also developed by the research team.

"With this new facility, we will be able to test our own catalysts as well as design, produce, test, and analyze catalysts for external clients. Alternatively, clients can use our unique facilities and expertise to design and test their own products," says Ibrahim.

"As an institute of higher learning, part of our role is to provide fundamental research and objective, third-party verification of technologies for industry – this is what this facility is designed to do," adds Idem.

The catalyst production facility will enable both the University of Regina and other research groups to produce catalysts in the quantity and quality needed for research purposes. "Currently, it is hard for researchers to obtain catalysts in the quantities and qualities they need – typically, catalysts are only available in very large or very small quantities and only a few producers can claim consistent catalyst quality," explains Ibrahim. "This facility will assist researchers all around the world with getting the supplies they need."

The $2.7 million hydrogen production pilot plant will be located in a specially-designed section of the Greenhouse Gas Technology Centre (GHGTC). Using the centre's advanced control systems enhanced by artificial intelligence, researchers will monitor and control the plant and collect data while maintaining safe, secure operations of the hydrogen plant along side the other labs and pilot facilities located in the building.

Carbon capture process

Another key feature of the novel process design is the incorporation of carbon capture and use as part of the process. "Carbon dioxide is a byproduct of hydrogen production processes," remarks Idem. "If we do not capture the carbon dioxide, we are more or less defeating the purpose of producing clean-burning hydrogen."

One of the University of Regina team's processes uses a new, unique dual-reactor system. In the first phase, the group's patented catalytic reactor processes the feedstock into carbon monoxide and hydrogen, as well as residual (i.e. unconverted) carbon dioxide and methane. This process uses carbon dioxide as a co-feed gas and operates at a comparatively low temperature, as opposed to traditional steam-driven processes. In the second phase, the unique catalytic membrane reactor process transforms the products from the first phase, with the addition of water, into separate carbon dioxide and hydrogen streams.

A portion of the carbon dioxide is recycled into the first phase catalytic reactor, while the remainder can be used in secondary processes, such as carbon dioxide-based enhanced oil recovery and geological stor-

age operations. Consequently, large quantities of carbon dioxide will be captured from the feedstock sources, resulting in a zero-emissions process when fossil fuel feedstocks are used and producing a carbon-sink with the use of bio-feedstocks. The hydrogen produced will thus become a truly clean energy source.

Scalability

The use of carbon dioxide along with the unique catalyst also provides plant scalability. "Production of large quantities of heat and steam will no longer be necessary for hydrogen production," explains Idem. "This means we can design plants on scales large enough to generate power regionally or small enough to provide power for a single facility like an airport or hospital."

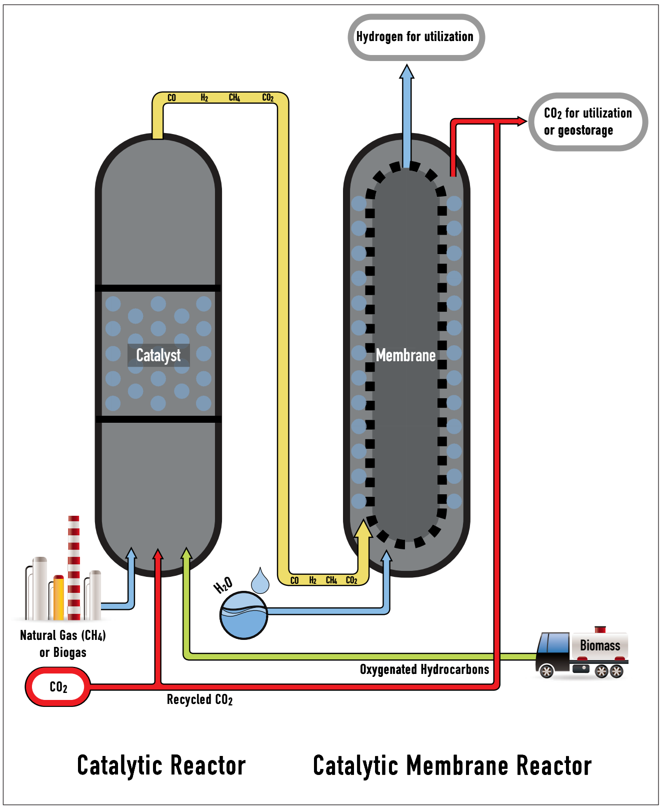
The technology is envisioned as a long-term clean energy strategy. "We recognize that a lot of technical and economic transitions need to take place before wide-scale adoption of this type of technology will happen," admits Idem. "But we believe our technology does provide a single solution to overcoming the major barriers to implementing wide-scale hydrogen production as an alternative energy resource."

The technology also helps address a fourth barrier to the adoption of hydrogen as a viable energy source. "Our current infrastructure isn't really designed for using hydrogen," explains Idem. "In particular, there are some challenges concerning hydrogen transportation and storage. However, many of our colleagues are making great strides in addressing this barrier. In the meantime, our technology, because of its scalability and flexibility, will enable hydrogen production on demand at the sites where it is needed, reducing the need for hydrogen transportation and storage infrastructure."

Project information

Components of the feed- and process-flexible pilot plant project are currently under construction. The plant is expected to begin operations in early-to-mid 2012.

Funding for the project was provided by Western Economic Diversification (WED) in partnership with Enterprise Saskatchewan through a $2.7 million Western Economic Partnership Agreement (WEPA) grant. The project complements those supported by the Natural Science and Engineering Research Council (NSERC)'s Strategic Hydrogen Canada Networks (H2Can) on "Hydrogen Production from Biogas," as well as the NSERC Strategic Projects grant on "Hydrogen production from biomass sources with carbon capture."



Process schematic of the Feed-Flexible and Process-Flexible Hydrogen Production Plant designed by researchers at the University of Regina. ©University of Regina

More information

www.urengineering.ca/research/hydrogen

Bellona - recommendations for optimizing the CO2 value chain

Through the ECCO project, Bellona has given recommendations on the regulatory framework, financial incentives and organization of the CCS value chain to the European Commission.

Bellona has released an article resulting from scientific work in the ECCO project, - a project which has received funding from the European Community`s Seventh Framework Programme (FP7/2007-2013). The main objective of the project is to facilitate strategic decision making regarding early and future implementation of CO2 value chains.

Europe is the world region with the most comprehensive pricing of CO2 emissions. Yet, CCS is not widespread. ETS is leading the way, but provides insufficient investment security. Other incentives are thus needed.

There is a range of alternative ways to stimulate investments in CCS - without putting the burden on public budgets. Among these are the Netherlands' CCS Task Force recommendation of a 'bonus-malus' scheme and the Forward capacity market dedicated to low carbon electricity generation.

If general CCS incentives are not politically feasible, specific incentives aimed at CO2 for enhanced petroleum production (CO2-EOR) could be considered. An opportunity to achieve CCS in a faster and more economical way is to use the captured anthropogenic CO2 as a resource to enhance petroleum production. CO2-EOR is a hydrocarbon recovery process that involves the injection of CO2 to flood mature reservoirs and produce petroleum substances that would otherwise remain unrecoverable.

"The deployment of CO2-EOR has the potential to kick off the full deployment of CCS", says energy advisor in Bellona, and co-author of the article, Gøril Tjetland.

The article also covers the current legal regime, regulatory framework and the overall organization of the CO2 value chain.

Download the report at:
www.bellona.org

Crunch time for UK CCS policy

Chris Littlecott, senior policy adviser at the environmental thinktank Green Alliance, looks at the progress so far of the UK's coalition government, and highlights the top priorities for action in the coming months.

Time is running out for the UK's coalition government. The lifetime of this Parliament is supposed to extend until 2015, but the government's ambitions on CCS may well be finished by the time the coalition reaches 18 months in office. The remainder of 2011 will see decisions made that will set the UK on the path for either success or failure. The difference between them is stark.

Let's remind ourselves of where things stand now. When the coalition entered office in May 2010 hopes were high for UK delivery on CCS. The CCS levy had been passed with cross-party support during the final months of the Labour government, promising to deliver up to £11bn of support over the next 15 years. CCS project developers were busy drawing up plans ahead of the launch of the EU NER300 competition, subsequently providing 7 out of the total of 13 projects across the EU. The coalition government itself committed to making the UK 'first choice for investment in CCS', and pledged to deliver funding for four UK projects together with a raft of other measures.

But now, in Autumn 2011, things are not nearly so rosy. While the headline commitments to CCS still remain, and individual wins have been secured, the credibility and coherence of the government's position overall is much reduced. Let's look at some of the key areas in turn.

Box 1 - What to do about Demo 1?

The future of 'Demo 1' itself further complicates this picture. The Scottish Power project at Longannet has been the sole survivor of a process that has operated more by attrition than competition. Negotiations are still ongoing as to the potential level of government support that could be available for the project, but it is no secret that these discussions are difficult. With parent company Iberdrola also seeming to have concerns about taking on a CCS project at the only coal power plant in its international portfolio there is a real risk that the whole negotiation could fail. This would be a disappointment, but not a mortal blow. The initial process of selecting CCS projects was always going to flush out problems as well as solutions, so UK delivery needs to be judged on the strength of its programme overall, not just on individual projects. The negotiators need to continue their efforts: if they succeed, then great, we'll finally have the UK's first full scale CCS project. But if a deal cannot be reached then all is not lost. Any monies committed so far to demo 1 should be recycled into the rest of the demo programme and used to supplement NER300 funding.

Funding and launching the UK demonstration programme

The biggest loss so far was the CCS levy, attacked by HM Treasury at the Comprehensive Spending Review last year, then finally killed off in the Budget of March 2011. Funding for demo 1 was maintained (see Box 1 for more details), but as a dependable forward signal to investors the loss of the levy was far more significant.

The result has been that there are no further funds available in this Comprehensive Spending Review period for UK demonstrations. The Office of CCS within DECC has therefore been trying to find alternative ways of enabling capital milestone payments to be made out of the EU's NER300 programme. This is possible within the EU's rules, as long as member state governments can guarantee to repay monies in the event that the recipient project fails. Under accounting rules, this liability has to sit somewhere within the UK government's accounts – a problem seemingly tailor-made to aid HM Treasury intransigence.

We can also add to this the fact that the UK will very soon need to be able to confirm the 'value and structure' of any additional public support for demonstration projects, in order for NER300 competition winners to be confirmed. The EU scrutiny process is due to complete in February 2012, but the UK seems to be on a much slower timetable. We are still awaiting the launch of the UK call for projects 2 to 4, which would also provide the government with criteria for judging between the 7 UK projects already bidding for EU funds.

Unless a solution is found this autumn to both the accounting problem and the co-funding arrangements for NER300 projects, then the UK risks throwing away millions of pounds in European funding. This would be a hammer blow to both the CCS industry and perceptions of UK government competence. For we must remember that the NER300 is itself a largely British creation in the first place, secured under the last government thanks to proactive diplomacy, industry engagement, and cross-party support from Liberal Democrat MEP Chris Davies and Conservative members of the European Parliament. To not take full advantage of the NER300 now would leave the UK looking ridiculous, and allow other member states to take full advantage in the absence of UK projects moving forward.

Electricity Market Reform

A big headline win for CCS was its inclusion side by side with Renewables and Nuclear Power as a technology able to receive financial support under forthcoming Contracts for Difference Feed in Tariffs. Yet the details of how this will be delivered remain much fuzzier for CCS, as indeed is the potential impact of 'capacity payments' to support the availability of additional generating capacity. Until the levels of support are known it will be difficult for CCS industry to start to scale up.

This is particularly the case in respect to the market signals coming from elsewhere in the EMR package. The government has proposed to introduce an Emissions Performance Standard that would only affect coal plant, with levels specifically grandfathered into the future, as part of its efforts to make the construction of new unabated gas plant more attractive in the short term. The risk for CCS, however, is that new gas plant would eat into the likely market for CCS plant during the 2020s, potentially crowding out CCS projects.

There is therefore a problem of coherence within the EMR package, in that although the headlines look promising for CCS, the details point in different directions.

What level of ambition?

In line with the approach taken under EMR, the government does not want to pre-determine targets for levels of CCS deployment within the electricity sector, as recently championed by the CCSA's call for 20 to 30GW of CCS by 2030. Until demonstration projects move forward the government views CCS as not yet on a par with Nuclear or Renewable technologies. There therefore appears to be a circular problem developing, with industry calling for future signals to improve investor confidence, and government asking for demonstrations before it will give

those same market signals.

The CCS industry is rightly concerned about what happens next, because without improved forward visibility of market demand it will be extremely difficult to attract private sector investment and build broader stakeholder support for CCS. It is up to government to find a way through. As so often with politics, much can be done through adopting the right tone. My suggestion would be that ministers and officials need to communicate a much more positive approach, and use the government's existing commitment to the 4th Carbon Budget period for 2023 to 2027 as a means of drawing out a range of options for CCS deployment going forward.

By focussing on the need to rise to the decarbonisation challenge, and setting out proactive policies to aid investment in CO2 transport and storage infrastructure, the government will help to facilitate the development of clusters that will bring down the future costs of CCS. The long-awaited CCS Roadmap scheduled for November 2011 provides the best opportunity to tell this future story and address existing policy barriers.

The time is now

The central conclusion to be drawn from each of these three areas is that a positive outcome for CCS is still possible, but that decisions are required on an urgent basis. The pressure is now on DECC and HMT to find a way of resolving the funding situation in order to meet the EU timetable. Similarly the details of Electricity Market Reform need to be sorted ahead of legislation entering Parliament in early 2012.

This autumn the government will further set out its views on power sector decarbonisation as it responds to the Committee on Climate Change recommendations in its Carbon Plan and Annual Energy Statement. The processes are all in place, but the political heavy lifting is still to be sorted.

If the government can get these decisions right the UK will (still) be on track. But if it gets them wrong, however, then we can wave goodbye to the development of a CCS industry in the UK in the next 5 years. Not only that, but the costs and (in)feasibility of UK power sector decarbonisation will surge. The coalition's commitment to being the 'greenest government ever' would be hanging by a thread.

But the implications of a UK failure would run far deeper and further than the government has yet acknowledged. For the UK is on the critical path for international CCS demonstration and deployment. Despite the policy struggles presently experienced, the UK offers the prospect of coherent policy for CO2 regulation, demonstration support, deployment incentives, and a decarbonisation commitment. This provides a more credible foundation for CCS than anywhere else in the world. UK demonstration projects are an integral part of the international effort to reduce costs and prove that full chain CCS can become commercially available.

That is the prize within reach. Lose it, and the questions about the future of CCS really will start to fly. For if the UK can't get CCS right, who will?

More information
www.green-alliance.org.uk

CCSA launches new UK CCS strategy

The Carbon Capture and Storage Association (CCSA) has launched a plan, "A Strategy for CCS in the UK and Beyond".

It sets out a strategy to save 100Mt of CO2 per year and sequester 500Mt per year by 2030 in the UK.

It outlines the potential of CCS to provide secure, cost-competitive, low carbon electricity as part of the portfolio of low-carbon technologies that will be needed to meet UK climate change targets.

The strategy describes the policy and regulatory framework required by industry for a smooth and strong uptake of CCS, which the CCSA says could create a market worth £10bn/year to UK plc by 2025, with more than 50,000 quality jobs by 2030.

Key highlights and recommendations of the report include:

- A clear framework for maintaining the momentum of the CCS Demonstration Programme and enabling a 'Progressive Roll-Out', with a steadily increasing build rate from 1GW in 2018 to 3GW per year in 2030 and beyond;
- Up to 30GW of power station capacity equipped with CCS by 2030;
- The need to urgently launch CCS demonstration in the industrial sector;
- Proposals for the early planning, development and deployment of CCS infrastructure, optimized for the long-term CCS industry, which could create cost and operational efficiencies going forward;
- Analysis of further important factors to facilitate roll out, including: regulatory barriers, R&D, and political and public perception.

The UK government is due to publish its own CCS Roadmap on 17 November 2011.

"CCS is a vital low-carbon technology for the UK," said Jeff Chapman, Chief Executive of the CCSA. "It is recognised by the Government as one of the three key technologies (alongside nuclear and renewables) to reach a near-decarbonisation of the electricity sector by 2030 – which will be imperative if we are to meet our longer-term climate change targets. The UK is currently proposing a reform of the electricity market and estimates that we will need 70GW of generation to meet 2030 electricity demand. It is therefore imperative that we move towards 20-30 GW of CCS by 2030, if we are to reach these goals."

"We are very positive about the future of CCS in the UK. It is an important time for the industry, as investors await the certainty they need to deliver this step-change in our energy future. We are confident that Government appreciates how crucial it is that the right decisions are made (and made on time) regarding the structure and pace of the deployment programme, funding mechanisms ,and transport and storage infrastructure, – to enable the long-term CCS industry to take shape."

"In addition to the benefits of providing low-carbon electricity, CCS has huge related potential for investment, jobs, and growth. CCS is fundamental to the decarbonisation of many core energy-intensive industries, currently struggling to remain competitive in the UK against the rising costs of energy and CO2 reduction."

"To lock in these benefits, and meet our emissions targets, we need 20-30GW of power plant with CCS in operation by 2030. This is the industry's plan to make that happen."

More information
www.ccsassociation.org.uk

Policy, company and regulation news

ETI to invest £23.5m in project with Costain

www.energytechnologies.co.uk

The UK Energy Technologies Institute (ETI) has announced that it will invest £23.5 million in a project to develop new carbon capture technology.

The ETI is working with Costain to deliver a project which will see a carbon capture pilot plant capable of capturing up to 95% of carbon dioxide emissions designed, built, operated and tested by the middle of 2015.

The ETI investment means it has now announced more than £100m of projects in offshore wind, marine, distributed energy, buildings, energy storage and distribution, transport and bio energy as well as CCS since it was formed in 2008. The project will be aimed at pre-combustion carbon capture applications, involving CO2 removal by physical separation and will be split into two parts.

The first lasting 16 months and costing £3.5m will provide the front end engineering design for the demonstration unit. Costain will work with the University of Edinburgh, and Imperial College, London on the first stage, to help understand and optimise performance of the technology.

The ETI expects to invest £20m in the second stage, as the pilot plant is built, demonstrated and the results analysed. Demonstration is a key element to building user group confidence in the capture element. A potential site has been identified for the pilot plant, and will be reviewed and ranked against other options and then confirmed during the first stage of the project.

"The ETI's Energy System Model has shown that around a third of the UK's electricity could be generated from coal, gas, biomass or hydrogen turbines fitted with CCS by 2050," - Dr David Clarke, ETI Chief Executive

ETI launches project to support UK CCS

The UK Energy Technologies Institute (ETI) has launched a £3m project that will help support the future design, operation and roll-out of cost effective CCS systems in the UK.

The two-and-a-half year project will create a modelling tool-kit capable of simulating the operation of all aspects of the CCS chain, from capture and transport to storage.

It will involve modelling technology provider Process System Enterprise, energy consultancy E4tech, and industrial partners EDF Energy, E.ON, Rolls-Royce and Petrofac, who expect to be involved in capturing, compressing, transporting and storing CO2 in the future. The project is intended to result in a commercial modelling environment built on PSE's gPROMS modelling platform.

The CCS System Modelling Tool-kit will be used to support the initial conceptual design and eventual detailed design and operation of CCS systems by helping to identify and understand system-wide operational issues such as the effects of power station ramp-up or ramp-down on downstream storage operation, or the effect of downstream disturbances on power generation.

It will benefit owners or developers of power stations who need to know the effect of CCS on their operations, future transport and storage operators and technology suppliers who will want to understand future requirements for their equipment. It will also provide policy makers with a powerful support tool to help with decisions related to overall CCS operation.

"The ETI's Energy System Model has shown that around a third of the UK's electricity could be generated from coal, gas, biomass or hydrogen turbines fitted with CCS by 2050," said Dr David Clarke, ETI Chief Executive.

"CCS infrastructure is complex and will need to be rolled out rapidly to meet those targets and our CCS Modelling project will play a crucial role in ensuring a practical, cost effective and robust network of assets.

"Without it, there is a risk of problems occurring as poorly optimised systems are developed and commissioned.

"The ETI project brings together stakeholders from the whole CCS chain from power station to storage, with a world-leading UK technology company providing the modelling know-how and software platform. It will help inform decisions at all levels, from strategic planning and system design to plant operation and maintenance."

"System-wide modelling is essential for understanding the interactions and trade-offs between components up and down the CCS chain," added Costas Pantelides, PSE MD and chief architect of the new modelling tool-kit.

"The end-to-end modelling tool that we are developing will support the optimal design and operation both of the individual components and of the overall system. It will also provide a coherent and open software framework within which other current and future industrial and academic developments for the model-based engineering of CCS chains may be incorporated."

The ETI has already announced £29m worth of CCS projects, including a next generation capture demonstration project led by Costain and an appraisal of the UK's potential storage sites led by Senergy.

The ETI is also commissioning a project to develop and demonstrate cheaper carbon capture technologies specifically for gas fired power stations. An announcement on who will carry out the work on this project is expected in early 2012.

Alberta government agrees funding for Swan Hills project

www.energy.alberta.ca

The Government of Alberta and Swan Hills Synfuels have signed a final funding agreement for a CCS project that will capture carbon dioxide from a deep coal gasification process.

The province has committed $285 million to the Swan Hills Synfuels project as part of its $2 billion CCS funding program. Construction is expected to begin in 2013 with carbon capture beginning in late 2015.

The in-situ coal gasification project will tap into a deep, unmineable coalbed near Swan Hills and turn the coal into a synthetic gas or "syngas" while underground. The syngas will then be used to generate electricity. The project will also capture up to 1.3 million tonnes of CO2 per year that will be used for enhanced oil recovery in the area.

"The support of the province is helping to make this major energy project a reality, upgrading a low-value resource into valuable clean energy in Alberta," said Martin Lambert, Chief Executive Officer of Swan Hills Synfuels.

Energy Institute launches new CCS training course

www.energyinst.org

The Energy Institute (EI) has developed a training course covering the capture, storage and transport of CO2, whilst assessing the technical and safety requirements along the chain.

Participants will understand the characteristics of CO2, the challenges involved, and the lifecycle management of CO2 storage sites, the EI says.

The training has been developed to support the technical work programme undertaken by the EI over the past four years. Working with the Health and Safety Executive (UK), the Carbon Capture and Storage Association and the Global Carbon Capture and Storage Institute, the EI offers a platform bringing relevant companies together to discuss issues surrounding the implementation of the associated technology with both a global and domestic outlook.

Learning from stakeholder events, meetings and investigations, the EI has published guidance based on this combined industry knowledge and experience for the benefit of the future development of CCS. This has resulted in the following technical publications:

- Good plant design and operation for onshore carbon capture installations and onshore pipelines

- Technical guidance on hazard analysis for onshore carbon capture installations and onshore pipelines

The Energy Institute (EI) is the leading chartered professional membership body for the international energy industry.

Illinois CCS demonstration begins construction

www.fossil.energy.gov

Construction activities have begun at an Illinois ethanol plant that will demonstrate carbon capture and storage.

The project, sponsored by the U.S. Department of Energy's Office of Fossil Energy, is the first large-scale integrated carbon capture and storage (CCS) demonstration project funded by the American Recovery and Reinvestment Act (ARRA) to move into the construction phase.

Led by the Archer Daniels Midland Company (ADM), a member of DOE's Midwest Geological Sequestration Consortium, the Illinois-ICCS project is designed to sequester approximately 2,500 metric tons of carbon dioxide (CO2) per day in the saline Mount Simon Sandstone formation at depths of approximately 7,000 feet. Researchers estimate that the sandstone formation can potentially store billions of tons of CO2 and has the overall potential to sequester all of the more than 250 million tons of CO2 produced each year by industry in the Illinois Basin region.

The injected CO2 will come from the byproduct from processing corn into fuel-grade ethanol at ADM's biofuels plant adjacent to the storage site in Decatur, Illinois. Because all of the captured CO2 is produced from biologic fermentation, a significant feature of the project is its "negative carbon footprint," meaning that the sequestration results in a net reduction of atmospheric CO2.

The Office of Fossil Energy's National Energy Technology Laboratory manages the Illinois-ICCS project, which receives $141.4 million in ARRA funding and another $66.5 million private sector cost-sharing. Since ADM does not presently have a locally feasible CO2 re-utilization option, such as enhanced oil recovery, the federal funding offsets potential technical and economic risks and provides an opportunity for ADM and its partners to gather crucial scientific and engineering data in advance of carbon capture requirements.

The Illinois-ICCS project includes the design, construction, and demonstration of a CO2 compression and dehydration facility as a precursor to CO2 storage and subsequent monitoring, verification, and accounting of the stored CO2. The operations phase of the project—capture and storage of the CO2—is expected to begin in late summer 2013. The operations phase will create approximately 260 jobs and add to an understanding of long-term CO2 storage in saline formations.

The Illinois-ICCS project is designed to sequester approximately 2,500 metric tons of carbon dioxide per day in the saline Mount Simon Sandstone formation (Photo: NETL)

Integral to the project will be the formation of an educational and training facility, the National Sequestration Education Center, slated to be housed at nearby Richland Community College in Decatur. The center will contain classrooms, training, and laboratory facilities, and it will offer students associate degrees in sequestration technology.

Global CCS Institute opens Japan office

www.globalccsinstitute.com

The GCCSI has opened an office in Tokyo headed by a senior energy and climate change expert.

Morikuni Makino, the new Global CCS Institute General Manager-Japan, has had a long career with METI and across the areas of energy, science, technology and innovation.

The Global CCS Institute has more than 300 members, 30 of whom are Japanese.

Japan's Ministry of Economy, Trade and Industry (METI) Director General for Energy and Environmental Policy, Hiroshi Asahi said,

"The Institute's presence here highlights that Japan has become a key player in CCS technology development around the world. We are proud to be leaders in the development of these technologies, which will help significantly reduce global greenhouse gas emissions."

Diesel from CTL with carbon capture at a cost of $53 / barrel

UK company Altona Energy believes it can supply vehicle ready diesel at $53 a barrel (33¢ a litre), with a coal to liquids plant, incorporating carbon capture for underground carbon storage, with financial support from China. It has a site for a coal mine 800km North of Adelaide where the conversion of coal to liquids plant will also be located

Altona Energy of the UK has plans to develop a coal mine, coal to liquids plant, carbon storage and electricity generating plant on a site 800km North of Adelaide, Australia.

With financial support from China National Offshore Oil Corporation (CNOOC), it believes it can provide road ready diesel at $0.33 a litre.

The coal to liquids process is often considered a dirty way to create vehicle fuels, because carbon dioxide is emitted into the atmosphere both in the coal processing plant and from the vehicle.

But if the carbon dioxide from the coal processing plant is sequestered (buried underground), then the overall carbon emissions are just the same as for traditional motor fuels, but with the added benefit of much lower emissions of other pollutants (SOX, NOX, particulates), because they are removed in the processing plant, rather than coming out of the vehicle's exhaust.

So far, Altona has conducted an initial, or "pre-feasibility" study, by engineering giant Jacobs Engineering. Now, at CNOOC's expense, it has embarked on a far more comprehensive study, known as a "bankable feasibility study", or in other words a study so thorough a bank can lend money on the results. This study will cost Aus$440m (US$415m) and will be primarily completed in 2012 or early 2013.

Coal to liquids

In the coal gasification process, coal is reacted with oxygen and steam. The carbon in the coal is oxidised, ending up with a mixture of carbon dioxide, carbon monoxide, water vapour and hydrogen.

The carbon dioxide is separated out, dehydrated, compressed and is ready to be sent to the carbon storage system. The hydrogen and carbon monoxide are sent to the Fischer Tropsch plant, where they are processed to form a liquid hydrocarbon which is then refined to produce diesel naptha.

If carbon storage is incorporated, running vehicles from synthetic fuels is arguably more environmentally friendly than conventional transport fuels. The carbon emissions from the vehicle itself are the same, but all of the impurities (for example sulphur) can be removed in the processing plant, not through the vehicle's exhaust. There are lower particulates in the emissions (small particles of unburnt carbon / soot), and less NOX emissions and also zero aromatics such as benzene.

Synthetic fuels are also 10 per cent lighter (in mass per kilojoule) than conventional fuels for the same energy content. This makes a big difference when putting them in aeroplanes – because it means that the plane can go 10 per cent further distance for the same mass of fuel.

The process to converting coal to liquid fuels on an industrial scale was first done in Germany, to provide liquid fuels for German equipment in World War 2. It was then further developed by SASOL in South Africa to provide liquid fuels during the apartheid era, when sanctions prevented delivery of oil tankers.

Currently coal-to-liquids is enjoying a resurgence due to high oil prices, the need to create a diversity of supply, and reduce risk of supply concerns. There are coal gasification projects underway in the US, UK, China, South Africa and South Korea.

Jet fuels produced by the coal-to-liquids process have been provided to airlines refuelling at Johannesburg and Cape Town since 1998, in a 50:50 mix (synthetic and kerosene).

In 2008, 100 per cent synthetic fuel was approved for aviation, and has been used since 2009 by Qatar Airways on its London to Doha route, sourced from Shell's Pearl gas to liquids project in Qatar, for the production of synfuels using Sasol technology.

In 2010, total worldwide synthetic fuels plants in operation exceeded 330,000 barrels per day, with an extra 270,000 barrels of oil per day plants expected to be operational in 2011, with US Air Force expected to complete 100 per cent certification of its whole fleet to use synthetic fuels blend, Altona says.

By 2030, the US Department of Energy has predicted that synthetic fuels consumption will be over 3m bopd, if sour crude oil price is over $57 a barrel.

It is therefore possible that coal to liquids could create a more viable financial pathway for carbon capture, or 'clean coal', than just using coal to make electricity.

If coal is used to make electricity, then investors and the public are faced with a simple charge for the carbon capture – do they want to pay around 20% more for electricity or not? Since many people care far more about their bank balances than they do about their carbon emissions, this could be a tough sell. (However the risk of price escalation of LNG, which is used in thermal power stations, as a lower carbon alternative to coal, is eliminated).

But if the coal is used to make a liquid fuel, then the public gets the option of liquid fuels for their vehicles which are cleaner and cheaper than conventional fuels. If the carbon dioxide from the coal processing is sequestered, then there are no objections about use of synfuels produced from coal.

Altona's project

Altona's project in the state of South Australia is known as the "Arckaringa" project, because Arckaringa is the name of the coal basin.

The amount of mine-able coal in the basin has been estimated at 7.8bn tonnes, and this has already been verified as part of a detailed AU$440m study of the project, currently being conducted by CNOOC (see below).

The coal basin has been studied by geologists for decades, although previously there has not been any mine on the site due to techno-economics. Altona Energy has acquired rights to build an open cast mine on the site.

A railway line has been built in the past few years which passes through the basin, connecting Adelaide with Darwin, which could be used to transport coal or liquid fuels from the region.

Altona plans to mine 15m tonnes of coal a year. If the total resource is 7.8bn tonnes, this means the mine can operate for 520 years.

It will build a coal to liquids plant which will convert this coal to 10m barrels

of diesel a year (equivalent to a 27,000 barrels of oil per day well).

It will also build a power station to provide the power necessary to operate the facilities as well as being able to export 560 MW into the grid.

The power supply will come in handy – South Australia currently has 2 power stations with total output of 750mW, and the region actually uses 3.5 gigawatts. There is an estimated electricity deficit of 1 GW for the region being forecast, says Altona's finance director Anthony Samaha. Being able to supply baseload power has helped get the Australian government's support for the project, he says.

Once the plant is built, the syngas production (hydrogen and carbon monoxide mixture) can be varied to the electricity generating plant, or the coal to liquids plant, according to the demands (and pricing) of the day.

To illustrate the importance of the project, the Arckaringa UEJV (Unincorporated Evaluation Joint Venture Agreement) - signed in June 21 2010 in Canberra, in the presence of the VP of China Xi Jinping, prime minister of Australia Kevin Rudd, President of CNOOC Fu Chengyu and Minister for Trade and industry South Australia Tom Koutsantonis.

"Arckaringa is a project as important to South Australia as North Dome (the world's largest gas field) is to Qatar," says Peter Fagiano, executive director of Altona. Arckaringa has been described as "one of the world's largest untapped energy banks," he says.

Altona also plans to build a plant which will react carbon dioxide with hydrogen to form fuel grade methanol, which can be added to the local gasoline pool.

The gasification technology can be used to gasify biomass (for example, wood) as well as coal. This means that you could build a system which can actually take carbon dioxide out of the atmosphere and make electricity or liquid fuels at the same time. You grow trees to absorb the carbon dioxide, gasifying the biomass, and separating the resulting hydrogen and carbon dioxide, sequestering the carbon dioxide and using the hydrogen to make electricity or liquid fuels.

It can also gasify black liquor, a by-product from the paper and pulp industry – as well as sewage and municipal waste.

The gasification processing technology can make a range of plastics as well as liquid fuels, by the conversion of syngas into methanol, which can then be converted into olefins and finally polypropylene.

The plan is to store the carbon in an underground aquifer near the site, about 150km away, so the carbon dioxide can be transported by pipeline to the site.

The region is very low population (desert), so the company does not anticipate public concerns about underground carbon storage, as there have been in other countries which are densely populated.

Study

So far a 2008 "pre-feasibility" study of the project has been made by US engineering giant Jacobs Engineering, which developed the design of the coal to liquids plant, which is estimated to have a refinery gate cost of $0.33¢ per litre (or $53/barrel) for diesel.

The $53 per barrel includes the cost of capital expenditure. Operating costs only are $38 per barrel.

According to the initial "pre-feasibility" study, the plant (including coal gasification, coal to liquids plant, IGCC power plant and carbon storage) will cost $3bn to build, and the coal mine $500m.

Now, CNOOC is financing a full scale feasibility study into the project, with a cost of AU$440m (US$ 415m), and has been given a 51 per cent stake in Arckaringa coal asset in return.

Currently a CNOOC team based in Adelaide is looking at the mine and CNOOC in Beijing is looking at coal to liquids plant development.

The study is known as a "bankable feasibility study" – in other words, the level of detail should be sufficient enough for a commercial bank to lend money based on the results.

Altona's full scale financial evaluation is based on costs of the 4th quarter of 2010. The re-evaluation of the coal resource by CNOOC and Chinese institutions was completed in Q1 2011, including the quantity and quality of coal. Now CNOOC's consultants are evaluating the plant project design.

Altona Energy

Altona Energy has been listed on the UK's Alternative Investment Market (AIM) since 2006.

Altona Energy is 20.1 per cent owned by Tonjiang International Energy Co Ltd, a company whose CEO is Zheng Qiang, previously management at China Economic Commission, China Rare Earth office of the State Council Rare Earth Leading Group of the State Planning Commission. Mr Zheng introduced Altona to CNOOC and is also a non executive director of Altona.

UK investment company Investco Perpetual has a 17 per cent stake in Altona.

If the coal to liquids plant goes ahead, CNOOC can increase its interest in the overall project up to 70 per cent, with Altona owning 30 per cent. (CNOOC owns half of Arckaringa project licenses, so CNOOC would effectively own 85 per cent of the project). CNOOC would also provide debt finance for the whole project, including its own equity, leaving Altona needing to raise 15 per cent of the project costs.

Peter Fagiano, executive director of Altona, was previously director of operations for the process and technology division at Jacobs Engineering UK Limited. Parent company Jacobs Engineering is one of the world's largest project engineering firms. Mr Fagiano was also previously managing director of ABB Global Engineering UK & International Oil and Engineering Division.

Altona is the only coal to liquid company on the UK's Alternative Investment Market (AIM).

By buying a stake in Altona Energy, you also get a share of other projects the company might get involved with, with lots of possibilities for projects within China itself, says Altona's finance director Anthony Samaha.

Capture news

Codexis reports enzyme carbon capture developments

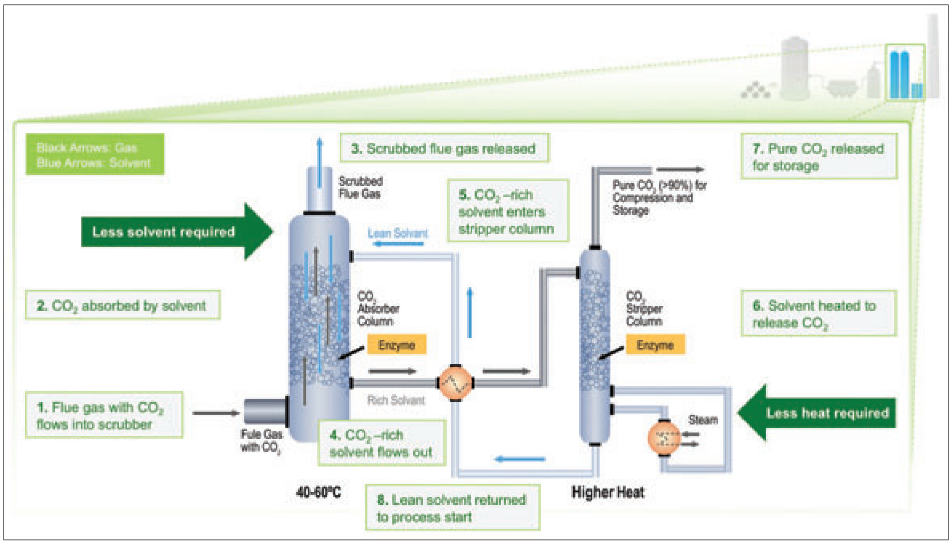
www.codexis.com

Data showed that the performance of its engineered enzymes has been improved by about two million fold over natural forms of the enzyme.

Its work is supported by a grant from the DOE's ARPA-E Recovery Act program and is jointly developed with CO2 Solution, Canada. The research program is based on development of customized carbonic anhydrase (CA) enzymes that could catalyze carbon capture under industrial conditions.

Evolved CA enzymes are functional and stable in relatively inexpensive, energy efficient solvents for 24 hours at temperatures greater than 90 degrees C, the company said.

Codexis presented the results at a CO2 Capture Technology Meeting being sponsored by the U.S. Department of Energy/National Energy Technology Laboratory in Pittsburgh.



Codexis CA enzymes can be used to capture CO2 under industrial conditions

U.S. DOE invests $41m in 16 post combustion projects

www.fossil.energy.gov

The U.S. Department of Energy has selected 16 projects aimed at developing advanced post-combustion technologies for capturing CO2 from coal–fired power plants.

The projects, valued at $41 million over three years, are focused on reducing the energy and cost penalties associated with applying currently available carbon capture technologies to existing and new power plants.

The selections will focus on developing carbon capture technologies that can achieve at least 90 percent CO2 removal and reduce the added costs at power plants with carbon capture systems to no more than a 35 percent increase in the cost of electricity produced at the plant. The Obama Administration has made a goal of developing cost-effective deployment of carbon capture, utilization and storage technologies within 10 years, with an objective of bringing 5 to 10 commercial demonstration projects online by 2016, the DOE says.

"Charting a path toward clean coal is essential to achieving our goals of providing clean energy, creating American jobs, and reducing greenhouse gas emissions. It will also help position the United States as a leader in the global clean energy race," said U.S. Energy Secretary Steven Chu.

Existing CO2 capture technologies are not efficient when considered in the context of large power plants.Current CO2 capture systems require large amounts of energy for their operation, resulting in decreased efficiency and reduced net power output when compared to plants operating without these technologies. The net electricity produced could be significantly reduced - often referred to as parasitic loss - since 20 to 30 percent of the power generated by the plant would have to be used to capture and compress the CO2.

The goal of the research is to reduce the energy penalty with carbon capture and sequestration technologies, thereby reducing costs and helping to move the technology closer to widespread use. Post combustion CO2 capture can be applied to both new and existing plants by adding a "filter" for CO2 that can take the form of membranes, solvents or sorbents.

DOE invests in advanced CO2 capture research

Four projects aimed at reducing the energy and cost penalties of advanced carbon capture systems applied to power plants have been selected for further development by the U.S. Department of Energy's Office of Fossil Energy (FE).

Valued at approximately $67 million (including $15 million in non-federal cost sharing) over four years, the overall goal of the research is to develop CO2 capture and separation technologies that can achieve at least 90 percent CO2 removal at no more than a 35 percent increase in the cost of electricity. This would represent a significant improvement over projected increases in electricity costs using existing technologies.

Existing carbon capture systems currently require large amounts of energy for their operation, resulting in decreased efficiency and reduced net power output when compared to plants without CCUS technology. These penalties can add as much as 80 percent to the cost of electricity for a new pulverized coal plant

The projects focus on slipstream-scale development (0.5 to 5 MWe) and testing of advanced solvent-based post-combustion CO2 capture technologies.

Rotterdam project releases first knowledge sharing report

www.globalccsinstitute.com

The ROAD CCS project has released a knowledge sharing document on CO2 capture technology selection.

ROAD stands for 'Rotterdam Opslag en Afvang Demonstratieproject' (Rotterdam Capture and Storage Demonstration Project) and is one of the largest integrated demonstration projects in the world for the capture and storage of CO2.

In the report, the selection methodology developed by the ROAD project team is described and evaluated, starting with the request for proposal for preliminary studies and ending with the final selection of the capture plant supplier. The report aims to help other CCS projects using post-combustion capture technology to design their own capture plant supplier selection methodology.

It is the first in a series of seven reports. Other knowledge sharing reports and case studies to be released in the coming months will cover a wide range of topics including: permitting, stakeholder consultation, commercial and funding arrangements, as well as the FEED study for the capture facility for the ROAD project.

Using CCS to improve U.S. and global energy supply security

Combining carbon capture and storage with enhanced oil recovery using CO2 injection (CO2-EOR) can help produce more oil from mature oil fields while economically sequestering CO2.

By Michael Godec, Vice President of Advanced Resources International, Inc.

The CCS-EOR combination can provide significant benefits; especially if value-added opportunities for productively using captured CO2 from industrial sources – the proverbial "low-hanging fruit" – is encouraged and pursued.

Significant expansion of oil production using CO2-EOR, both in the U.S. and globally, will require volumes of CO2 that cannot be met by natural CO2 sources alone. Thus, not only does CCS need CO2-EOR to help promote economic viability for CCS, but CO2-EOR needs CCS to ensure adequate CO2 supplies to facilitate growth in production from CO2-EOR projects. Promoting CO2 storage via CO2-EOR can provide large new revenues to federal/state treasuries and other participants in the value chain.

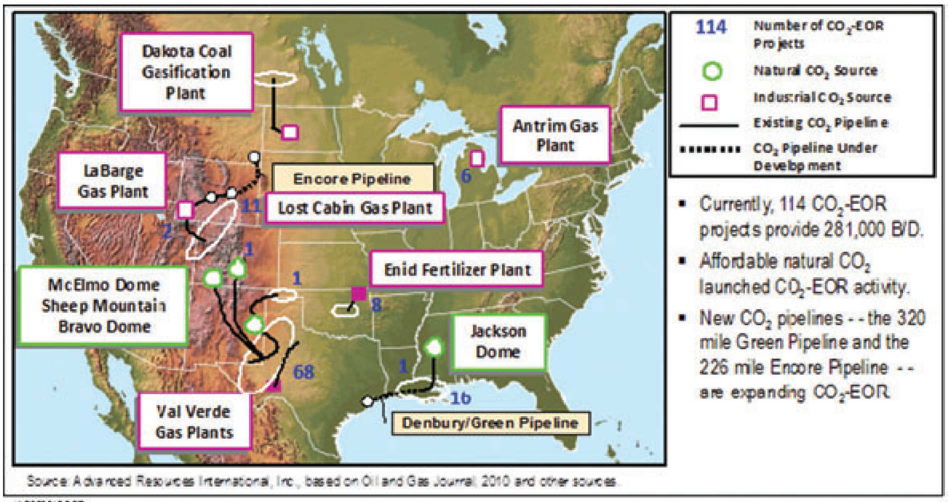


Figure 1 - Map of Major CO2-EOR Activity in the U.S.

Current CO2-EOR Activity

CO2-EOR has been demonstrated at commercial scale for over 30 years. In the U.S., 114 CO2-EOR projects provide over 281,000 barrels per day of incremental oil production (Figure 1), mostly in the Permian Basin of West Texas and Eastern New Mexico in the U.S. Production from CO2-EOR projects has been increasing in every region of the U.S., Figure 2.

Natural CO2 fields -- sources of CO2 that are high purity and low cost -- are the dominant source of CO2 for the U.S. CO2-EOR market, providing CO2 supplies amounting to an estimated 55 million metric tons per year (Table 1). Anthropogenic (industrial) sources are accounting for a steadily increasing share of this CO2 supply, currently providing 17 million metric tons per year of CO2 for EOR. The largest sources of industrial CO2 used for CO2-EOR in the U.S. are ExxonMobil's Shute Creek gas processing plant at the La Barge field in western Wyoming that provides CO2 to several fields in Wyoming and to the Rangely field in western Colorado, the Northern Great Plains Gasification plant in Beulah, North Dakota that transports CO2 via pipeline to two EOR projects in Saskatchewan, Canada, and SandRidge Energy's Century Gas treatment plant in West Texas, which is providing CO2 for Oxy's EOR projects.

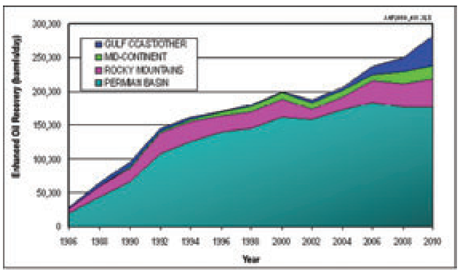


Figure 2. U.S. CO2-EOR Production (1986-2010) Source: Advanced Resources International, Inc., 2011

Limits to Expansion of CO2-EOR

Today, the main barrier to growth in CO2-EOR production, both in the U.S. and worldwide, is insufficient supplies of affordable CO2. The growth of CO2 flooding in West Texas, Wyoming, and Mississippi in the U.S.

Existing CO_2 Supplies for U.S. CO_2-EOR Operations							
State/Province (Storage Location)	Source Type (Location)	CO_2 Supply (MM tonnes/year)			CO_2 Supply (MMcfd)		
		Natural	Anthropogenic	Total	Natural	Anthropogenic	Total
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing	33	6	40	1,730	335	2,065
Colorado-Wyoming	Gas Processing (Wyoming)		7		-	340	340
Mississippi-Louisiana	Geologic (Mississippi)	21		21	1,100	-	1,100
Michigan	Ammonia Plant (Michigan)		0	0	-	15	15
Oklahoma	Fertilizer Plants (Oklahoma)		1	1	-	30	30
Saskatchewan	Coal Gasification (North Dakota)		3	3	-	150	150
Total		**55**	**17**	**71**	**2,830**	**870**	**3,700**

Table 1. Significant Volumes of Anthropogenic CO2 Are Being Injected for EOR
** Additional CO2 supplies are anticipated in 2012 from the Lost Cabin gas processing plant in Wyoming (50 to 60 MMcfd) and from Train II of the Century gas processing plant in West Texas (180 MMcfd).*
***MMcfd of CO2 can be converted to million metric tons per year by first multiplying by 365 (days per year) and then dividing by 18.9 Mcf per metric ton.*
Source: Advanced Resources Int'l (2011)

is constrained by CO2 supply, and CO2 from current supply sources is fully committed. While a number of efforts have been underway to alleviate this CO2 supply shortage, any new supplies are absorbed quickly.

In fact, the situation in Texas as resulted in "demand pull" on anthropogenic CO2 capture, where state legislative and regulatory activity has evolved to support increasing CO2 supplies from anthropogenic sources to serve the CO2-EOR market.

U.S. Potential for CO2-EOR and CO2 Storage

A recent study by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) concludes that "next generation" CO2-EOR can provide 135 billion barrels of additional technically recoverable oil in the U.S., with about half (66 billion barrels) economically recoverable at oil prices of $85 per barrel.[1]

As shown in Figure 3, technical CO2 storage capacity potential offered by CO2-EOR would equal 45 billion metric tons. Over 19 billion metric tons of CO2 will need to be purchased by CO2-EOR operators to recover the 66 billion barrels of economically recoverable oil. Of this, about 2 billion metric tons would be from natural sources and currently operating natural gas processing plants. The remainder of the CO2 demand (17 billion metric tons) would need to be provided by anthropogenic CO2. This market for captured CO2 emissions would be sufficient to store the CO2 emissions from 91 large one GW size coal-fired power plants over 30 years.

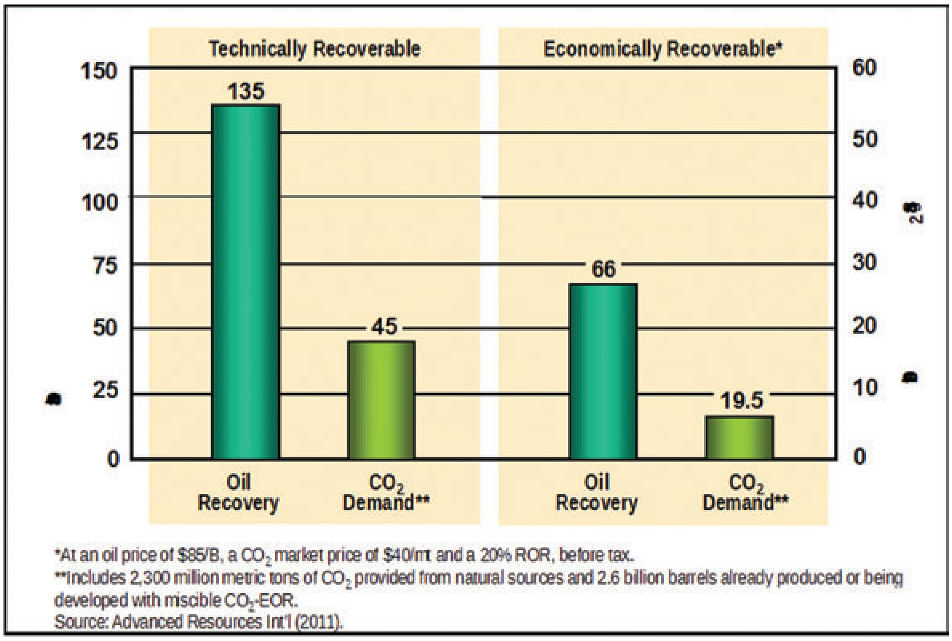


*Figure 3. Potential U.S. Oil Supplies and CO2 Demand (Storage) Volumes from "Next Generation" CO2-EOR Technology***

Region	CO_2-EOR Potential (Billion Barrels)	CO_2 Storage Potential (billion tonnes)
1. Asia Pacific	30	8
2. C. & S. America	60	20
3. Europe	28	8
4. FSU	152	42
5. Middle East/N. Africa	412	125
6. N. America/Non U.S	29	9
7. United States	121	34
8. South Asia	-	-
9. S. Africa/Antarctica	49	15
Subtotal	**881**	**261**
Add'l w/ Res. Growth	191	57
TOTAL	**1,072**	**318**

Table 2. Potential Global Oil Supplies and CO2 Demand (Storage) Volumes from the Application of CO2-EOR Technology

Global Potential for CO2-EOR

A recent study by Advanced Resources for the International Energy Agency Greenhouse Gas Program (IEA GHG)viii assessed the CO2-EOR and CO2 storage potential of the largest 54 oil basins in the world. The assessment concluded that fifty of these basins have reservoirs amenable to miscible CO2-EOR.

Assuming "state-of-the-art" technology, oil fields in just the largest discovered fields in these basins (those greater than 50 million barrels of original oil in place) have the potential to produce 470 billion barrels of additional oil, and store 140 billion metric tons of CO2. If CO2-EOR technology could also be successfully applied to smaller fields, the additional anticipated growth in reserves in discovered fields, and resources that remain in fields that are yet to be discovered, the world-wide application of CO2-EOR could recover over one trillion additional barrels, with associated CO2 storage of 320 billion metric tons, Table 2.

Current Research Activities and Plans for CO2-EOR and CCS

A number of efforts are underway to demonstrate the potential of CO2-EOR with CCS. The Global CCS Institute reports 77 joint government-industry large-scale integrated projects (LSIPs) 2 at various stages of the asset life cycle. These include eight operating projects and a four projects in the early execution phase. Of the 77 LSIPs, 34 (44%) are targeted for EOR applications. Eight of the nine executing or operating LSIPs target EOR.

Barriers to Greater CO2-EOR/CCS Implementation

As previously described, the main barrier to growth in CO2-EOR production, both in the U.S. and worldwide, is insufficient supplies of affordable CO2. Since storing CO2 in association with EOR can substantially offset some of the costs associated with CCS, it can encourage CCS application in the absence of other incentives for CCS deployment. On the other hand, significant expansion of oil production using CO2-EOR will require volumes of CO2 that cannot be met by high purity sources alone.

This is resulting in a fundamental change in the CO2-EOR project paradigm;

1. In addition to an oil price of $85 per barrel (WTI), the economic analysis assumes a CO2 market price of $40 per metric ton and a 20% return on investment, before tax.

that is, not only does CCS need CO2-EOR to help provide economic viability for CCS, but CO2-EOR needs CCS in order to ensure adequate CO2 supplies to facilitate growth in the number of and production from CO2-EOR. Therefore, critical to any significant growth in production from CO2-EOR projects will be incentives for reducing emissions.

The inability of the U.S. to pass climate legislation hinders CCS project deployment within its borders. In developing countries, controversy around CCS in the Clean Development Mechanism (CDM) has made pursuing CCS and CO2-EOR project deployment in developing countries difficult if not impossible. Without the potential incentives offered by the CDM, CO2-EOR in developing countries will only take place sporadically in niche sectors.

The Conference of Parties to the U.N. Framework Convention on Climate Change in Cancun recognized that CCS "…is a relevant technology for the attainment of the ultimate goal of the Convention and may be part of a range of potential options for mitigating greenhouse gas emissions…" and asked that specific conditions and modalities for its eligibility under the CDM be developed.

However, the storage of CO2 with CCS, especially if deployed in conjunction with CO2-EOR, still faces many challenges in order to be adopted within the CDM. As noted by de Coninck, "…debate around CCS in the CDM has developed into a highly polarised discussion, with a deep divide between proponents and opponents and no view on reconciliation between the various perspectives."

Finally, numerous regulatory and liability issues and uncertainties are currently associated with CCS that are hindering widescale deployment. These uncertainties are also hindering the pursuit of CO2-EOR with CO2 storage, particularly because of the lack of regulatory clarity regarding the process and requirements associated with the transition from EOR operations to permanent geologic storage.

Actions to Overcome Barriers to CO2-EOR/CCS Implementation

In the past few years, significant progress has been made on the development of such legal and regulatory frameworks, most notably in Australia, the European Union and the United States. Based on this progress, the International Energy Agency (IEA) published its Carbon Capture and Storage Legal and Regulatory Review to provide a knowledge-sharing forum to support national-level CCS regulatory development, as well as its Carbon Capture and Storage Model Regulatory Framework, which seeks to assist governments to develop appropriate frameworks by drawing on CCS regulatory frameworks already in place.

Revenue Recipient	Value Chain Function	Revenues	
		Per Barrel ($)	TOTAL ($ billion)
1. Federal/State Treasuries	Severance/Income Taxes	$21.20	$1,400
2. Power/Industrial Companies	Sale of Captured CO_2 Emissions	$10.80	$710
3. Oil Industry	Return of/on Capital	$19.50	$1,280
4. Other	Mineral Rights	$7.70	$510
5. U.S. Economy	Services, Materials and Sale of CO_2	$25.80	$1,700
	Total	**$85.00**	**$5,600**

Table 3 - Revenue streams from CO2-EOR

In the U.S., on July, 12, 2011, the National Enhanced Oil Recovery Initiative was launched, aimed at increasing the supply of U.S. oil produced through CO2-EOR. Facilitated by the Great Plains Institute and the Pew Center on Global Climate Change, the Initiative will develop recommendations for policymakers on how to ramp up CO2-EOR to improve U.S. energy security, create economic opportunities, support high-paying jobs, and reduce GHG emissions.

Finally, again in the U.S., on June 20, 2011, Senator Dick Lugar introduced his Practical Energy Plan. In Section 101 of this plan, a series of initiatives are proposed to expand U.S. oil production and facilitate CO2 storage via CO2-EOR.

The benefits associated with overcoming these barriers are unquestionable. CO2-EOR can provide large new revenues to federal/state treasuries and other participants in the value chain. In the U.S., for example, assuming an oil price of $85 per barrel (WTI) and a CO2 market price of $40 per metric ton, recovery of 65.8 billion barrels would result in $5.6 trillion of new domestic revenues and economic activity accruing to the participants in the CO2-EOR value chain, with the allocation shown in Table 3 and summarized below:

Federal/State treasuries would be a large beneficiary, receiving $21.20 per barrel in the form of severance, ad valorem and corporate income taxes, amounting to total revenues of $1,400 billion.

Electric power and other industrial companies would receive $10.80 per barrel from the sale of CO2, with total revenues of $710 billion.

The U.S. oil industry would receive $19.50 per barrel for return of and return on capital investment. Private mineral owners would receive the remainder of the proceeds, equal to $7.70 per barrel.

The general U.S. economy would be the largest beneficiary, receiving $25.80 per barrel in the form of wages and material purchases. Total revenues would equal $1,700 billion.

Conclusion

The economics of CCS can clearly benefit by combining with CO2-EOR. The revenues (and cost avoidance) from sale of CO2 to CO2-EOR (combined with other policies) can help make CCS economically feasible, overcomes some barriers to CCS, while producing oil with a lower CO2 emissions "footprint." In addition, CO2-EOR can provide large new revenues to federal/state treasuries and other participants in the value chain.

In addition, CO2-EOR needs CCS. Large-scale implementation of CO2-EOR is dependent on growing CO2 supplies from industrial sources. The result is that CO2-EOR can offer large amounts of potential CO2 storage capacity. CO2-EOR in oil fields can accommodate a major portion of the CO2 captured from industrial facilities for the next 30 years.

However, both CCS and CO2-EOR need supportive policies and actions. Supportive policies and pre-built CO2 pipelines would greatly accelerate the integrated use of CO2-EOR and CCS.

More information

Mr. Godec has twenty years of experience in supporting the policy, planning, market analysis, and evaluation missions of both public and private sector organizations.

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CO2 dehydration for pipeline safety

Failing to dehydrate carbon dioxide, for most applications, can result in the costly formation of hydrates and the very rapid corrosion of normal pipe. Wayne McKay at U.S. company Gas Liquids Engineering Ltd. explains DexPro, their patent-pending gas dehydration method.

Several options are available for dehydrating carbon dioxide but the traditional methods come with their individual drawbacks.

Is there a "better" way of dehydrating carbon dioxide? Yes there is, and here is what it looks like compared to the traditional methods:

- Lower Capital Cost
- Lower Operating Cost
- Much Smaller Physical Footprint
- Simpler, no Rotating Equipment
- No Chemicals
- Smaller Environmental Footprint

Before you look at how the various methods measure up, you first need to establish how much dehydration is required, and why.

Why?

Hydrates and internal corrosion create safety and economic project risks. Since water is the common factor to both, dehydration is an obvious risk mitigation tool.

Carbon dioxide (as well as other acid gases) reacts with water to produce an acidic aqueous phase resulting in the corrosion of conventional carbon steel materials.

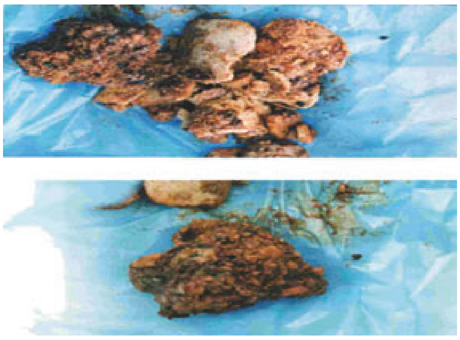

Figure 1 - typical natural gas hydrate

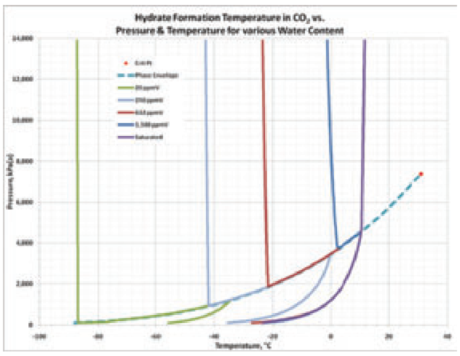

Figure 2 - Hydrate Formation Temperature in CO2

Carbon dioxide (as well as many other acid gases) when combined with water can produce a hydrate at relatively high temperatures, 10°C (50°F) or higher.

Corrosion can be managed through careful selection of metallurgy. Hydrate formation can be managed through continuous chemical addition, assuming the chemicals are compatible with the final end use. Both solutions have significant cost implications. Removal of some of the water is often the best choice for most applications.

How Much is Enough?

Like many situations in nature, removing some of the water is relatively easy but each incremental amount of water removed is more difficult and costly to remove than the previous. The main question then becomes, "How much dehydration is required?"

The "one size fits all" water content criteria in Europe is typically 500 ppmV (23.7 lb. per MMscf) and is 30 lb. per MMscf (632 ppmV) in North America.

Knowing the end use and the local ambient conditions is essential to establishing the water content design criteria. The requirement for food grade carbon dioxide is significantly different than the requirement for onsite sequestration in Texas. It will be different again for an application in the North Sea or for an above ground pipeline in the Arctic. Applying the "one size fits all" water content criteria blindly to all applications can result in problems.

Some of the things that should be considered in establishing the water content design criteria:

- Contractual and end use restrictions
- Ambient conditions
- System configuration
- Consequences of a pipeline failure on operation and safety
- Variations in pressure and temperature during normal operation, stand by, and shut in
- Variations in pressure and temperature during upset conditions
- Variations in fluid composition
- Reliability, availability, and performance of dehydration process equipment

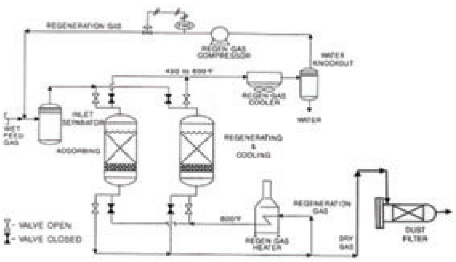

Figure 3 - Typical Molecular Sieve Schematic

How?

Dehydration methods can be placed into three categories:

- Mechanical
- Desiccant
- Thermodynamic

Mechanical separation processes, such as membranes, have not yet proven to be broadly economically viable as a standalone method. Advances continue to be made in that area and one option may be to use this technology in a preliminary separation function to reduce the loading on one of the other methods.

Desiccant technology can be separated into two categories, adsorption and absorption. The adsorption group includes molecular sieves, silica gel, carbon bed and other dry materials. Water content levels of about 10 ppmV (~0.5 lb per MMscf) are achievable.

Absorption includes solids, such as calcium chloride, and liquids such as glycol and glycerol. A water content down to about 100 ppmV (~5 lb. per MMscf) is typically achievable.

Thermodynamic dehydration can be accomplished using increased pressure, decreased temperature, or both, when carbon dioxide is in a vapour state.

At increased pressures, the saturated water content of carbon dioxide is decreased. Since compression is typically required in the transportation of carbon dioxide, it is the most obvious primary weapon in the carbon dioxide dehydration arsenal. For example, water saturated carbon dioxide might contain 84,200 ppmV (~4,000 lb. per MMscf) of water at the compressor inlet. Depending upon the inter-stage cooling temperature, a significant amount of water is removed in the inter-stage separators and the final vapour stage of compression may only contain about 3,500 ppmV (~166 lb. per MMscf). Water content levels of 1,500 - 3,600 ppmV (70 - 170 lb. per MMscf) may be achievable through compression alone.

Decreasing the temperature reduces the

water content of saturated carbon dioxide. For example, saturated carbon dioxide at 2,800 kPaa (~400 psia) might contain 4,200 ppmV (~200 lb. per MMscf) of water at 43°C (~110°F) but will contain less than 10% of that amount, about 400 ppmV (~19 lb. per MMscf), at 4°C (~39°F). Depending upon the inter-stage pressures, a water content of about 350 ppmV (~16 lb. per MMscf) is achievable with supplemental cooling during compression.

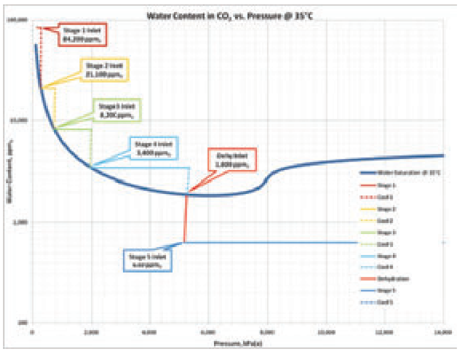

Figure 4 - Water Capacity vs. Pressure @ 35°C

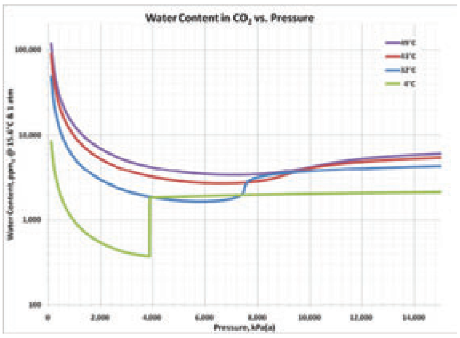

Figure 5 - Water Capacity vs. Temperature

Comparison

For comparison, consider 1,000 tons (907 tonnes) per day of carbon dioxide compressed from 40 kPag (~6 psig) to 13,800 kPag (~2,000 psig) with necessary dehydration to meet 632 ppmV (30 lb. per MMscf) water content specification.

At 49°C (~120°F), the inlet vapour contains about 84,200 ppmV (~4,000 lb. per MMscf) of water. Assuming inter-stage cooling to 41°C (~106°F), compression alone reduces the final saturation water content to about 2,800 ppmV (~133 lb. per MMscf). To meet the water content specification, an additional 2,170 ppmV (~103 lb. per MMscf) of water removal is required through some additional dehydration process.

Initial screening eliminates adsorption (molecular sieve) due to its high capital and operating cost for this relatively moderate water content requirement. Mechanical separation (membrane) will also be dropped leaving absorption (glycol) and two thermodynamic (cooling) methods: external refrigeration and a simple internal, or auto-refrigeration process, DexPro™, using the natural refrigeration properties of the carbon dioxide itself.

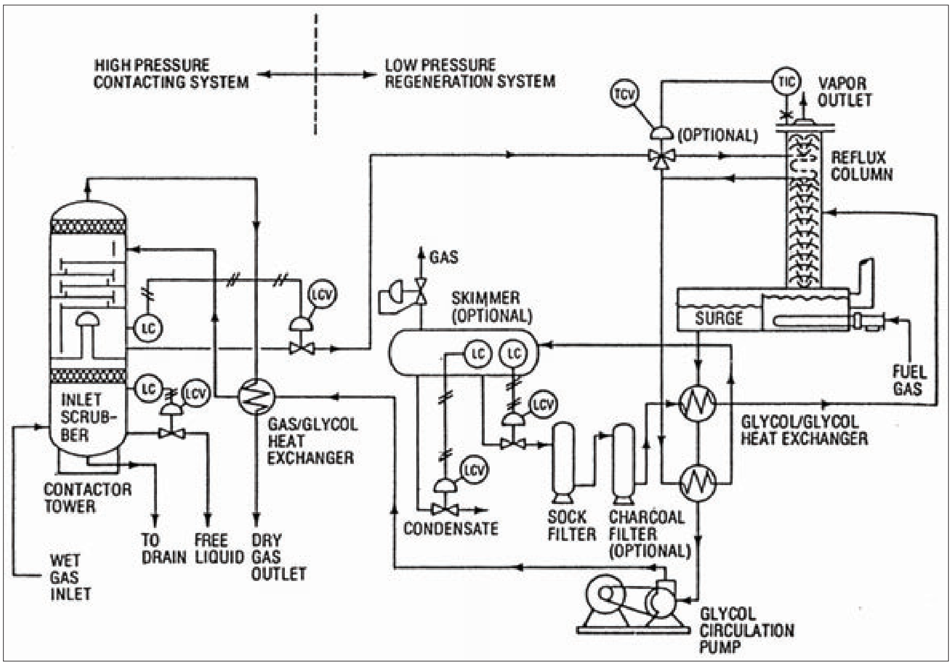

Figure 6 - Typical Glycol Dehydration Schematic

a) Economics

The installed cost of DexPro is significantly lower than the other options. An external refrigeration system is about 75% higher and the glycol system is about 170% higher than DexPro, including a one-time site license fee.

In a comparison against the do nothing, "no dehydration" baseline, not including manpower, the annual operating cost of DexPro is only +1.5% higher, while external refrigeration and glycol are +6.5% and +9.6% higher. The DexPro advantage increases when manpower is considered.

In an NPV comparison over 20 years at a discount rate of 7%, DexPro exhibits a $1.90 million cost saving over refrigeration and $3.46 million over the glycol option.

		No Dehydration	Triethylene Glycol	External Refrigeration	DexPro™
Dehydration Capital Cost (including license fee)	installed	$ -	$ 2,100,000	$ 1,350,000	$ 775,000
Annual Operating Cost					
Compression	$70/MWhr	$ 2,502,206	$ 2,513,218	$ 2,479,409	$ 2,533,788
Triethylene Glycol	$1.00/lb	$ -	$ 17,830	$ -	$ -
Methanol	$0.25/lb	$ -	$ -	$ 50,812	$ -
Annual Maintenance Cost			$ 210,000	$ 135,000	$ 6,000
Total Annual Cost		$ 2,502,206	$ 2,741,048	$ 2,665,221	$ 2,539,788
Present Value of Operating Cost (discount rate 7%, term (years) 20)		$ 26,508,403	$ 29,038,697	$ 28,235,388	$ 26,906,550
	TOTAL NPV	$ 26,508,403	$ 31,138,697	$ 29,585,388	$ 27,681,550
	difference	$ -	$ 4,630,295	$ 3,076,986	$ 1,173,147

Table 1 - Capital and Operating Cost Comparison

b) Size and Weight

Both the glycol and the external refrigeration systems are similar in weight and footprint. Both require their own foundation, structural steel skid, buildings with heating/cooling (depending upon local climate), and safety systems.

The DexPro option is significantly smaller. Due to its inherent interdependence with compression and its small size, DexPro is typically located within the compressor package, shareing the foundation, structural skid, building and utilities with the compressor. The result is a dehydration package that is less than 7% of the weight and 11% of the footprint of the other options… significant for offshore applications.

TEG Dehy	
	Weight
Weight (kg.)	15,000
tonne	15.0
	Size
Height	9.2 m.
Length	4.3 m.
Width	2.4 m.
Footprint (m^2)	10.3

DexPro™	
	Weight
Weight (kg.)	1,000
tonne	1.0
	Size
Height	1.8 m.
Length	1.8 m.
Width	0.6 m.
Footprint (m^2)	1.1

Table 2 - Size Comparison

c) Process and Operating

Total process power consumption for the options varies slightly from -0.9% to +1.3% from the 4,080 kW (5,470 hp) required without dehydration. The range of cooling requirements varies even less between the options -0.5% to +0.4%. External refrigeration is lowest in both categories.

Environmentally, DexPro does not produce any emissions and has the fewest number of potential leak points. The glycol system has the most number of potential leak points and releases about 123 tonne (135 ton) per year of carbon dioxide from regeneration, more if hydrocarbon fuels are used in combustion to provide the process heat for regeneration. Glycol and methanol losses exist for both the glycol and external refrigeration options.

The glycol system is perhaps the most operationally complicated. Also the glycol has direct contact with the carbon dioxide, and its associated contaminants, adding to the maintenance cost and the potential requirement to capture emissions released from the regeneration system.

External refrigeration maintenance cost suffers primarily due to the rotating equipment and due to the potential requirement for hydrate formation control with continuous methanol injection.

DexPro is designed for unattended operation and, with a single control valve being the only moving part, is the simplest of the three processes.

d) Performance

Both the glycol and external refrigeration process options have been around for decades. The 'good', the 'bad', and the 'ugly' are well known and documented for these processes, although not nearly so much in a carbon dioxide or acid gas service.

DexPro is at first glance a new process, but the thermodynamic principle is well understood, and the process is inherently simple. The control system is PLC based with multiple levels of redundancy and failsafe options that provide increased reliability.

The first DexPro units have been operating continuously in a 98% carbon dioxide and 2% hydrogen sulphide service at a large natural gas processing facility in north eastern British Columbia, Canada, since February, 2011.

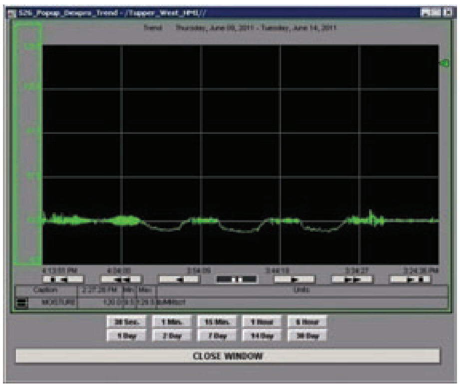

Figure 7 - DexPro Performance (screen capture)

			No Dehydration	Triethylene Glycol	External Refrigeration	DexPro™
Compression	main	hp_{gas}	*5,469.9*	5,494.0	5,256.8	5,539.0
	refrigeration	hp_{gas}			163.3	
		total	*5,469.9*	5,494.0	5,420.1	5,539.0
				0.44%	-0.91%	1.26%
Cooling Water	main	gpm_{US}	*1,441*	1,446	1,340	1,447
	condenser	gpm_{US}			94	
		total	*1,441.0*	1,446.0	1,434.0	1,447.0
				0.35%	-0.49%	0.42%
Total Cooling		btu/hr	*25,425,192*	25,508,355	25,309,234	25,489,160
Heat	regenerator	btu/hr		80,257		
Pipeline	CO_2	lb/hr	*83,330.7*	83,300.0	83,330.6	83,330.6
	Water	lb/hr	*93.3*	21.6	21.6	21.6
	Glycol	lb/hr		2.0		
	Methanol	lb/hr			23.2	
		total	*83,424.0*	83,323.6	83,375.4	83,352.2
	volume	MMscfd	*17.29*	17.25	17.26	17.26
	H_2O content	lb/MMscf	*129.5*	30.0	30.0	30.0
Regenerator Vent	CO_2	t/yr		135.2		
	Water	t/yr		280.6		
	Glycol	lb/yr		41.0		
Glycol losses	pipeline	lb/yr		17,788.9		
	vent	lb/yr		41.0		
Methanol losses	pipeline	lb/hr			23.2	
		bbl/d			2.0	

Table 3 - Process Summary

Summary

For most applications, the DexPro process is a "better way of dehydrating carbon dioxide":

Lower Capital Cost

The installed cost of DexPro is less than 40% of the installed cost of a glycol dehydration system and less than 60% of the installed cost of an external refrigeration system.

Lower Operating Cost

The DexPro annual operating cost, including compression power, is more than 7% lower than the glycol dehydration system and more than 4% lower than the external refrigeration system.

Smaller physical footprint

DexPro is the smallest of the options by nearly a 10 to 1 margin.

Simpler, no rotating equipment

DexPro is the simplest of the dehydration processes and has no rotating equipment.

No chemicals

DexPro does not require the use of any chemicals beyond a small quantity of methanol during starting up.

Smaller environmental footprint

DexPro and the external refrigeration option have negligible fugitive emissions. Also, due to the small amount of raw materials required in the manufacture of the DexPro unit, the full cycle environmental carbon footprint of DexPro should be the smallest of the options.

More information

Gas Liquids Engineering Ltd. was founded in Alberta, Canada in 1987 by owners Doug Mackenzie, P. Eng. and Jim Maddocks, P. Eng., who continue to lead the firm today. Since its inception, GLE has developed a reputation for surpassing customer expectations, technical skill and outstanding project-cost performance.

GLE is a multi-discipline engineering firm specializing in gas purification and liquids recovery. With over 235 employees, GLE possesses broad expertise in all of the engineering and project management services necessary for the successful design, procurement, installation and optimum operation of your oil and gas processing facilities. The ingenuity of our exceptional engineers and in-house drafting and electrical design departments set us apart in the petroleum engineering industry.

GLE has completed projects across Canada as well as Argentina, Azerbaijan, Bahrain, Bolivia, Czech Republic, Egypt, Italy, Kazakhstan, Kuwait, Pakistan, Oman, Poland, Romania, Syria, Ukraine, United Arab Emirates, United Kingdom, the United States and Venezuela.

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Health fears over CO_2 storage are unfounded, study shows

A University of Edinburgh study concluded that capturing CO_2 from power stations and storing it deep underground carries no significant threat to human health.

Researchers found that the risk of death from poisoning as a result of exposure to CO_2 leaks from underground rocks is about one in 100 million – far less than the chances of winning the lottery jackpot.

Scientists from the University of Edinburgh studied historical data on deaths from CO_2 poisoning in Italy and Sicily, where the gas seeps naturally from the ground because of volcanic activity.

They found that the number of recorded deaths was very low and say that engineered gas storage underground could be even safer, as it will be planned and monitored.

Recent CCS projects in northern Europe and Canada have been criticised by residents over health concerns arising from potential leakage.

Carbon capture and storage enables collection of CO_2 before it can escape into the atmosphere. The technology involves the collection of CO_2 at a power station or industrial site. The gas is liquefied and piped to the storage site, where it is injected deep below ground. The gas is stored in microscopic rock pores and eventually dissolves in underground water. Storage sites will have several barriers between the store and the surface.

The dry gas seep 'Mefite D'Ansanto' is Italy's largest flux CO_2 seep. Also a site of archeological interest, the seep has claimed at least 3 human lives in the past twenty years and animal fatalities are not uncommon. The seep has a warning sign but free public access and is located close to a farm house. Degassing takes place over only a few square meters but is estimated to be over 0.73 Mt of CO_2 per year, equivalent to the CO_2 output from a small gas fired power station.

There are 286 CO_2 seeps documented by the INGV (www.ingv.it). These have various CO_2 degassing rates and various surface expressions, as indicated by the coloured icons (Base map - Google)

Storing CO_2 gas underground prevents it from contributing to global warming. Such technologies will play an important role over the next 50 years, as a bridge to the development of clean energy.

Jennifer Roberts from the University of Edinburgh's School of GeoSciences, who undertook the work, said: "These Italian CO_2 seeps are natural, are often neither signposted nor fenced off, and yet there have been remarkably few accidents."

Professor Stuart Haszeldine of the University of Edinburgh's School of GeoSciences, who led the study, said: "Our findings show that storing CO_2 underground is safe and should allay any concerns that the technology poses a significant threat to health."

More information
www.sccs.org.uk

Transport and storage news

Carbon Management Canada develops tools on CO2 storage

www.cmc-nce.ca

Carbon Management Canada (CMC) is funding a University of Saskatchewan project that will involve laboratory testing and the development of new computer simulations to find out how to inject CO2 underground and make sure it stays there.

The project is supported by a $633,000 grant from CMC, a Network of Centres of Excellence that supports research to reduce carbon emissions from the fossil energy industry.

The grant was part of CMC's second funding competition which saw $10 million awarded to Canadian researchers working on 18 projects.

To help predict performance of porous rock-caprock formations, University of Saskatchewan geological engineering researcher Chris Hawkes and the U of S geomechanics group are collaborating with researchers at the University of Waterloo and the University of Calgary, including graduate students funded by the U of C's Institute for Sustainable Energy, Environment and Economy (ISEEE).

"This unconventional approach brings together state-of-the-art tools and methods from geomechanics and reservoir engineering and is expected to yield better, more powerful computer simulations," Hawkes said.

To mimic field conditions, the researchers squeeze rock cores to simulate conditions deep underground, then inject them with pressurized water or CO2 to see how they deform under stress and how fluids flow through them. The cores can also be heated to test how they hold up to temperature change — an important consideration, as sudden temperature changes can cause some rock types to crack.

This information will form the basis for computer simulations to predict how injected CO2 might behave underground. These powerful tools will allow assessment of potential CCS sites, from deep saltwater aquifers to mature oil reservoirs, and point to the most effective injection methods.

"These enhanced tools are badly needed to determine whether underground CO2 storage is a viable and secure option that can be scaled up to play a significant role in managing global emissions," Hawkes said.

While the typical rate of injection in CO2 storage pilot studies is one megatonne (million tonnes) per year or less, it is thought this rate needs to be several times higher. Enhanced simulation tools, such as those developed by this research, will allow engineers to predict and respond to changing conditions at CO2 storage sites where the rate of injection is an expected 10 to 30 megatonnes per year.

DOE project in Utah begins field operations.

southwestcarbonpartnership.org

Phase III of the DOE Southwest Regional Partnership on Carbon Sequestration's (SWP) CO2 storage project is moving forward with field operations.

The project is to be sited at Thunderbird's Gordon Creek natural gas plant located in Carbon County, Utah. The project is supported and managed by the National Energy Technology Laboratory (NETL) of the US Department of Energy (DOE). Thunderbird's wholly-owned subsidiary Gordon Creek, LLC is a sub-recipient of the NETL financial award and will act as the project field operator.

Phase III of the project is intended to demonstrate proof of concept technologies for the potential commercialization of carbon dioxide storage. A key project objective will be the storage of up to 1 million tons of CO2 per year at Gordon Creek.

The Phase III project budget is roughly $90 million, of which up to $67 million has been committed by the US Department of Energy (DOE) through the NETL - the balance to be provided by the participating organizations. The project is a multi-faceted effort by a number of entities. The lead Organization is the New Mexico Institute of Mining and Technology, with project manager Dr. Robert Lee. Dr. Lee is the director of the Petroleum Recovery Research Center, a research division of NMT. Dr. Reid Grigg of the PRRC and Dr. Brian McPherson of the University of Utah/NMT are Co-Principal Investigators. Other organizations involved in this far-reaching proof of concept research project are NETL, Los Alamos National Laboratory, Sandia National Laboratories, USTAR, Utah Geological Society, and the University of Missouri.

The initial phase of field operations will include an extensive 3D seismic shoot and the drilling of up to two deep (12,000 foot) CO2 source wells.

The purpose of this phase to establish the potential size of the known CO2 resource at Gordon Creek and thereby secure a long-term supply of CO2, that will be sufficient to satisfy the Phase III requirements and beyond.

The field program at Gordon Creek will also include drilling and/or re-completing monitoring wells, upgrading Thunderbird's existing injection facility, constructing roads, pipelines and surface facilities, as well as ongoing supervisory and monitoring operations. Operations are expected to commence immediately following the completion of required permitting.

DOE sponsored study finds CO2-EOR feasible in Kansas

www.fossil.energy.gov

The feasibility of using CO2 injection for recovering between 250 million and 500 million additional barrels of oil from Kansas oilfields has been established in a study funded by the U.S. Department of Energy (DOE).

The University of Kansas Center for Research studied the possibility of near-miscible CO2 flooding for extending the life of mature oilfields in the Arbuckle Formation while simultaneously providing permanent geologic storage of carbon dioxide.

Miscibility refers to the pressure at which the CO2 and oil are completely soluble in one another or form a single phase. Below the minimum miscibility pressure (MMP) the injected CO2 mixes with and swells the oil to reduce its viscosity, increasing its ability to flow through the reservoir more easily to the production well.

In the laboratory, researchers subjected core samples from the Arbuckle Formation to simulate CO2 flooding. The studies showed that more than 50 percent of the residual oil remaining after water-flooding could be recovered from Berea Sandstone, Baker dolomite, and Arbuckle dolomite cores at pressures below the MMP.

The investigators also conducted simulation studies which indicated that the ultimate oil recovery is highly dependent on the degree of reservoir heterogeneity. Maximum recovery efficiency can be achieved by proper design and implementation of CO2 injection, with optimization of injection pressure, injection rates, and the well pattern.

The project is now moving into a second phase of research, in which researchers will conduct a variety of tests to improve characterization of Arbuckle reservoirs. The testing will determine the nature of the flow paths and average properties in the reservoir, assess the effect of geology on process performance, calibrate a reservoir simulation model, and identify operational issues and concerns for future applications of near-miscible CO2 flooding. Future work, if funded, would include field demonstration of the

methodology.

Following primary oil recovery (in which oil is naturally driven from a reservoir) and secondary recovery (in which pressure is applied to force the oil from the reservoir, usually by water flooding), as much as two thirds of the original oil in place typically remains stranded in a reservoir. Additional oil can be recovered using improved oil recovery techniques that increase the mobility of the crude oil.

Near-miscible CO2 flooding may be applicable to thousands of mature oilfields in Kansas and prevent them from being abandoned prematurely. According to the Kansas Geologic Survey, more than 6,400 highly compartmentalized reservoirs exist in Kansas.

Texas Clean Energy project to sell CO2 to Whiting Petroleum Corporation

www.texascleanenergyproject.com

Summit Power Group and Blue Strategies have announced the signing of a sales agreement with Whiting Petroleum Corporation for CO2 that will be captured by Summit's Texas Clean Energy Project (TCEP).

TCEP will be an integrated gasification combined cycle (IGCC) 400MW power/poly-gen plant that will capture 90 percent of the carbon dioxide produced by the process.

Summit, a leading power developer based in Seattle, and Blue Strategies, a Houston-based developer of CO2 projects, partnered in October 2009 to market TCEP's 2.5 million tons per year of CO2 to oil producers in the West Texas Permian Basin.

Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that acquires, develops and explores for crude oil, natural gas and natural gas liquids. The Company's largest projects are in the Bakken and Three Forks plays in North Dakota and its Enhanced Oil Recovery projects, which have historically used naturally occurring geological CO2 for injection in its EOR projects in Oklahoma and Texas.

Under the new agreement, Whiting will purchase 80 million cubic feet (80,000 Mcf/d) of compressed CO2 per day from TCEP, representing approximately 60 percent of TCEP's total volume of captured CO2, during the first five years of TCEP's operation, with gradually declining amounts and an option to extend the purchases thereafter.

The 15-year Whiting-TCEP contract is historic because CO2 for EOR operations in the Permian Basin and elsewhere have generally been carried out with CO2 that is geological in origin, i.e. formed naturally in underground reservoirs in New Mexico and Colorado and brought to the surface by wells such as those used to produce natural gas. More than 3,000 miles of CO2-dedicated pipeline currently transports and distributes geologic CO2 throughout the Permian Basin.

Whiting will be the first in the Permian to purchase CO2 from a power project that will be produced through the coal-gasification process.

In oil fields such as Whiting's, the injected CO2 mixes with the oil that is left behind in the primary oil-well production and the secondary water-injection stage. Approximately 40 percent of the initially injected CO2 remains trapped underground. The remainder comes to the surface with the oil, but is then recaptured, recompressed, and re-injected. Ultimately, some 99 percent of the injected CO2 can be permanently stored (i.e. geologically sequestered) deep underground.

ICO2N backgrounders on CO2 storage and CO2-EOR

www.ico2n.com

ICO2N has released two new free guides, one on the basics of CO2 storage and the next on Enhanced Oil Recovery (EOR) as a technology to help jump start CCS.

The first document explains the geological trapping mechanisms that keep CO2 trapped safely and permanently deep underground as well as the knowledge base and potential for storage in Canada and internationally.

It is the first in a series of concise backgrounders that will be distributed by ICO2N to help promote a better understanding of various aspects of Carbon Capture and Storage.

The second explains the process of EOR using CO2, its role in advancing carbon capture and storage, economic benefits, and potential in Canada and globally.

ICO2N is the Integrated CO2 Network, a group of Canadian companies representing multiple industries, including coal and the oil sands.

University of Victoria research into fibre optic CO2 storage monitoring

Carbon Management Canada funding is helping a project to test fibre optic monitoring of CO2 storage reservoirs to move into field trials.

Headed by the University of Victoria's Peter Wild, the three-year project will begin in the lab, then shift outdoors for field tests of the sensor system, first in shallow ground, then in deeper environments. The goal is create a system that could be placed underground near CO2 injection sites or overlying storage formations.

Monitoring, measuring and verifying what becomes of injected CO2 over the long term is difficult because of harsh environmental conditions, combined with the deep location and size of the storage sites. Capturing and storing CO2 underground is seen as a viable way of reducing the levels of atmospheric carbon. Although the process is not unproven – for decades oil companies have been injecting CO2 into reservoirs to enhance the recovery of oil – researchers are working on new methods to verify that the compound is securely stored.

Since salt water and other fluids stored underground are affected by the presence of stored CO2, Wild, an engineering professor, plans to use arrays of specialized fibre-optic sensors to measure this impact. "Through this method we hope to better determine if CO2 is being stored safely or if it's moving or leaking," he explained.

The project is supported by a $983,578 grant from Carbon Management Canada (CMC), a Network of Centres of Excellence that supports game-changing research to eliminate carbon emissions from the fossil energy industry. The grant iss part of CMC's Round 2 competition which saw 18 projects in Canada receive a total of $10 million.

University of Calgary geophysicist Don Lawton is the CMC Lead for Secure Carbon Storage projects and a collaborator on the CO2 sensor project. "Verification of secure storage is in the public interest and will be required for commercial projects before a closure certificate will be issued by the government," he says.

In designing a new system to monitor CO2 concentrations, Wild and his collaborators will make use of patented fibre-optic technology, developed at UVic, as well as patented techniques to measure CO2 fluxes, developed by the St. Francis-Xavier University's "Flux Lab," which is headed by David Risk, an assistant professor in the university's Department of Earth Sciences.

Collaborating with Wild's own fibre-optics research group at UVic's Institute for Integrated Energy Systems (IESVic), are experts in environmental monitoring, nanofabrication and micromachining, as well as petroleum engineering. Mechanical engineer David Sinton, formerly of UVic but who now works at the University of Toronto, is one of Wild's collaborators. UVic investigators on the team include mechanical engineer Martin Jun as well as UVic students.

"It's a complex problem with lots of dimensions to it," says Wild, stressing that only an interdisciplinary approach could make the project a success.

Status of CCS project database

The status of 78 large-scale integrated projects data courtesy of the Global CCS Institute

For the full list, with the latest data as it becomes available, please see the pdf version online at www.carboncapturejournal.com or download a spreadsheet at www.globalccsinstitute.com/resources/data

Project Name	Description	Asset Lifecycle Stage	Country	Volume CO_2	Operation Date
ADM Company Illinois ICCS	The project will capture around 1 million tonnes per annum of carbon dioxide from ethanol production. The carbon dioxide will be stored approximately 2.1 km underground in the Mount Simon Sandstone, a deep saline formation.	Define	UNITED STATES	1 Mtpa	2012
AEP Mountaineer 235MWe CO2 Capture	AEP's Mountaineer coal-fired power station was retrofitted with Alstom's patented chilled ammonia carbon capture technology. This project has been operational at pilot scale since September 2009 and full-scale operation is expected by 2015.	Define	UNITED STATES	1.5 Mtpa	2015
Air Liquide	Air Liquide is building a new hydrogen plant in Rotterdam. The installation of a cryogenic purification unit (CPU) at the plant, capturing up to 550,000 tonnes per annum of carbon dioxide, is under evaluation.	Define	NETHERLANDS	0.55 Mtpa	2012
Air Products Project	This project proposes to capture more than 1 million tonnes per year of carbon dioxide from two steam methane reformers. The CO2 will be transported via Denbury's Midwest pipeline to the Hastings and Oyster Bayou oil fields for enhanced oil recovery.	Define	UNITED STATES	1 Mtpa	2015
Belchatow	Alstom and PGE EBSA are partnering to build an 858 MW lignite-fired power plant with CCS. Around 1.8 million tonnes per annum of carbon dioxide will be captured and stored in deep saline formations.	Define	POLAND	1.8 Mtpa	2015
Bow City	The Bow City Power Project is a proposed super critical 1,000 MW coal-fired power plant incorporating post combustion carbon capture and storage. Around 1 million tonnes per annum of carbon dioxide will be captured at the plant.	Evaluate	CANADA	1 Mtpa	2016
Browse LNG	Up to 3 million tonnes per annum of carbon dioxide will be captured at this proposed liquid natural gas development located in the government precinct near James Price Point on the Dampier peninsula.	Evaluate	AUSTRALIA	3 Mtpa	2017
C.Gen Killingholme	C.Gen is proposing this new IGCC plant in north Lincolnshire that would capture around 2 million tonnes per annum of carbon dioxide feeding into the National Grid transport and storage network. The project is part of the Yorkshire Forward initiative.	Define	UNITED KINGDOM	2.5 Mtpa	2015-2016
Cash Creek	The ERORA Group proposes to build a Hybrid IGCC project in Henderson County, Kentucky. It will produce about 565 MW as well as synthetic natural gas. The plant will capture about 2.5 million tonnes per annum of carbon dioxide for enhanced oil recovery.	Evaluate	UNITED STATES	2.5 Mtpa	2015
Coffeyville Gasification Plant	Coffeyville Resources is proposing to build a carbon capture unit at an existing gasification plant in Kansas. The project would capture around 770,000 tonnes per annum of carbon dioxide for urea production and enhanced oil recovery.	Define	UNITED STATES	0.585 Mtpa	2013
Compostilla Project	This project uses oxyfuel and fluidised bed technology on a 30 MW pilot plant which will scale up to 300 MW. It has received funding from the European Energy Programme for Recovery (EEPR).	Define	SPAIN	1.1 Mtpa	2015
Coolimba	Aviva Corporation Ltd proposes the construction of a 400-450MW coal-fired base-load power station using circulating fluidized bed technology and capturing up to 2 million tonnes per annum of carbon dioxide. Suitable storage sites are being sought.	Identify	AUSTRALIA	2 Mtpa	2015
Don Valley	2Co Energy is developing this project to capture nearly 5 million tonnes per annum of carbon dioxide from a new build natural gas-fired power station. The project is part of the Yorkshire Forward initiative.	Evaluate	UNITED KINGDOM	4.75 Mtpa	2015
Dongguan	Dongguan Taiyangzhou Power Corporation intends to construct an 800 MW IGCC plant capturing up to 1 million tonnes per annum of carbon dioxide, which would be stored in depleted oil and gas reservoirs.	Define	CHINA	1 Mtpa	2015
Drax	Alstom UK Ltd, Drax Power Limited and National Grid plc are jointly developing a new 426 MW oxy-fired plant in North Yorkshire which would capture around 2 million tonnes per annum of carbon dioxide. The project is part of the Humber CCS Cluster.	Evaluate	UNITED KINGDOM	2 Mtpa	2015
Emirates Steel Industries	This project proposes to capture around 800,000 tonnes per annum of carbon dioxide from a steel plant in the Industrial City of Abu Dhabi (ICAD) by 2014. The project is being developed as part of the Abu Dhabi CCS Network (Masdar).	Evaluate	UNITED ARAB EMIRATES	0.8 Mtpa	2014
Enhance Energy EOR Project	Enhance Energy and Fairborne Energy Trust are jointly developing an enhanced oil recovery project at their Clive D2A and D3A fields, using carbon dioxide captured from a refinery and a fertiliser plant, and transported via the Alberta Carbon Trunk Line.	Execute	CANADA	1.8 Mtpa	2012

Facility Details	Capture Type	Transport Type	Transport Length	Storage Type	Project URL
Ethanol plant	Industrial Separation	Pipeline	1.6 km	Deep Saline Formations	#http://www.adm.com/#
235 MWe slipstream from 1300 MW net coal-fired power plant	Post-Combustion capture	Pipeline	30 km	Deep Saline Formations	http://www.aep.com/environmental/climatechange/carboncapture/
130,000 Nm3/h hydrogen plant	Pre-Combustion capture	Combination	Not specified	Enhanced Oil Recovery	#http://www.airliquide.com/#
Hydrogen production at oil refinery	Pre-Combustion capture	Pipeline	Not specified	Enhanced Oil Recovery	http://www.airproducts.com/index.asp
260 MW equivalent on 858 MW lignite-fired power plant	Post-Combustion capture	Pipeline	60-140 km	Deep Saline Formations	#http://www.bot.pl/#
1000 MW coal-fired power plant	Post-Combustion capture	Pipeline	6-30 km	Enhanced Oil Recovery	www.bowcitypower.ca
Liquefied natural gas (LNG) plant	Gas Processing	Pipeline	Not specified	Not Specified	#http://www.woodside.com.au/#
430-520 MW net IGCC	Pre-Combustion capture	Pipeline	Unspecified	To Be Determined	#http://www.cgenpower.com/en/projects_killingholme.html#
565 MW IGCC and 130 MSCF/day SNG gasifier	Pre-Combustion capture	Pipeline	Not specified	Enhanced Oil Recovery	#http://www.erora.com/#
Fertiliser plant	Pre-Combustion capture	Pipeline	112 km	Enhanced Oil Recovery	http://www.cvrenergy.com/NitrogenFertilizerOperations/index.html
300 Mwe (Phase 2) coal-fired oxyfuel combustion power plant	Oxyfuel Combustion capture	Pipeline	120 km	Deep Saline Formations	#http://www.compostillaproject.es/#
2x200 MW or 3x150 MW coal-fired CFB power plant	Post-Combustion capture	Pipeline	20-80km	Depleted Oil and Gas Reservoirs	www.coolimbapower.com.au
Natural gas-fired power plant	Oxyfuel Combustion capture	Pipeline	175 km	To Be Determined	#http://www.2coenergy.com/#
800 MW net coal-fired IGCC power plant	Pre-Combustion capture	Pipeline	100 km	Depleted Oil and Gas Reservoirs	#http://www.dgpowerfuel.com/english/profile.asp#
426 MW gross coal-fired power plant	Oxyfuel Combustion capture	Pipeline	Not specified	Depleted Oil and Gas Reservoirs	#http://www.draxpower.com/#
Steel plant	Industrial Separation	Pipeline	50 km	Enhanced Oil Recovery	http://www.esi-steel.com/#http://www.esi-steel.com/#
Fertiliser production and hydrogen production at the oil refinery	Pre-Combustion capture	Pipeline	240 km	Enhanced Oil Recovery	http://www.enhanceenergy.com/projects/clive.html