carbon capture journal

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Front cover:
Doosan Babcock's 40 MWt OxyCoal™ Firing Demonstration Facility in Renfrew, Scotland

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Contents

CCS technology developments and the clean coal situation in the UK

The world is facing an increase in energy demand and Government and Industry have to come up with solutions to meet this growing need whilst also reducing emissions. Clean coal is a vital part of the ongoing balanced energy portfolio, and Government must demonstrate a commitment to clean coal technologies and strive to make power generation from coal as clean as possible.

By Dr Mike Farley, Director of Technology Policy Liaison, Doosan Babcock Energy

The future of energy

A recent independent study on the future value of coal carbon abatement technology to the UK industry, which was carried out by consultants AEA Group and released by the Department of Energy and Climate Change (DECC) revealed that clean coal technology could bring between £2-4 billion a year into the UK economy by 2030, and support between 30,000-60,000 jobs[1]. Experts forecast that the CCS industry will be comparable in size with the oil industry. We believe that CCS has the potential to be a positive engine for economic growth.

Earlier this year Energy Secretary Ed Miliband made a commitment to a more definite route to carbon capture and coal-fired power stations. In June 2009 Miliband announced that permission would not be granted to build new coal power stations unless they included demonstration-scale CCS projects from the outset, and could be easily retrofitted once CCS became viable on a large scale.

We support this plan and would urge implementation on the fastest possible timescale. Unless there is early certainty of funding for energy companies for CCS demonstration plants, the UK faces being left behind at a time when the United States have put funding of such demonstrations at the heart of the country's economic stimulus package.

Carbon Capture and Storage technology and demonstrations

To gain a competitive advantage and set an example on a global level, it is important that progress in the field of clean coal in the UK is made as soon as possible.

It is predicted[2] that in the EU alone, reductions of CO2 by CCS from the power sector could reach 161 Mt (metric ton) in 2030 and 800-850 Mt (20%) in 2050. New coal stations are 20% cleaner than existing coal-fired plants and will be 80-90% cleaner once CCS is added.

The International Energy Agency (IEA) Energy Technology Perspectives "Blue" Scenario, which is consistent with the World Energy Outlook 450ppm case, defines how the CO2 emissions reductions might be shared over a range of measures. CCS has a vital role, accounting for 19% of the emissions reduction from the baseline. To meet GHG reduction targets the 2008 IEA Energy Technology Perspectives require 19% of reductions to come via CCS. It will be necessary to build 80 power plants per year with CCS from 2020 to 2050, approximately half being coal and half gas.

We believe Europe can set an excellent example by using a "twin-track" approach - building modern high efficiency capture-ready clean coal power plants in parallel with demonstrating suitable carbon capture and storage technologies on a large scale is the quickest, and most valuable immediate contribution the UK can make towards cutting CO2 emissions from fossil fuels globally.

In the UK, all fossil-fuelled power plants must now be designed "capture-ready", with plants located and designed such that they can be retrofitted with CCS. To avoid "carbon lock-in" it is essential all fossil power plants globally are similarly built capture–ready. Between 2010 and 2020, around 1000 such plants can be anticipated globally.

The demonstrations would be in two tranches:

- Initial large-scale demonstrations – 12 in Europe, 20 globally – committed by 2010 and operational by 2015
- Additional 100 full-scale early stage deployment projects globally, building up from 20/year to 40/year, committed by 2015 (i.e. before the initial demonstrations are running) and operational by 2020

Such a programme, in which the UK must take an above-average share, would be sufficient to build confidence in the technology and build the necessary capacity in the industry to allow commercialisation from 2020.

"Unless there is early certainty of funding for energy companies for CCS demonstration plants, the UK faces being left behind at a time when the United States have put funding of such demonstrations at the heart of the country's economic stimulus package." - Dr Mike Farley, Doosan Babcock Energy

Doosan Babcock offers advanced supercritical capture-ready boilers with full guarantees, giving a 23% CO2 saving in comparison to the average UK coal power plant. The company has also established a global R&D centre in Renfrew for power plant boilers and carbon capture technologies.

Doosan Babcock and its parent Doosan Heavy can provide all three CCS technologies – Post Combustion, Oxyfuel and Pre-combustion – and will participate in large-scale demonstration projects.

The company recently acquired an equity stake in HTC Purenergy, a leading post combustion CCS technology provider, and signed a licensing agreement with HTC to use University of Regina amine scrubbing technology.

For oxyfuel firing the company is cur-

[1] http://www.edie.net/news/news_story.asp?id=16600&channel=0&title=Government+comes+under+fire+on+clean+coal

[2] EUR-LEX, the portal to European Union law, Brussels, 23.01.2008: "Supporting early demonstration of sustainable power generation from fossil fuels", http://eur-lex.europa.eu/en/index.htm

rently commissioning its OxyCoal Clean combustion Test facility at its Renfrew R+D Centre. During the summer of 2009 we will demonstrate OxyCoal combustion on a full size 40 MWth coal burner suitable for new and retrofit applications.

Government action

The UK electricity generation fleet is ageing and there is a need for up to 15,000 MWe replacement fossil power plants by 2015. New nuclear plant is not an option in this time frame and whilst renewable energy will contribute, it will not be able to meet the need for new capacity alone.

Gas generation is the default option but this aggravates energy security by giving increased exposure to the price volatility of imported gas and has less beneficial environmental credentials than when fuelled by indigenous gas as approximately 25% of the available energy is used to liquefy and transport gas as LNG.

Coal power projects with CCS can provide very cost effective, reliable low carbon electricity compared to some forms of renewable generation. Supporting the introductory tranche of four coal CCS projects proposed in the DECC consultation will enable Government to have much greater certainty of meeting its carbon reduction targets.

All four projects are necessary to achieve the government's four tests of the proposed policy - emissions reductions, affordability, security of supplies and jobs for UK workers.

CCS technologies need to be promoted, developed and deployed quickly, and effectively commercialised by 2020. The Government needs to provide sufficient incentives to drive four CCS projects covering the ranges of capture technologies and storage sites as soon as possible.

In the longer term, 2020 onwards, it is hoped such incentives will be provided by the carbon price under the ETS or global equivalent but, if not, CCS may need to be mandated, perhaps by an Emissions Performance Standard. If an EPS is pursued it needs to be at a level which will require CCS to be fitted to coal and gas power plants. The initial proposals made in Europe for an EPS of 350 or 500 g/kwh would permit unabated gas fired generation whilst preventing the building of capture ready coal fired plant.

In the short and medium term, demonstration projects will require incentives as long as the CO2 allowance price is not sufficient. The funding for such incentives should be found from proposed levy on electricity – at a cost less than the cost of an equivalent amount of electricity from offshore wind. Full auctioning is envisaged from 2013 and could raise £5 Bn/year to the UK exchequer for a carbon price of £33/tonne.

Positive high level endorsement of the future role for coal has been given by the government and endorsed by the Conservative opposition. There should be a target for the proportion of clean coal in the portfolio and a timescale for the achievement of near-zero emissions for coal and gas generation with the objective of decarbonising electricity generation by 2030. If we are to avert the impending energy gap, still more ambition and action is urgently needed by the government.

Doosan Babcock's 40 MWt OxyCoal™ Firing Demonstration Facility in Renfrew, Scotland

Further information

Visit: www.doosanbabcock.com
Or contact:
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Sulzer - putting a chill on global warming

Sulzer Pumps and Sulzer Chemtech are leading manufacturers of pumps and mass transfer equipment that can be used in all stages of the CCS chain to help successfully reduce CO2 emissions.

CO2 emissions from the global use of fossil fuel totaled around 27 Gt CO2/yr in 2005. Public electricity and heat production are by far the largest cause of CO2 emissions in this category. Almost 60% of emissions were attributable to large (>0.1 Mt CO2/yr) stationary emission sources.

Fossil fuel power plants that use natural gas or coal as feedstock account for approximately 30% of this figure. There are more than 2000 power stations globally that each emit over 1 Mt CO2/year. They are the most important potential targets for CO2 capture.

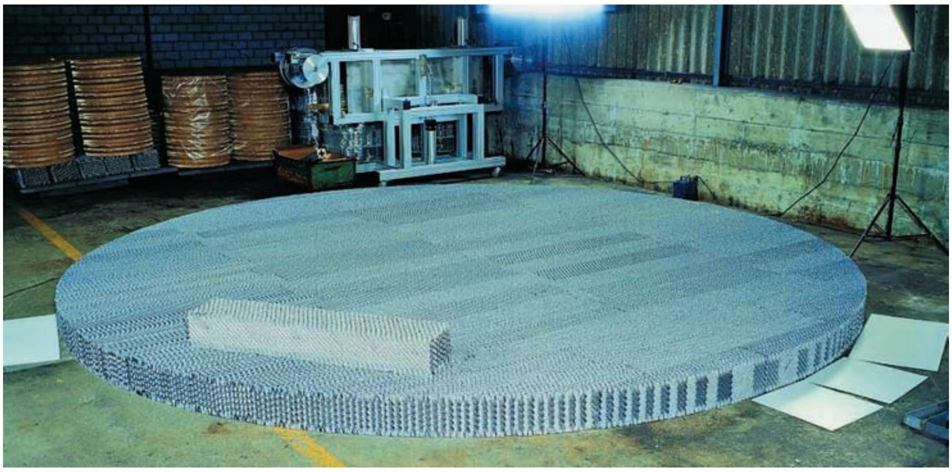

Figure 1 - Sulzer's Mellapak™ and MellapakPlus™ packings are ideal for CCS applications as they combine low pressure drop with high capacity and efficiency to allow for a substantially reduced column size

Carbon capture

CO2 is a volatile gas at ambient conditions. A considerable level of investment and additional energy is required to capture it from inert gases—mainly nitrogen. Conventional fossil power stations burn natural gas or coal at close to atmospheric pressure, which means that the CO2 must be removed under difficult conditions before the clean inert gases are released into the atmosphere. The objective is to produce a concentrated, easily transportable stream of CO2 at high pressure. There are three principal methods of achieving this:

Precombustion: CO2 is separated prior to combustion. This process is complex but offers significant potential.

Postcombustion: CO2 is separated from the flue gas after combustion. This method reduces the net electricity output of the power station by more than 20%. However, CCS development currently focuses on this form of technology due to the fact that it is already available and existing power plants can be retrofitted.

Oxyfuel process: Oxygen is used instead of air in the combustion process and therefore produces a flue gas consisting mainly of CO2 and water. The CO2 can then be separated by condensation. The energy penalty that results from the oxyfuel process is similar to the penalty in the case of postcombustion technology. Existing power plants can be retrofitted for this purpose. This process is promising, and demonstration plants are currently under construction.

Sulzer solutions to carbon collection challenges

Conventional fossil power stations have extremely high flue gas rates. For example, a 400 MW combined-cycle natural gas power plant has a flue gas flow rate of more than 2 000 000 m3/h. Absorbers that are capable of handling such exceptionally high gas volumes require diameters of around 18 m or rectangular footprints of 10 m× 25 m (the column shape depends on the process licensor).

Sulzer Chemtech is experienced in designing columns of similar sizes and in manufacturing the related proprietary equipment. In addition, a considerable amount of solvent (mainly amines) is needed to capture CO2 by absorption (e.g., 2000m3/h for a 400MW power station). The rich solvent is pumped to the regenerator to release CO2, and the lean solvent is pumped back to the absorber. Producing a design for the liquid distributors that will spread the solvent evenly over the column cross-sectional area is challenging.

Test rigs for liquid distributors are available at Sulzer to overcome these challenges; the rigs make it possible to conduct tests with water before installing the distributors in the columns.

A variety of Sulzer single-stage standard pumps can be used to circulate liquids in the postcombustion capture proess. Sulzer Pumps has extensive experience in the area of column is another critical issue: Sulzer Chemtech uses computational fluid dynamics (CFD) to optimize gas inlet geometry with the aim of achieving the equal velocity distribution of gas after entry into the column (Fig. 2).

The packing height required to absorb 85% to 90% of the CO2 depends on the choice of the scrubbing liquid. The faster the CO2 reacts, the less packing height is required. However, less packing height typically means more energy is needed to release the CO2 in the regenerator.

Intensive research is therefore being conducted in almost all regions of the world to develop new solvents that will require less energy. A fan is required to force the large flue gas stream through the absorber. The reduction in the pressure drop across the packing and column internals is a key parameter in order to save energy.

Sulzer Mellapak™ is the ideal column packing for this application because it combines the requirements of vacuum applications (low pressure drop) with gas sweeten-

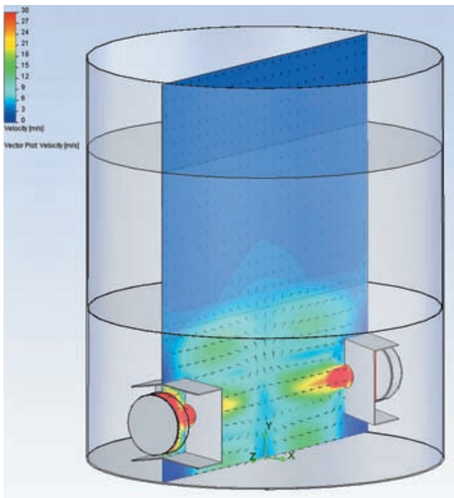

Figure 2 - Sulzer Chemtech has years of experience using computational fluid dynamics (CFD) to derive optimal gas inlet geometry

ing (high capacity and efficiency). In addition, Mellapak has a mechanically stable structure that allows the manufacturing process to be completed with a minimum amount of material.

Mellapak offers a greater geometric area for gas/liquid contact per kg of stainless steel than with random packing—an important factor in improving mass transfer (Fig. 1).

At present, CO2 is only routinely separated at a few large industrial plants such as natural gas processing and ammonia production facilities. No power stations are equipped with a full size CO2 capture unit, but several pilot units are already in operation, and many others are planned. Furthermore, a demonstration unit that will capture 100 000 t of CO2 per year is scheduled to be built in 2009. The construction of a full-size plant is planned for 2011.

Transportation of the delicate substances

The CO2 captured is usually compressed to a supercritical state (pressure > 74 bar) for transportation. CO2 can be transported via pipelines or by rail, road, or sea in tankers. Pipelines are the preferred option when transporting large quantities of CO2 over distances of up to around 1000 km. The selection of the pump, the mechanical seal, and the operation of the pump are critical. Sulzer has over 25 years of experience in pumping solvents to capture CO2, as well as in pumping liquefied CO2 and similar low-lubricity fluids (e.g., ethylene) in the USA and Europe. Sulzer Pumps offers a wide portfolio of pumps capable of compressing the CO2 for transportation, injection, and storage.

CO2 compression

CO2 usually exits the regenerator at relatively low pressure and has to be compressed to at least 80 bar to get it above its critical pressure. At 80 bar to 250 bar, CO2 density mainly varies in line with changes in temperature. A higher density results in smaller pipeline diameters, smaller machinery (pumps or compressors), and potentially lower costs—for the same mass flow.

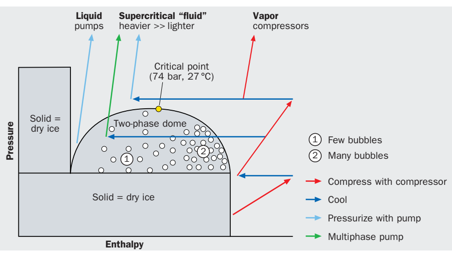

Figure 4 - Multiphase pumps handle gas contents of up to 95%. They may be used in CCS applications if a cooling stage can be performed economically through the 2-phase dome of the CO2 pressure-enthalpy diagram

Figure 3 - Multistage GSG diffuser pumps are used for heavy-duty applications in refineries, petrochemical plants, and gas processing. They pump compressed CO2 or, as in this example, 0.4 specific gravity cold ethylene

The cost of cooling CO2 to less than 27 °C to achieve dense phase can be substantial. Pumps are more efficient than compressors for the last compression stage in colder climates, where cooling down to 10°C to 15 °C can be performed economically using cold sea water (Fig. 4). Sulzer multiphase pumps may be used for 2-phase compression with suction pressures below critical pressure.

CO2 transportation and injection

The CO2 for injection has to be almost pure and dry to comply with existing European regulations. Sulzer pumps, used for the last compression stage, can be applied for pipeline booster and CO2 injection duties. The suction pressure is ~80 bar to 100 bar and discharge pressure can be up to 300 bar (depending on the injection environment, i.e., depth and formation). CO2 is also used for enhanced oil recovery (EOR). It is currently widely used for EOR in the USA.

Applications of CCS

No applications currently exist to confirm the scale-up of CCS technology when fitted to a full-size power plant. The priority in the development of CO2 capture technology is to reduce costs and increase efficiency. The priority in the storage of CO2 is to establish the credibility of this approach using a safe and reliable method of long-term storage. Sulzer is one of the main suppliers in major segments involved in the CCS business and has strong customer relationships with the companies involved in CCS business development.

Outlook

CCS technology is still at an early stage. Companies and countries are lining up projects to demonstrate CCS technology while they await government backing and funding.

Sulzer is liaising with customers and is involved at an early stage in the process design phase of CCS projects. At present, most customers are designing pilot plants—especially for the CO2 capture business—or are evaluating more CO2 pipelines for EOR.

They are likely to proceed with full-scale implementation in the next few years in conjunction with technology providers they know and trust. Sulzer is committed to seizing the opportunities emerging in this field.

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High rate CO2 injection into oil reservoirs for EOR - potentially large storage benefit

Injection of CO2 into oil reservoirs for Enhanced Oil Recovery (EOR) may provide the additional benefit of sequestering CO2. Some operators of CO2 EOR schemes onshore in the United States, for example Denbury Resources Inc., inject CO2 continuously at high rates achieving high oil recoveries. This article describes one example which suggests this policy might also be successfully applied to some North Sea reservoirs, both for the benefit of EOR and CO2 storage.

Eugene Balbinski, Matthew Goodfield and Barry Mead all of RPS Energy

RPS Energy carried out a number of simulation studies of CO2 EOR schemes for the UK government using a fully compositional model incorporating a representative UKCS geology. The anticlinal structure contained about 220 MMSTB oil originally in place and was 50 ft thick at the crest.

The initial reservoir pressure was just over 4000 psia and the minimum miscibility pressure (MMP) for CO2/oil was 3460 psia, so it was expected that a highly miscible flood could be achieved. An initial 12 year waterflood recovered 40% of the oil originally in place but, although this maintained voidage, pressures around the crestal producers fell significantly below the MMP.

In order to promote CO2/oil miscibility injection was started for three months without production, raising producer pressures back towards the original reservoir pressure.

Four basic CO2 injection scenarios were considered depending on how or whether the vertical injectors were re-located from their original waterflood positions, see Table 1. Four to five hydrocarbon pore volumes were injected in 20 years, see Figure 1. Injector pressures were limited to 6000 psia and producers were limited to minimum bottom hole pressures of 3500 psia to avoid pressures falling below the MMP. Producer watercut limits of 99% were set, but no minimum oil rates or maximum CO2 production rates were applied.

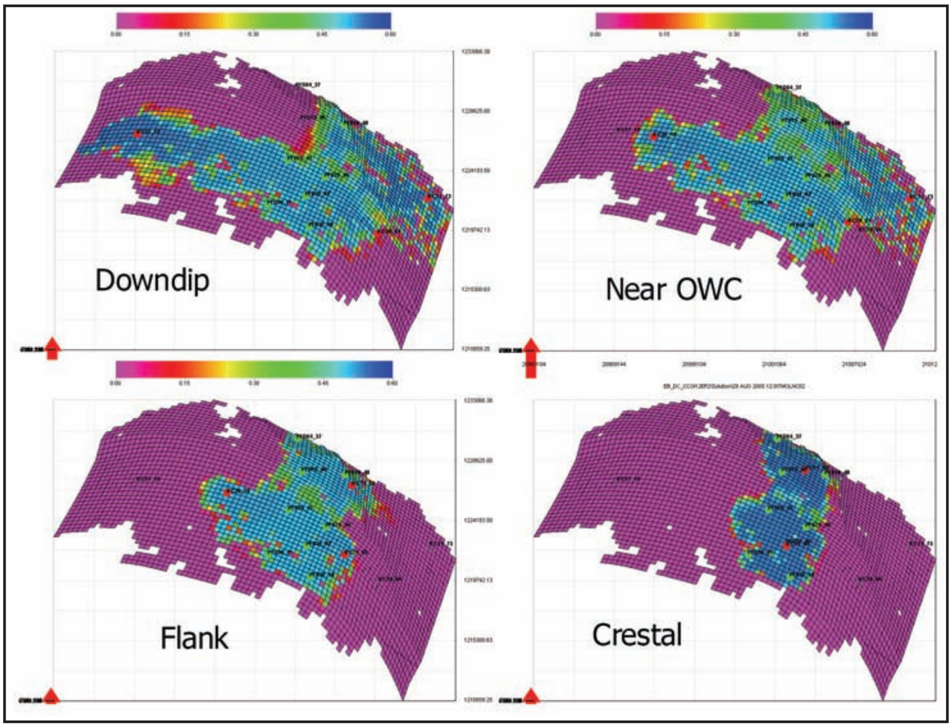


Figure 1 - CO2 concentrations after 20 years injection

No attempt was made to optimise these cases, or to construct a single optimal case, as part of the purpose of the project was to demonstrate the strengths and weaknesses of each scenario. In practice, for an actual project it would be possible and likely to be worthwhile, to construct a single optimal scenario. In two of the cases ('Downdip' and 'Near OWC'), producer-injector well spacings were typical of UKCS offshore fields, but in the other two cases well spacings were less, with one ('Crestal') being typical of onshore fields.

CASE	DESCRIPTION
Downdip	Injectors remain in their original waterflood locations injecting into the water zone below the original Oil/Water Contact (OWC).
Near OWC	After waterflooding, injectors re-located updip, just within the original oil zone.
Crestal	After waterflooding, injectors re-located updip to the crest of the field, typically about 2400 ft from producers.
Flank	After waterflooding, injectors re-located updip at an intermediate position between the 'Crestal' and 'Near OWC' cases.

Table 1: Simulation Case Descriptions

If none of the original injection wells are re-located ('Downdip Case'), oil production rates build up slowly as the injected CO2 must then traverse about 7000 to 9000 ft of water before contacting oil. However, in this case oil rates are maintained at higher rates for longer than for the cases were injectors are re-located much nearer the crest ('Crestal' and 'Flank').

For injectors re-located just within the oil zone, ('Near OWC' case), oil production rates do rise quickly, but are also maintained for longer. For both the 'Downdip' and 'Near OWC' cases, there is a long period, exceeding ten years, of relatively low backproduction of CO2, see Figure 2.

[1] Report to the North Sea Basin Task Force, "Development of a CO2 Transport and Storage Network in the North Sea", Element Energy, Poyry Energy and the British Geological Survey, for BERR 2007.

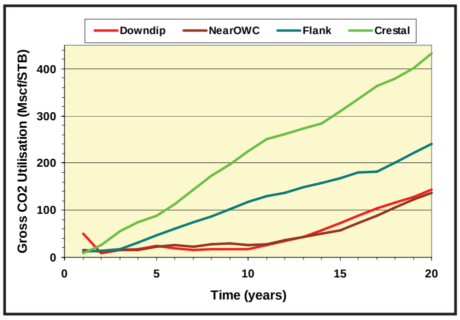


Figure 2 - Gross CO2 Utilisation Against Time

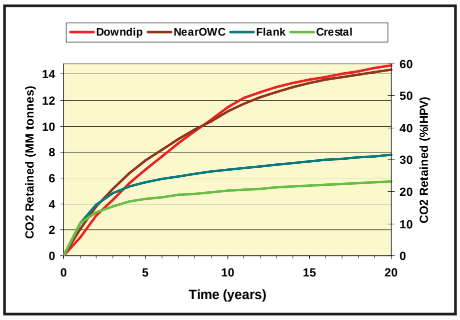


Figure 3 - CO2 Stored in Reservoir Against Time

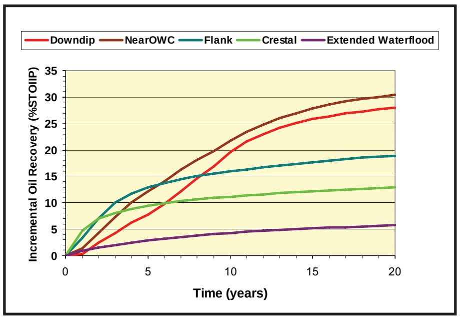


Figure 4 - Cumulative Incremental Oil Recovery Against Time

This shows the Gross CO2 Utilisation, the ratio of injected CO2 to incremental oil recovery, calculated on an annual basis. For both these cases CO2 is stored in almost 60% of the initial hydrocarbon pore volume after 20 years injection, see Figure 3. High incremental recoveries over extended water flooding of 22 to 25% STOIIP were achieved after 20 years injection, see Figure 4.

In the cases for which injectors are relocated near the crest ('Crestal' and 'Flank'), high oil production rates are obtained from the start. However, there is also an immediate rapid rise in CO2 production with a high percentage of CO2 injected being backproduced after a short time, see Figure 2. Oil production rates also fall very substantially by about five years CO2 injection, because the target oil is significantly less in these two cases. These cases only store about half the CO2 of the other cases, Figure 3. Incremental recoveries over extended waterflooding after 20 years are about 7% STOIIP for the 'Crestal' case and 13% for the 'Flank', see Figure 4.

Discounted economic analysis was performed for continuous CO2 injection comparing each of the four cases studied using cost and value assumptions made in a report to the North Sea Basin Task Force[1] for a range of economic scenarios. Overall the 'Near OWC' and 'Flank' cases have typically the greatest economic value, though the 'Near OWC' case has the advantage that about double the amount of CO2 is stored and CO2 backproduction remains relatively low for about 10 years. The absolute economic viability depends on the specific economic scenario considered, particularly the oil price and cost of supply pipeline.

It has been demonstrated that continuous CO2 injection at high rates into a medium size UKCS type reservoir may be feasible and can achieve both high incremental oil recoveries and CO2 storage in areas where reservoir thickness is comparable to onshore reservoirs in the USA, and where wells can be located to optimise EOR performance.

Acknowledgement

The authors are grateful to the UK Department of Energy and Climate Change (DECC) for funding this work and permission to publish. Any views expressed or interpretations made are those of the authors.

More information

A detailed version of this article is available at:
www.og-mrp.com/dissemination/co2/resmod/HighRateContinuous.pdf
Or visit: www.rpsgroup.com

About the company

RPS Energy is an international consultancy providing independent advice on the exploration and development of oil and gas, renewable energy and other natural resources; the management of the environment; the health and safety of people and the development of energy related infrastructure. RPS Energy advises governments and a wide variety of energy sector clients on issues such as establishing safe and secure sources of energy. RPS Energy also provides specialist technical advice on carbon emissions reduction and carbon capture and storage.

UK releases clean coal consultation and proposes funding bill

The UK has set out its intention to be at the forefront of CCS development in "A Framework for the development of clean coal: consultation document." A new Energy Bill has also been proposed for the forthcoming session of Parliament.

The proposals under consultation include:

- Providing financial support for up to four commercial-scale CCS demonstrations in Britain, including the CCS demonstration competition that we launched in 2007, covering a range of CCS technologies;
- Requiring any new coal power station in England and Wales to demonstrate CCS on a defined part of its capacity;
- Requiring new coal power stations to retrofit CCS to their full capacity within five years of CCS being independently judged technically and economically proven. We will plan on the basis that CCS will be proven by 2020;
- Preparing for the possibility that CCS will not become proven as early as expected

The document sets out several options for funding the first generation of CCS plants in the UK including an obligation on suppliers to buy a proportion of CCS electricity, a levy on electricity suppliers, a feed-in tariff and funding through the EU Emissions Trading Scheme.

The Government is also consulting on the development of pipeline infrastructure to transport CO2 into the North Sea, through a regional cluster approach. Clusters will be concentrated in the Firth of Forth, Thames Gateway, Teesside, Merseyside and the Humber areas.

The consultation opened on 17th June, and will run for a period of 12 weeks until 9th September 2009.

The proposed Energy Bill was announced in 'Building Britain's Future', published by Prime Minister Gordon Brown, which outlines the UK Government's priorities and its draft legislative programme.

The shift to low carbon at home and abroad, and capitalising on the opportunities presented by new green industries, is an important part of building Britain's future.

Responses

Urging the Government to maintain momentum in developing CCS, **Jeff Chapman, Chief Executive of the Carbon Capture & Storage Association** comments:

"The publication of this consultation is a welcome step on the road to developing the first generation of CCS plants in the UK."

"However, this should be a swift, sharp and focussed consultation aimed at developing a robust funding framework for CCS and enabling the infrastructure needed to transport CO2 for storage."

"We cannot afford to drop the ball at this point. We are close to getting an appropriate framework to develop CCS at a commercial scale."

"Industry stands ready to deliver on CCS and as 2009 is a critical year in terms of tackling climate change and building green jobs, the Government needs to move quickly to ensure CCS can fulfil its climate change potential as well as delivering prosperity and employment."

Stephen Hale, director of Green Alliance, says:

"This is the litmus test for Labour's commitment on climate change. Britain's coal policy is still on a knife edge. Ed Miliband has sketched out a tantalising picture of a dramatic new coal policy."

"By October, he must deliver a definitive policy that secures the multi-billion pound investment we need for carbon capture and storage technology. This must combine a clear regulatory framework with financial support to bring CCS to market."

Lord Chris Smith, Chairman of the Environment Agency says:

"This is a big step forward for UK climate policy. The Government's decision not to build any new coal power stations without carbon capture technology offers real hope of a new era of 'clean coal'. It is an essential element of any sensible energy policy for the next 20 years and is vital in our fight against climate change."

"The proposal for up to four large scale demonstration projects in the UK will help ensure the technology is robust and we welcome the proposed role for the Environment Agency in assessing when the technology is proven and should be retrofitted."

"The Environment Agency recognise that there are still some significant issues to address including contingency plans should it take longer than anticipated to prove the technology. We will be working with the Department for Energy and Climate Change to ensure such obstacles are overcome."

Shadow Energy and Climate Change Secretary, Greg Clark says:

"I welcome the fact that the Government has now recognised the scale of the challenge of meeting our urgent energy security needs and reducing our CO2 emissions by using Conservative policy as the basis for their CCS plans."

"However, the Government has missed a golden opportunity to set an Emissions Performance Standard that would set a legal limit on the release of greenhouse gases from new power stations."

"This announcement should have closed the door on unabated coal, but the Government has left the door ajar"

Sam Gomersall of CO2DeepStore comments:

"DECC's new framework for the development of clean coal offers some CCS progress but fails to get to grips with some of the key challenges for introducing CCS into the UK. The proposed 2% tariff on electricity bills will not provide any incentive to deliver CCS beyond the initial four demonstration projects. The government needs to plan for sustained development of the market if it is to achieve its aim of all UK coal plants being CCS compliant by 2025."

"While the current focus of government policy is to develop and trial carbon capture facilities, a matching emphasis is also required on the development of offshore CO2 storage facilities," he says.

"The government has still not taken the necessary steps to ensure that a market develops in CO2 storage provision – currently one of the key gaps in the CCS infrastructure. It is clear that the established oil and gas companies are not interested in this field. Overall we still detect a serious mismatch between stated ministerial ambitions and the plans actually being put forward."

More information

The full consultation report is available at: www.decc.gov.uk

www.hmg.gov.uk/buildingbritainsfuture

www.green-alliance.org.uk

www.environment-agency.gov.uk

www.co2deepstore.com

Policy, company and regulation news

DOE invests $408 Million in two coal CCS projects

www.fossil.energy.gov

Projects by Basin Electric Power Cooperative and Hydrogen Energy International LLC have been selected for up to $408 million in funding from the American Recovery and Reinvestment Act.

The selection of the two projects is part of the third round of the Clean Coal Power Initiative (CCPI). The Department of Energy will provide up to $408 million in federal funds - $100 million to Basin Electric Power Cooperative and $308 million to Hydrogen Energy International LLC - to support the innovative demonstrations.

The CCPI is a cost-shared collaboration between the federal government and private industry to increase investment in low-emission coal technology by demonstrating advanced coal-based, power generation technologies. The goal of CCPI is to accelerate the readiness of advanced coal technologies for commercial deployment, ensuring that the United States has clean, reliable, and affordable electricity and power.

The selected proposals will employ different technological concepts to achieve a goal of at least 90 percent CO2 capture efficiency. Descriptions of the selected proposals include:

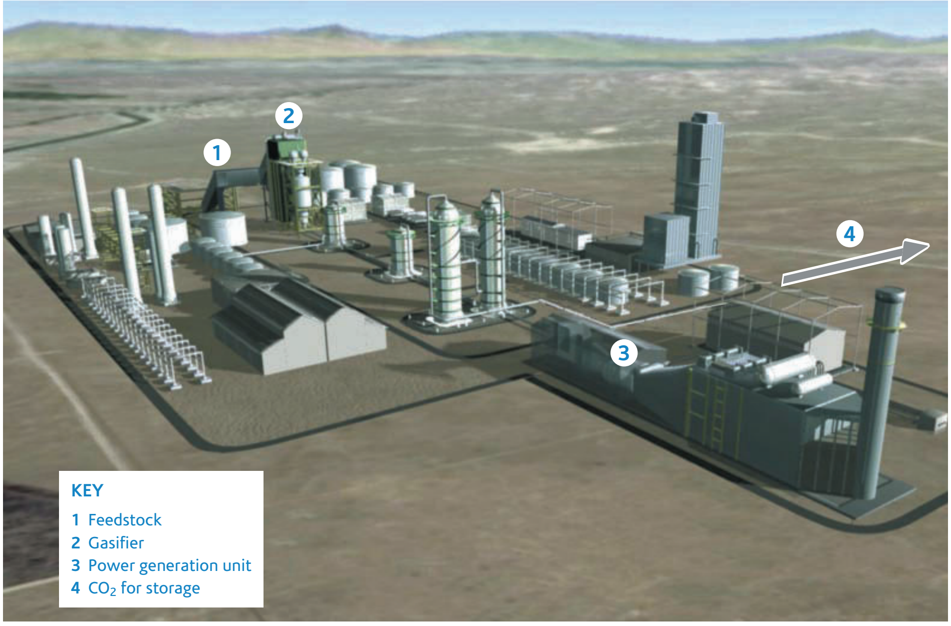
• Hydrogen Energy International LLC ($308 million)

Kern County, California

Hydrogen Energy California Project: Commercial Demonstration of Advanced IGCC with Full Carbon Capture - Hydrogen Energy International LLC, a joint venture owned by BP Alternative Energy and Rio Tinto, will design, construct, and operate an integrated gasification combined cycle power plant that will take blends of coal and petroleum coke, combined with non-potable water, and convert them into hydrogen and CO2. The CO2 will be separated from the hydrogen using the methanol-based Rectisol process. The hydrogen gas will be used to fuel a power station, and the CO2 will be transported by pipeline to nearby oil reservoirs where it will be injected for storage and used for enhanced oil recovery. The project, which will be located in Kern County, California, will capture more than 2,000,000 tons per year of CO2.

• Basin Electric Power Cooperative ($100 million)

Post Combustion CO2 Capture Project - Basin Electric Power Cooperative will partner with Powerspan and Burns & McDonnell to demonstrate the removal of CO2 from the flue gas of a lignite-based boiler by adding CO2 capture and sequestration (CCS) to Basin Electric's existing Antelope Valley Station, located near Beulah, N.D. Powerspan's ECO2® ammonia-based technology will be used to capture CO2 on a 120-megawatt electric-equivalent gas stream from the 450 megawatt Antelope Valley Station Unit 1. The net result will be 90 percent removal of CO2 from the treated flue gas, yielding 3,000 short tons per day (1,000,000 tons per year) of pipeline-quality CO2. The ammonia based SO2 scrubbing system will also produce a liquid stream of ammonium sulfate that will be processed into a fertilizer by-product.



Hydrogen Energy International's IGCC with carbon capture project in Kern County, California has received $308M in funding from the DOE

DOE creates National Carbon Capture Center

The NCCC will develop and test technologies to capture CO2 from coal-based power plants.

Southern Company will establish and manage the NCCC at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama.

The NCCC will meet a critical need of the Energy Department, said the DOE, by serving as a test center for emerging carbon capture technologies. It will enable testing and analysis at a scale large enough to provide meaningful data under real operating conditions.

The NCCC is expected to create or sustain nearly 170 jobs that will last the duration of the 5-year project.

"The management of CO2 from coal-fired processes is considered by many to be the single most important component required for successful development of advanced coal-fired power systems," said Dr. Victor K. Der, Acting Assistant Secretary for Fossil Energy. "The creation of a national research center focused on carbon capture from fossil-fueled power plants bolsters U.S. efforts to reduce greenhouse gas emissions while taking advantage of America's vast coal resources."

The PSDF was established by DOE with cooperation from Southern Company, and has established a consistent record of testing, development and scale-up of numerous advanced coal-based power generation technologies, many of which are now entering commercial deployment.

With an existing coal gasifier and combustor already in place, the facility offers an opportunity for conducting large-scale research and development for CO2 capture technologies from coal-based power generation.

Processes that have been studied at laboratory or bench-scale under ideal conditions can be quickly deployed to the NCCC for testing and evaluation under conditions that would be expected at a commercial coal-based power plant.

The center will also work with technology developers around the world to develop innovations needed to create high-performing CO2 capture technologies that can be cost-effectively deployed by power generators.

A major benefit of the NCCC will be its flexibility. The facility will offer multiple slip-stream capabilities for testing candidate

processes, with the ability to investigate different ranks of coal, biomass, and other fuels. In addition, multiple projects can be tested in parallel with a wide range of testing equipment. Long-term testing will also be available to establish the durability and reliability of new technologies.

Technology development at the NCCC will include both pre- and post-combustion CO2 capture. The pre-combustion CO2 capture component will be located at the PSDF, and the post-combustion component will be developed at Plant Gaston, an Alabama Power coal-fueled generating plant adjacent to the PSDF.

In addition to DOE and Southern Company, current participants in the NCCC project include American Electric Power, Luminant, the Electric Power Research Institute, Arch Coal, Peabody Energy, and RioTinto. The center anticipates adding more partners as its work progresses.

Alabama Power's Plant Barry will be used by Southern Company to demonstrate CCS on a coal-fired power plant with Mitsubishi Heavy Industries' proprietary process

Southern Company & MHI to Demonstrate CCS Technology

www.southerncompany.com

Southern Company has announced plans to demonstrate CCS on a coal-fired power plant near Mobile, Alabama.

Along with the U.S. Department of Energy (DOE), Mitsubishi Heavy Industries Ltd. (MHI), the Electric Power Research Institute and other partners, Southern Company will build a demonstration facility to capture carbon dioxide emissions from an existing unit of subsidiary Alabama Power's Plant Barry.

Beginning in 2011, between 100,000 and 150,000 tons of CO2 per year - the equivalent of emissions from 25 megawatts of the plant's generating capacity - would be captured for permanent underground storage in a deep saline geologic formation.

The CO2 will be supplied to the DOE's Southeast Regional Carbon Sequestration Partnership (SECARB), which will transport it by pipeline from the plant and store it underground at a site within the area of the Citronelle Oil Field, about 10 miles from the plant, operated by Denbury Resources. The Southern States Energy Board is leading the SECARB effort.

"This project will help increase our knowledge of carbon capture and sequestration, technology we must demonstrate at a commercial level in the effort to reliably generate electricity using coal with reduced greenhouse gas emissions

"The main challenge facing deployment of carbon capture and sequestration technology is demonstrating its effectiveness at a large scale," said David Ratcliffe, Southern Company chairman, president and CEO. "Our involvement in this and other related projects is part of our commitment to be a leader in finding solutions that make technological, economic and environmental sense."

The CO2 capture technology to be used in this project, called KM-CDR™, was jointly developed by MHI and the Kansai Electric Power Company Inc. It deploys an advanced amine-based solvent that reacts readily with CO2 in flue gas before being separated and compressed so that it is ready for pipeline transport.

According to MHI, the process offers improved performance and lower cost than other existing capture technologies. It has been demonstrated at smaller scale at a coal-fired generating station in Japan, and is currently being deployed commercially on natural gas-fired systems around the world. This project represents the largest coal-fired demonstration of the technology.

"We are excited to be a partner in this important project that will help further the global goal of reducing carbon dioxide emissions for the benefit of everyone," said Shunichi Miyanaga, executive vice president and representative director general manager of MHI's Machinery & Steel Structures Headquarters.

"The confidence our partners have shown in the MHI CO2 capture technology is a testament to the research and development efforts we have undertaken during the past 20 years. Together with our partners, we are ready to deploy and demonstrate to the world the safety and viability of commercial-scale CCS."

Plant Barry has a total capacity of 2,525 megawatts and includes seven generating units - five coal-fired units and two natural gas-fired combined-cycle units.

FutureGen agreement reached

www.fossil.energy.gov

U.S. Secretary of Energy Steven Chu has announced an agreement with the FutureGen Alliance that paves the way for the project to restart.

Under the terms of the provisional agreement between the Department of Energy and the FutureGen Alliance, the Department will issue a Record of Decision on the project by the middle of July, with the following activities to be pursued from the end of July 2009 through early 2010:

• Rapid restart of preliminary design activities.

• Completion of a site-specific preliminary design and updated cost estimate.

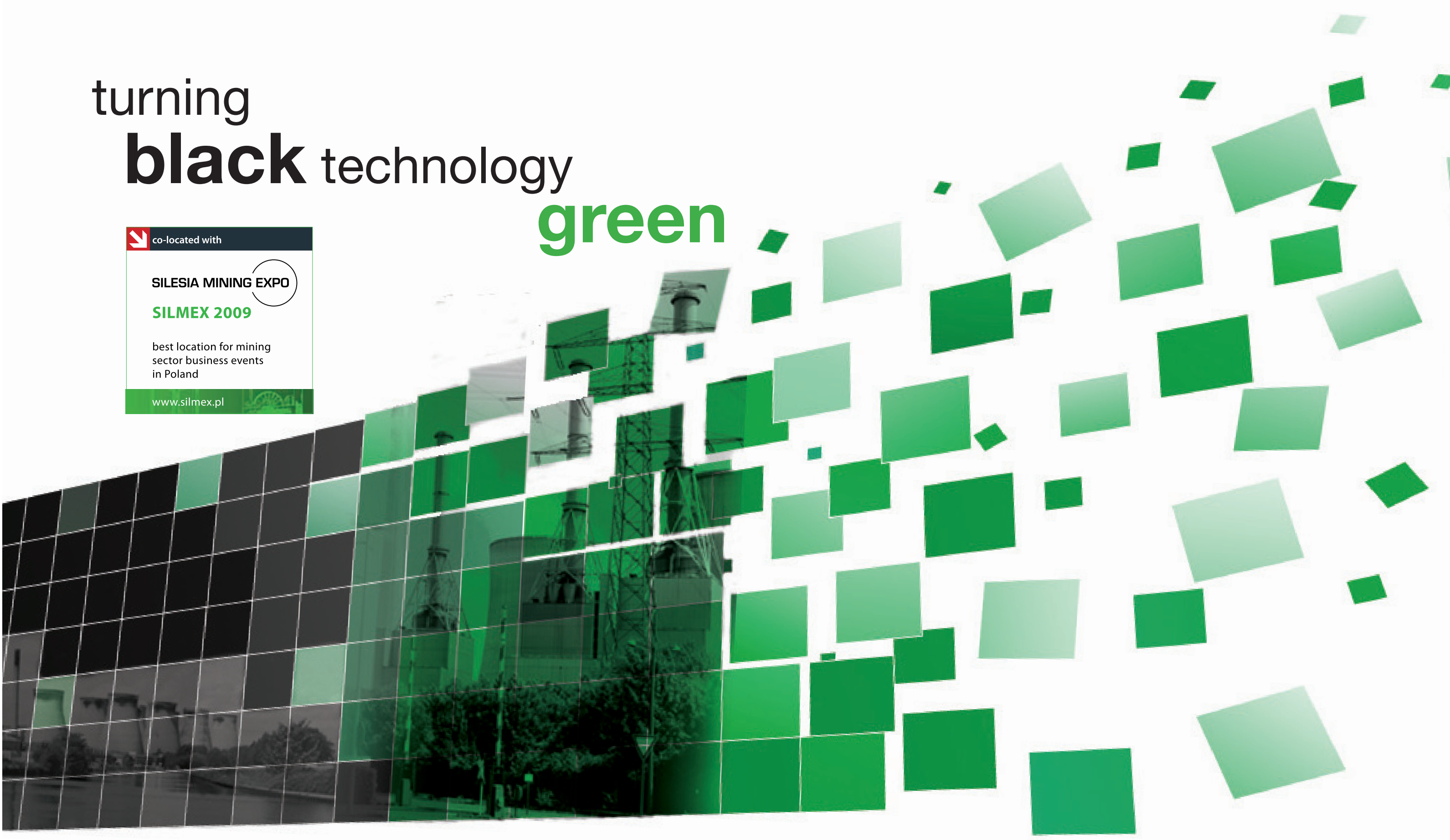
• Expansion of the Alliance sponsorship group.

• Development of a complete funding plan.

• Potential additional subsurface characterization.

Following the completion of the detailed cost estimate and fundraising activities, the Department of Energy and the FutureGen Alliance will make a decision either to move forward or to discontinue the project early in 2010.

Both parties agree that a decision to move forward is the preferred outcome and plan to reach a revised cooperative agreement that will include a funding plan for the full project. Funding will be phased and conditioned based on completion of NEPA review.



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The Department of Energy's total anticipated financial contribution for the project is $1.073 billion, $1 billion of which comes from Recovery Act funds for CCS research. The FutureGen Alliance's total anticipated financial contribution is $400 million to $600 million, based on a goal of 20 member companies each contributing a total of $20 million to $30 million over a four to six year period.

The Alliance, with support from DOE, will pursue options to raise additional non-federal funds needed to build and operate the facility, including options for capturing the value of the facility that will remain after conclusion of the research project, potentially through an auction of the residual interests in late autumn.

Norway pledges EUR 140 million for CCS

www.regjeringen.no

Norway will earmark EUR 140 million over five years for CCS projects in selected EU member states.

The money is part of the already allocated Norwegian contribution to the EU, but will now be earmarked specifically for developing CCS technology.

The announcement was made by Prime Minister Stoltenberg today at the Government's high-level conference Fighting Climate Change with Carbon Capture and Storage in Bergen.

"The EU is a driving force in the development and implementation of CCS technologies. As part of our total contribution during the next period of the EEA Financial Mechanisms, Norway wants to earmark at least EUR 140 million over five years to support CCS projects in selected EU member states," said Prime Minster Jens Stoltenberg.

"A new international climate regime should promote technology transfer and cooperation. CCS is essential for reducing global greenhouse gas emissions," the Prime Minister added.

ScottishPower begins CO2 capture test

www.scottishpower.com

ScottishPower has begun operations on a test project to capture CO2 emissions from Longannet power station – the first time in the UK that they have been captured from a working coal-fired power plant.

The prototype, developed by Aker Clean Carbon, is an exact, small-scale replica of a full-scale carbon capture plant. It will allow ScottishPower to test the complex chemistry involved in capturing CO2 from power station flue gases and is a major milestone in delivering the reality of carbon emission free coal generation.

At the same time, ScottishPower's parent company Iberdrola confirmed that it will establish a global Centre of Excellence to develop CCS technology in the UK. To launch this, the company announced today that it will be funding a Chair in Carbon Capture and Storage at the University of Edinburgh to provide a academic focus for the Centre of Excellence.

"We believe that the UK can lead the world with CCS technology, creating new skills, jobs and opportunities for growth," said

Iberdrola and ScottishPower Chairman Ignacio Galán. "There is the potential to create an industry on the same scale as North Sea Oil, and we will invest in Scotland and the UK to help realise this potential. Iberdrola will set-up its global Centre of Excellence for CCS in the UK to help accelerate the deployment of full-scale CCS."

"This prototype carbon capture unit is a major step on the road towards our Centre of Excellence and the essential data from the unit will shape our research. We are proud to be working with the University of Edinburgh, and this partnership will be pivotal in developing our Centre of Excellence."

The prototype unit, which weighs 30 tonnes and covers an area of 85m2, will be able to process 1000 cubic metres of exhaust gas per hour from Longannet. Amongst other tests being carried out, ScottishPower scientists will be monitoring the effectiveness of the chemical amine solution that captures the CO2 under different conditions. The data will allow ScottishPower to better understand the science before a full-scale demonstration project is built, eventually capturing up to 90% of CO2 from Longannet.

"The test unit uses the exact same technology that we aim to retrofit to the station for a commercial scale CCS project by 2014, and the leap from 1MW to 330MW is now within sight," said Nick Horler, Chief Executive of ScottishPower. "There are over 50,000 fossil fuel power stations in operation throughout the world, and by proving that CCS technology can be retrofitted to existing stations, we can begin to address the carbon lock-in from these power plants."

"The switch-on today, coupled with the recent Scottish Regional Study highlighting the Central North Sea's potential to store all of Europe's CO2 emissions well into the next century, means that a major new industry is now on the brink of being formed in the UK."

CCS Chair at Edinburgh University

The CCS Chair will be located in the Carbon Capture and Storage Group within the School of Geosciences, part of an alliance between the University of Edinburgh, Heriot Watt University and the British Geological Survey, known as the Scottish Centre for Carbon Storage. The Professor will be an expert leader of CCS development in the UK and globally.

ScottishPower has selected the University of Edinburgh to host its CCS Chair as a result of the strong ties developed over the past 3 years working on collaborative CCS research and development projects. Under the umbrella of the Scottish Centre for Carbon Storage, the University of Edinburgh led the work of the Scottish Regional Study that recently published an in-depth report highlighting the Central North Sea's potential to store all of Europe's CO2 emissions well into the next century.

ScottishPower will also engage with other academic institutions to which they have ties, including Imperial College London.

Indiana University publishes CCS brief

www.iu.edu

CCS is a promising tool that may help the United States meet future energy needs while controlling emissions of greenhouse gases linked to climate change, Indiana University researchers say in a new policy brief.

But CCS presents policy and technical challenges that must be addressed if the nation is to make effective use of its plentiful supplies of coal, researchers say in the May 2009 issue of SPEA Insights.

Authors of the brief are A. James Barnes, professor and former dean of the School of Public and Environmental Affairs at IU Bloomington, and Kenneth R. Richards, associate professor in the school.

"Policy analysts, social scientists and lawyers must work with scientists, engineers and technologists to design public policies that will encourage the demonstration of CCS systems that are safe, effective and affordable," Barnes and Richards write.

To help guide the implementation of CCS, they recommend:

• CCS should be deployed only if it is a cost-effective solution for reducing greenhouse gas emissions -- or as a "backstop" to less expensive measures.

• Congress must be careful in designing incentives for CCS, making sure it doesn't create measures that lead companies to overproduce electricity.

• States need to be involved in developing CCS regulations, particularly with regard to property rights, safety and liability.

• Policy makers must be sensitive to the complex politics of CCS, including the com-

peting interests of geographic regions and business sectors.

While CCS may not currently be cost-effective, the authors say, it may make sense to support development of the technology to learn about its costs, challenges and potential improvements. But projects underwritten by the government should include rigorous and open evaluation systems, with data made available to all interested stakeholders.

In the area of political complexity, Barnes and Richards note that initial efforts to develop CCS are taking place in the industrial Midwest, rather than in regions where coal is controversial. They say that the stance taken toward CCS by environmental groups is likely to be critical to the future of the technology.

£675,000 for UCL Carbon Capture Legal Programme

www.ucl.ac.uk/cclp

UCL's Carbon Capture Legal Programme has received a £675,000 donation from The Crown Estate, Rio Tinto, RPS Group, Schlumberger Carbon Services and Shell.

UCL launched the programme, which sits within the Faculty of Laws, in 2007 to bring together information on the different elements of law surrounding the fast evolving field of CCS in a fully open access online resource - the first of its kind.

The CCLP is also the sole academic partner in the International Energy Agency's (IEA) International Regulators Network, which provides a forum through which regulators can discuss on a regular basis a range of challenges faced by policy makers and regulators in the construction of regulatory solutions.

Through the CCLP, UCL is also a founding member of the Global Carbon Capture and Storage Institute (GCCSI), a global institute launched by the Australian government last month to facilitate CCS sequestration demonstration projects and their subsequent deployment around the world. UCL is the only academic institution to hold founding member status.

E.ON selects MHI and Foster Wheeler for UK demonstration

www.eon-uk.com

Following a major review of available technology, E.ON has selected MHI and Foster Wheeler Energy Limited as the project team to lead on the development and engineering for CCS at the proposed Kingsnorth plant in Kent, UK.

During the consultation process, E.ON says it will seek further clarity on issues such as the conditions of a new-build coal project, the funding mechanism for fitting CCS and the framework for associated CCS infrastructure. The company is also calling for more detail on how the Government intends to create a level playing field between new, cleaner coal and existing unabated coal and gas in the UK.

E.ON believes that the best way forward for the development of CCS would be to develop ‘clusters' of developments by linking a number of fossil-fired power stations and other industrial sites to a single carbon transportation system. To this end, the company has identified a Thames Cluster in the south east of England, the highest energy using region of the UK, to be an ideal location.

EU to raise funding for China CCS project

ec.europa.eu/environment/climat/future_action.htm

The European Commission has set out plans to co-finance the EU-China Near Zero Emissions Coal Plant project through a public-private partnership.

In 2005 the EU agreed to cooperate with China on a range of climate change issues, including CCS, in the context of the EU-China Climate Change Partnership.

It has now set out the Commission's plans for establishing an investment scheme to co-finance the design and construction of a power plant to demonstrate CCS technology in China.

The Commission has programmed funding of up to €50 million for the construction and operation phase of the project, out of a total of €60 million that has been earmarked for cooperation with emerging economies on cleaner coal technologies and CCS.

Depending on the choice of technology used, and assuming China introduces some form of carbon pricing instrument, the additional cost of constructing and operating over 25 years a new power plant equipped with CCS in China has been estimated at €300-€550 million.

The Commission will work closely with China, Member States, other European Economic Area (EEA) countries and industry to secure the additional financing required. The Commission proposes to combine these funding sources in a public-private partnership, possibly in the form of a a Special Purpose Vehicle.

This investment scheme could serve as a model for other technology cooperation activities between developed countries and emerging/developing countries in the context of a post-2012 climate change agreement.

The Commission invites EU Member States, interested EEA States and China to pledge financial and political support for this initiative. It also invites the European Parliament to provide its political support.

Mitsubishi to participate in Australia ZeroGen project

www.mhi.co.jp

Mitsubishi Heavy Industries (MHI) and Mitsubishi Corporation (MC) will provide a feasibility study for the ZeroGen IGCC project in Queensland, Australia.

The project will be the world's first commercial-scale IGCC power plant with CCS capability, producing 530 megawatts of electricity starting operation in 2015.

MHI is serving as the exclusive manufacturer, supplier and builder of the IGCC facility, including CO2 recovery and storage systems. MC will coordinate the overall project.

ZeroGen, which is wholly owned by the Queensland State Government, will be the project implementation body, responsible for the selection of potential sites in Queensland both for the IGCC plant and for a carbon transport and storage area, and will also handle other crucial areas such as infrastructure, coal supply, stakeholder engagement and environmental studies.

CMS Cameron McKenna launches EU 2020 climate package guides

www.law-now.com

Following the EU’s final approval of a set of directives aimed at helping the EU reach its climate change targets for 2020, CMS Cameron McKenna has launched a series of Q&A brochures aimed at helping those who wish to understand the key elements of this new legislative package and the potential key impacts on businesses.

The series will initially consist of 3 brochures looking at the following 3 directives:

- the new EU Emission Trading Scheme (EU ETS) Directive, which introduces various changes to the design of the EU ETS ahead of Phase 3 of the Scheme (due to start in 2013) aimed at helping the EU reduce its emissions of greenhouse gases by 20% below 1990 levels by 2020
- the new Renewable Energy Directive, which aims to increase the EU’s consumption of energy from renewable sources to 20% of the EU’s total gross consumption by 2020
- the new Carbon Capture and Storage Directive, which introduces a new regulatory framework for the onshore and offshore storage of carbon dioxide.

Cryogenic carbon capture technology

Sustainable Energy Solutions has commercialized an innovative CO2 capture technology called the cryogenic CO2 capture (CCC) process, developed by Dr. Larry Baxter at Brigham Young University. It is designed to separate a nearly pure stream of CO2 from power plant gases and according to SES has significant energy and cost advantages compared to alternatives.

The process is a post-combustion technology that cools CO2-laden flue gas to desublimation temperatures (-100 to -135 °C), separates solid CO2 that forms from the flue gas from the light gases, uses the cold products to cool incoming gases in a recuperative heat exchanger, compresses the solid/liquid CO2 to final pressures (100-200 atm), and delivers a compressed CO2 stream separated from an atmospheric pressure light-gas stream.

The overall energy and economic costs appear to be at least 30% lower than most competing processes that involve air separation units (ASUs), solvents, or similar technologies. In addition, the CCC process enjoys several ancillary benefits, including (a) it is a minimally invasive bolt-on technology, (b) it provides highly efficient removal of most pollutants (Hg, SOx, NO2, HCl, etc.), (c) possible energy storage capacity, and (d) potential water savings.

This article outlines the process details and economic and energy comparisons relative to other well-documented alternatives.

Process Description

The cryogenic CO2 capture (CCC) process (Figure 1) dries and cools flue gas from existing systems, modestly compresses it, cools it to a temperature slightly above the point where CO2 forms a solid, expands the gas to further cool it, precipitating an amount of CO2 as a solid that depends on the final temperature, pressurizes the CO2, and reheats the CO2 and the remaining flue gas by cooling the incoming gases.

The final result is the CO2 in a liquid phase and a gaseous nitrogen stream. CO2 capture efficiency depends primarily on the pressure and temperature at the end of the expansion process. At 1 atm, the process captures 99% of the CO2 at -211 °F (-135 °C) and 90% at -184 °F (-120 °C). These are relatively mild conditions as compared to competing processes, as is discussed next. Most alternative processes are not reasonably capable of achieving 99% CO2 capture.

Furthermore, the captured CO2 has virtually no impurity in it. A thermodynamic feature of CO2 in flue gases (< 15% CO2 on a dry basis) is that the CO2 will not form a liquid phase at any temperature or pressure. Rather, the CO2 desublimates, forming an essentially pure solid phase rather than a liquid solution that must be distilled.

This process shares some similar unit operations with oxygen-fired combustion followed by CO2 compression, often called oxyfiring and a competing CO2 separation process.

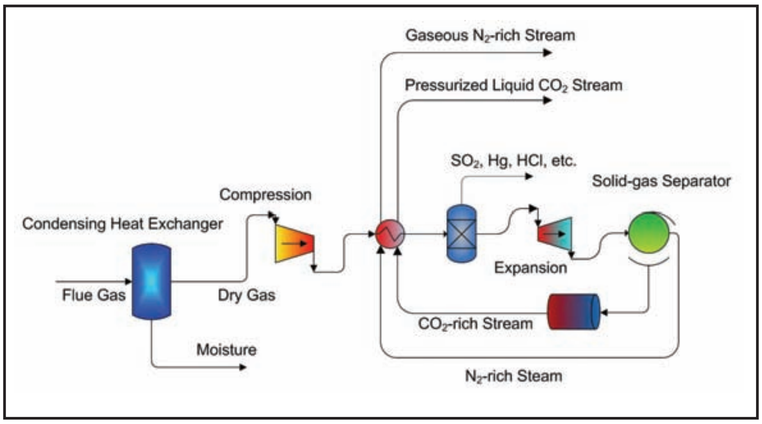

Figure 1- Simple schematic diagram of the cryogenic carbon capture process

A comparison of the two illustrates the cost and energy efficiency advantages of CCC (Figure 2). A typical oxyfiring process (1) separates oxygen from nitrogen in an air separation unit (ASU) that includes compressors, expanders, heat exchangers and distillation columns; (2) fires the combustion process with nearly pure oxygen, producing a gaseous CO2 and H2O product (plus impurities); (3) recirculates a fraction of the CO2 to manage the temperatures and heat loads in the boiler; (4) condenses the water in the exit gas to produce a nearly pure CO2 product; and (5) compresses the resulting CO2 stream to nominally 100 bar.

The steps that consume the greatest energy appear in the top of Figure 2. By comparison, the CCC process deals with a slightly lower volumetric flow rate of gases leaving the combustor on a dry basis compared to the dry volumetric flow rate of air entering the combustor with which the oxyfiring system deals. More significantly, the lowest temperatures in the CCC process range from -211 °F (-135 °C) to -184 °F (-120 °C), depending on desired capture efficiency. By comparison, the lowest temperatures in the ASU are about -328 °F (-200 °C), leading to higher losses in the cooling cycles, requiring more energy for cooling, and constraining quite severely suitable materials of construction.

More significantly still, the CCC process compresses a solid/liquid CO2 stream whereas the oxyfiring process compresses a gaseous CO2 stream, both from nominally atmospheric pressure to about 100 atm. Solids and liquid compression requires a very small fraction of the energy required for gaseous compression. Finally and most significantly, the CCC separates solid CO2 from nitrogen, a far less capital and energy intensive task than separating oxygen from nitrogen. The distillation stages in an air separation unit and the associated gas compression and cooling represent the most energy intensive portion of an ASU.

As indicated later, the oxyfiring process has about the same energy and cost performance as the alternative (mostly solvent-

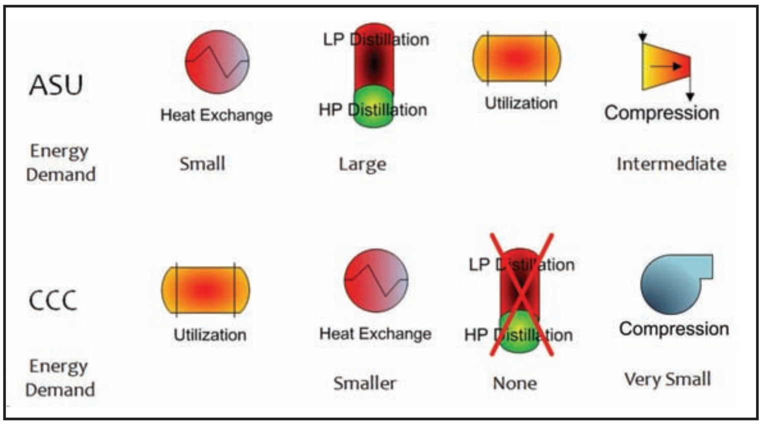

Figure 2 - Comparison of the energy demand in an air-separation-based unit and in the cryogenic carbon capture process

based) processes. The solvent-based systems differ in more significant ways from the CCC process and the systems do lend themselves to step-by-step comparisons.

However, the CCC process also handily outperforms the solvent-based systems, primarily because the solvent-based systems require a large mass of solvent to be cyclically heated and cooled (or in some cases pressurized and depressurized) to produce a comparatively small amount of CO_2.

The energy invested in the cyclical heating and cooling represents a major entropy source and hence energy sink in the process. Such cyclical and energy-intensive steps that involve the same materials generally represent the largest energy sinks in all of these processes. The analog in oxyfiring is the reflux in the distillation columns.

By comparison, there are no materials in the CCC process that cyclically change temperature, pressure or phase. The flue gas heating and cooling always involves new flue gas. In this sense, aside from losses in compression, expansion, and heat exchange, this process consumes no energy other than that required for the phase change and separation. That is, the CCC process has no embedded cycles that primarily produce energy.

Ancillary Advantages

In addition to the cost and energy efficiency advantages, the CCC process enjoys several ancillary benefits, including leveraging of existing capital investments, pollutant control, water savings, and potential energy storage. Each of these are discussed below, followed by some quantitative estimates of the costs of the CCC process.

Retrofit Technology

This CCC process can be installed either as a bolt-on retrofit technology or as an integrated technology. The bolt-on option makes this technology highly attractive for existing assets and for permitting new assets. In this configuration, essentially no changes to the existing facility are required. The flue gas is intercepted prior to the stack and flows through this process without modification of upstream systems. The only major requirement is that enough footprint is available for the new equipment (compressors and turbines).

Retrofitting existing plants leverages existing capital investments, improving project economics markedly. The economics of carbon capture processes that require new plant construction or significant alteration of existing plants often are dominated by the levelized plant capital costs, that is, the levelized capital expenses for the new/modified plant exceed all other costs. If permitting costs and construction costs and delays are also incurred, the new/modified plant becomes by far the largest cost element in the project. A retrofit technology such as CCC mitigates most of the problems and substantially reduces cost.

Pollutant Control

There are several compelling benefits to a fully integrated installation. The cooled, compressed gases make it possible to extract SO_2, NO_2, HCl, and Hg (among other things) in condensed-phase forms with efficiencies that exceed current best available control technologies.

NO does not condense as readily as the previous gases and will need alternative treatment, but pressure and temperature regimes of this process offer alternative means of removing NO that may reduce costs as well. Therefore, a green-field, fully integrated plant can redirect the capital, operating cost, and footprint resources currently dedicated to SO_x, NO_x, and Hg control and redirect these toward the carbon capture system.

Reduced Water Use

The substantial energy savings of this process directly lead to significant cooling water decreases relative to other carbon capture processes. Additionally, a fully integrated installation can heat the pressurized, nitrogen-rich stream with the boiler to drive a light-gas turbine cycle which requires no cooling water.

A pressurized nitrogen stream heated to the same temperature as typical steam turbine inlet temperatures (nominally 600 °C) generates power with approximately three times the efficiency as steam under similar conditions if the gas need not be recompressed. On a once-through basis, the steam is far more efficient than steam/water and avoids the cooling water load associated with water. This further reduces water demand by between 25-30%.

Energy Storage

Depending on the temperature and pressure of operation, the processes can produce a pressurized gaseous stream useful for energy storage. The CCC process is most energy efficient when the exiting light-gas stream is at atmospheric pressure.

However, if the end-point pressure is above atmospheric, the gases do not need to be cooled as far for a given capture efficiency or the capture efficiency increases at a given temperature, improving the process performance. These performance increases couple with the energy storage potential of the compressed gas to provide a solution, or at least a partial solution, to what the authors believe one of the largest issues in CO_2 capture and storage – the impact on peak load generating capacity.

The compressed gas could be released through a turbine or, better still, heated to higher temperatures and released through a turbine at peak load times to compensate for the capacity losses associated with carbon capture. The process would need to store enough compressed gas to last through the peaking period and would recompress gas at off-load times.

Performance Comparisons

Figure 3 illustrates estimated levelized costs for electricity for the proposed process (Bx1) and several alternatives, including the fuel, fixed operating and maintenance (FOM), variable operating and maintenance (VOM), capital (Cap), and transportation, storage and monitoring (TS&M) costs associated with CO_2 management.

Systems include supercritical pc combustion (SC), ultra-supercritical pc combus-

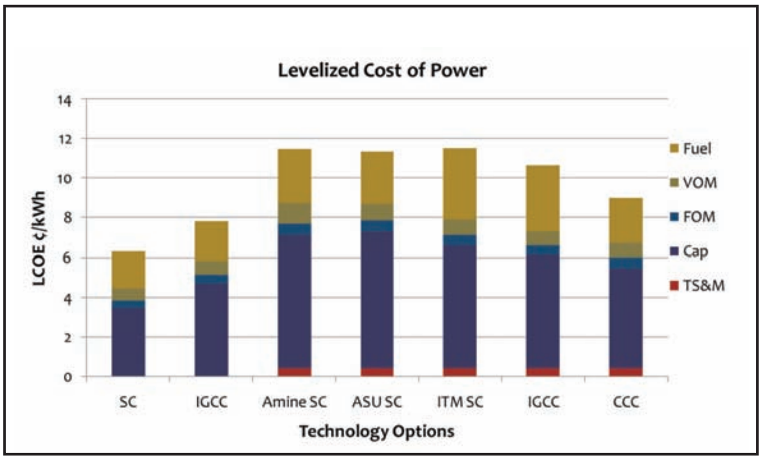

Figure 3 - Comparative levelized cost of electricity for the proposed process (BX1) and several alteratives, including the fuel, fixed operating and maintenance (FOM), variable operating and maintenance (VOM), capital (Cap), and transportation, storage and monitoring (TS&M) costs associated with CO_2 management. Systems include supercritical pc combustion (SC), ultra-supercritical pc combustion (USC), integrated gasification combined cycle (IGCC), and CO_2 capture technologies based on amine scrubbing (Amine), air separation units (ASU) , and ion-transport membranes. Non-Bx1 data come from DOE reports (Ciferno 2007; Klara 2007; Klara 2007)

tion (USC), integrated gasification combined cycle (IGCC), and CO2 capture technologies based on amine scrubbing (Amine), air separation units (ASU) , and ion-transport membranes (ITM). Aside from Bx1, the costs come from US Department of Energy NETL-based analyses (Ciferno 2007; Klara 2007; Klara 2007), with methods and assumptions as similar as possible between the NETL-based systems and the Bx1 system.

However, the extensive documentation of the NETL-based systems does not include many critical parameters, including such basic things as turbine and compressor efficiencies and costs associated with SOx and NOx control. NETL personnel indicate their commercial partners who helped develop the report asked that these numbers not be published and that the process simulations not be shared publicly.

The estimated cost of reducing CO2 emissions is substantially less in the Bx1 process than the other processes, as summarized in Figure 4. These data indicate a clear economic advantage for this process, which when coupled with the other advantages suggests it would be the process of choice among those reviewed here.

Energy costs for CO2 capture depend on both the purity of the resulting gas and the capture efficiency. This process produces an essentially pure CO2 product (thermodynamically, 100% pure), which is another advantage of this process compared to competitive processes.

The energy required per ton of CO2 captured from this processes appears in Figure 5 as a function of capture efficiency. The final point is greater than 99.99% capture. The dominant energy consumption is for flue gas compression. The two lines represent results from simulations with the best advertised polytropic compressor efficiencies (87%) and for very modest compression efficiencies (72%). Six-stage compressors with interstage cooling were assumed in both cases and at all compression ratios.

By comparison, detailed simulations of competitive processes indicate energy intensities of 1.6-1.9 GJ/ton (US Department of Energy 2007; US Department of Energy 2007; US Department of Energy 2008) while both purity and capture efficiency are lower. Unpublished results communicated to the authors suggest rates as low as 1.3 GJ/ton for some processes at about 90% capture efficiency.

All of these numbers assume a work-equivalent measure of energy. That is, adsorption processes, which primarily consume heat rather than shaft work, are evaluated on the basis of their impact on the net plant power output, not on the amount of heat energy used.

The cost and the energy comparisons discussed here use advanced process and cost modeling techniques, including vendor-vetted costing in many cases, sophisticated and validated non-ideal thermodynamic modeling, and detailed analyses.

Nevertheless, they are only accurate to within about 30% for all of the results. Even with this uncertainty the cost and energy advantages of the CCC process seem clear. We continue to improve the models and develop laboratory demonstrations and validations of the process and believe that the CCC process will prove considerably more attractive than the alternatives, as indicated here.

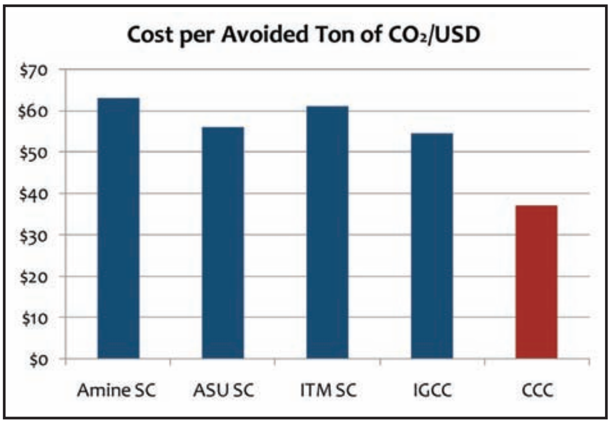

Figure 4 - Estimated cost per avoided ton of CO2 for a variety of processes and perturbations of these processes compared with the Bx1 process. Non-Bx1 data come from DOE reports (Ciferno 2007; Klara 2007; Klara 2007)

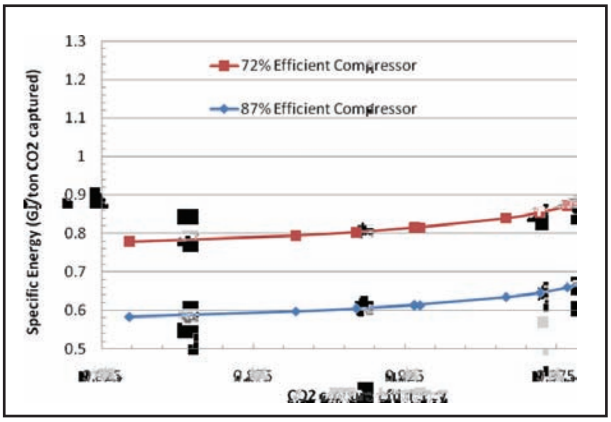

Figure 5 - Specific energy required for CO2 capture (GJ/ton captured CO2) as a function of capture efficiency. The final point is greater than 99.99% capture

Conclusions

Cryogenic CO2 capture (CCC) represents an innovative, new, and near-term alternative to most well-discussed processes in terms of cost, energy demand, and equipment/process compatibility at a power plant. CCC minimize the economic and energy demands of climate change management from stationary CO2 sources compared to well-documented alternatives.

Ancillary advantages include (1) it is a bolt-on/retrofit technology that can leverage existing power plants; (2) it is a multi-pollutant technology that may reduce or eliminate the need for several current and near-term pollutant controls devices (SO2, Hg, HCl, etc.); (3) it can incorporate energy storage that synergistically interacts with the CO2 capture process to improve the economic and energy performance of both; and (4) it can reduce water demand. CCC represents a leading alternative method of carbon capture for these and additional reasons.

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Further information

For more information about the cryogenic carbon capture system developed by Dr. Larry Baxter go to:
www.SustainableES.com
Or contact:
info at SustainableES.com

Capture news

CO2CRC H3 capture project launched

www.co2crc.com.au

Australia's most comprehensive post-combustion CO2 capture research facility has opened at International Power's Hazelwood Power Station in Victoria's Latrobe Valley.

"The CO2CRC H3 Capture Project will trial three CO2 capture technologies with Australian brown coal flue gases and evaluate them for larger scale capture," said Mr Barry Hooper, Chief Technologist of the Co-operative Research Centre for Greenhouse Gas Technologies (CO2CRC), one of the world's leading CCS research collaborations.

"Projects such as this will make retrofitting of post-combustion capture technology more practical and affordable for all power stations."

The project is using the 30 metre high solvent capture plant installed by International Power as part of the Hazelwood Carbon Capture Project to test and evaluate new and improved solvents, compare equipment performance, investigate impurities removal and optimise solvent capture processes.

The project will use purpose-built research modules to evaluate two new technologies for CO2 capture; membranes and adsorbents.

New types of membranes can be used to sieve out CO2 molecules from gas streams and can be integrated with solvent systems.

Adsorbents are solids that can capture CO2 on their surface, release it by reducing the pressure and be reused over and over.

The project will allow CO2CRC to use the existing research base of its capture activities in Victoria. The University of Melbourne is developing solvent and membrane technologies while Monash University performs research and development on adsorbents.

The project is part of the Latrobe Valley Post-Combustion Capture Project and is supported by the Victorian Government, through their Energy Technology Innovation Strategy (ETIS) Brown Coal R&D funding, and by the Federal Government, through the CRC Program.

MIT releases report on CCS retrofit

web.mit.edu/mitei/research/reports.htm

Professor Ernest Moniz, director of the MIT Energy Initiative (MITEI) and former undersecretary of the U.S. Department of Energy, has unveiled a report on reducing CO2 emissions from existing coal plants.

The report is based on the findings of a major MIT symposium on retrofitting coal-fired power plants, and identifies a range of possible next steps for the consideration of policy makers, industry, and others engaged in CO2 emissions mitigation.

"There is no credible pathway toward prudent greenhouse gas stabilization targets without CO2 emissions reduction from existing coal power plants. We urgently need technology options for these plants and policies that incentivize implementation," Moniz said. "We may not see a strong CO2 price signal for many years. In the interim, we need a large, focused federal program to develop and demonstrate commercial-scale technologies."

The focus of the March 2009 symposium was the retrofitting of existing pulverized coal plants with the capture of CO2 from flue gases after coal is combusted, or post-combustion capture technology.

Participants also identified a range of additional technology options for cutting CO2 emissions, including efficiency retrofits, co-firing of coal plants with low-carbon fuels, rebuilding existing subcritical units to ultra-supercritical units with capture, more extensive rebuilds such as oxy-combustion or Integrated Gasification Combined Cycle with capture, poly-generation, and the repowering of existing boilers with alternative fuels such as biomass or natural gas.

Some of the key findings of the report include:

• Relatively large, high-efficiency coal plants already equipped with desulfurization and nitrogen oxide emissions controls are the best candidates for post-combustion capture retrofit. Such plants make up less than half of the existing fleet. However, specific retrofit projects will need to pass various site-specific screens, such as available space, increased water supply, and CO2 off-take options.

A fleet-wide, detailed inventory of plants and sites is urgently needed to determine which plants are suitable for retrofitting, rebuilding, or repowering or for partial CO2 capture solutions tailored to the current plant configuration. This inventory should inform policy makers about the range of options for significant reduction of CO2 emissions from operating coal plants in different climate policy scenarios.

• The primary focus of research and development for existing coal plants should be on cost reduction of post-combustion capture. This is essential if retrofits are to be affordable in developing countries. An expanded R&D program should also include efficiency upgrades, rebuilds, repowering, poly-generation, and co-firing with biomass.

The CO2CRC H3 Capture Project. Image shows the solvent capture plant (pictured at back) installed by International Power as part of the Hazelwood Carbon Capture Project , as well as a CO2CRC adsorption rig (front left) and membrane rig (front right). (©CO2CRC)

Consideration should be given to including a component for research on CO2 capture from natural gas power plants. A robust U.S. R&D effort with this scope requires about $1 billion per year for the next decade (not including support for commercial scale demonstration).

• The federal government should dramatically expand the scale and scope for utility-scale commercial demonstration of coal plants with CO2 capture, including demonstration of retrofit and rebuild options for existing coal power plants. New government management approaches with greater flexibility and new government funding approaches with greater certainty are a prerequisite for an effective program.

• The world cannot achieve significant reductions in CO2 emissions, avoiding the most disruptive impacts of climate change, without commitments to reduce emissions from existing coal-fired power plants in the United States and China. Bilateral approaches on climate change should be encouraged and supported as a matter of U.S. policy. Joint R&D programs between the United States and China should be supported and funded.

The symposium included 54 subject matter experts from a range of stakeholder groups, including academia, government, public interest groups, and industry. Symposium participants were provided three commissioned white papers on key issues in advance.

Australia's first pre-combustion capture project launched

www.co2crc.com.au

The CO2CRC/HRL Mulgrave Capture Project was launched in May 2009 at HRL's gasifier research facility at Mulgrave in Melbourne, Victoria.

The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) has commissioned three CO2 capture rigs with the aim of reducing CO2 emissions from the next generation of high efficiency coal gasification power stations.

"The CO2CRC rigs will capture CO2 from syngas, the product of the brown coal gasifier, using three innovative new technologies," said Mr Barry Hooper, Chief Technologist of the CO2CRC. "These capture technologies are equally applicable to syngas from brown and black coal, gas or biomass fuels."

Advanced gasifier technologies are highly suitable for CO2 capture prior to storage as they produce a concentrated stream of CO2. During the project, researchers will evaluate solvent, membrane and adsorbent technologies for efficiency and cost-effectiveness.

"Our key objective is to reduce the technical risk and cost of capturing CO2 from the next generation of coal gasification power stations," said Mr Hooper. "Projects such as this can also help demonstrate that CCS is not only possible but practical.

"It's an exciting step up from lab research and will allow CO2CRC researchers from the University of Melbourne and Monash University to undertake applied research in an industrial environment."

The project is part of CO2CRC's CO2 capture research program, one of the world's most comprehensive. Australian CCS research is part of an international drive to make deep cuts in global greenhouse gas emissions by capturing and storing CO2 from major sources such as power stations.

The project has been supported by the Victorian Government, through Energy Technology Innovation Strategy (ETIS) funding. CO2CRC is supported through the Australian Government's CRC Program.

CO2CRC researchers are using this solvent rig to evaluate and improve solvent technologies for separating carbon dioxide from syngas during the CO2CRC/HRL Mulgrave Carbon Capture Project (Image ©CO2CRC)

US DOE selects pre-combustion projects

www.fossil.energy.gov

The DOE has selected nine projects that will develop pre-combustion carbon capture technologies for coal-based IGCC plants.

The projects, totaling nearly $14.4 million, will be managed by the Office of Fossil Energy's National Energy Technology Laboratory.

High-Temperature, High-Pressure Membranes

The focus of this research area is membrane-based separation devices approaching the theoretical separation selectivity and flux compatible with throughput rates of today's gasification technology

High Efficiency Solvents

In this research area applications were sought for R&D leading to optimal performance of novel, high-efficiency solvents for CO2 absorption allowing a step-change reduction in energy requirements compared to conventional solvents.

Solid Sorbents

In this research area applications were sought for R&D leading to optimal performance of novel sorbents for adsorbing CO2 with fast adsorption-desorption, and regeneration kinetics, and a low energy requirement to regenerate the sorbent material.

Novel Concepts

DOE solicited novel ideas on pre-combustion removal of the carbon content of the fuel and separation devices beyond current benchmarks of performance and cost that can separate hydrogen or CO2 from the water gas shift mixtures. In either option, the hydrogen must be available for the IGCC plant at practical rates and purity.

Siemens and TNO sign exclusive CO2 capture agreement

www.siemens.com/energy

Siemens Energy and TNO, the Netherlands Organisation for Applied Scientific Research, have signed an exclusive cooperation agreement aimed at the further advancement of amino-acid salt-based carbon capture technology.

Both Siemens and TNO have been working in the field of CO2 capture for some time. Siemens is developing a proprietary second generation amino-acid process for CO2 capture in the industrial park at Frankfurt Hoechst. TNO is involved in research as part of the CATO project in the Netherlands.

Under the terms of the agreement, know-how and experience in this area are now to be bundled in order to better use common resources. The process is to be further optimized with respect to power demand, and the associated costs reduced.

Siemens is currently building a pilot facility at the Staudinger power plant operated by E.ON, where it will be testing its process under real operating conditions.

"TNO is one of the first parties piloting second generation capture solvents," said Lodewijk Nell, Business Development Manager CO2 Capture at TNO. "We have been testing various solvents since April 2008 in our CATO pilot plant at the Rotterdam site of E.ON Benelux. We look forward to bring in our experience with amino acid salts supporting Siemens."

The technology for CO2 capture from the flue gas of power plants is an important feature of the Siemens environmental portfolio. In 2008, revenue from the products and solutions of Siemens environmental portfolio was nearly EUR19 billion, which is equivalent to around a quarter of Siemens total revenue.

Revaluing mine waste rock for carbon capture and storage

Current research at the University of British Columbia, Norman B. Keevil Institute of Mining Engineering and the Department of Earth and Ocean Science is focusing on harnessing and optimizing a natural process - Carbon Mineralization, as an industrialized solution to the problem of CO2 storage.

By Dr. Michael Hitch, Assistant Professor, Norman B. Keevil Institute of Mining Engineering

Environmental sustainability and responsibility has become an integral aspect of modern industries, and the mining industry in British Columbia is certainly no exception. Rising concerns over anthropogenic contributions to global warming through excessive greenhouse gas (GHG) emissions are creating demand to improve environmental practice, with many new environmental action plans currently in the works.

While the implementation of these policies will be an invaluable addition to current environmental practices, it is important to assess the economic and financial implications these regulations will have on the industry.

The process

Recent breakthroughs in sequestration research have shown that carbon mineralization is both realistic and technically feasible practice that may sequester large amounts of carbon as stable carbonate minerals. In a thermodynamic context, carbonate minerals are the most stable form of elemental carbon.

This is extremely important in carbon capture technologies since leakage, commonly attributed to other CO2 sequestration options, is prevented by forming naturally occurring and inert by-products. Mineral carbonation simply takes advantage of and accelerates the natural weathering process of silicate rock and its tendency to react with ambient CO2 to form carbonate minerals. This chemical reaction is represented as follows:

$$MgSiO_2 + CO_2 = MgCO_3 + SiO_2$$

Mg-silicates are ideal minerals for use in mineral carbonation. The relatively low solubility of alkaline earth metals promotes the fact that sequestered carbon is stable on a geologic time scale, thus reducing the risk of CO2 leakage over time and increasing the storage options available. These metals are also relatively invaluable in other applications and are abundantly found worldwide in silicates.

Nickel mines with their associated waste materials have proven to provide the best material for carbon mineralization. That being said other types of mines also have significant sequestration potential.

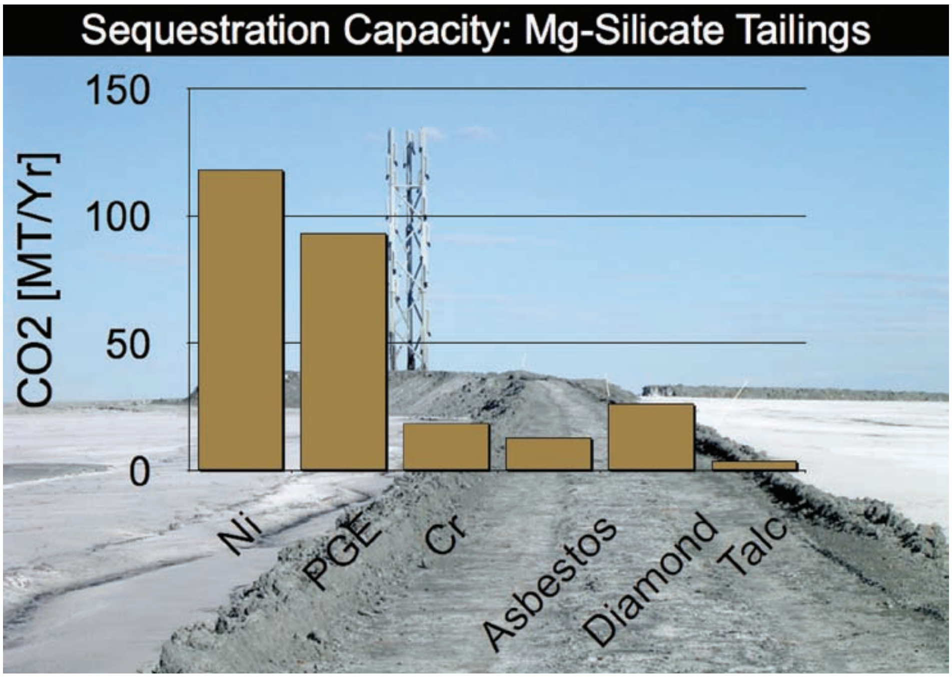

Figure 1 - Relative sequestration capacity of Mg-Silicate tailings with wastes from other commodity mines (courtesy of G. Dipple, Dept. of Earth and Ocean Sciences, University of British Columbia, Vancouver Canada)

How mine waste rock and tailings play a role

Historically, materials that do not contain ore minerals, industrial minerals, metals, coal or mineral fuels, or when the concentration of these materials is sub-economic, have been considered mine waste. These materials must also contain commodities with a concentration great enough to be mined profitably.

The notion of cut-off is used to differentiate waste rock from metalliferous ore. Cut-off is determined by the market value of the ore in each unit of rock that is mined compared to the cost of mining that unit. As a result, every mining operation has a different cut-off and criteria for the separation of waste from ore. Material that is not mineralized or has had the valuable commodity extracted from it is disposed of in an appropriate manner.

The mass excavation of mineralized material produces waste rock. This material is commonly drilled, blasted, and hauled to a permanent storage location and disposed of in stockpiles. Generally, these stockpiles or dumps are large and represent complex geotechnical structures. The heterogeneous nature of the material stored in waste dumps and the method of placement favours material segregation.

This process determines the geotechnical and hydrogeological behaviour of the pile. The internal architecture of the pile is influenced by the material's grain size, porosity, hydraulic properties, alteration of rock forming minerals, and the dynamics associated with water (e.g. precipitation, evaporation, runoff, seepage, and water retention).

The handling and storage of mine waste constitutes a financial cost to the mine operator. Estimates suggest around 1.5% – 3.5% of the total operating costs are associated with mine waste management. A direct, positive impact on the project cash flow can be realized from the revenue of a saleable mine waste product.

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CO_2 Geological Storage: latest progress

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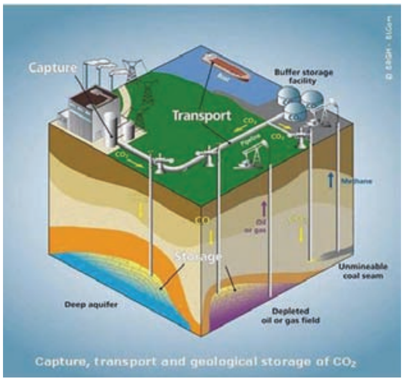
Capturing CO_2 at large industrial plants and storing it underground in deep geological layers is a top priority in the race to significantly reduce atmospheric emissions of greenhouse gases (GHG), thus helping to mitigate climate change and ocean acidification. By storing CO_2 underground, the carbon released through burning coal, oil and gas is returned back to where it was extracted, rather than released into the atmosphere.

Since the 90s, a huge research effort on CO_2 geological storage, especially in Europe, has led to significant outcomes and the technology has now reached a transition stage between research and worldwide deployment. There is now a need to assess the progress made, to bridge gaps between industry and research, to spread the results to a larger community of scientists and to train young engineers and researchers.

The aim of this conference is therefore to draw conclusions from the last decades of research and to outline the future challenges to be faced along the road to industrial implementation.

The interlinked presentations will unroll as follows: Firstly, a run-through of the characteristics of a good site for geological storage and how to select such sites (day 1), then the modelling techniques available to determine the behaviour of CO_2 in the reservoir (day 2), and consequently how to assess the risks linked to geological storage (day 3), followed by how to monitor a storage site (day 4). Finally, a summary of the whole process of a CO_2 geological storage project, from design through injection to closure and then abandonment, will be given (day 5). In addition, two sessions will focus on current and planned industrial demonstrations worldwide (days 2 and 4). At the end of each day, an open discussion session will enable participants to raise specific issues and to take on a broader perspective of the whole process. A poster session will also be organised, giving the opportunity for participants to present their work.

Special **grants** will be available for young scientists to cover their conference fee and possibly travel expenses.
Abstracts and grant requests should be submitted via the online application form.



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Co-chairs:
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Dr. Rob Arts, *CO_2GeoNet - TNO, NL*

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- Frank van Bergen, *CO2GeoNet-TNO, NL*
- Christian Bernstone, *Vattenfall, SE*
- Hubert Fabriol, *CO2GeoNet-BRGM, FR*
- Robert Finley, *Illinois State Geological Survey, US*
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- Aleksandra Kalinowski, *Geoscience Australia, AU*
- Anna Korre, *CO2GeoNet -Imperial College, UK*
- Mingyuan Li, *U. of Petroleum, Beijing, CN*
- Salvatore Lombardi, *CO2GeoNet - URS, IT*
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An obvious indirect benefit can be realized if creating this product results in reducing the size and area of the waste rock storage facility, thus reducing the environmental footprint of the operation. A smaller waste dump requires less capital expenditure at the end of the mine life for rehabilitation, closure, and long-term monitoring.

Rehabilitation of mine sites is a legislative requirement throughout Canada and in many parts of the world. Mining companies commit to a program of rehabilitation from the onset of operations. If the program is developed effectively, it incorporates the handling and storage of topsoil, waste rock, and tailings in such a way that will assist in the final rehabilitation of the sites. Mine planners must therefore consider the movement of materials, as well as the most appropriate storage of materials to minimize disturbance and amount of work required for site rehabilitation.

The potential economic return of the commodities to be mined drives mine design and operation. Optimization of an open pit is an economic exercise where the cost of removing overlying unmineralized 'waste' rock just equals the revenues – including profit. Simply put, cut-off is determined when financial unfeasibility or high operating costs prevent the mining of an ore block in sequence.

The optimal cut-off grade varies directly with anticipated changes in commodity prices and can change dramatically during the life of the mine. All material that falls below the cut-off grade is designated as waste and material above the cut-off grade is classified as ore. Cut-off grades drive the amount and sequence of mining waste and ore, and leads to the development of the open pit's strip ratio.

Strip ratio is equal to the amount of waste rock mined to release or uncover ore material. High strip ratios imply more waste rock is produced to release a unit of ore as compared to operations with low strip ratios. Defining these materials is predominantly determined by comparing the revenues and the cost of extracting the commodity being mined.

Fluctuating commodity prices poses one of the greatest risks to consider during mine planning and operation. Prices are determined on a global scale subject to the actual or perceived supply and demand for them. Pricing is fluid and is influenced by macroeconomic and geopolitical factors that are beyond the control of a mine. The common methods used to mitigate risks associated with unpredictable commodity prices include the use of forward sales contracts, hedging and long term smelter contracts. Successful mines also build in the capacity to adjust strip ratios to respond to commodity pricing.

An important consideration is the chemistry of the waste rock material being disposed of. Potential long-term impacts of weathering and subsequent release of deleterious liquors and dissolved metals determine how waste is handled and stored.

Implications of processing waste

The implications of using mine waste as a substrate for carbon mineralization fall in two broad categories. Each of these provide both the means by which carbon can be managed as well as having a direct and positive impact on both the supplier of raw material (miner) and the emitter.

Improved Mine Economics

The impact on the project's strip ratio is similar to that of the cut-off grade. By taking what was once a net cost item and revaluating it as a co-product or by-product, the strip ratio of the project decreases since a greater percentage of the material mined has value.

The costs associated with mining this new value added material can be apportioned to the overall strip of waste (by-product basis) or netted against any possible revenue from the sales (co-product basis). In either case, the revenue stream from the revaluated material will be greater than the costs associated with mining it in the first place.

Carbon Management

As climate change policies evolve, operations will be defined by their amount of greenhouse gas emissions. The development of mineral carbon sequestration could make suitable mines greenhouse gas neutral and could possibly become net-sequesters. This has great implications for the role of mines with mineral carbonation capabilities in future carbon policies and regulations.

Under market-based policy approaches, such as a cap and trade system (e.g. British Columbia's 2008 Greenhouse Gas Reduction Act and the European Union's Emissions Trading Scheme), firms that exceed a regulated carbon emissions limit will have to buy credits from firms that emit below the set limit or firms that sequester carbon.

In such policy arrangements, a suitable mine would be able to provide (or sell) carbon offset credits to firms that exceed their carbon emissions limit. Alternatively, mine waste suitable for mineral carbon sequestration could be sold to a firm which would then use the waste as part of its own operations to lower its carbon emissions (Government of British Columbia, 2008).

The long-term costs of global warming have been deemed too high to not act. Thus, setting a price on carbon is inevitable and essential to lowering emissions. Successful operations will be those who embrace climate change policies and incorporate the costs and benefits into their business plans.

All climate change policies are developed in response to the genuine concern for the environmental effects of CO_2 emissions. There is a growing consensus amongst political and economic analysts that policies successful in curtailing carbon dioxide emissions in a timely manner will require, in part, the use of carbon capture and storage technologies. As part of a climate change plan, mineral carbon sequestration would not only provide a potential financial asset to a suitable mining operation, it would be part of a practical and lasting solution to lowering greenhouse gas emissions.

Summary and conclusions

The waste from mining operations often has certain chemical properties that have the potential for use in other industries. Detailed evaluation of the waste material's chemistry, specifically its reactivity, dictates its end use. By its nature, relative to the ore material being mined, waste rock has no value. Under a scenario whereby rock waste can be used in an alternate industry, it gains value and immediately influences technical aspects of operations such as strip ratio, cut-off grade, and consequently the project's overall economic performance.

This paper has attempted to illustrate a developing mining project that can produce a mineral product as a co- or by-product that has far reaching value. The implications of this shift in the value of solid mine wastes improves the project's economics by increasing the revenue generating resource, reducing the amount of non-revenue generating material that has to be mined and land-filled, and by having a positive impact on the capture and sequestration of anthropogenic CO_2 emissions.

The author

Dr. Michael Hitch, Assistant Professor, Norman B. Keevil Institute of Mining Engineering

Transporting CO2 by pipeline: US issues and opportunities

Thus far, the approach to widespread CCS deployment has mostly focused on the more demanding undertaking of carbon capture, but the practicalities involved in transporting CO2 to storage sites are just as vital because an extensive interstate pipeline network will be required.

By Jude Clemente, Homeland Security Department, San Diego State University

Issues related to the onshore piping of CO2 – the most economical transportation method – must be resolved because a number of large point sources are removed from storage sites. The US has around 3,500 miles of CO2 pipelines, mostly in the Permian Basin of West Texas and New Mexico, transporting approximately 45 million tons of CO2 from natural and anthropogenic sources, primarily for the functional use of EOR.

Tertiary oil recovery in the US has been commercial since the 1970s and now yields about 250,000 barrels per day. But the potential is vast, as the US Department of Energy (DOE) says 90 billion barrels of oil could become technically recoverable if CO2-EOR expands to a national level.

The present analysis discusses the four key transportation issues that could constrain the construction of a national CO2 pipeline system in the US: 1) Technical Standards 2) Regulatory Issues 3) Pollutant vs. Commodity and 4) Costs.

1) Technical Standards

Transporting CO2 by pipeline in a liquid or gaseous state is a proven and mature technology. Specific Issues related to CO2 in its dense, high-pressure phase, however, are not fully covered in existing pipeline standards or regulations. For an interstate CO2 pipeline system to take shape in the US, consistent industrial guidelines are necessary.

Det Norske Veritas (DNV), a Norwegian firm specializing in energy transportation technologies, is joining with partners to develop the first industrial standards for the construction and operation of CO2 pipelines. The goal is to establish rules for limiting and managing uncertainties and risks throughout the pipeline's lifetime, such as the design, testing, inspection, operation, maintenance, and de-commissioning phases. Due to limited current industrial standards, DNV's project will examine issues specifically related to:

- Safety
- Fast propagating ductile fractures
- Fatigue crack growth
- Pipeline operation conditions
- Flow assurance
- Corrosion
- Material compatibility

Specifications and protocols would help CO2 pipelines gain more understanding and public acceptance. Pure CO2 is non-toxic and non-flammable, but it retains some special characteristics that make its transport a safety concern. CO2, which is heavier than air and tends to accumulate in low lying areas if ventilation is poor, may cause adverse health effects at concentrations above 10% by volume and poses a significant asphyxiation hazard at concentrations above 25%.

Restrictions on the chemical composition of the fluids that move through CO2 pipelines need to be more thoroughly developed. Too much water, for example, can produce carbolic acid and corrode carbon steel.

There is a need for a more robust and transparent approach to smooth out the irregularities that persist. The current pipeline standards do not consider issues relating to piping CO2 from large-scale capture sources to storage sites. These uncertainties could become a barrier to the effective deployment of CCS on a broad scale.

Existing hydrocarbon pipelines can generally be retrofitted to transport CO2 and provide a window for guideline specifications. A 2007 report by the Massachusetts Institute of Technology (MIT) favorably compared CO2 infrastructure with that of natural gas, as the pipelines are constructed with a similar attention to design.

There are about 300,000 miles of natural gas transmission pipelines operating in the US. The MIT study concluded capturing the nearly 2 billion tons of CO2 emitted by coal-fired power plants in the US each year would generate a CO2 flow with just 33% of the volume of the natural gas now flowing in the US pipeline system. Dooley et al (2006) argued a CO2 pipeline network built in response to climate change goals for 2050 might only require the construction of a few hundred to less than a thousand miles of new pipelines a year from now until 2030.

On the other hand, depending on how much CO2 the US seeks to sequester, ICF International claims a total CO2 pipeline network length between 15,000 miles and 66,000 miles by 2030 would be required. For an expansion of this magnitude, consistent technical guidelines are essential to rapid permitting, siting, construction, and operation of new CO2 pipelines. The engineering obstacles involved are not insurmountable.

The Intergovernmental Panel on Climate Change (IPCC) states, "There is no indication that the problems for CO2 pipelines are any more challenging than those set by hydrocarbon pipelines in similar areas or that they cannot be resolved."[1] DOE's Pacific Northwest National Laboratory (PNNL) adds, "The sheer scale of the required infrastructure should not be seen as representing a significant impediment to US deployment of CCS technologies."[2]

2) Regulatory Issues

The US agency that would be responsible for regulating a national CO2 pipeline system has not been identified. Currently, CO2 pipelines have similar siting requirements as oil pipelines. CO2 pipelines are sited under state law, and operators are free to set their own rates and terms of service. The US Department of Transportation's (DOT) Surface Transportation Board (STB) can hold proceedings to determine if rates are reasonable when a third party files a complaint – of which there are no known cases.

The federal regulation of CO2 pipelines demands more consideration because both STB and the Federal Energy Regulatory Commission (FERC) declare they lack jurisdiction. Oversight would ensure common carriers charge reasonable rates and do not discriminate among shippers.

Recent studies by the Congressional Research Service and others have found regulatory gaps could hinder the development of a national CO2 pipeline network. The Pipeline and Hazardous Materials Safety Administration (PHMSA), a part of DOT's Office of Pipeline Safety, oversees the construction and operation safety of pipelines (CO2 is listed as a non-flammable gas but treated as a hazardous liquid when piped).

Common carriage and private contract carriage are the two broad regulatory con-

cepts for CO2 pipelines (oil pipelines evolved as common carriers because operators did not own the oil they carried).

Texas, the state possessing the most mileage of CO2 pipelines, requires the pipeline be a common carrier to obtain eminent domain powers. In certain states, developers are forced to certify the pipeline is in the public's best interest before projects are approved. These various differences among states could significantly impede the development of an interstate highway of CO2 pipelines in the US.

Federal agency permits for CO2 pipelines may be required depending on various jurisdictions across federal lands. The number of state, local, and federal permits needed for construction is expected to vary by pipeline route. Because CO2 pipelines are already in use, policy decisions impacting them take on an urgency perhaps not immediately recognizable.

The regulatory frameworks for the oil and gas industry are seen as potential analogues. Figure 1 illustrates the similarities and differences regarding the regulation of the three types of pipelines. For the regional CO2 pipeline infrastructure to extend to a national network, it is clear an explicit federal regulatory framework must take root – there are currently only six interstate CO2 pipelines in the US.

Realizing that uncertainties in the regulatory process of CO2 pipelines inhibit network growth, the US Congress is attempting to resolve some of the key issues. The Energy Independence and Security Act of 2007 seeks to clarify the framework for issuance of CO2 pipeline rights of way on public land.

The Carbon Dioxide Pipeline Study Act of 2007 requires the Secretary of Energy to study the feasibility of constructing and operating a national CO2 network. Under the American Clean Energy and Security Act of 2009 (Waxman-Markey bill), DOE and FERC are directed to study the barriers involved in the widespread deployment of CO2 pipelines.

Factor	Oil Pipelines	Natural Gas Pipelines	CO2 Pipelines
Rates Regulation Authority (Interstate)	FERC	FERC	None (Possibly STB)
Regulatory Regime	Common Carriage	Common Carriage / Contract Carriage	Private, Contract, or Common Carriage
Ownership of Commodity	Mostly third-party ownership	Mandated interstate pipelines only transports gas owned by others	Common for CO2 owned by pipeline owner / third-party
Tariffs / Ongoing Regulatory Oversight	Yes - rates approved by FERC and increase indexed to PPI +/- an increment	Yes - rates periodically set by rate cases before FERC	No - STB, but only if a rate dispute is brought before it
Rate Disputes	Every five years the increment to PPI ismodified	Rare for disputes outside of rate cases, but they can be brought before FERC	Uncommon due to ownership relationships and prearranged deals
Siting	State and local governments	FERC	State and local goverments
Safety	PHMSA	PHMSA	PHMSA
Market Entry and Exit	Unregulated entry and exit	Need approval for both entry (construction) andexit (abandonment)	Unregulated entry and exit
Product Quality	"Batch" modes transport different products at different times	Specifications individually set in tariff approved by FERC	No Federal Regulations
Posting Information	Tariff information is available on-line	Daily operational and tariff information is available on-line	None Required
Eminent Domain	Yes - varies by state. More often if pipeline is a common carrier	Yes	Varies by State Law

Figure 1 – US Regulatory Framework: Oil, Natural Gas, and CO2 Pipelines
Note: PPI = Producer Price Index (Source: developed from ICF International data, 2009)

3) Pollutant vs. Commodity

CO2 transported for functional purposes brings with it issues distinct from its transportation as an industrial pollutant. For example, operators piping CO2 for EOR must ensure the pressure of any fluid in the pipeline is not too high to restrict production when mixed with the oil in the depleted reservoir.

According to ICF International, pipelines carrying CO2 for EOR use would need "minimum requirements for CO2 and maximum limits on nitrogen and hydrocarbons. A pipeline that was built to transport CO2 for disposal in saline reservoirs would not need to have these same limits."[3] The US oil and gas industry has a long history of moving CO2 as a commodity for tertiary recovery operations that can help serve as a model for its transport as a waste product. In fact, "The design of markets for CO2 as a commodity in EOR will guide the way markets develop for CO2 as a pollutant," remarks Owen Phillips, an economist at the University of Wyoming's Enhanced Oil Recovery Institute.[4] Contracts for CO2 sold as a commodity can serve as a template for its sale as a pollutant.

CO2 was classified as a pollutant by the US Supreme Court in 2007. This decision could initiate new automobile regulations and lead to a national "Cap and Trade" CO2 policy. There are important questions relating to transportation. For example, whether or not separate rates should exist for pipelines carrying CO2 as an important commercial commodity versus those carrying it as pollution headed for disposal.

In fact, Phillips (2008) points out there are a number of legal obstacles when CO2 is classified as a pollutant, as liability issues increase when an underground geological formation becomes a waste site. The uncertainties that could potentially slow CCS deployment include:

- Who owns the pore space and how are boundaries decided?
- What are the issues associated with induced seismic events, subsurface trespass, groundwater contamination, infringement of other mineral rights?
- What environmental and natural resource laws apply? For example, what happens if there are CO2 leaks?

The classification of CO2 will have a profound impact on CCS costs and could negatively influence the public acceptance of any CO2 transport and sequestration process. This could alter the complexion of future liabilities for emitters and pore space owners.

4) Costs

The construction and operation cost estimates for CO2 pipelines are generally based on comparisons to natural gas pipelines. PNNL reports the history of natural gas pipeline land construction costs suggest capital costs are about $40,000 (all financial data in US $) mile per inch of pipeline diameter.

A large CCS fitted power plant producing 10 million tons of CO2 per year (adequate for three 500 MWe plants) and having a main trunk pipeline 26 inches in diameter would cost $1.2 million per mile. Pipeline transport costs for CO2 are mostly a function of the type and characteristics of the point source, design mass flow rate, and the transport distance and terrain the pipeline must navigate to the selected storage reservoir. These factors and other variables, notably pipeline diameter, can cause costs to fluctuate by a factor of five.

MIT (2007) estimated overall annualized pipeline transportation (and storage) costs of about $5.50 per ton of CO2. The group concluded that pipelines transporting captured CO2 from a 1 gigawatt coal-fired plant would require a diameter of 16 inches.

A study at the University of California

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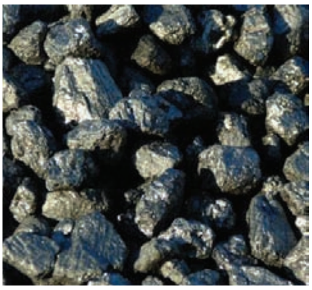

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at Davis in 2004 concluded such pipelines built between 1991 and 2003 cost $800,000 per mile. The analysis found labor, materials, rights of way, and miscellaneous costs respectively constituted 45%, 26%, 22%, and 7% of the total construction costs of US transmission pipelines built between 1991 and 2003.

The miscellaneous costs included surveying, engineering, supervision, administration and overhead, interest, contingencies, and regulatory filing fees. Ranging from 15% to 35% of total construction costs, the price of materials was closely dependent upon pipeline size.

To evaluate the cost of complying with possible emission policies, EPA modeling systems use $15 per ton of CO2 to represent the transport and storage cost of CO2 once it has been captured from a large anthropogenic point source. Figure 2 illustrates PNNL's cost split for six sample points on the CO2 transport and storage cost curve where the totals are roughly $15 per ton.

Case

1) Oil refinery in Mississippi in the close vicinity of a depleted gas basin

2) Small gas-fired power plant in Louisiana in the close vicinity of a depleted gas basin

3) Coal-fired power plant in Iowa 85 miles from a deep saline formation

4) Coal-fired power plant in Wisconsin 50 miles from a deep saline formation

5) Gas-fired power plant in New Mexico 60 miles from an unmineable coal seam

6) Smaller cement kilns in Kansas in the close vicinity of a depleted oil field

Eventually, CO2 pipeline costs could become even less of an economic barrier to developing a national CCS program. Kinder Morgan reports advancing technologies for EOR have allowed overall CO2 transport costs to drop 40% since the 1980s. As global production issues persistently mount, increases in the price of oil will raise technically recoverable reserve levels and boost EOR production.

As for non-EOR CO2 storage projects, ICF International claims shorter pipelines can be financed with corporate debt, while longer pipelines may require some sort of up-front financing supported by long-term contracts.

Overall, the role of government funding in the development of a large-scale interstate pipeline network is an ongoing debate. The capture, transport, and storage of industrial CO2 provides a dual economic benefit of working to reverse a declining US oil and industry and help obtain climate change goals.

Conclusion

Last year, DOE reported the US has the capacity to store 3,900 billion tons of CO2 at 230 different underground sites. Considering the US emits 6-7 billion tons of CO2 every year, this means ample space exists to store 100% of its emissions for approximately 560 years.

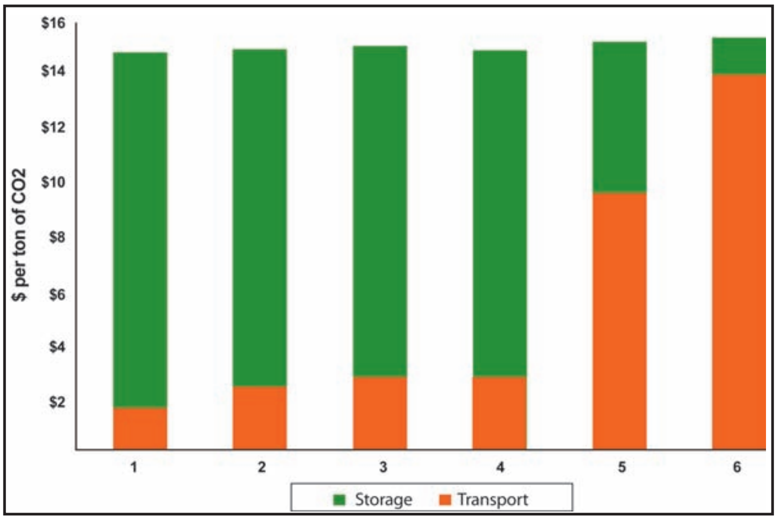

Figure 2 – CO2 Transport and Storage Cost. The figure depicts projects that have a transport and storage cost totaling approximately $15 per ton of CO2, as shown by six sample points on the cost curve. (Source: developed from Pacific Northwest National Laboratory data, 2008)

The very reason petroleum accumulates in reservoirs in the first place is because they are nearly perfect traps for buoyant fluids – CO2 can be maintained as a supercritical fluid in reservoirs greater than 800 meters. According to IPCC, properly managed geological formations are likely to retain more than 99% of the injected CO2 for over 1,000 years. CO2 becomes much less mobile over time.

Research at the Bureau of Economic Geology at the University of Texas has indicated the storage of CO2 in underground geological formations is a bridge to America's energy future. Forming a national CO2 pipeline network in the US could be accelerated by the fact the topic is now a worldwide discussion. With CCS now being viewed as the possible game-changer in the battle to reduce greenhouse gas emissions around the world, effective carbon management and transportation revolves around the large-scale development of CO2 pipelines.

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The author

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Clemente's research specialization is energy security at the international level. His publications include Oil & Gas Journal, Pipeline & Gas Journal, Energy Pulse, and Energy Bulletin.

New study into the challenges and potential for CO2 pipeline infrastructure

CO2 transportation tends to receive a lower profile than CO2 capture and CO2 storage. But this crucial link in the CCS chain should not be brushed aside.

By Harsh Pershad, Element Energy

Where the designs, financing, regulation and siting of CO2 transport infrastructure are carefully chosen, the safety, scale, cost-effectiveness and public acceptance of transporting CO2 may be significantly improved. Conversely, insufficient attention to these details has the potential to thwart CCS projects, resulting in stranded assets, stalled development of CCS generally, and greater risks of climate change.

At large scale, the most economic means of transporting are by ship and by pipeline. Ship transport is expected to have a niche role – as it offers the potential for lower capital costs for sources, short project lifetimes, and flexibility. However, most in the industry agree that the much lower operating costs and higher reliability will favour pipeline transport in most circumstances. Nearly 4000 miles of high pressure pipeline are used safely to transport CO2 in North America for enhanced oil recovery, and this number is growing. More recently a dedicate CO2 pipeline transports purified CO2 for offshore storage in Norway as part of the Snohvit project.

However the challenges for deployment of a low cost CO2 pipeline infrastructure consistent with widespread adoption of CCS are large and diverse. One important challenge is financing – obtaining sufficient funding to support high capital expenditures with long payback periods in a climate of great uncertainty over supply and demand for CCS. Other challenges include the appropriate selection of models, that provide all stakeholders reassurance that CO2 pipelines will be run in familiar ways, that they will operate safely, and that they provide a genuinely low cost and large scale solution – which is the ultimate driver for CCS.

In light of these requirements, the IEA Greenhouse Gas R&D Programme recently commissioned a consortium led by Element Energy Ltd to investigate the opportunities and barriers for CO2 pipeline infrastructure. The consortium includes Professor Martin Downie from Newcastle University, Dr. Paul Zakkour from Carbon Counts and Mr. Paul Hunt, an independent consultant who has provided advice on the economic regulation of natural gas networks to numerous governments and industry.

The scope of the study is large – it will encompass

1. A review of the health, safety and engineering design challenges for CO2 pipelines – recognizing the novel physicochemical properties of CO2 streams derived from capture processes.

2. Scenarios for the future global locations, capacities, and costs of CO2 transmission pipeline infrastructure, given estimates of CCS demand, sources and sinks.

3. An assessment of the economics of integrated pipeline networks with multiple sources and sinks, vs. 'point-to-point' networks. This would guide governments and industry on the benefits of collaborative approaches.

Harsh Pershad, Element Energy

4. A review of legal and regulatory barriers to optimum pipeline deployment. This would include identifying legal conventions that forbid cross-border transport and also regulatory structures that reduce the potential for efficient investment and operation of pipelines.

More information

The study is due to submit draft findings in September 2009. Interested readers who wish to provide input to the study are requested to email Harsh Pershad at the earliest opportunity at: harsh.pershad@element-energy.co.uk

Transport and storage news

US in partnership to monitor Sleipner

www.fossil.energy.gov

In a newly awarded project, researchers funded by the U.S. Department of Energy (DOE) are partnering with European scientists to track injected CO2 at the Sleipner gas field in the North Sea.

Researchers from the Scripps Institution of Oceanography at the University of California, San Diego, and the Lamont-Doherty Earth Observatory (LDEO) in New York will conduct surveys on the seafloor to monitor injected CO2.

An ocean vessel will position sensitive gravity meters on the seafloor using a ship-tethered remotely operated vehicle carrying the instruments. Data from the instrument packages on the seafloor will be transmitted to operators aboard the ship.

Academic researchers from Scripps and LDEO will collaborate with their Norwegian colleagues from StatoilHydro in the analysis of the results. The project will create approximately eight full-time jobs per year, which will be supported throughout the two-year project.

The technology to be used in the project recognizes that, as gas is injected into the sandstone reservoir, the density of the formation is altered as water in the pore spaces is displaced by lower density CO2. This density change affects the strength of the Earth's gravity field.

Gravity surveys performed by the scientists at different times provide snapshots of the CO2 plume migration deep below the seafloor. Surveys performed by Scripps in 2002 and 2005 validated the gravity technique as an effective monitoring tool and assessed CO2 reservoir conditions for those years.

E.ON to explore CO2 storage potential in Germany

www.eon.com

E.ON Gas Storage GmbH (EGS) has filed an application with the Lower Saxony mining, energy and geology office (LBEG) for permission to carry out geological investigations in the Weser area in Germany.

Over the next five years the area is to be examined to see whether geological conditions are suitable for building an underground CO2 storage facility. This study is part of an E.ON programme for carbon capture and storage (CCS).

The application for an exploration per-

mit covers 17 towns and districts in Lower Saxony and Bremen. The study is divided into three phases: In the first two years, geological underground data will be collected and evaluated. In the third and fourth years, seismic surveys are to be carried out and exploration wells drilled. In the fifth year, the study is to be completed with geological three-dimensional modelling of a conceivable CO_2 storage facility together with all collected data on a supercomputer.

UK-Norway to study role of North Sea in CO2 storage

www.decc.gov.uk

A study of the role of the North Sea in providing storage space under the sea-bed for CO2 from European countries has been commissioned jointly by the UK and Norway.

Lord Hunt and the Norwegian Minister Terje Riis-Johansen, met to agree on a clear vision for the potential role of the North Sea in the future deployment of CCS in Europe, at the conference on Climate Change and Technology in Bergen, Norway.

The study will look at how quickly the base of the North Sea could be needed for carbon dioxide storage and what the UK, Norway and other countries have to do to get it ready in time.

The aim of the study will be to build a profile for the whole of the North Sea, assessing each countries' storage potential and projections of likely volumes and locations of CO_2 flows, against a rising price of carbon.

This will involve identifying network issues and proposing methods for managing CO_2 flows across borders.

The study will also consider how the offshore storage business might develop.

The UK and Norway have also agreed to campaign for international recognition of the important role that CCS can play and exchange information on national CCS demonstration plants and to encourage other countries to explore the potential role of CCS within their own energy generation programmes.

Call for PhD proposals in CO2 geological storage

www.ciuden.es

The Spanish Foundation CIUDAD DE LA ENERGÍA (CIUDEN) has launched a Call For Proposals for the realization of Doctoral Thesis on Geological Storage of CO2.

CIUDEN is a Research and Development Institution created by the Spanish Administration in 2006 and one of the current European CCS R&D Initiatives.

Ciuden has launched a Call for Proposals for the realization of 9 Doctoral Theses on Geological Storage of CO_2. The final goal of these grants is to train new researchers for Ciuden's staff. The grant-holders will work in R&D centres under the supervision of the current Foundation researchers.

Length of the grants is 4 years (maximum) and applicants should be in possession of a Bachelor's degree in a subject related to the purposed research topics, be an EU Citizen and proficient in Spanish and English.

Deadline for applications is July 31, 2009.

CO2 injection begins in Kentucky project

www.kyccs.org
sequestration.org

A Department of Energy sponsored project in Hopkins County, Kentucky has begun injecting carbon dioxide into a mature oil field to assess the region's CO2 storage capacity and feasibility for enhanced oil recovery.

The project is part of DOE's Regional Carbon Sequestration Partnership (RCSP) program and is being conducted by The Midwest Geological Sequestration Consortium (MGSC). The project is part of the RCSP's "validation phase," where field tests are being conducted nationwide to assess the most promising sites to deploy carbon capture and storage technologies.

The Kentucky test is designed to inject up to 8,000 tons of CO_2 over a period of 6-8 months into an existing brine-water injection well at depths of about 1,900 feet. At this depth, the CO_2 will remain in a gaseous state and will only partially mix with the oil it encounters.

This type of enhanced oil recovery, termed an "immiscible" CO_2 flood, can recover an additional 5–10 percent of a reservoir's original oil-in-place. Following injection, the oil, gas, and water produced will be measured to evaluate the field's enhanced oil recovery characteristics.

To monitor the fate of the CO_2, the MGSC, with technical support from the Kentucky Geologic Survey, will implement a monitoring program at the site. The program will consist of tracking the rate and volume of injected CO_2, and the pressures and temperatures within the well. These measurements will provide an indication of how efficiently the CO_2 displaces oil within the reservoir and how efficiently the reservoir stores the CO_2.

Ambient air quality around the wells will also be continuously monitored to ensure worker safety, as will groundwater quality to ensure that injected CO_2 is not leaking from the oil reservoir.

Illinois Basin - Sugar Creek site - image shows the CO2 pump skid located in a covered hut. The low temperature of the CO2 flowing through the pipe causes water in the air to condense on the pipe and freeze

Western Kentucky CO2 test well drilling begins

Fifteen months after project planning began, drilling has started in Hancock County, Kentucky for a test well to research the permanent storage of CO2.

The 8,300-foot well will help determine the feasibility of injecting CO_2 into geologic formations to help reduce emissions of greenhouse gases to the atmosphere.

The project is the result of a joint effort between Kentucky state government agencies, the Kentucky Geological Survey (KGS), and a consortium of public and private participants.

The project was made possible by a $5 million grant awarded to the geological survey from the Kentucky Department for Energy Development and Independence as a result of appropriations from the Kentucky General Assembly.

A portion of this grant is used for the west Kentucky project, with substantial matching funds provided by industry partners. The KGS recruited corporate partners who have contributed the majority of the funding and services crucial to completing the project.

NorAm Drilling, Inc. of Houston, Texas, has been selected to drill the well, a task that is expected to take 45 to 60 days. To protect shallow groundwater and oil and gas resources of the drilling site, the upper 3,800 feet of the well will be lined with steel casing.

Project plans call for drilling through the Knox and Mount Simon formations to test their potential to permanently store CO_2. Studies have indicated these formations may have characteristics needed for such storage.

The well will penetrate Precambrian basement rocks at its total depth. Samples of geologic formations will be taken for testing and analysis, and up to 1,500 tons of carbon dioxide will be injected into deep formations to further the understanding of the feasibility of commercial CO_2 storage.


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