



## **Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA)**

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### **Introduction**

Technology for carbon capture and storage (CCS) from coal-based electric power plants is rapidly emerging. The component technologies for capture and transport exist, although they are relatively costly compared to other emission control systems (increasing the cost of electricity by over 60%). Technologies for injecting carbon dioxide (CO<sub>2</sub>) into partially depleted oil reservoirs have been used for enhanced oil recovery (EOR) in the U.S. for over 30 years. Similar techniques have been used since 1990 to inject CO<sub>2</sub> into saline reservoirs in Canada, in association with oil and natural gas processing<sup>1</sup>. Additionally, a limited number of power plants have used chemical sorbents to capture CO<sub>2</sub> for reuse at very small scale (a few hundred tons per day, or less).<sup>2</sup> However, there is no commercial experience with commercial scale power plants capturing and storing large quantities of CO<sub>2</sub> in geologic formations. Additionally, there is no existing regulatory framework that adequately addresses one unique feature of carbon storage: it must be permanent to be effective.

The challenge facing industry, and the regulatory community, is to address the technical gaps in integration of the technologies at hand, move aggressively with research and demonstration projects to significantly reduce the cost of more advanced carbon-controlled systems, build an improved understanding of the long-term behavior of CO<sub>2</sub> stored underground, and craft a pragmatic risk management framework for conducting CO<sub>2</sub> storage. Increasing the difficulty of this challenge is the fact that all of this must be done simultaneously, with limited resources, and at a time when continuous construction of new power plants is necessary to supply a healthy and growing economy.

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<sup>1</sup> Overview of Acid-Gas Injection Operations in Western Canada, S. Bachu, Alberta Energy and Utilities Board, Edmonton, Canada, <http://uregina.ca/ghgt7/PDF/papers/peer/588.pdf>.

<sup>2</sup> For example: Kerr-McGee/ABB Lummus Crest Process using MEA (Mono-Ethanolamine), Fluor Daniel ECONAMINETM MEA process, Kansai Electric Power Co. / Mitsubishi Heavy Industries, Ltd. (KEPCO/MHI) process using KS-1, KS-2, and KS-3 solvents. Source: Carbon dioxide Capture and Storage, IPCC, 2005, p.116.

This paper will discuss the status of technology to capture CO<sub>2</sub> both from combustion-based and gasification-based power generation fueled by coal, and technologies to transport and store CO<sub>2</sub> in underground (geologic) formations. This paper is not intended to be a technology treatise, but rather to draw from the work of others to present decision-makers in the utility sector and the regulatory sector with an overview of what is practical today and what is possible in the near future.

## **CO<sub>2</sub> capture from combustion-based coal power plants**

Two CO<sub>2</sub> capture approaches are receiving strong interest for application with combustion-based power plants. The first is based on absorption of flue gas CO<sub>2</sub> by an aqueous solvent. CO<sub>2</sub> concentrations in flue gas are modest, 12-15%, due primarily to presence of significant amounts of combustion-air nitrogen, and to “excess” air needed to ensure complete combustion of coal. For these concentrations, chemical sorbents have been shown to be effective at separating CO<sub>2</sub> from the other flue gases, and releasing it in a concentrated stream for further processing. Figure 1 presents a diagram of a conventional pulverized coal power plant, equipped with such a CO<sub>2</sub> “scrubber”. Possible solvents include a family of amine chemicals, which are molecular “cousins” to ammonia; proprietary solvents designed specifically to capture CO<sub>2</sub>, such as “KS-1” solvent from Mitsubishi Heavy Industries; and advanced solvent concepts, such as chilled ammonia. For these chemical solvent-based capture systems, the CO<sub>2</sub> is captured in an absorption vessel (amines typically operate at 50 °C (120 °F)). The CO<sub>2</sub>-enriched sorbent is then pumped to a second vessel and heated to about 120 °C (250 °F) to drive off a concentrated stream of CO<sub>2</sub> and regenerate the lean solvent. The concentrated CO<sub>2</sub> is dried and compressed to about 2200 psia for pipeline transport in a supercritical state to a site for use or storage. Parasitic power needs are substantial and include pumps, fans, solvent regeneration, and CO<sub>2</sub> compression. In addition, the CO<sub>2</sub> solvents tend to form “heat stable salts” with any remaining SO<sub>2</sub> or NO<sub>x</sub> in the flue gas. These stable salts do not break down in the solvent regenerator, so there is loss of solvent unless SO<sub>2</sub> and NO<sub>x</sub> are reduced to extremely low concentrations. These factors combine to lead to a 25% increase in fuel consumption per kilowatt-hour generated, and increase cost of electricity by over 60%.<sup>3</sup>

Looking to the future, an absorption process using ammonia is under development by Powerspan, and will be tested on a slipstream from First Energy’s 50 MW Burger plant in 2007 and 2008. Alstom and EPRI will test a chilled ammonia system at a 5 MW scale at WE-Energy’s Pleasant Prairie station in 2007. AEP has signed a memorandum of understanding to test the technology at the Mountaineer Plant in West Virginia in 2008, and if successful, at the Northeastern Station in Oklahoma in 2011, for use with enhanced oil

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<sup>3</sup> Carbon Dioxide Capture and Storage, IPCC, Chapter 3, 2005.

recovery.<sup>4</sup> Ammonia is lower cost, has higher levels of CO<sub>2</sub> absorption, and requires less energy for regeneration than currently used chemical solvents, so success in these technologies could reduce the cost and energy penalty of CO<sub>2</sub> capture at conventional power plants.

Oxy-combustion is a second approach to capturing CO<sub>2</sub> from pulverized coal power plants, and takes a radically different approach than CO<sub>2</sub> absorption. With oxy-combustion, the coal is burned with pure oxygen, not air, so the products of combustion are primarily CO<sub>2</sub>, water vapor, and some excess oxygen (see Figure 2). To moderate boiler temperatures to about 1900 °C (3450 °F), it is necessary to recirculate a portion of the flue gas CO<sub>2</sub> (downstream of the particulate matter control system) back into the boiler. Particulate matter must be removed as usual, but nitrogen oxide formation is very low so the traditional selective catalytic reduction (SCR) system is unnecessary. The SO<sub>2</sub> system can be significantly downsized because it does not process the flow of excess air or nitrogen normally encountered with air-based combustion. The CO<sub>2</sub> capture system consists essentially of gas drying and compression, although some additional gas purification may be needed. This design approach can take advantage of higher temperatures and improved heat transfer from CO<sub>2</sub>/H<sub>2</sub>O mixtures to allow a more compact (cheaper) boiler. Parasitic energy demands are high (e.g., 25%), because of the oxygen plant and CO<sub>2</sub> compression. None of these systems has been operated at a commercial scale, although most of the component technology is commercially available.

Looking to the future, AEP has announced its intent to conduct a pilot demonstration of oxy-combustion in Summer 2007, followed by retrofit to an existing commercial coal-fired unit by 2015.<sup>5</sup> In addition, DOE is working with Air Products and Chemicals, Inc., to develop an Ion Transport Membrane approach for producing oxygen, to replace the conventional cryogenic oxygen plant, thereby reducing the cost and energy required for oxygen production.<sup>6</sup>

### **CO<sub>2</sub> capture from IGCC**

A different approach to CO<sub>2</sub> capture is associated with Integrated Gasification Combined Cycle (IGCC) power plants. In a conventional IGCC, coal is gasified to produce synthesis gas (primarily hydrogen, carbon monoxide, and carbon dioxide), which is then treated to remove contaminants and burned in a combustion turbine, which drives a generator to produce power. Hot exhaust gases from the combustion turbine are moved through a heat recovery steam generator to produce steam, which is expanded through a steam turbine and

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<sup>4</sup> Corporate Citizenship, the role of technology, AEP news release, <http://www.aep.com/citizenship/crreport/climatechange/theroleoftechnology.asp> .

<sup>5</sup> Ibid.

<sup>6</sup> Development of Ion Transport Membrane Oxygen Technology for Integration in IGCC and Other Advanced Power Generation Systems, NETL project factsheet #136, May 2006, <http://www.netl.doe.gov/publications/factsheets/project/Proj136.pdf> .

generates additional power (hence, the term “combined cycle”). Rather than capture the CO<sub>2</sub> at the end of this process, in an IGCC CO<sub>2</sub> is captured prior to combustion of the synthesis gas. This is possible because the synthesis gas can be reacted with water in a catalytic “shift reactor” to convert most of the carbon monoxide to hydrogen and CO<sub>2</sub>. This leaves a modified synthesis gas consisting largely of hydrogen, water vapor, and CO<sub>2</sub>, still under the relatively high pressure created in the gasifier. CO<sub>2</sub> is much easier to separate in this concentrated, pressurized state, than in normal flue gas. Following H<sub>2</sub>S removal, a physical solvent process, such as Selexol, can be used to separate the CO<sub>2</sub> from the hydrogen. The CO<sub>2</sub>-rich solvent is then pumped to a separate vessel where concentrated CO<sub>2</sub> and lean solvent are regenerated by a reduction in pressure, rather than by the addition of heat as with chemical sorbents (see Figure 3). The hydrogen (instead of CO-rich syngas) is burned in a combustion turbine, and waste heat is used to generate steam which generates additional power, similar to an IGCC without CO<sub>2</sub> capture. The inherent advantage of this power generation approach is that the CO<sub>2</sub> capture system uses much less parasitic power, and costs less than systems designed for pulverized coal power plants. The inherent disadvantage is that the basic IGCC system (without CO<sub>2</sub> capture) remains a relatively immature technology, and costs more than comparably sized pulverized coal system without CO<sub>2</sub> capture. For example, Duke Energy estimates the capital cost of its proposed Edwardsport, Indiana, IGCC to be \$1.985 billion for the 630 MW facility, or over \$3000/kw.<sup>7</sup> These costs are substantially higher than recent government reports which projected costs for such systems.<sup>8</sup> Complicating this high capital cost is the fact that none of the four existing coal-based IGCCs has met its original design reliability goal with coal. In addition, high-efficiency combustion turbines fueled by hydrogen have not been commercially demonstrated.

It may be possible to reduce the cost of CO<sub>2</sub> capture from IGCC systems, and use generation systems that do not require a hydrogen turbine, by capturing less than 90% of the plant’s CO<sub>2</sub>. For example, DOE’s most recent analysis of IGCC gasifiers indicates that the GE system converts about 30% of the coal carbon into CO<sub>2</sub> in the synthesis gas (the rate for the ConocoPhillips design is about 25%, and the Shell system analyzed was much less).<sup>9</sup> This CO<sub>2</sub> could be captured at lower cost and with much less disruption to the overall plant design than a system including a shift reactor. Alternatively, the gas could be partially shifted, lowering the cost of the shift reaction, and probably leaving enough CO in the syngas to enable use of demonstrated combustion turbines, at the sacrifice of high rates of CO<sub>2</sub> capture. However, neither of these systems has been commercially demonstrated, or even well developed in published technical papers providing

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<sup>7</sup> Edwardsport IGCC FEED Study Report, (Redacted Copy), Duke Energy, as filed with the Indiana Utility Regulatory Commission, 2April2007.

<sup>8</sup> Cost and Performance Baseline for Fossil Energy Plants – Updated Technical Performance, DOE/NETL, 10April2007, <http://www.netl.doe.gov/technologies/coalpower/refshelf.html> .

<sup>9</sup> Ibid.

detailed design or cost estimates. And neither would appear to overcome the basic cost and reliability issues associated with IGCCs without CO<sub>2</sub> capture.

A number of developments that are underway are intended to make IGCC both more reliable and affordable. These include improved refractory, for refractory-lined gasifiers, which should reduce the outage time for rebricking, as well as allow higher gasifier temperatures, which will help carbon conversion; lower cost oxygen production processes (see above discussion of Ion Transport Membranes); warm gas H<sub>2</sub>S cleanup, which allows efficiency improvements; dry-feed coal “pumps” for gasifiers to replace lock-hopper approaches, and possibly, slurry feeds; and R&D on hydrogen fueled combustion turbines. Several of these improved system components should be ready for commercial-scale demonstration on the FutureGen system, which is scheduled to begin operation in late 2012.

### **CO<sub>2</sub> transport**

Quantities of CO<sub>2</sub> on the scale of a coal-fired power plant’s production (3 million tons per year for a 500MW unit) will almost certainly be transported by pipeline unless injection occurs at the plant site. For pipeline transport, CO<sub>2</sub> is pressurized to a supercritical state that has the low viscosity of a gas, and yet can be efficiently pumped like a liquid. Because of the extensive use of CO<sub>2</sub> for enhanced oil recovery, CO<sub>2</sub> pipelines are a mature technology, and have been operating reliably in the U.S. for over 30 years. There are over 1500 miles of CO<sub>2</sub> pipelines in the U.S., transporting over 50 million tons of CO<sub>2</sub> per year. For example, the Weyburn pipeline carries 5000 tonnes per day of CO<sub>2</sub> (96% CO<sub>2</sub> and 0.9% H<sub>2</sub>S) for 200 miles between the Great Plains Synfuels plant in North Dakota and the Weyburn EOR project in Saskatchewan, Canada. Although CO<sub>2</sub> is considered an “acid” gas, as long as the flow is kept moisture free, standard carbon-manganese steels can be used for pipelines.<sup>10</sup> It should be noted that different states have different constraints on the concentrations of non-CO<sub>2</sub> gases permitted in CO<sub>2</sub> pipelines.

Pipeline transport cost is generally not a major component of overall capture, transport, and storage costs. However, pipeline costs vary by the size of the pipeline with significant economies of scale. For example, transport via a 150 mile pipeline for CO<sub>2</sub> from a 500 MW power plant (about 3 million TPY) is estimated to cost about \$3.00 – 5.00/Tonne CO<sub>2</sub>, whereas transport for a 2,000 MW facility would cost about \$1.40 – 2.10/Tonne CO<sub>2</sub>.<sup>11</sup> An important issue related to pipelines is obtaining right-of-way for the pipeline. Additional legislation may be needed to ensure the ability to construct CO<sub>2</sub> pipelines (eminent domain).

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<sup>10</sup> Op.Cit., IPCC 2005, p.182-3.

<sup>11</sup> Op.Cit., IPCC 2005, p. 192; figures are in 2002 dollars.

## CO<sub>2</sub> storage

A number of options are available for CO<sub>2</sub> storage. Figure 4<sup>12</sup> presents several of these options, including storage in depleted natural gas or oil reservoirs (which can involve EOR), storage in deep saline structures, and use for enhanced coal-bed methane production. It appears that those storage options that provide a “rebate” on storage, such as EOR, will be insufficient to meet the storage requirements of a program requiring industry-wide capture and storage of CO<sub>2</sub>. Additionally, power plants must compete with other, lower cost sources of CO<sub>2</sub>, such as CO<sub>2</sub> produced from underground deposits, or CO<sub>2</sub> from natural gas processing plants. Most CO<sub>2</sub> currently used for EOR in the U.S. is from underground deposits, and most of the remainder is from natural gas processing plants. However, it also appears that, at least in the U.S., additional saline reservoirs will be adequate to handle storage needs for hundreds of years of emissions.<sup>13</sup> An important caveat on storage is that the needed geological storage formations are not evenly distributed throughout the U.S. Figure 5, taken from DOE’s Sequestration Atlas, shows the distribution of deep saline formations.<sup>14</sup>

In general, the process for injecting CO<sub>2</sub> into geological formations is well understood, having been used for approximately 90 EOR projects worldwide, which cumulatively store about 40 million tonnes per year of CO<sub>2</sub> (compared to about 3 million tons per year (TPY) of CO<sub>2</sub> from a single 500 MW coal-based power plant).<sup>15</sup> The key features separating CO<sub>2</sub> injection for long-term storage versus CO<sub>2</sub> injection for EOR are:

- CO<sub>2</sub> retention is not the primary goal for EOR operations. EOR operations focused on maximizing CO<sub>2</sub> retention would likely follow different procedures.
- With EOR operations, an impermeable caprock is likely associated with the oil deposit. In saline formations, the presence of caprock is presumed if the site is being considered for storage, but the integrity of the caprock has not been established by its ability to retain oil or natural gas over hundreds of thousands of years.
- In EOR situations, the operator’s liability generally ends with the decommissioning of the injection well, as demonstrated by the return of surety bonds held by state agencies to assure remediation in the event of a leak.

Leakage of CO<sub>2</sub> from a properly designed and operated storage facility is considered unlikely. The IPCC concluded that “it is considered likely that 99% or

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<sup>12</sup> Op.Cit., IPCC 2005.

<sup>13</sup> Carbon Sequestration Atlas of the U.S. and Canada, USDOE/NETL, March 2007.

<sup>14</sup> Ibid.

<sup>15</sup> Discussion Paper For 2<sup>nd</sup> IEA/CSLF Workshop on Legal Aspects of Storing CO<sub>2</sub> (draft), International Energy Agency, 17October2006.

more of the injected CO<sub>2</sub> will be retained for 1000 years.”<sup>16</sup> However, if leakage occurs, it can be a serious matter. Figure 6 displays various pathways by which CO<sub>2</sub> can escape storage.<sup>17</sup> The most commonly stated concern is leakage via existing oil or gas wells that might penetrate the caprock near the CO<sub>2</sub> injection site. It is commonplace in oil producing regions to “discover” wells long since abandoned and forgotten. Mitigation is straightforward: plug the well at a cost of \$15,000 - \$25,000.

Although relatively low concentrations of CO<sub>2</sub> are essential for the support of plant life, concentrations over 50,000 ppm have been shown to cause impairment of mental processing, and death is possible from exposure to concentrations exceeding about 10% CO<sub>2</sub>. Volcanic leaks leading to soil root concentrations of 20-30% CO<sub>2</sub> have killed trees at Mammoth Mountain, California.<sup>18</sup> If CO<sub>2</sub> escaped a deep saline reservoir, it might also migrate into a more shallow fresh water aquifer, and there is concern that the acidic nature of CO<sub>2</sub> could mobilize metals that would harm such aquifers. It should be noted that no leakage or safety incident has been reported for the Canadian acid gas injection program, which has been operational since 1990.<sup>19</sup>

The FutureGen project implemented a comprehensive above ground and below ground site analysis for all sites being considered for the project.<sup>20</sup> Three types of criteria were considered:

- Qualifying criteria, which were required to be fully met.
- Scoring criteria that involve a numerical evaluation, but did not have to be met 100%. There were 261 such criteria.
- “Best value” criteria, which were non-quantitative, but important to the goals of the project.

This type of comprehensive analysis is a useful template for the next generation of CO<sub>2</sub> storage projects. Site selection will follow an extremely cautious approach until much more experience has been gained with this technology.

In a report on regulatory needs related to carbon capture and storage (CCS), the Interstate Oil and Gas Compact Commission (IOGCC) concluded that most aspects of CCS were adequately addressed by existing regulatory frameworks, but that post-injection monitoring and risk management needed additional attention.<sup>21</sup>

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<sup>16</sup> Op.Cit., IPCC, p.197.

<sup>17</sup> Op.Cit., IPCC, p. 243.

<sup>18</sup> Lessons Learned from Natural and Industrial Analogues for Storage of CO<sub>2</sub> in Deep Geological Formations, S. Benson, et.al., Lawrence Berkeley National Laboratory, March 2002.

<sup>19</sup> Op.Cit., Bachu.

<sup>20</sup> Results of Site Offeror Proposal Evaluation, FutureGen Alliance, 21 July 2006.

<sup>21</sup> Carbon Capture and Storage: A Regulatory Framework for States, Interstate Oil and Gas Compact Commission, January 2005.

EPA has issued guidance applicable to pilot-scale CO<sub>2</sub> injection projects, such as those being conducted by the DOE Regional Partnerships program. However, the guidance was clear in stating that it did not extend to commercial-scale projects, and implied that projects storing both CO<sub>2</sub> and other materials like SO<sub>2</sub> or H<sub>2</sub>S would face additional, unstated requirements.<sup>22</sup> It is reasonable to expect that EPA will eventually adopt regulations governing CO<sub>2</sub> injection for non-EOR purposes, probably under the Underground Injection Control (UIC) program. Until then, however, commercial scale projects will be regulated on a case-by-case basis, using current UIC regulatory authority. One can assume an abundance of caution will accompany early commercial projects, which could impact both the cost of the storage project and the time needed for obtaining necessary permits.

It should be noted, particularly in light of the IOGCC report, that there is no existing legal framework within which to address the long-term liabilities associated with CO<sub>2</sub> storage. The timeframes for storage integrity exceed normal life cycles for corporations, and insurance instruments for such long periods have no “actuarial” basis for calculating appropriate fees. It seems likely that this gap will have to be filled, probably by a system of sharing liability between the private and public sector, before most entities will be willing to embrace non-EOR CO<sub>2</sub> storage projects.

## Costs

We are in a period of rapid cost changes for major construction projects such as power plants. Therefore, any generic cost estimate must be taken as establishing an approximate value. The following capture cost estimates are taken from an April 2007 DOE/NETL report<sup>23</sup>; pipeline and injection costs are taken from an IPCC report<sup>24</sup>, and adjusted to 2007 dollars using the Chemical Engineering plant cost index.

- Capture and compression, new IGCC: \$30-40 \$/tonne CO<sub>2</sub> avoided.
- Capture and compression, new SCPC w/ amine scrubber: 69 \$/tonne CO<sub>2</sub> avoided
- 150 mile pipeline, 12 million tonne per year capacity (~ 2000 MW): 1.80 – 2.70 \$/tonne CO<sub>2</sub>. Costs per tonne approximately double for a pipeline capacity of 3 million tonne per year.
- Injection: Saline formation, 0.50 – 5.80 \$/tonne CO<sub>2</sub>
- Injection: Depleted oil field, 0.65 – 5.20 \$/tonne CO<sub>2</sub>
- Injection: Depleted gas field, 0.65 – 15.70 \$/tonne CO<sub>2</sub>

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<sup>22</sup> Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UICPG #83), From C. Dougherty & B. McLean (EPA HQ), to Water management Division Directors and Air Division Directors, EPA Regions I-X, 1March2007.

<sup>23</sup> Op.Cit., DOE/NETL 2007, p.36.

<sup>24</sup> Op.Cit., IPCC 2005, p.192, 260.



The approximate value of CO<sub>2</sub> purchased for EOR might range from 1-2 \$/thousand standard cubic feet, or about 18-36 \$/tonne CO<sub>2</sub>, and varies with the price of oil.

Several caveats are essential for proper interpretation of these cost estimates.

1. It must be emphasized that they apply to a new facility, where there is freedom of design. Retrofitting would amplify costs not only due to space limitations, less likelihood of proximity to storage geology, and generally lower “beginning” plant efficiency (which exacerbates the impacts of parasitic power consumption), but also due to hardware issues such as the inability to easily extract steam for CO<sub>2</sub> sorbent regeneration.
2. The apparent lower cost of capture from IGCC, compared to SCPC, is significantly offset by the higher cost of the IGCC system without capture, compared to SCPC without capture. If both systems with capture are compared to a SCPC system without capture, the overall impact of capture and pressurization (without the transport and injection) is typically in the range of a 60-70% increase in the levelized cost of electricity.
3. The DOE estimates are for bituminous coal-based systems. Most studies conclude that capital costs are higher for both IGCC and SCPC systems on subbituminous coals, but the increase is greater for IGCC units.
4. One should not assume that power plants built near old oil or gas fields will enjoy a large “rebate” from CO<sub>2</sub> sales for oil or gas recovery. A number of existing industrial processes produce voluminous supplies of relatively pure CO<sub>2</sub> which are already separated from other gases.<sup>25</sup>

Probably most important, is the fact that no power plant in the world has demonstrated CO<sub>2</sub> capture, transport, and storage in saline reservoirs. Such demonstrations are several years away. Pieces of the puzzle have been solved, but no one has yet assembled the entire puzzle. Moreover, it would seem very prudent to take the time to evaluate the technology at commercial scale before embarking on large scale deployment, regardless of how the costs look.

It is very likely that additional RD&D will reduce the cost of CO<sub>2</sub> capture and compression, perhaps significantly. However, pipeline and injection systems use relatively mature technologies and are not likely to enjoy such declines over time.

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<sup>25</sup> Natural gas processing plants, for example, often process raw gas that is too high in CO<sub>2</sub> for sale to pipelines, so the CO<sub>2</sub> is separated and vented to the atmosphere. As noted earlier, this gas is available and much cheaper to capture than CO<sub>2</sub> from power plants, and natural gas processing plants are usually in the vicinity of gas and oil fields. It is not coincidence that most of the CO<sub>2</sub> now used for EOR that is not from natural deposits comes from natural gas processing plants. In a carbon constrained world, it is reasonable to assume that these processes will need to find storage for their emissions, and that the value of CO<sub>2</sub> will drop as more emitters seek to sell their CO<sub>2</sub>.

## **Summary: Key issues requiring additional attention**

With respect to CO<sub>2</sub> capture from coal-based power plants, the major issues are technology integration and costs. CO<sub>2</sub> capture from conventional power plants has occurred only at a very small scale (a few megawatts), and without integration with storage systems. Integration requires development of systems to address malfunctions in the carbon capture/compression/transport/or storage system. Cost barriers at new conventional pulverized coal power plants suggest that much cheaper sorbent systems, or lower cost oxygen production systems will be needed to avoid a major increase in power costs. Retrofit systems present additional issues that exceed the scope of this paper.

For gasification-based systems (IGCC), the major challenges are the relatively high cost of the IGCC itself, absent CO<sub>2</sub> capture, and concerns regarding reliability. In addition, for 90% CO<sub>2</sub> capture, the resulting fuel for the combustion turbine will be almost all hydrogen, and high efficiency combustion turbines fueled with hydrogen have not been commercially demonstrated.

Transport and injection of CO<sub>2</sub> are relatively mature technologies. But we have very limited experience with the fate of CO<sub>2</sub> injected in non-EOR applications at rates of 3 million TPY or more (comparable to a 500 MW coal-based power plant). We will need several multi-year research projects, at commercial scale, in which injected CO<sub>2</sub> is carefully monitored, to gain the necessary understanding of what happens to such CO<sub>2</sub> volumes over long periods of time. And it must be emphasized that not all areas of the U.S. are proximate to attractive storage formations.

As a final caveat, it should be noted that people often fear what is not well understood, and CO<sub>2</sub> storage is not well understood by the general population, or by government bodies that regulate power plants. It would not be particularly challenging for groups opposed to coal use in general to generate public opposition to plants pursuing CCS technology, or unexpected for regulators to impose overly onerous requirements in an abundance of caution. The next few years will be a critical period during which we must both exercise due caution and yet embrace projects that will develop commercial scale knowledge about these technologies. Aggravating this situation is the lack of a system to manage CO<sub>2</sub> storage sites decades after injection has been completed. The most obvious solution to this social/regulatory barrier is to immediately develop an interim regulatory plan, covering a limited set of pioneer plants that are injecting large volumes of CO<sub>2</sub>, to apply until we can generate the data needed to support a permanent regulatory framework for broad deployment of this technology.

About the author – Doug Carter is an independent consultant on energy technology and related environmental issues. His current practice focuses on advising clients regarding advanced coal-based technologies and their potential role in mitigating global climate change. Mr. Carter’s resume includes 25 years with the U.S. Department of Energy, where he was Director of the Office of Planning and Environmental Analysis, within the Office of Fossil Energy. He had previously served with the Office of Enforcement and Office of Air Quality Planning and Standards at the U.S. Environmental Protection Agency. Mr. Carter holds degrees in Mechanical Engineering and Environmental Engineering. He can be reached at [Carter2250@comcast.net](mailto:Carter2250@comcast.net) .

## Figures

Figure 1. Conventional PC with post-combustion capture.

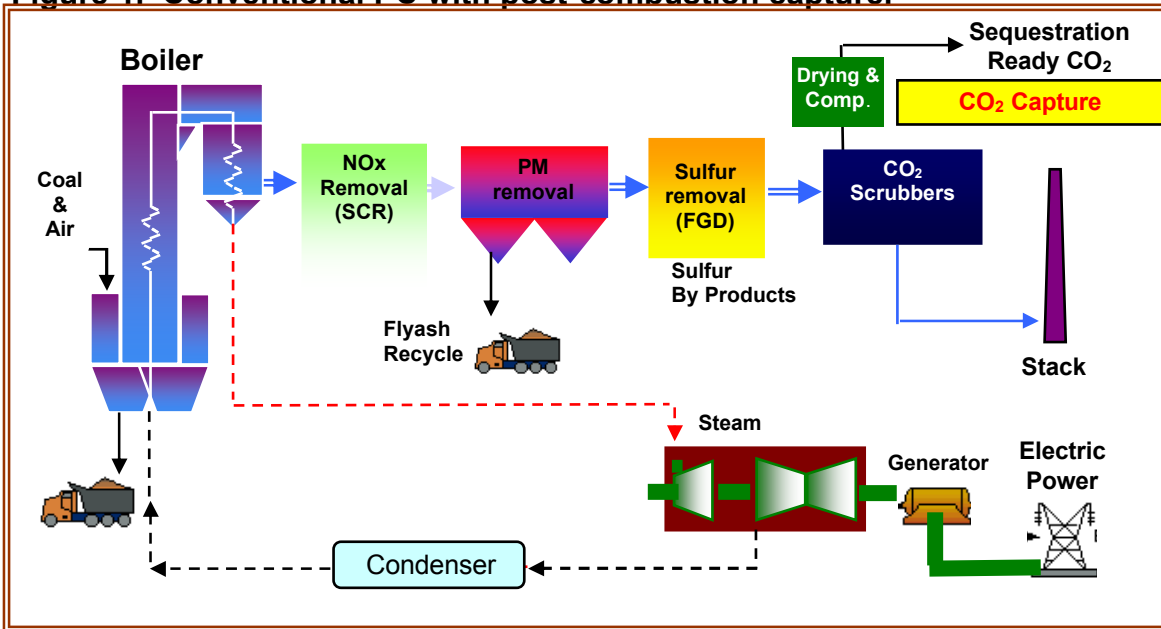


Figure 2. Oxy-combustion system with CO<sub>2</sub> capture.

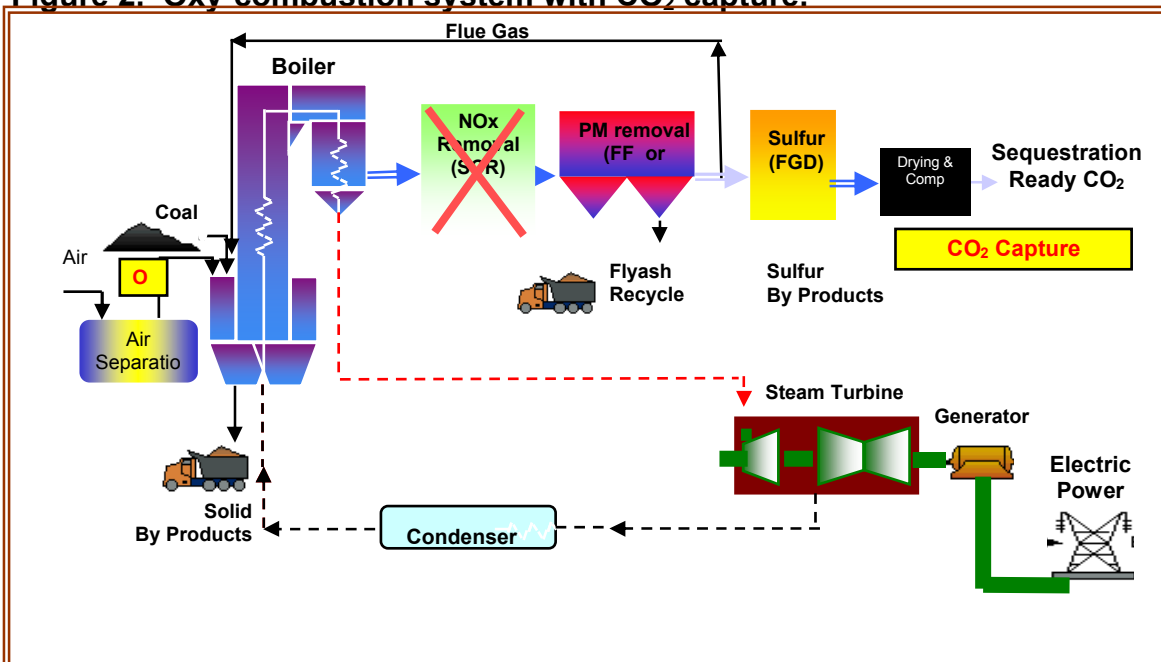


Figure 3. IGCC power plant with CO<sub>2</sub> capture.

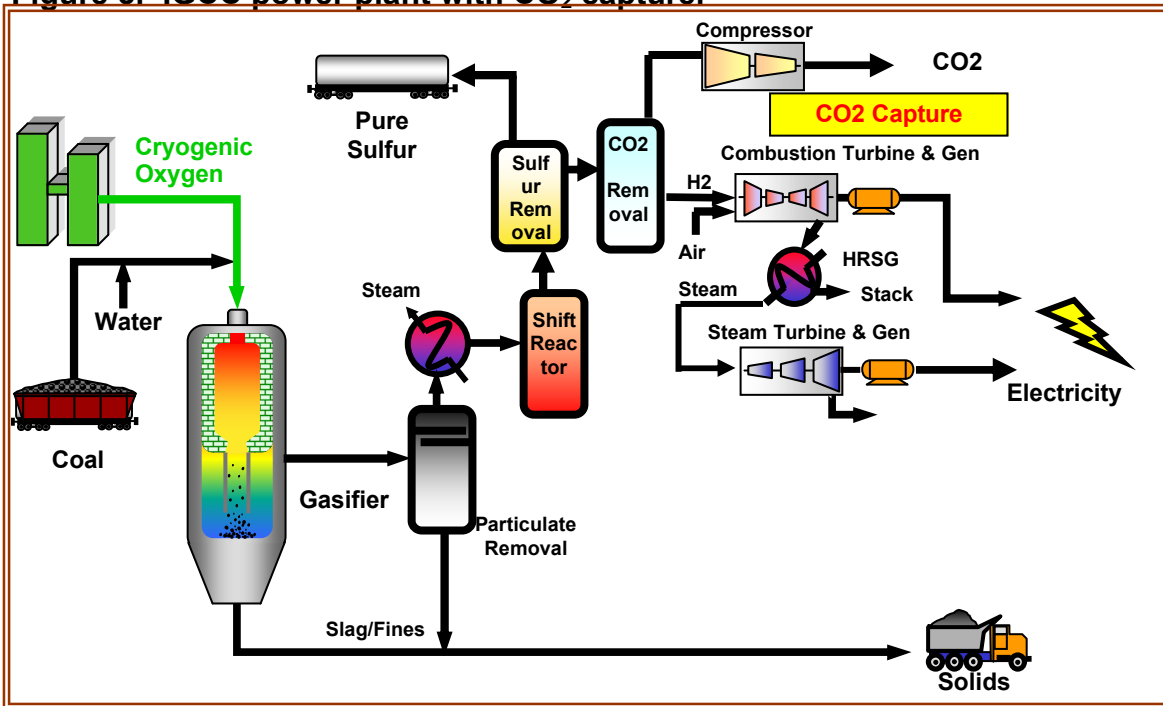
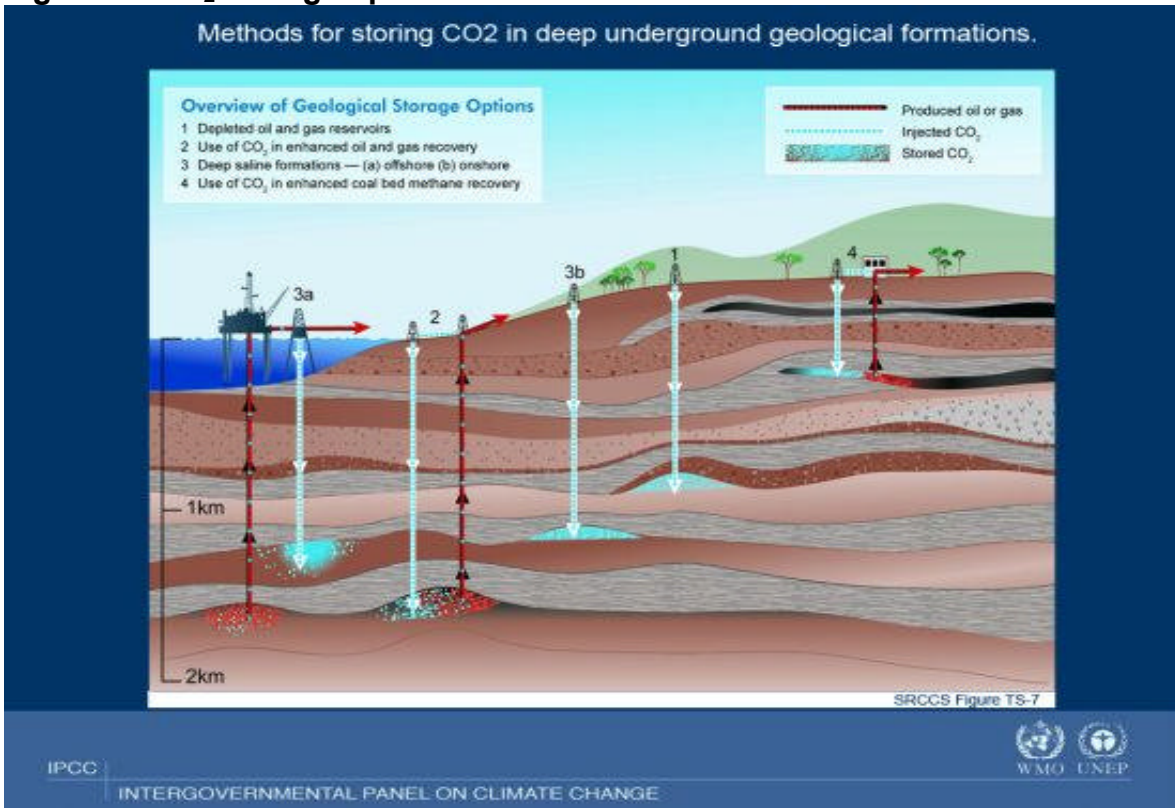
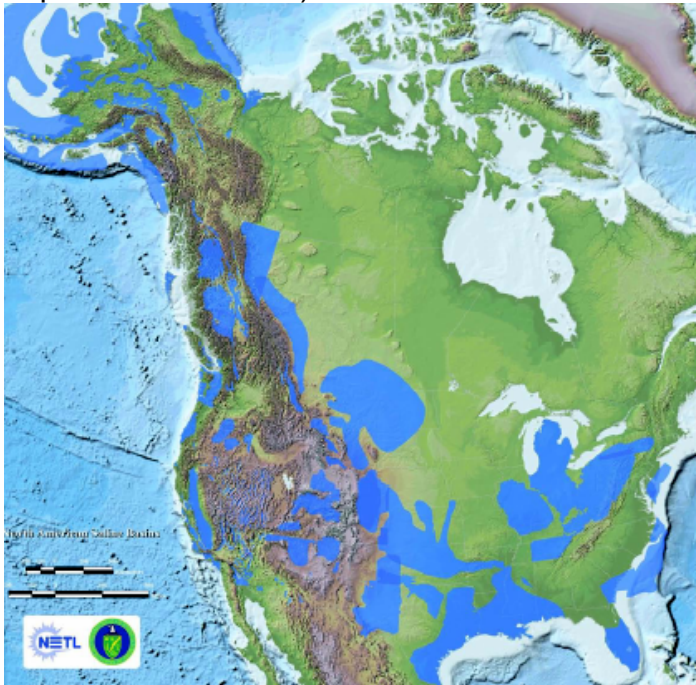


Figure 4. CO<sub>2</sub> storage options.



**Figure 5. Deep saline formations in the U.S. and Canada.** (Formations are depicted in dark blue)



**Figure 6. Potential pathways for CO<sub>2</sub> leakage.**

