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# Coal Generation Technology & Carbon Capture & Storage

## A Primer for State Commissions

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## INTRODUCTION

Coal, because of abundant reserves and relatively low cost, provides an important domestic source of fuel for generation of electricity that enhances the economic security of the United States. When compared to the volatility of oil and natural gas prices, waste and cost issues associated with nuclear generation, and the intermittent nature of wind generation coupled with transmission issues that must be addressed to utilize the most attractive wind resources, it is apparent that coal must remain an integral component of the Nation's fuel mix for the foreseeable future.

Despite the domestic abundance of coal, environmental issues have and will continue to play a role in coal-fired generation of electricity in the United States. It is possible that regulation of greenhouse gases such as carbon dioxide ($CO_2$) will be added to the existing regulation of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and mercury (Hg) emissions from coal-fired power plants, in the immediate future. Despite uncertainty about potential $CO_2$ regulation and the associated timeframe, concerns over $CO_2$ have moved utilities and policy-makers to begin to look into potential $CO_2$ emission capture and storage for fossil-fueled power plants.

From a regulatory perspective, it is important to recognize that the technology adopted for coal-fired electricity generation can impact the method and amount of $CO_2$ that can be captured and potentially made ready for storage. If capturing $CO_2$ is expensive or difficult, choosing a plant type that emits less $CO_2$ may prove a crucial factor in evaluating overall regulatory compliance costs. In addition, costs associated with the long term storage of $CO_2$ may also present an opportunity to initially consider issues that will impact the overall review of technical, efficiency, and effectiveness questions regarding the type of new coal-fired generation unit that is constructed. If a price is ascribed to $CO_2$ emissions, where no price currently exists, this may provide the regulatory certainty needed to provide a competitive advantage to plants that ultimately release less $CO_2$.

Recent legislative proposals in the U.S. Congress have sought to put a price on carbon in order to use economic signals as the primary tool of regulation. The U.S. Environmental Protection Agency (EPA) analysis of the Lieberman/Warner Climate Security bill forwarded in 2008 showed a modeled allowance price ranging between \$61 - \$83/t $CO_2e$ in 2030, and \$159 - \$220/t $CO_2e$ in 2050. At these prices, the price paid by consumers for electricity was modeled to increase 44% in 2030 and 26% in 2050. Adding a price to $CO_2$ would have a direct effect on the use of coal and result in significant increases in the price of electricity. In addition, adding a price to $CO_2$ may have potentially serious consequences on U.S. economic security and its competitiveness in the global market place so it is essential that the Nation expend considerable effort in developing cost-effective strategies to deal with $CO_2$.

Currently, the capture and geologic storage of $CO_2$ is one of the most immediate and viable strategies for mitigating the release of $CO_2$ into the atmosphere. As such, various groups including the Interstate Oil and Gas Commerce Commission (IOGCC), with sponsorship from the U.S. Department of Energy, have been actively studying technical, legal and policy issues related to the safe and effective storage of $CO_2$ in geologic formations. The EPA, along with DOE and the IOGCC, is currently developing new regulations specifically for geologic sequestration of $CO_2$. In this vein of study, the IOGCC recently developed a model $CO_2$ storage statute, drafted a set of model rules and regulations governing $CO_2$ storage into geologic formations, and looked at issues regarding ownership and legal rights involving injection of $CO_2$ into the subsurface.[1]

[1] *Road to a Greener Energy Future, $CO_2$ Storage in Geologic Structures: A Legal and Regulatory Guide for States and Provinces*, IOGCC, September 27, 2007. http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf

For economic regulators, the foregoing distinctions are important to understanding the overall role that coal may continue to play in the generation of electricity in the United States. While this Primer does not seek to comprehensively address all the factors that must be weighed with respect to each new proposed plant, it should provide an effective introduction to key issues and act as a useful foundational resource on emerging issues regarding coal-fired generation.

The Primer is divided into two main sections. Part I provides an overview of the fundamentals of coal-fired generation technologies in light of rapidly developing advances in the field. This section also provides an introduction to leading technology options that may be proposed for approval by Public Utility Commissions in the coming decade. Part I also includes a review of technical factors that could affect the final delivered energy costs from various types of plants.[2]

Part II focuses on the technologies and policy considerations regarding Carbon Capture and Storage (CCS). This section summarizes leading technologies under development for new coal-combustion power plants as well as tools to retrofit existing power plants. Part II also explores basic questions regarding CCS in order to assist Public Utility Commissions in gaining a greater understanding of the technological and governing policies faced by CCS.[3]

[2] A compilation of coal and natural gas power generation technologies is available as a Desk Reference that provides expected technical and cost performance of pulverized coal, integrated gasification combined cycle and natural gas fired electric power generation technologies. Fossil Energy Power Plant Desk Reference, Bituminous Coal and Natural Gas to Electricity Summary Sheets, May 2007, DOE/NETL-2007/1282. http://www.netl.doe.gov/energyanalyses/pubs/Cost%20and%20Performance%20 Baseline-012908.pdf

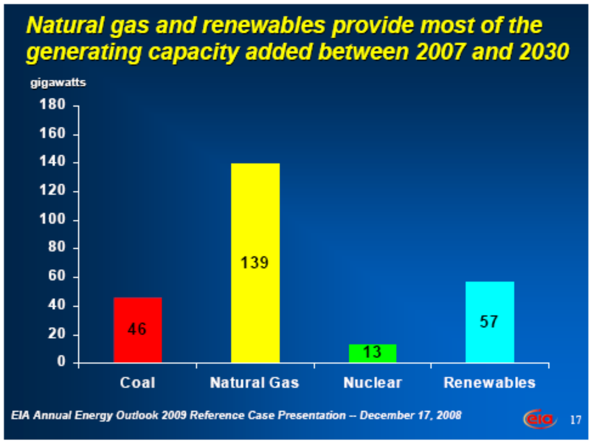
[3] While coal-fired power plants may not be the only ones that use CCS, the high embedded content of $CO_2$ in coal makes it likely that proposed power plants using this fuel-type will have a strong economic incentive to invest in carbon-reducing technologies (such as lower $CO_2$-emitting technologies and CCS) if regulations are established putting a price tag on $CO_2$ emissions. For readers charged with regulating to ensure reliable and affordable service, it is hoped that this Primer will help introduce the information that will go into these decisions going forward. In this regard, NETL's Carbon Sequestration Reference Shelf provides a comprehensive library of key information including the Carbon Sequestration Technology Roadmap (2007) and Carbon Sequestration Atlas-Version 2 (2008).

# PART I: CLEAN COAL GENERATION TECHNOLOGIES FOR NEW POWER PLANTS

## Increasing demand for electricity requires a portfolio of resources–including coal

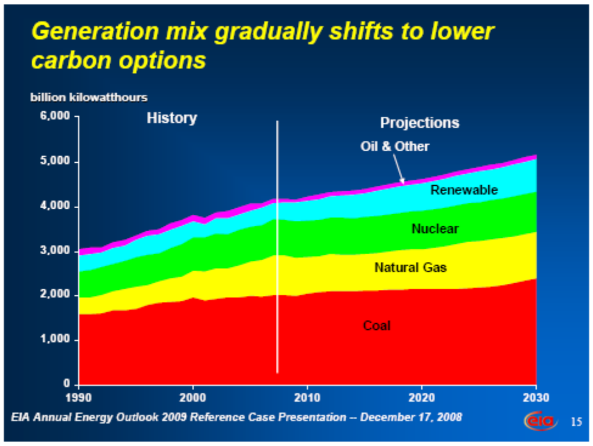
Substantial new generating capacity will be required before 2030 to meet the growing U.S. demand for electricity. Even assuming that the U.S. will move aggressively to adopt programs that will encourage the utilization of energy efficiency programs and renewable resources, coal will still play an important role in meeting this rising demand. A recent projection by Energy Information Administration (EIA) of the energy resources that will be mobilized to meet the growing demand for electricity is shown in Figure 1. These capacity projections are from EIA's Annual Energy Outlook 2009 that weighs the impacts of growing concerns about greenhouse gas (GHG) emissions. Clearly natural gas is projected to be the largest single source of new generating capacity followed by renewables and coal. According to EIA, while more natural gas capacity may be built than coal, coal will continue to make up a large share of the electricity produced (Figure 2). This use of coal reflects the historical and on-going dependence on baseload coal-fired generation to satisfy America's electricity needs.

***Fig. 1: Capacity Additions, By Fuel, 2007-2030***




(EIA, *2009 Annual Energy Outlook*)

***Fig. 2: Fuel Types for Generating Electricity to 2030***




(EIA, *2009 Annual Energy Outlook*)

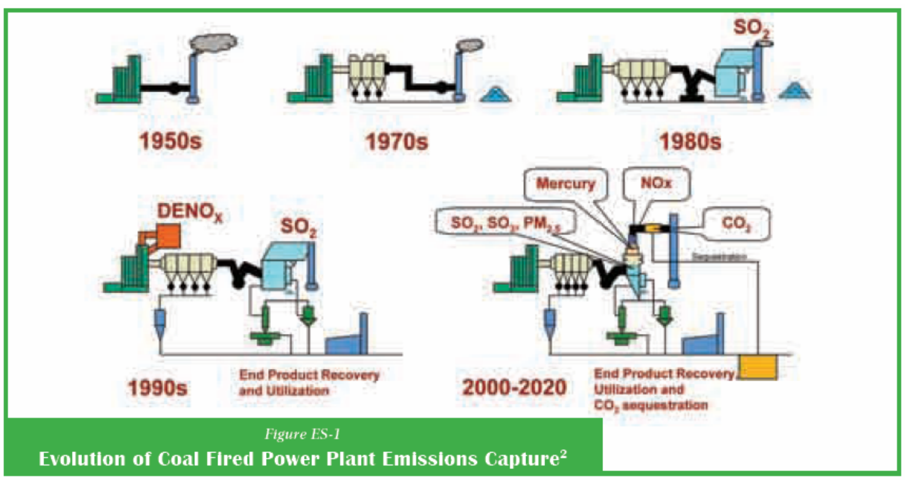
## Environmental concerns and benefits of coal-fired generation

The current debate about climate change has focused on man-made sources, primarily the consumption of fossil fuels with emphasis on burning coal to produce electricity. As climate change concerns increase, more attention is being paid to technologies that result in lower GHG emissions, including $CO_2$ from new power plants. Because of its high carbon content per embedded unit of energy, emissions of $CO_2$ from coal are higher than for other types of fossil fuels. Even with the possibility of new GHG emission regulations, however, it is likely that coal will remain a major source of fuel used to produce electricity in the U.S. Its domestic availability, low cost, and the reliability of operating coal-fired plants make coal an attractive fuel-type for running baseload power plants. In fact, because coal is almost always used to operate baseload resources, its role on an energy basis is higher than other fossil fuels. Some estimates predict that in the future coal will play an increasing role on a percentage energy basis in the United States.

## Improving coal-fired generating technologies

In 2007, more than one hundred and fifty coal-fired plants were in some stage of the planning or permitting process before state commissions or other regulatory bodies, totaling 90 GW of generation capacity.[4] In addition to subcritical pulverized coal (PC) technologies that are widely used today, the technologies which are part of total proposed projects include Circulating Fluid Bed (CFB) technology, Supercritical PC, Ultra-Supercritical PC, Integrated Gasification Combined Cycle (IGCC) and Chemical Looping Combustion (CLC).

***Fig. 3: Pollution Control Technology and PC Power Plants***




(NCC 2007, *Technologies to Reduce or Capture and Store Carbon Dioxide Emissions*)

In addition to the evolution of generating technologies, as shown in Figure 3, there have also been advances in pollution control technologies with respect to coal-fired generating units since the 1950s. While coal use has essentially doubled since 1970 there has not been a corresponding increase in emissions because emission controls for $NO_X$, $SO_2$ and particulates have significantly improved. In addition to the use of emission controls, improved fuel efficiency also plays a role in reducing emissions – including $CO_2$. A recent report by the National Coal Council (NCC) states that "new high-efficiency power plant designs using

[4] However, of the 36,000 MW announced to be built in 2002, only about 4,500 MW were actually constructed or about 12% (NETL 2007). The number of cancellations appears to be due to the strain on project economics caused by escalating costs, uncertainty related to potential climate-related regulation, and changing conditions in the financial sector.

advanced pulverized coal combustion and gasification could reduce (compared to existing coal plants) more than 500 million metric tonnes (MMt) of $CO_2$ over the lifetime of those plants, even without installing a system to capture $CO_2$ from the exhaust gases."[5]

***Subcritical, Supercritical and Ultra-Supercritical Pulverized Coal***

In any pulverized coal combustion plant, steam harnessed from burned coal is used to generate electricity. More specifically, electricity is produced when main steam from the boiler is expanded through a steam turbine. After expansion through the high-pressure turbine stage, steam is typically sent back to the boiler to be reheated before expanding through the intermediate and low-pressure turbine stages. Reheating in this manner increases the cycle efficiency by raising the mean temperature of heat addition to the cycle.

Pulverized coal (PC) technologies – subcritical, supercritical, and ultra-supercritical – are different in a few ways. They all operate at varying main steam and reheat temperatures as well as different pressures. As temperature and pressure increase, the technology moves from subcritical to supercritical to ultra-supercritical steam parameters. It is important to note that the net output efficiencies of these three technologies also varies as is illustrated in Table 1.

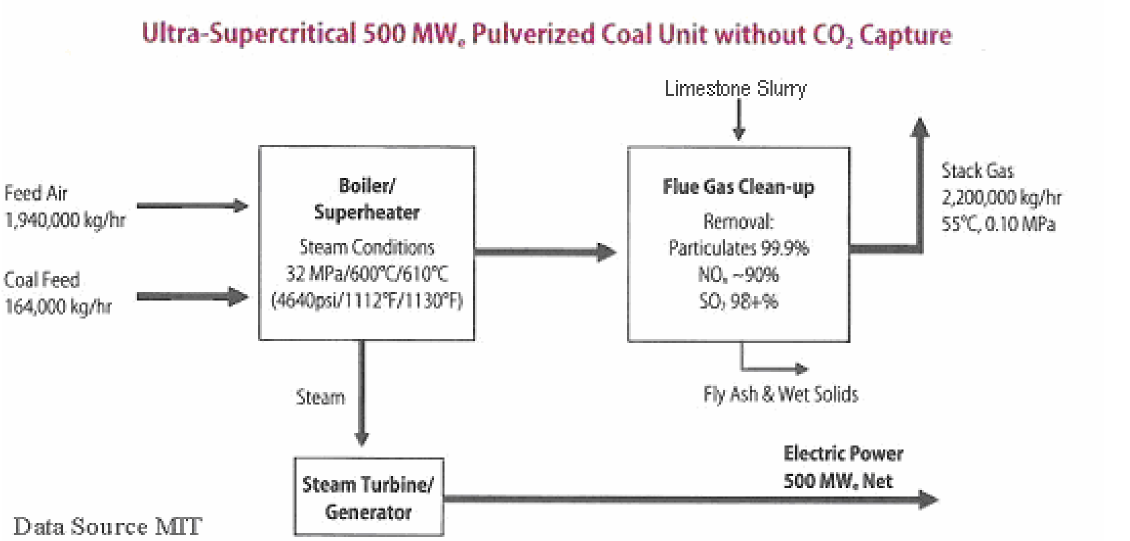
**Table 1: Average Efficiency Levels at PC Coal-Fired Power Plants**

| | Net Output Efficiency |
|---|---|
| Subcritical | 37% |
| Supercritical | >40% |
| Ultra-supercritical | 42-45% |

(World Resources Institute, *Pulverized Coal Power*)

Generation efficiency can be further increased by designing new coal-burning units to operate at even higher steam temperature and pressure. Although a number of supercritical units were built in the U.S. through the 1970's and early 1980's, most of the existing U.S. coal fleet is in the subcritical category. Today, most new PC plants proposed in the U.S. are higher efficiency supercritical designs. However, in other countries, higher fuel prices have driven the need for efficiency and supercritical and ultra-supercritical power plants are more commonplace.

***Fig. 4: The Operation of a 500 MW Ultra-supercritical Pulverized Coal Power Plant***

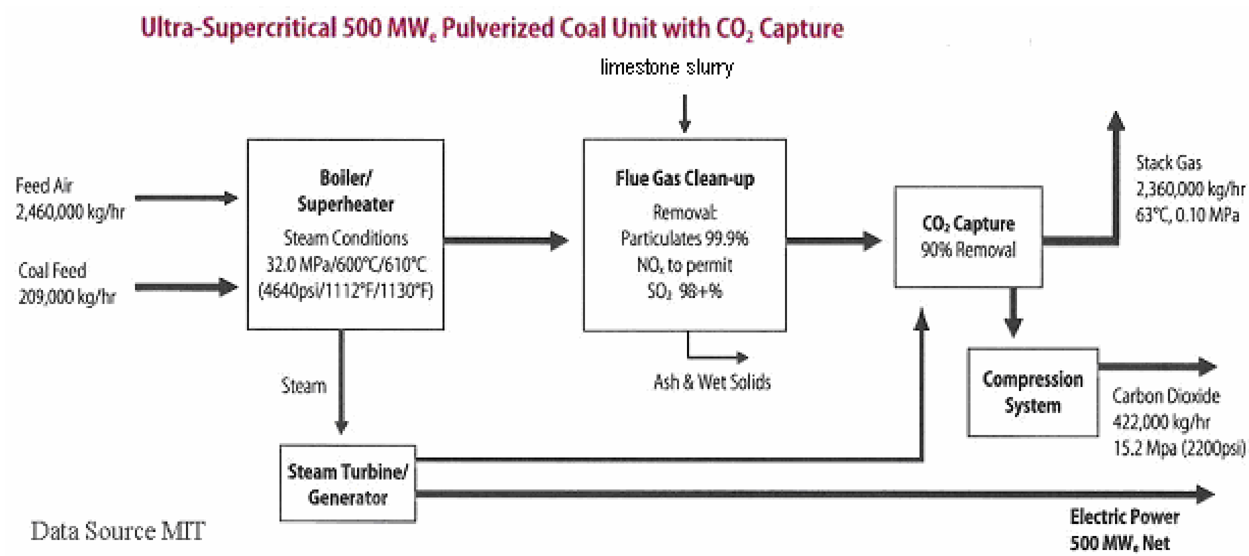



(MIT 2007, *The Future of Coal)*

[5] NCC, 2007: "Technologies to Reduce or Capture and Store Carbon Dioxide Emissions", The National Coal Council, June 2007. http://www.nationalcoalcouncil.org/Documents/JUNE25EXECSUMMARY.pdf

Anticipating that carbon capture and storage may be a viable option in the future, the image below illustrates how carbon capture would be integrated into an ultra-supercritical pulverized coal plant. Carbon capture technology can be integrated into subcritical and supercritical plants as well.

***Fig. 5: A 500 MW Ultra-Supercritical Pulverized Coal Power Plant with Carbon Capture***

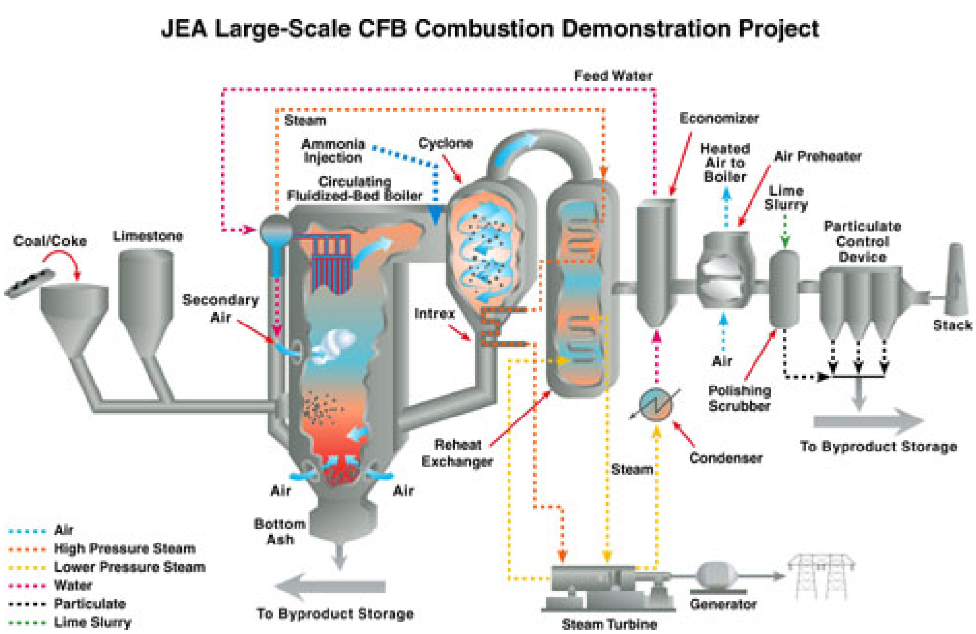



(MIT 2007, *The Future of Coal*)

### *Circulating Fluid Bed (CFB)*

Circulating fluid-bed combustion is a variation on PC combustion that uses a fluidized bed, an apparatus that mixes coal and air with a sorbent such as limestone during the combustion process, to facilitate more effective chemical reactions and heat transfer.

***Fig. 6: The Operation of a Circulating Fluid Bed Power Plant***



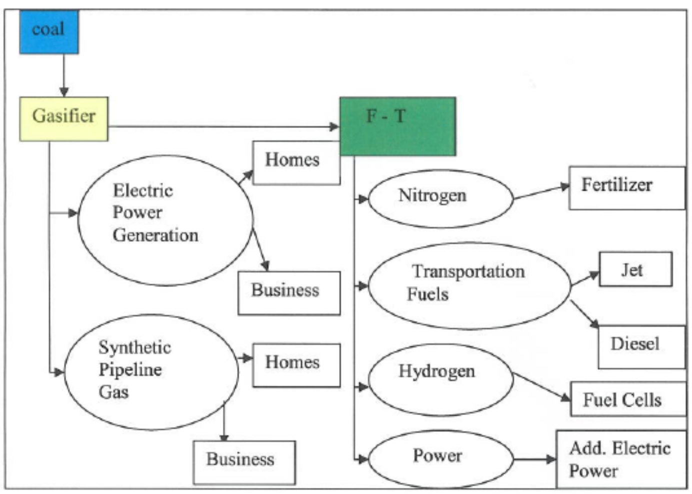

(NETL, JEA Large-Scale CFB Combustion Demonstration Project)

Most often this device includes a circulation component to help catalyze combustion. The bed operates at relatively low temperatures creating less $NO_x$ and allowing the lime to capture greater amounts of $SO_2$. Utilizing this process, more than 95% of the sulfur pollutants in coal can be captured inside the boiler by the sorbent.[6] This technology has also captured interest because fluid bed combustors are well suited to co-firing biomass. One of the largest CFB unit constructed in the US is 500 MW and was completed as part of the Department of Energy's Clean Coal Technology Demonstration Program (DOE-CCTDP)[7]; a larger supercritical unit is being constructed in Europe.

***Integrated Gasification Combined Cycle (IGCC)***

Coal gasification technology has been widely deployed in commercial industrial applications for many years. Gasification for electric power production has been initially demonstrated at commercial scale with two 250 MW projects completed as part of the DOE-CCTDP efforts.[8] Gasification of coal is used for three purposes: the production of chemicals and fertilizers; the production of synthesis gas or syngas, a mixture of hydrogen and carbon monoxide;[9] and, as fuel in power plants (operating examples of these plants are located in Florida and Indiana). Using a variety of control technologies, syngas can be cleaned of particulate and sulfur and either used as fuel for electricity production in a gas turbine or further processed to create methane and put into a pipeline to replace natural gas. Alternately, syngas also can be sent to a chemical processing unit to produce fertilizer, clean transportation fuels, and hydrogen as final products. The system diagram below depicts the applications and flexibility of coal gasification technology.

***Fig. 7: The Operation of Coal Gasification Technology***




(MIT 2007, *The Future of Coal*)

There are several types of commercial gasifiers that can be employed with IGCC. The production of syngas follows a similar process in all gasifiers. Gasification is a thermo-chemical process that breaks down coal into its basic chemical components. This reaction is achieved by exposing coal to steam and

[6] DOE, Office of Fossil Energy NETL, "Fluidized Bed Technology- Overview." http://www.fossil.energy.gov/programs/powersystems/combustion/fluidizedbed_overview.html

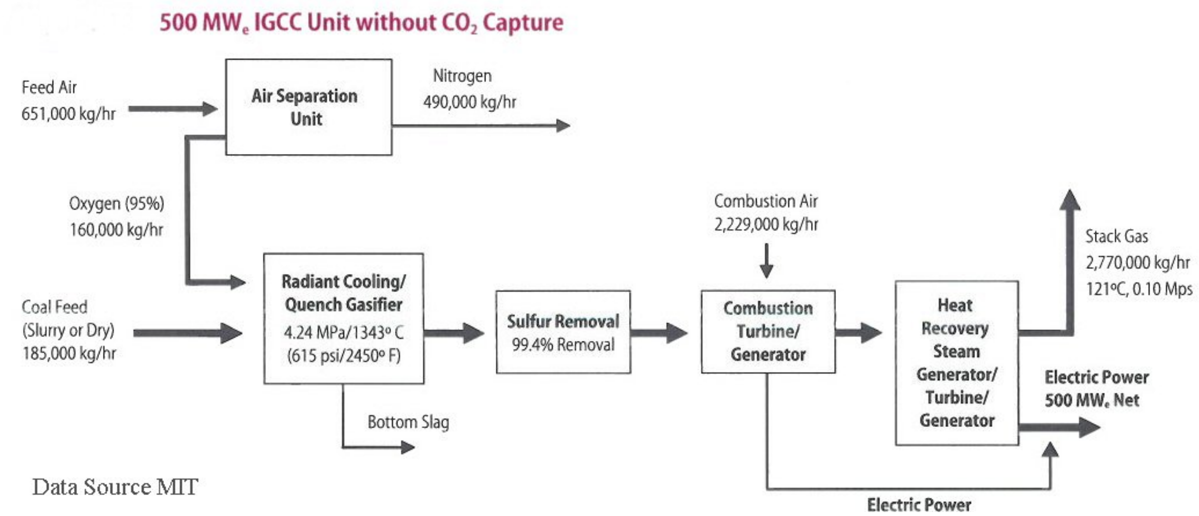
[7] DOE: NETL Topical Report, "JEA Large-Scale CFB Combustion Demonstration Project." 2003. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical22.pdf

[8] NETL Topical Report, "Wabash River Coal Gasification Repowering Project." 2000 http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical20.pdf; NETL Topical Report, "Tampa Electric Integrated Gasification Combined-Cycle Project." 2000. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical19.pdf

[9] A compound consisting of hydrogen and carbon monoxide.

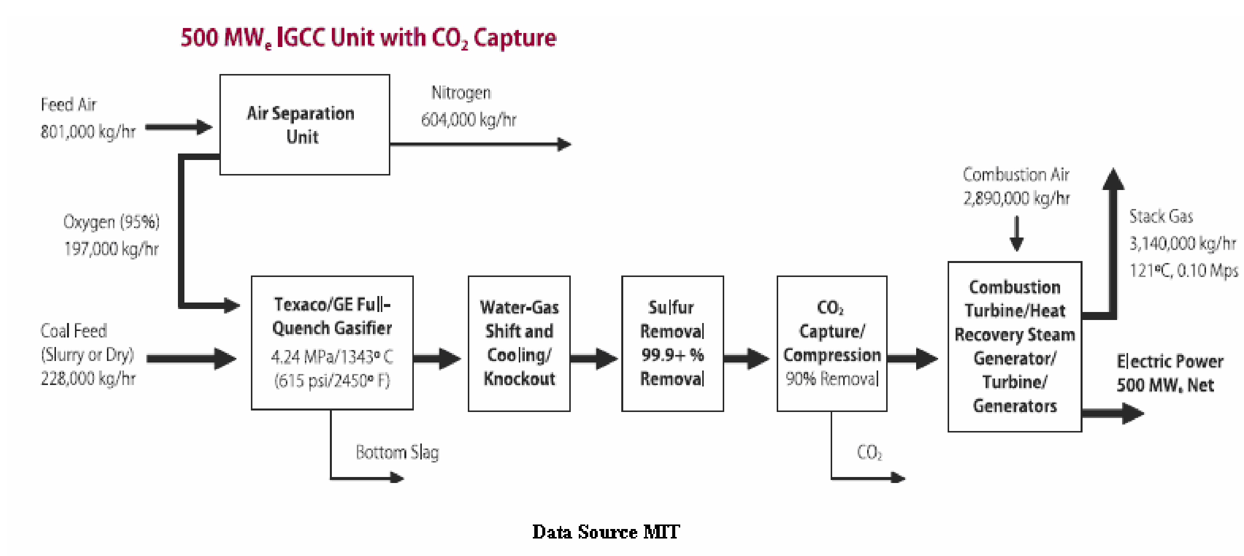
carefully controlled amounts of air or oxygen under high temperatures and pressures.[10] This produces the syngas, which is cleaned and then burned as fuel in a combustion turbine (much like natural gas is burned in a turbine). The combustion turbine drives an electric generator. Exhaust heat from the combustion turbine is recovered and used to boil water, creating steam for a steam turbine-generator. The "combine cycle" part of IGCC comes from the fact that two types of turbines are used – combustion and steam. Using these two types of turbines in concert is one reason why IGCC plants can achieve high power generation efficiencies, around 40% or more for commercially available gasification-based systems. The IGCC process is illustrated in the diagrams below, which also highlight the differences between units with and without $CO_2$ capture.

***Fig. 8: System operation of a 500MW IGCC Power Plant without $CO_2$ Capture***




(MIT 2007, *The Future of Coal*)

***Fig. 9: System operation of a 500MW IGCC Power Plant with $CO_2$ Capture***




(MIT 2007, *The Future of Coal*)

[10]DOE, Office of Fossil Energy NETL, "Gasification Technology R&D." http://www.fossil.energy.gov/programs/powersystems /gasification/index.html

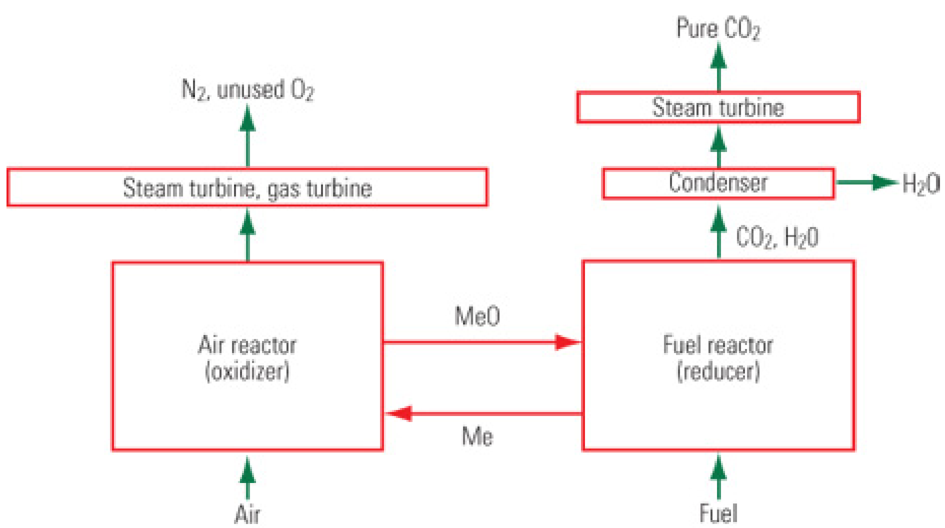
One additional quality of IGCC, is that when oxygen is used in the gasifier (rather than air), the carbon dioxide produced by the process is in a more concentrated gas stream, making it easier and less expensive to separate and capture.

***Chemical Looping Combustion (CLC)***

CLC is an emerging technology that can be used to convert either coal or gasified coal to energy with relatively pure $CO_2$ and $H_2O$ byproducts.[11] Combining fuel and a metal oxide oxygen carrier, this combustion process does not require direct contact of air and fuel.[12] As a result of this process, CLC provides a combustion option that limits the energy penalty[13] that traditional fossil fuel-fired combustion systems incur to produce pure $CO_2$ while at the same time minimizing the amount of $NO_x$ produced as compared to other fossil fuel combustion processes.

Work is being done to move CLC toward commercial scale use by a number of interested parties. The National Energy Technology Laboratory (NETL), for example, has conducted lab-scale research comparing various metal oxide carrier performances with the University of Pittsburgh.[14] NETL has worked also with Ohio State University to develop simulations and system level chemical looping models. Currently, Alstom has built a small-scale pilot facility in Connecticut to develop and verify the high temperature chemical and thermal looping process, working toward future demonstration and commercial scale use of this technology.[15]

***Fig. 10: Proposed System Operation of a CLC Power Plant***




(POWER 2008, *Chemical looping and coal*)

[11] DOE: NETL, "Chemical Looping for Combustion and Hydrogen Production." http://www.netl.doe.gov/publications /factsheets/rd/R&D128.pdf
[12] POWER Magazine: Patel, Sonal, "Chemical looping and coal." Oct 15, 2008. http://www.powermag.com/issues/departments/global_ monitor/Chemical-looping-and-coal_1461.html
[13] Loss in net energy output.
[14] DOE: NETL, Glen Tomlinson, David Gray, and Charles White, "The Ohio State Chemical-Looping Process in a Coal-to-Liquids Configuration." 2007. http://www.netl.doe.gov/energyanalyses/pubs/DOE%20Report%20on%20OSU%20Looping%20final.pdf
[15] DOE: NETL, "Hybrid Combustion-Gasification Chemical Looping Coal Power Technology Development." 2008. http://www.netl.doe.gov/publications/factsheets/project/Proj293.pdf

## Comparing Coal Technologies and Incorporating $CO_2$ Capture

With a number of coal generation technologies available, understanding the costs and efficiencies associated with each is vital. In evaluating the attributes of each technology, researchers have compared these technologies both with, and without, carbon capture. Table 2, on the following page, highlights the results of cost and performance assessments recently conducted by the NETL. These assessments provided updated information and assessed the ramifications of the rapidly increasing labor, material and equipment costs experienced at the time across the industry. In addition, the assessments provided a perspective on cost and performance by drawing on information presented by the Massachusetts Institute of Technology (MIT) that included results from many early studies.

As reflected in Table 2, costs change dramatically when you introduce technologies to control $CO_2$ emissions. Cost advantages that could be attributable to any of the technologies without carbon-capture technology may shift substantially with the addition of $CO_2$ capture technologies. For example, without $CO_2$ capture equipment, subcritical pulverized coal technologies appear to have advantages in total plant cost, and PC and CFB technologies provide the lowest cost of electricity per kWh. If regulations issued at the State or Federal level require plants to install carbon capture equipment, the cost advantages of subcritical pulverized coal will, at a minimum, be significantly eroded. Additions to a power plant to provide carbon-capture capabilities will also create losses in capacity that Commissions would need to weigh on a case-by-case basis.

Although it uses the most recently available cost analysis, it is important to note that the power plant cost data in Table 2 may already be out of date. Across the board, until recently power plant construction costs increased dramatically due to increased labor, materials, and other capital costs. A February 2008 estimate by Cambridge Energy Research Associates (CERA) suggested that power plant construction costs increased 27% between 2006 and 2007 alone. However, some prices have since dropped due to the world-wide financial downturn and declining energy prices toward the end of 2008 and beginning of 2009. The net effect of these events on the estimated costs of new energy projects remains dynamic, difficult to predict, and hence uncertain. Table 2 demonstrates relative cost comparisons that should hold true even if the actual plant costs have changed.

As shown, the addition of $CO_2$ capture technology will result in an overall increase in the cost of electricity regardless of the technology platform that is utilized. Numerous factors may impact costs, and over the long term there is no clear leader among the various technologies considered in this Primer and the merits of each will need to be evaluated on a case-by-case basis. Different technologies may have cost advantages depending on factors such as the impact of coal quality on the projected cost and efficiency; the recent escalation in actual equipment costs; and the lack of demonstration of $CO_2$ capture on commercial power plants.

Although the NETL report provides updated cost analysis data, and considers natural gas-fired technologies as well as coal-fueled technologies, it does not consider Ultra-Supercritical and CFB generators. Additionally, both NETL's and MIT's analyses vary from those provided by the most recent Intergovernmental Panel on Climate Change (IPCC) report in 2007. Costs seen in recent industry press and recent State Commission filings are much higher than in any of these reports, and have escalated and remain in a dynamic condition. Further uncertainty in the total plant cost, benefits, and risks of any technology choice arises for any number of reasons including limited operational experience with some of the technologies that demonstrate their long-term performance under a variety of circumstances; and untested assumptions regarding post-combustion $CO_2$ capture technologies.

## Table 2: Comparison of Costs for New Power Plants for Various Coal-Fired Generation and Natural Gas Combined Cycle Technologies

| | SUBCRITICAL PULVERIZED COAL | | SUPERCRITICAL | | ULTRA-SUPERCRITICAL | | SUBCRITICAL CIRCULATING FLUID BED | | IGCC[1] | | NATURAL GAS COMBINED CYCLE (F Series) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Without $CO_2$ capture | With $CO_2$ Capture | Without $CO_2$ capture | With $CO_2$ Capture | Without $CO_2$ capture | With $CO_2$ Capture | Without $CO_2$ capture | With $CO_2$ Capture | Without $CO_2$ capture | With $CO_2$ Capture | Without $CO_2$ Capture | With $CO_2$ Capture |
| Total Plant Cost ($/KW, MIT) | $1,280 | $2,230 | $1,330 | $2,140 | $1,360 | $2,090 | $1,330 | $2,270 | $1,430 | $1,890 | N/A | N/A |
| Total Plant Cost ($/kW, NETL) | $1,549 | $2,895 | $1,575 | $2,870 | *N/A* | *N/A* | *N/A* | *N/A* | $1,813 (GEE)<br>$1,733 (CoP)<br>$1,977 (Shell) | $2,390 (GEE)<br>$2,431 (CoP)<br>$2,668 (Shell) | $554 | $1,172 |
| Efficiency (MIT)[2] | 34.3% | 25.1% | 38.5% | 29.4% | 43.3% | 34.1% | 34.8% | 25.5% | 38.4% | 31.2% | N/A | N/A |
| Efficiency (NETL)[3] | 36.8% | 24.9% | 39.1% | 27.2 % | *N/A* | *N/A* | *N/A* | *N/A* | 38.2% (GEE)<br>39.3% (CoP)<br>41.1% (Shell) | 32.5% (GEE)<br>31.7% (CoP)<br>32.0% (Shell) | 50.8% | 43.7% |
| Cost of Electricity (¢ per kWh, MIT) | 4.84 | 8.16 | 4.78 | 7.69 | 4.69 | 7.34 | 4.68 | 7.79 | 5.13 | 6.52 | N/A | N/A |
| Cost of Electricity (¢ per kWh, NETL) | 6.40 | 11.88 | 6.33 | 11.48 | *N/A* | *N/A* | *N/A* | *N/A* | 7.80 (GEE)<br>7.53 (CoP)<br>8.05 (Shell) | 10.29 (GEE)<br>10.57 (CoP)<br>11.04 (Shell) | 6.84 | 9.74 |
| Costs of $CO_2$ Avoided ($/tonne, MIT)[4] | | 41.3 | | 40.4 | | *41.1* | | *39.7* | | 19.3 | N/A | N/A |

Basis: 500 MW plant.

1 – MIT IGCC data assumes GE radiant gasifier for no-capture case and GE full-quench gasifier for capture case.
2 - MIT uses an 85% capacity factor
3 -NETL assumes a capacity factor of 85% for PC and NGCC cases and 80% for IGCC, (IGCC technologies examined by NETL include GE Energy (GEE), ConocoPillips E-Gas (CoP), and Shell)
4 – MIT Cost of $CO_2$ avoided vs. same technology without capture; does not include costs of transportation, injection, storage

All MIT data from MIT 2007 study, *The Future of Coal*, http://web.mit.edu/coal
All NETL data from *Cost and Performance Baseline for Fossil Energy Plants*, http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf

Research also suggests that there are geographic considerations that should be considered in the context of advanced coal generation technologies, both in terms of the location of the generation facility and its coal fuel type. It is worth noting that all of the discussed technologies facing the same conditions will experience similar regional challenges. In general, it is believed that IGCC units constructed in the West, at higher altitudes, will experience some unique operating challenges due to lower atmospheric pressures.

Regarding fuel, research by the Electric Power Research Institute (EPRI) in 2005 indicates that there may be a difference in the overall lifecycle plant cost related to coal heating value. EPRI research indicates that these types of regional differences, among other factors, influence the range of cost uncertainty. Therefore, when Commissions consider new power plants, it may be that no technology has clear universal cost advantages with or without a carbon-constraining regulatory regime. While capital costs will always be critical, location and coal stock may be the determining factors.

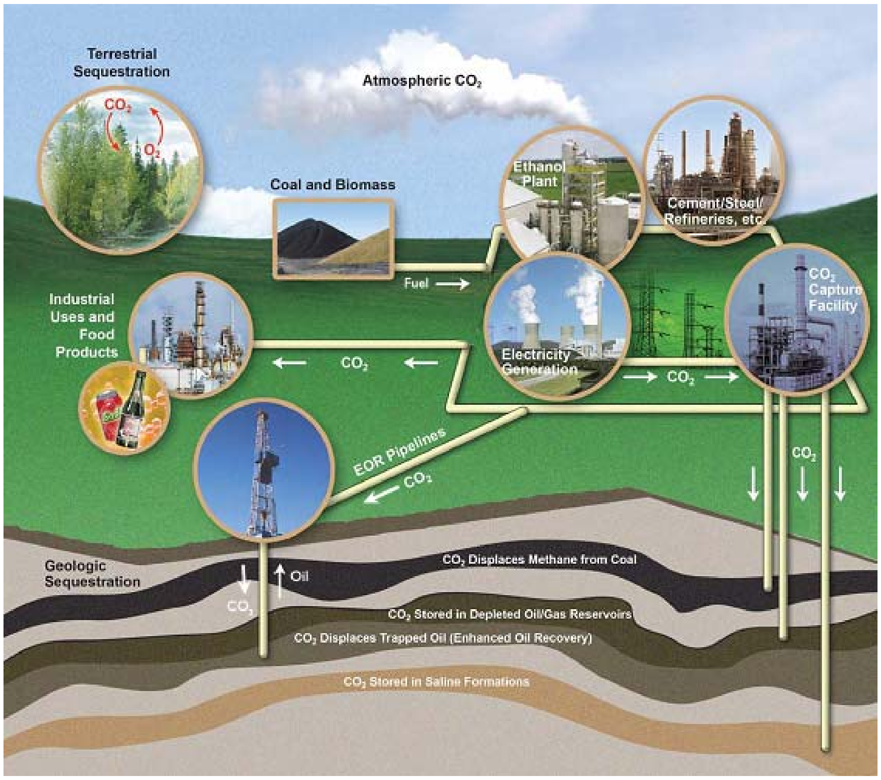
**Summary**

Resource additions over any planning horizon are necessary. While efficiency improvements and renewables will help to reduce the need to construct new fossil-fuel generating capacity, meeting forecasted demand for electricity in a cost-effective and reliable manner will require State Commissions to consider coal-fired generation as a component of the entire resource mix. State Commissions are already considering proposals for new coal-fired generators. As such, it is important to put the various technologies in context to facilitate decision-making that best achieves the goals of a safe, reliable, affordable, clean and secure supply of electricity for consumers. Regardless of the technology, uncertainty with respect to the overall costs associated with new technologies may complicate actual deployment. It is critical to note that the long-term direction of cost changes is not uncertain. The cost of electricity is almost certain to increase in the long-run compared to the status quo. To successfully evaluate the deployment of the different types of technologies, it is important that Commissions are prepared to fully evaluate the costs and benefits of any proposed project over the short and long term, in an extraordinarily uncertain financial market and with the likelihood of future regulation of $CO_2$.

## PART II: TECHNOLOGICAL AND REGULATORY CONSIDERATIONS FOR CARBON CAPTURE AND STORAGE

The goal of carbon capture and storage is to prevent the emissions of man-made $CO_2$ from entering the atmosphere. Industrial activities and electric power production, as shown in Figure 11, produce about two-thirds of the $CO_2$ currently released to the atmosphere in the United States.

***Fig. 11: Capture & Storage of $CO_2$***




(DOE-NETL 2007, *Carbon sequestration atlas of the United States and Canada*)

As a result of the desire to address $CO_2$ issues, the next generation of coal plants may look and function much differently from the traditional plants in operation today. Regulators may be faced with complex technology decisions regarding "carbon capture-capable" and "carbon capture-ready" designs. Capture-capable means that a generation plant has the technology to prevent atmospheric emissions of carbon dioxide. Capture-ready, on the other hand, is a more complex concept and no single definition has yet been established. In general however, the objective of capture-ready is to construct a new power plant that has the ability to reasonably add carbon control systems if needed at a later date. Efforts are underway to develop capture technologies, geologic storage opportunities, and the regulatory frameworks that will affect $CO_2$ transport and storage.

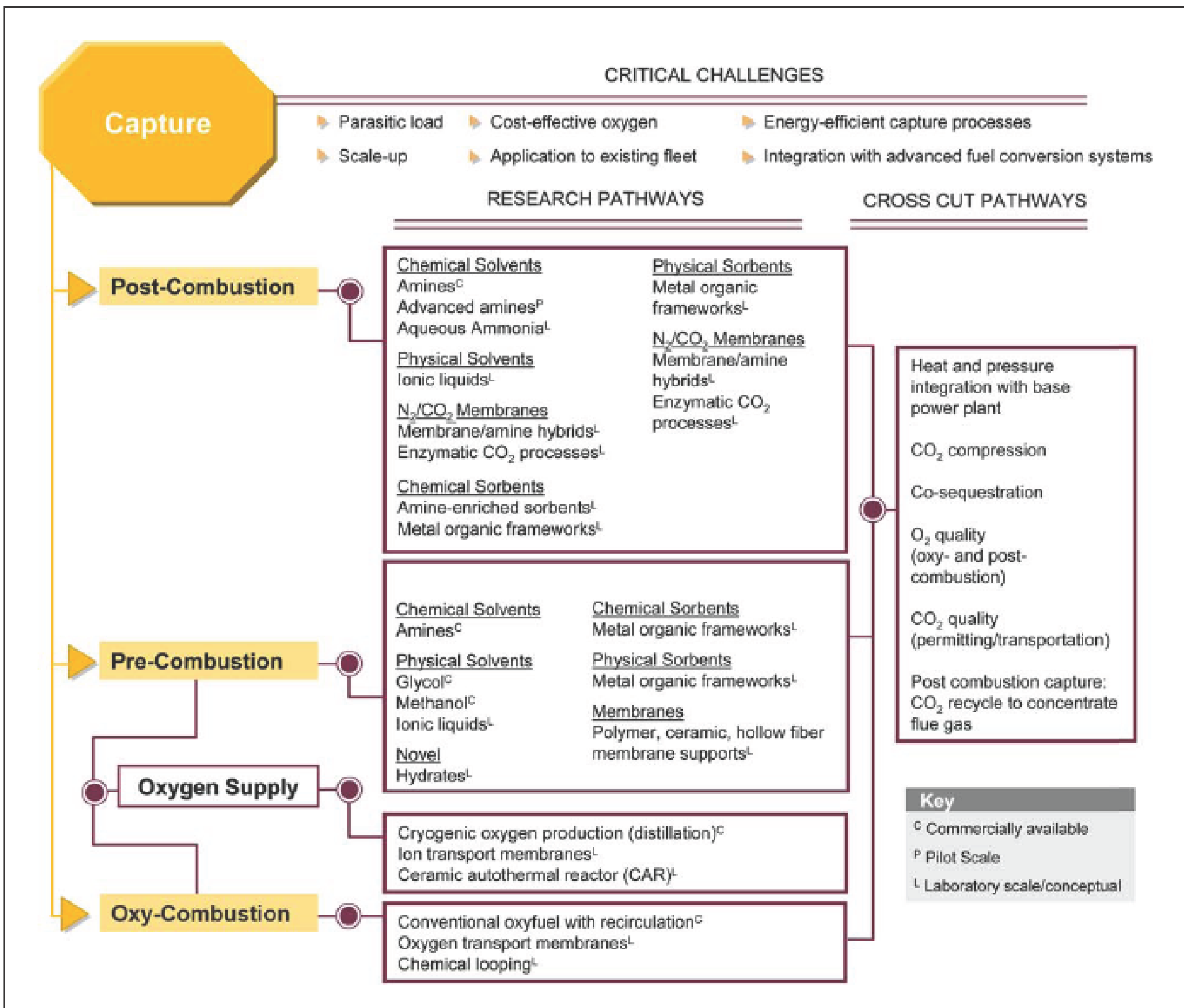
### Carbon Capture

Currently, there are still many barriers to commercial-scale carbon capture technologies for power plants. At the industrial level, however, the most common technology for capturing $CO_2$ from a gas stream uses a chemical amine solution to absorb the $CO_2$. Prior to absorption, $CO_2$ is 10-15% of the flue gas, by volume. After absorption, the amine and the absorbed $CO_2$ are heated, and the $CO_2$ desorbs such that it can be compressed and transported to a storage facility. The amine is then recycled back into the capture process. While $CO_2$ is effectively removed in this process there are notable trade-offs with this technology, including:

* Low pressure and dilute concentration dictate a high actual volume of gas to be treated,
* Trace impurities in the flue gas reduce the effectiveness of the $CO_2$ adsorption, and
* Compressing captured $CO_2$ from atmospheric pressure to pipeline pressure (1,200–2,000 pounds per square inch (psi)) represents a large parasitic load.

As a result, based on the high power and steam requirements of the process if this technology were applied to a power generating plant the overall efficiency and net capacity of the plant would be significantly lowered. Some analyses suggest that these capacity and efficiency losses are in the range of 20-30% relative to the same combustion without $CO_2$ capture.[16] These analyses also suggest that due to large amounts of flue gases to be processed, the equipment could impact the design requirements for power plants that must provide additional space for the future addition of these technologies.

***Fig. 12: Technology Roadmap for CCS***




(DOE- NETL, *Carbon Sequestration Technology Roadmap and Program Plan 2007*)

[16] DOE: "Retrofitting the Existing Coal Fleet with Carbon Capture Technology." 2008. http://fossil.energy.gov/programs/powersystems/pollutioncontrols/Retrofitting_Existing_Plants.html

Thus, currently several different approaches for power plant specific technologies are being explored. These technologies are based on capturing carbon at distinct phases of energy production: pre-combustion, combustion (via oxy-combustion) and post-combustion. Each strategy creates unique conditions that affect the performance of technologies for separating $CO_2$ from the process and making it ready for compression and transport to the sequestration site.

The relationship of the three basic capture strategies and supporting technologies available to each are described more fully in DOE's Carbon Sequestration Technology Roadmap-2007 and are depicted in the figure extracted from the Roadmap.

**Pre-combustion**

The pre-combustion capture process involves converting fossil fuel into hydrogen and $CO_2$, usually by gasification, and is appropriate for IGCC plants. During pre-combustion, coal is first transformed into syngas. Carbon monoxide in the syngas is converted into $CO_2$ and removed prior to combustion using a solvent. Electricity is generated by combusting hydrogen in a gas turbine with minimal $CO_2$ emissions. Further efficiencies are gained by using waste heat to power a steam turbine.

Compared to oxyfuel combustion, this process requires much less oxygen per unit of fuel feedstock or net power output as $CO_2$ can be recovered in a dry condition, at moderate pressure with the use of little or no steam. The result is a significant reduction in both the $CO_2$ compressor capital and power requirements, which reduce net capacity and efficiency losses. Additionally, the hydrogen produced in this process can be used to generate electricity in a fuel cell, a promising attribute for future generation technologies.

A novel $CO_2$ capture membrane is being developed by Los Alamos National Laboratory and SRI International through a DOE/NETL project. This polymeric membrane system is being developed to create a pre-combustion capture system that can operate at higher temperatures and pressures than the state-of-the-art Selexol-based system and therefore reduce parasitic power loss and capture cost.

At the present time, none of these technologies have been widely commercialized. A project that was funded by the Department of Energy called "FutureGen" was intended to develop a facility to explore advanced capture technologies on a commercial scale at a coal-fired power plant, however this program has been recently restructured to explore and prove these concepts in other ways. FutureGen and its restructuring will be discussed again in a later section of this overview.

**Oxygen-combustion**

With oxygen combustion (oxy-combustion) pulverized coal is burned in 95-99% pure oxygen rather than air. This process requires a recycle stream of flue gas to control temperature in the boiler since pure oxygen combustion would exceed temperature limitations of the boiler. Burning the fuel in this manner produces water and highly pure $CO_2$ exhaust that can be captured at relatively low-cost through cooling and compression that condenses and separates the two byproducts. The high cost of producing oxygen, however, has made this a cost-prohibitive option for commercial use in most power plants. Developing technologies in oxygen and ion transport membranes have the potential to reduce the cost of oxygen production and increase oxy-combustion's cost-effectiveness.

Oxy-combustion is most often considered for existing coal boilers burning lower sulfur coals without any $SO_2$ and $NO_x$ control in the hope that these pollutants can be captured and disposed of with the $CO_2$. However, disposing of all these pollutants together can be difficult due to the physical properties of the gases along with other potential regulatory and transportation issues. As with post-combustion capture, oxy-combustion presents trade-offs. The large power requirements for both oxygen production and operation of the $CO_2$ compressor may lead to a reduction in net capacity and efficiency in the range of 25-30% relative to the same combustion system without $CO_2$ capture.

There are a limited number of commercial scale oxy-combustion technologies that are currently being researched around the world. In North America, the Babcock & Wilcox Power Generation Group, Inc. and Air Liquide successfully operated a 30 MW generator in "full oxy-combustion mode" and are continuing research into the different types of coal mediums and plant designs that optimize carbon capture in different oxy-combustion models.[17] In September 2008, Vattenfall began operation of a 30 MW oxy-combustion system in Germany that will be utilized to produce process steam and will eventually have the ability to store captured $CO_2$ in a geological formation.[18] In addition to these projects, the DOE/NETL is currently funding multiple oxy-combustion $CO_2$ emission control projects in the laboratory and in small scale pilot programs along with advanced oxy-combustion system designs and analysis. The following table is a summary of the efforts currently underway sponsored through the DOE/NETL Existing Plants Program.

**Table 3: DOE/NETL Current Oxy-combustion Technology R&D Projects**

| Participant | Project Focus | Research Pathway | Scale |
|---|---|---|---|
| Babcock & Wilcox | PC Oxy-combustion Pilot Testing | Oxy-combustion | Pilot |
| Southern Research | Oxy-fired $CO_2$ Recycle Retrofit | Oxy-combustion | Pilot |
| Praxair | Oxygen Transport Membrane Boiler | Advanced Oxy-combustion | Laboratory |
| Jupiter Oxygen | PC Oxy-combustion with Integrated Pollutant Removal | Oxy-combustion | Laboratory |
| Argonne National Laboratory | Evaluation of Oxy-combustion with Incorporation of AMIGA Model | Oxy-combustion | Modeling |
| CANMET | Pilot-scale Oxy-combustion Research | Oxy-combustion | Pilot |
| Alstom | Tangentially-fired Oxy-combustion Pilot Testing | Oxy-combustion | Pilot |
| Reaction Engineering International | Multi-scale Oxy-combustion Testing and Model Development | Oxy-combustion | Multi-scale |
| Foster Wheeler | Oxy-combustion Environment Corrosion Testing | Oxy-combustion Corrosion | Bench |
| Air Products | Flue Gas Purification Utilizing $SO_x$/$NO_x$ Reactions | Oxy-combustion Flue Gas | Pilot |
| Praxair | Oxy-Combustion Flue Gas Purification | Oxy-combustion Flue Gas | Laboratory |

**Post-combustion**

Post-combustion capture focuses directly on power plant emissions, such as flue gas. Four of the most popular processes being researched today use absorption, adsorption, cryogenic separation and membrane separation.[19]

[17] Air Liquide, "Reducing carbon dioxide emissions using oxy-combustion processes." 2008. http://www.airliquide.com/file/other elementcontent/pj/oxy-combustion%20eng17713.pdf

[18] Alstom, "Alstom ahead of the curve for CO2 capture and storage." 2008. http://www.cn.alstom.com/home/media_center /alstom_news/53399.EN.php?languageId=EN&dir=/home/media_center/alstom_news/

[19] Researchers are also exploring many biological, chemical, and physical separation mechanisms. Descriptions of these additional methods of $CO_2$ capture can be found in a report from Stanford University titled *An Assessment of Carbon Capture Technology and Research Opportunities* (http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf).

***Absorption (Solvent Scrubbing) -*** This process uses solvents to absorb $CO_2$ gases and is akin to "scrubbing" exhaust gases. Commercially, it is the most well established of the techniques available for $CO_2$ capture and has been employed for over 60 years by the oil and chemical industries to remove $CO_2$ from gas streams.

Ammine scrubbing, a form of absorption, is currently being employed at the Warrior Run coal-fired power station in Cumberland, Md.[20] However, the amine scrubbing process can be energy intensive and research suggests that this process may be more effective if used with a pre-combustion process to reduce energy losses or with chilled ammine to minimize capacity and efficiency losses. The University of Notre Dame, through support from DOE/NETL, is currently developing another absorption carbon capture technology for use in new and existing coal-fired boilers: novel ionic liquids, or salts that are liquid at room temperature.[21] These solvents have no vapor pressure and can physically trap $CO_2$ without chemical reaction thereby reducing the amount of energy required for regeneration.

***Adsorption -*** Under this process a gas fixes to the surface of a porous solid with large surface areas which is able to adsorb (or attract and hold) large quantities of gas. Fitting the plant with an adsorbent bed can remove $CO_2$ from power plant flue gases. After the $CO_2$ has attached to the adsorbent substance it may be released and trapped by altering the pressure or temperature of various parts of the system or a sweep of the adsorbent bed with a gas that releases the $CO_2$.

NETL's Office of Research and Development is currently developing solid based sorbents for high temperature, high pressure operation in pre-combustion capture as well as for post-combustion capture. Additionally, the DOE/NETL is funding the development of metal organic frameworks (MOF) by UOP LLC, an industrial energy technology company, for use in post-combustion $CO_2$ capture. MOFs are solid sorbents with high micropore volume and surface areas as well as other properties that can be fine tuned based upon the materials chosen to compose the MOF structure. Research Triangle Institute (RTI) is also developing a dry, regenerable sorbent for $CO_2$ capture. This sodium carbonate based sorbent has exhibited promising results on testing with actual coal derived flue gas. DOE/NETL has also recently awarded projects to ADA-ES, TDA Research, and SRI International to develop other solid sorbents for post-combustion $CO_2$ capture.

***Cryogenic Separation -*** This process involves separating $CO_2$ from other gases by cooling and condensation. Cryogenics are used widely for separating highly concentrated $CO_2$ from other gases, making it suitable for pre-combustion capture. However, this process can be easily contaminated and can harm the plant's capture equipment. Also, the behavior of the $CO_2$ is complicated and may end up interfering with the equipment. As with other technologies, this process is very energy intensive.

***Membrane Separation -*** This process utilizes gas separation membranes that allow one component in the gas stream to pass through faster than others. The efficacy of a membrane depends upon its permeability (the rate of the flow of the gas through the membrane) and selectivity (the ability for one component of the gas to permeate faster than others). For CCS purposes, a permeable membrane that is highly selective with respect to $CO_2$ is desirable.

While membrane separation has been effectively utilized, membranes may not achieve a high degree of separation which may require the process to be carried out in multiple stages or repeated. Such repetition results in increased costs and energy consumption. Accordingly, significant development of the process may be needed before it can be used for capture at a commercial scale on power plants. NETL's Office of Research and Development is currently investigating the use of polymeric membranes combined with ionic

[20] DOE: Office of Fossil Energy NETL, "Winter 2000 Clean Coal Today." 2007. http://www.netl.doe.gov/technologies/coalpower/cctc/newsletter/documents/00_win.pdf
[21] DOE: NETL, "Ionic Liquids: Breakthrough Absorption Technology for Post-Combustion $CO_2$ Capture." 2007. http://www.netl.doe.gov/publications/factsheets/project/Proj471.pdf

liquids to achieve an optimal post-combustion $CO_2$ capture system. Carbozyme, Inc., through a project with the DOE/NETL, is examining the use of polymeric membranes facilitated by enzymes for $CO_2$ capture. Recently, projects were awarded to Membrane Technology and Research and RTI to investigate other polymeric membranes and membrane configuration for post-combustion $CO_2$ capture.

Unlike pre and oxy-combustion options, post-combustion technologies can potentially be utilized both for newly constructed power plants and existing plants. Some technologies, such amine and alternative solvent capture process, are already being tested in pilot projects at existing generation facilities. Wisconsin Energy in partnership with EPRI and technology developer Alstom, for example, are working to scale-up chilled ammonia process $CO_2$ capture research to demonstration scale at two American Electric Power facilities.[22] Considerations of additional land area for capture-related systems and conducting capture systems studies as part of the initial plant design would be part of the efforts needed to create a capture-ready condition. In addition, questions arise over possible "pre-investments" targeted on the capture readiness aspects such as over-sizing equipment to satisfy $CO_2$ compression requirements and other process changes that would be needed to accommodate capture. These decisions could affect base technology choices reaching back to the power plant itself or in pre-selecting the capture technology to be accommodated later. All such issues have the potential to increase upfront costs of electricity.

## Carbon Storage

In order to prevent $CO_2$ from being released into the atmosphere, capture alone is not sufficient. Researchers are currently exploring a number of options for what to do with the $CO_2$ once it has been sequestered. Geologic storage has emerged as a leading candidate because of the potential wide spread availability of these storage sites and their ability to handle large quantities of $CO_2$. Currently, three geologic storage options emerge as most feasible: depleted oil and gas fields and enhanced oil recovery (EOR), deep saline formations, and un-minable coal seams. Other promising candidates may exist onshore or offshore, but in every case $CO_2$ is injected into deep subsurface geologic formations.

### Enhanced Oil Recovery (EOR)

EOR for depleted oil and gas fields is attractive for a number of reasons. Oil and gas formations held gases and liquids for millions of years before they were removed for use signifying a viable capacity to store similar substances. At the depths and temperatures of these fields, supercritical $CO_2$ acts like a fluid. This means that where some recoverable oil or gas resource remains in the reservoir, $CO_2$ may be useful for filling the reservoirs for enhanced recovery of these resources. The geology of these formations is known as they have been mapped and studied through previous oil extraction endeavors. Scientists have a solid understanding of the available storage capacity of these fields.

In the case of an oil field, actual $CO_2$ storage is accomplished in two parts. First, some of the injected $CO_2$ is stored in the immobile oil remaining in the reservoir. The rest of the $CO_2$ is collected from the production well and re-used for EOR. Where resources remain in economically depleted oil reservoirs, using $CO_2$ to engage in enhanced recovery of these resources creates a revenue stream that can improve the economics of undertaking $CO_2$ storage. According to biennial EOR reports compiled by the *Oil & Gas Journal;* domestic EOR production equaled 649,000 barrels per day in 2006. The latest tabulation of $CO_2$-EOR activity in the U.S., shows approximately 237,000 barrels per day of incremental domestic oil is being produced by 86 $CO_2$-EOR projects, distributed broadly across the U.S. This amounts to about 5% of total domestic oil production. The Weyburn field in Canada is an example of $CO_2$ injection for EOR. In this project, 1.8 million tonnes of $CO_2$ per year is being captured from a coal gasification plant and injected into an oil field.[23]

[22] DOE: "Retrofitting the Existing Coal Fleet with Carbon Capture Technology." 2008. http://fossil.energy.gov/programs/powersystems/pollutioncontrols/Retrofitting_Existing_Plants.html
[23] IEA: International Energy Agency Greenhouse Gas R&D Programme, "Depleted Oil & Gas Fields for $CO_2$ Storage." http://www.ieagreen.org.uk/ccs.html

The $CO_2$ approach to EOR is likely to increase in response to increasing oil prices and the emergence of carbon constraints. However, implementation of $CO_2$ capture and storage at the scale of current U.S. emissions from power plants will outstrip EOR opportunities eventually, and may exceed the volume of known petroleum reservoirs in the U.S. in the next 50 to 100 years.

In a depleted gas field the injected $CO_2$ would fill the space previously occupied by natural gas. Research is underway to see if $CO_2$ can be used for enhanced gas production – a process mimicking EOR. Because of the economic yields, depleted fields and EOR are likely the most economically attractive options for storage in the short-term, but cannot be the only storage option due to geographic distribution and the ratio of emissions to storage space.

**Deep Saline Formations**

Deep Saline Formations, or deep saltwater reservoirs, are rocks with porous spaces that are filled with brine. They exist nearly world-wide and have great potential for $CO_2$ storage. The most suitable reservoirs are those at depths greater than 800m as at this depth $CO_2$ will behave more like a liquid than a gas, enabling much more to be stored. Carbon dioxide may remain buoyant for hundreds, if not thousands of years until it slowly dissolves in the brine, eventually sinking deeper into the reservoir. While in the supercritical state the buoyant forces push the $CO_2$ upward. Therefore, an impermeable cap-rock over the storage site is necessary to ensure that the $CO_2$ remains underground. The geology of deep saline formations is not as well characterized compared to that of oil and gas fields. However, saline reservoirs have been used as buffer stores for natural gas, which supports the belief that $CO_2$ could be stored safely in carefully selected sites. More research will be needed for these reservoirs to become viable options.

A commercial project in the North Sea currently injects $CO_2$ into an offshore deep saline formation. This project, at the Sleipner West gas field, has been operating since 1996.[24] Approximately one million tons of carbon dioxide is injected underground for storage annually. Another more recent project by EPRI in collaboration with the DOE and American Electric Power will demonstrate integrated CCS by combining two types of solvent-based carbon capture technologies with deep saline injection.[25] $CO_2$ will be injected into different kinds of typical U.S. underground formations as part of a comprehensive monitoring and measuring study to identify location and movement of injected underground $CO_2$. The project is to be completed by 2014.

**Un-minable Coal Seams**

Un-minable Coal Seams, or $CO_2$-enhanced coal bed methane ($CO_2$-ECBM) production, are a third storage option. The logic behind using these types of coal seams for storage is similar to that of using depleted oil fields for EOR. These coal beds contain large amounts of methane gas that, if released, can be captured and used for power generation or heating. By injecting $CO_2$ into the coal seam, the methane contained in the surface pores of the coal is displaced and released. Laboratory measurements suggest that twice as much $CO_2$ can be stored as methane was desorbed. However, since methane is also a greenhouse gas, all of the methane that is released must be captured and put to use for a greenhouse gas emissions benefit to occur. The revenue created by the capture of methane can help off-set $CO_2$ injection costs. ECBM is still in the early stages of research and compared to storage in other reservoir types, coal seams appear to have a lesser capacity for storing $CO_2$.

A $CO_2$-ECBM pilot project developed by Burlington Resources (now ConocoPhilips) and BP is underway in the San Juan Basin in the southwestern United States.[26] The project has achieved increased methane production. So far, no $CO_2$ has been found in the capture methane gas indicating that $CO_2$ is being

[24] IEA. International Energy Agency Greenhouse Gas R&D Programme. "$CO_2$ Storage in Deep Salt Water Reservoirs." http://www.ieagreen.org.uk /6.pdf
[25] EPRI: "Frequently Asked Question on $CO_2$ Capture and Storage." 2007. http://mydocs.epri.com/docs/public/000000000001015188.pdf
[26] IEA: International Energy Agency Greenhouse Gas R&D Programme. "Storing $CO_2$ in Unminable Coal Seams." http://www.ieagreen.org.uk/8.pdf

stored in the coal seam. Lessons learned from this experiment will be looked to for future consideration of these coal seams as a storage option.

**Potential of Worldwide and US Geologic Formations for Storage of Carbon**

The International Energy Agency's (IEA) Greenhouse Gas R&D Programme and the Intergovernmental Panel on Climate Change have explored the potential of the three primary storage options discussed in this paper, illustrated in Table 4.

**Table 4: Potential of Geologic Storage Options**

| **Geological Storage Option** | **Global Capacity** | |
|---|---|---|
| | **Gtonne $CO_2$** | **As a proportion of total emission 2000 to 2050** |
| Depleted Oil and Gas Fields | 920[27] | 45% |
| Unminable Coal Seams | >15[28] | >1% |
| Deep Saline Reservoirs | 400 – 10,000 | 20 – 500% |

(IEA 2007, http://www.ieagreen.org.uk/ccs.html)

The storage options presented above are not the only geologic formations under consideration. Other possible storage sites include basalt formations, organic rich shales, salt caverns, and abandoned mines. These options may not be suited for large scale $CO_2$ storage and/or require extensive additional research to assess their viability as storage sites.

The storage potential of types of geologic formations located within the U.S. has been under active investigation and their storage resources have been recently re-evaluated.[29] The range of storage potential for each major reservoir type is summarized below:

- Depleted Oil and Gas Fields 138-152 Gtonne $CO_2$
- Un-minable Coal Seams 157-178 Gtonne $CO_2$
- Deep Saline Reservoirs 3,297-13,909 Gtonne $CO_2$

The U.S. total $CO_2$ emission equals about 6 Gtonne per year. It is clear that the geologic storage potential within the U.S. is vast and represents a key strategy to be investigated.

**Site Selection Criteria for Geologic Storage of Carbon**

Site selection of storage reservoirs must take many factors into consideration. Various properties of the storage rock and seals, or "traps," must be considered including:

- Porosity - the measure of the space available for storing the $CO_2$ (acting as a fluid)
- Permeability - the measure of the ability of the rock to allow fluid to flow; and
- Injectivity - the rate at which the $CO_2$ can be injected into the site

[27] This is the upper limit. The lower limit is 675 $GtCO_2$.
[28] This is the lower limit. The upper limit is 200 $GtCO_2$.
[29] DOE: NETL, "Carbon Sequestration Atlas of the United States and Canada-Second Edition." 2008. http://www.netl.doe.gov /technologies/carbon_seq/refshelf/atlasII/index.html

*Fig. 13: Desired Characteristics for Geologic Storage*

**What is a Good Geologic Storage Site?**

Accessibility

- ✓ The location is economically accessible to the source of $CO_2$.
- ✓ The organization conducting storage has all the legal rights to do so on that site.

Capacity

- ✓ Storage formation has adequate porosity and permeability to store $CO_2$.
- ✓ The storage formation has adequate total storage volume to serve the intended sources.

Injectivity

- ✓ The formation can store $CO_2$ at the rate required to serve the intended sources.

Storage Security

- ✓ Well-defined trapping mechanisms exist within the storage formation.
- ✓ The $CO_2$ will be stored deep enough to be supercritical.
- ✓ Cap rock is adequately impermeable, continuous and thick to prevent upward migration.
- ✓ The geologic environment is adequately stable to ensure the integrity of the storage site.
- ✓ No pathway faults or uncapped wells penetrate the cap rock and storage formation.

(IEA 2008, *Geologic Storage of Carbon Dioxide – Staying Safely Underground)*

Generally, a suitable storage site will be highly porous, have a high degree of permeability, and $CO_2$ will be able to be injected at nearly the same rate as it is captured from the sources (see Figure 13). The seal over the storage site, however, should have low porosity and permeability in order to trap the fluids below. The primary sealant is called "cap rock", a dense layer of impermeable rock located on top of the rocks holding the $CO_2$. Over time, additional natural trapping processes become active; thus, in general, the longer $CO_2$ stays underground the more secure its storage becomes. More information on $CO_2$ safety is available in the January 2008 publication of IEA, *Geologic Storage of Carbon Dioxide – Staying Safely Underground* found at http://www.ieagreen.org.uk/glossies/geostoragesfty.pdf

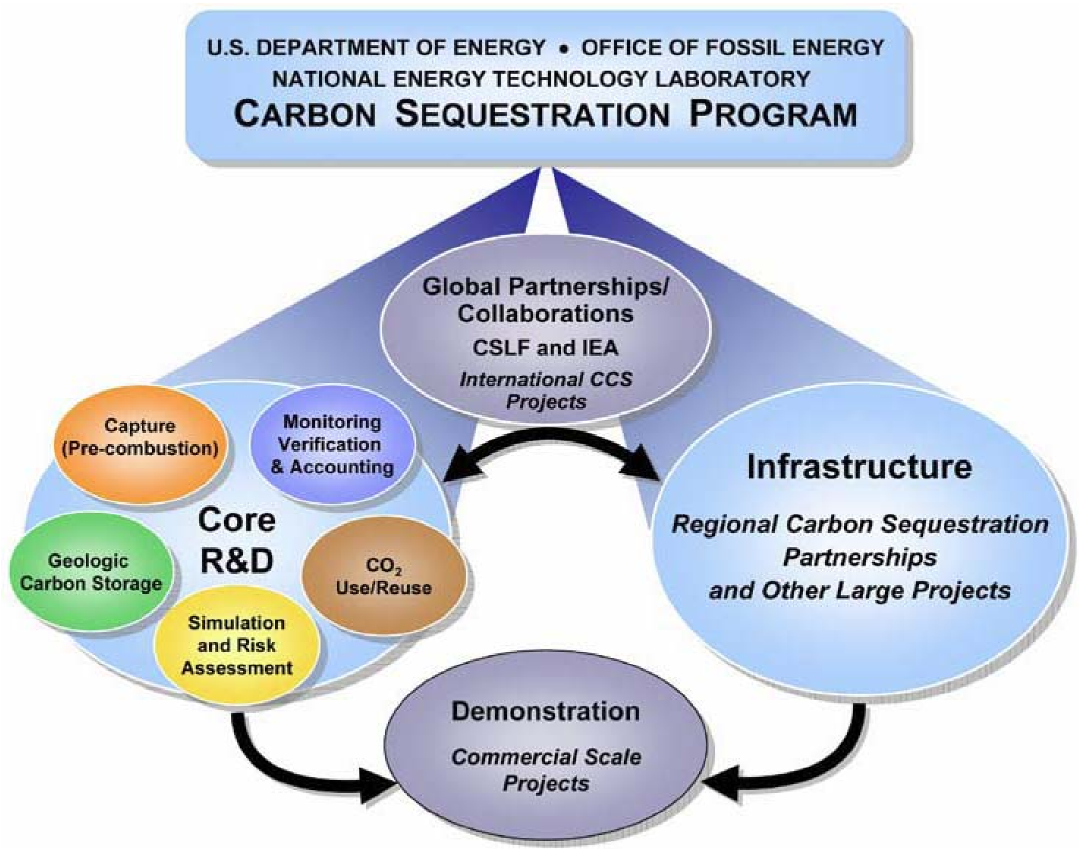
**Research Projects Investigating $CO_2$ Technologies and Storage**

Government, academic, industry, and other non-governmental research groups from around the world are actively researching CCS technologies. In the US in particular, DOE funds CCS research, from exploring potential geologic sites for storage to developing monitoring and verification techniques, through regional partnerships (see Figure 14).

FutureGen, the Clean Coal Power Initiative (CCPI), and Regional Carbon Sequestration Partnerships are noteworthy components of the DOE's research and large-scale demonstration programs. FutureGen was originally designed in 2003 as a $1 billion initiative to create and operate the world's first zero-emissions fossil fuel plant. The project was initially intended to: prove the effectiveness, safety and permanence of large scale

$CO_2$ sequestration through validating the technology under real world conditions; establish technology standards and protocols for $CO_2$ measuring, mitigation and verification; and, drive other projects to commercialization by 2020. However, in January 2008 the FutureGen project was restructured by the Department of Energy. FutureGen funds will now be used to demonstrate CCS technology at multiple commercial-scale coal-fired Integrated Gasification Combined Cycle or other advanced coal power plants. More information on the current status of the FutureGen project can be found at:
http://www.fossil.energy.gov/programs/powersystems/futuregen/.

***Fig. 14: U.S. DOE's Carbon Sequestration Program***

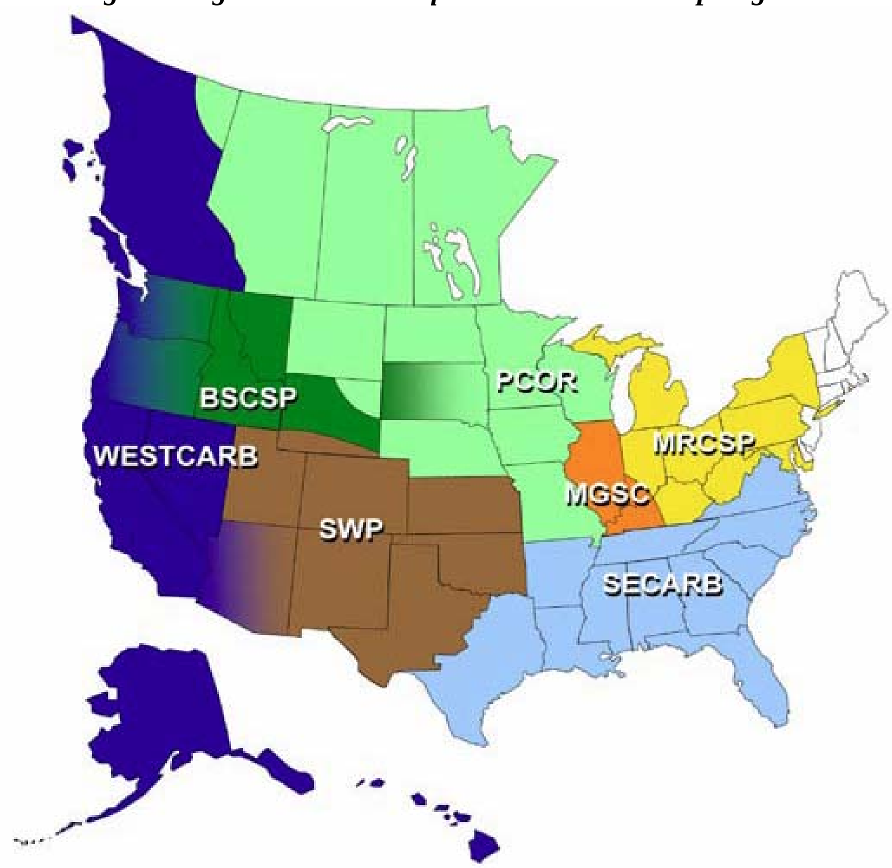



(DOE 2008, *Carbon Sequestration Atlas of the United States and Canada*)

CCPI is another demonstration program that seeks to partner with industry in order to demonstrate integrated CCS and power technologies at coal plants. DOE is seeking partnerships to demonstrate the next generation of technologies to capture and sequester, or put to beneficial reuse, carbon dioxide emissions from coal-fired power generation facilities. Round III of the CCPI is specifically targeting advanced coal-based projects that have progressed beyond the research and development stage, to a point of readiness for operation at a scale that, once demonstrated, can be readily replicated and deployed into commercial practice within the electric power industry. In the CCPI program, DOE will share up to 50 percent of the cost of qualified projects. More information on the current status of CCPI can be found at: http://www.fossil.energy.gov/programs/powersystems/cleancoal/.

Another CCS initiative of the DOE's is the Carbon Sequestration Regional Partnerships illustrated in Figure 15 below. Seven Regional Partnerships comprised of both public and private industries have been created to examine technologies, policies, and infrastructure necessary for large-scale carbon capture and storage. The formation of these Regional Partnerships is recognition of the different challenges and opportunities that exist for sequestration in varying geographic locations. The Regional Partnership Program is being conducted in three phases, concluding with large scale demonstration of CCS technologies (more information available at http://ww.fossil.energy.gov/programs/sequestration/partnerships/index.html).

***Fig. 15: Regional Carbon Sequestration Partnership Regions***




(DOE 2008, *Carbon Sequestration Atlas of the United States and Canada*)

Internationally, the IEA, an organization that serves as an energy advisor to 26 member countries including the United States, Australia, Canada, Germany, and Japan, is devoting significant resources to CCS research. The IEA's work focuses on energy security, economic development and environmental protection. In 1991, the IEA developed the IEA Greenhouse Gas R&D Programme (IEA GHG). IEA GHG supports international research collaboration to assess GHG reduction technologies. More information on the IEA's Greenhouse Gas R&D Programme can be found at http://www.ieagreen.org.uk/.

## Storage Siting and Permitting

The Safe Drinking Water Act currently regulates $CO_2$ injection and may provide a model for long-term storage, but a tailored regulatory structure for large-scale, long-term carbon dioxide storage does not yet exist. While some believe the current regulatory models are sufficient, questions remain as to who will regulate long-term storage, the timeframes tied to the responsibility for storage, and the economics of carbon dioxide storage. These questions are a driving force behind much research as these uncertainties translate into higher financial risk and complex liability problems, which will be discussed in the next section.

The EPA and States permit wells used in enhanced oil recovery and experimental $CO_2$ injection wells under Safe Drinking Water Act (SDWA) authority. Underground injection of $CO_2$, as directed by the SDWA, is managed through the EPA's Underground Injection Control (UIC) program, a program regulating underground injection of both fluids considered to be commodities and those deemed waste products.

In March 2007, the EPA finalized UIC Program Guidance #83 *Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects*. This document will assist State and EPA regional UIC programs in processing permit applications for experimental projects designed to assess the efficacy of $CO_2$ injection for the purpose of geologic sequestration. $CO_2$ behavior underground will be studied as will well construction and operations. The information from these projects will help regulators determine if new UIC regulations for commercial-scale $CO_2$ injection projects are needed. UIC Program Guidance #83 can be found at http://www.epa.gov/OGWDW/uic/wells_sequestration.html.

Under the UIC program there are five classes of wells:

- Class I is for deep injection of hazardous and non-hazardous industrial wastes.
- Class II permits are for wells associated with energy production (EOR).
- Class III is for mineral extraction.
- Class V is for everything else.[30]

As noted above, the EPA has classified experimental wells for geologic sequestration as Class V wells. It should be noted, however, that some groups are pushing for more stringent regulations generally associated with Class I or II wells. However, costs are not determined by well classification, but rather by the associated stringency of the regulations to the particular well. For example, a Class V well with strict and extensive regulatory requirements can be more costly than a Class II well. The EPA is currently developing regulations for commercial-scale geologic sequestration projects. The EPA's Underground Injection Control Program's website contains a number of resources for stakeholders involved with geologic sequestration of $CO_2$ including regulatory guidance and compliance documents as well as a schedule of technical workshops. Currently, EPA with DOE and IOGCC is completing the necessary work for a new class of well, Class VI, specifically for geologic injection of $CO_2$ to be promulgated in the 2011 timeframe. More information can be found at http://www.epa.gov/safewater/uic/wells_sequestration.html.

Other federal laws which may affect $CO_2$ storage include, but are not limited to, the Resource Conservation and Recovery Act (RCRA); the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA); and, the Toxic Substances Control Act (TSCA). States may impose additional siting and permitting requirements for carbon dioxide storage beyond federal requirements. Several states have reportedly been moving forward on such work including New Mexico, California, and Washington.

In addition to the foregoing, State and the federal governments will need to take many legal, physical, and safety considerations into account when determining an appropriate regulatory framework for $CO_2$ storage including but not limited to the following issues:

- How should multiple users of the same or overlapping underground storage facilities be licensed or permitted?
- How should trans-boundary migration of stored $CO_2$ be managed?
- How should the rights and interests of surface owners be protected?

[30] Class IV designations are no longer given.

## Risk and Liability

In addition to the issue of who will regulate $CO_2$ storage, there are also liability issues that may be applicable to storage facilities. There are three major sources of liability:[31]

- Liability from operational impacts;
- Liability from *in situ* risks; and
- Liability associated with deviations from the goal of permanent storage.

In general, liability from operational impacts can likely be managed in the same manner that $CO_2$ transportation, injection, and storage is currently handled in the oil and gas production industry. Liability from *in situ* risks include leaks to the surface, migration of carbon dioxide within the storage formation, hydrocarbon resource damage, groundwater contamination, and seismic and other geological events. These risks could have public health, environmental, and/or ecosystem impacts. There are questions surrounding the management of $CO_2$ leaks and how the escaped carbon dioxide will be accounted for in future carbon regimes. Lastly, there are questions about site closure and long-term stewardship of the closed site. Risk assessment, according to the World Resources Institute, should be an ongoing process rather than a one time activity in the early stages of establishing a capture site.

To gain an understanding of potential future $CO_2$ storage regulation, a number of current regulatory structures have been analyzed that may be important in understanding future regulatory regimes, illustrated in Table 5.

**Table 5: Regulatory Analogs for Carbon Storage Regulation**

| Regulatory Analog | Key Issues | Implications for Carbon Sequestration |
|---|---|---|
| Natural gas transport and storage | • “Routine activities” (not abnormally dangerous) Common Law Liability | • Carbon sequestration a part of everyday life?<br>• How would common law apply to carbon sequestration? |
| Radon | • Strict liability<br>• Implied warranties | • $CO_2$ leakage as a design defect<br>• Liability will lie with the agent representing the storage site or the operator of the site.<br>• Dealing with unknown risks (e.g. abandoned mines) |
| Low-level radioactive waste storage and disposal | • Interstate agreements | • Placing responsibility with federal government versus state<br>• Liability regimes may discourage storage |
| Hazardous waste storage and disposal | • Strict liability<br>• Joint and several liability<br>• Retroactive liability | • Who should be held liable for leakage?<br>• Liability may change over time |

(MIT 2007, *Towards a Long-term Liability Framework for Geologic Carbon Sequestration*)

Under any liability scheme, $CO_2$ transport and storage operators may need to address environmental and health risks. Though there is significant evidence that supports the general safety of $CO_2$ pipelines, risks must not be ignored. $CO_2$, while harmless at low concentrations, is an asphyxiant at high concentrations and can

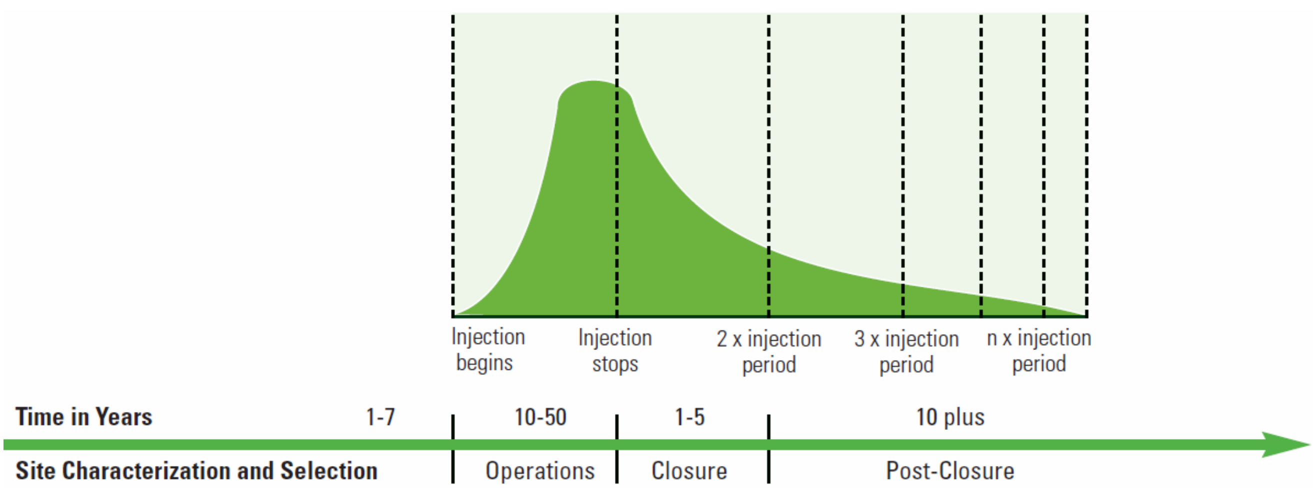
[31] MIT: Carbon Capture & Sequestration Technologies, Figueiredo, M.A and Herzog, H.J. and Reiner, D.M., “Towards a Long-term Liability Framework for Geologic Carbon Sequestration.” 2007. http://sequestration.mit.edu/pdf/defigueiredo_et_al_MIT_paper.pdf

accumulate close to the ground since it is heavier than air. A slow leak from a pipeline or a storage facility is dangerous only if the gas is inadvertently trapped, thereby increasing the concentration. Careful site selection and understanding of the topography, human use, and population of the area above the storage site will be required to mitigate harmful releases of $CO_2$. Similarly, pipelines routed through populated areas may require restrictions on levels of hydrogen sulfide ($H_2S$), which is also an asphyxiant at high concentrations. Route selection and leak detection will be key design components to mitigate the risk of $H_2S$ poisoning. All in all, adverse affects to human health from CCS are not thought to be great since $CO_2$ is a significantly less volatile gas than many other gases that are used for energy production.

Some researchers have expressed concern over the potential for $CO_2$ to migrate underground and interact with groundwater supplies. However, other researchers are convinced that $CO_2$ storage will occur in formations which are significantly deeper than groundwater supplies and overlain by impermeable formations which prevent $CO_2$ from migrating upward. In addition, as noted above, permitting requirements under the SDWA are intended to protect drinking water supplies. Acidification of soils and displacement of oxygen in soils are additional environmental concerns, but such hazards may be reduced through careful storage system design, siting, and detection techniques.

It is likely that careful monitoring and detection will be the key to the efficacy of long-term storage. The parties responsible for the long-term care of an injection site will likely need to monitor the integrity of the injection well against leakage, detect leakage early for effective remediation, and then monitor the effectiveness of remediation efforts. Possible risk scenarios, along with potential mitigation and remediation actions, are outlined in the World Resource Institute's (WRI) October 2008 paper, "Guidelines for Carbon Dioxide Capture, Transport, and Storage."[32]

***Fig. 16: Projected Timeline for a CCS Project***




(WRI 2008, *Guidelines for Carbon Dioxide Capture, Transport, and Storage)*

The IEA, supported by data from the IPCC, reports that with proper site selection, operation, and monitoring 99% or more of the $CO_2$ injected through CCS would remain in the intended storage formation for at least 1000 years. [33]

[32] WRI: Forbes, Sarah, et al., "CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage." 2008. http://pdf.wri.org/ccs_guidelines.pdf

[33] IEA: Greenhouse Gas R&D Programme. "Geologic Storage of Carbon Dioxide: Staying Safely Underground." 2008. http://www.ieagreen.org.uk/glossies/geostoragesfty.pdf ; IPCC: de Coninck, Heleen and Meyer, Leo, and Rubin, Edward. "Carbon

## Permitting $CO_2$ Pipelines

A network of $CO_2$ pipelines will be necessary to efficiently and cost effectively transport $CO_2$ from the emitting and capture facilities to geologic formations for long-term storage or to other sequestration or use applications. To address the pipeline issue, NETL is funding a two-phase $CO_2$ Pipeline Infrastructure Study, Developing a National $CO_2$ Pipeline Network. Phase I of the study that recently concluded identified the challenges that would be faced in developing such a network, how such a system would evolve, and how it would enhance the development of new markets and technologies for all the CCS process steps. Phase I supported the likelihood of pipelines initially developing at the regional level. Phase II of the study, currently underway, will perform regional case studies to determine the pipeline routes that are most likely to develop to efficiently deliver $CO_2$ emissions from generation sources to the nearest storage sites. The implications of economics, resources and timing of pipeline development are being evaluated. The study will also identify, characterize, and analyze specific regional challenges to gain a better understanding of the regional differences and how these differences will affect $CO_2$ pipeline development. A mapped view of the likely regional $CO_2$ pipeline networks will be created to produce a platform from which a national $CO_2$ network of pipelines can be developed.

Over 3600 miles (or 5800 km) of $CO_2$ pipeline already exist in the United States and have been in operation since the early 1970s.[34] Most of the pipelines transport $CO_2$ to EOR sites in Texas but some carry $CO_2$ to fields in Oklahoma, Wyoming, Colorado, and into Canada. This network of $CO_2$ pipelines may expand as $CO_2$ storage facilities begin operation around the country. Exactly how much the pipeline network will expand has yet to be determined. It is possible that nearly 75% of the total annual $CO_2$ captured from the major North American sources may be stored in reservoirs beneath the source of emissions. The MIT study concluded that most coal-fired power plants are located in regions where there are likely storage options in close proximity.[35] However, other studies seem to indicate unequal distribution of economically and technically feasible storage sites that would require more extensive pipelines. Regardless of where the pipelines will be, the network of $CO_2$ pipelines will likely expand and the questions of "who" and "how" these pipelines will be permitted will need to be answered.

Currently, interstate $CO_2$ pipelines fall under the jurisdiction of the U.S. Department of Transportation's (DOT) Surface Transportation Board. This Board regulates the transportation of commodities other than water, oil, or natural gas. However, if there are dramatic increases in the volumes of captured $CO_2$ being transported and stored, this regulatory scheme may be called into question.

Controls on $CO_2$ emissions will likely cause an increase in the number of interstate interconnections and users of the expanded $CO_2$ pipeline network. Such an expansion of pipeline capacity will cause Regulators to address a number of issues/questions.

- When setting rates, should there be separate rates for existing pipelines carrying $CO_2$ as a commodity versus new pipelines carrying $CO_2$ as a waste?
- Will State condemnation laws used to secure sites for infrastructure deemed to be in the public interest, allow for $CO_2$ pipelines to be treated as public utilities or common carriers?
- On federal lands managed by the Bureau of Land Management, will new $CO_2$ pipelines be sited under the provisions of the Mineral Leasing Act (has common carrier requirements) or the Federal Land Policy management Act (does not have such requirements)?

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Dioxide Capture and Storage: Technical Summary." IPCC Special Report. 2005. Intergovernmental Panel on Climate Change. 2007. http://www.ipcc.ch/pdf/special-reports/srccs/srccs_technicalsummary.pdf

[34] National Council for Science and the Environment: Folger, Peter and Parfomak, Paul W., "Carbon Dioxide ($CO_2$) Pipelines for Carbon Sequestration: Emerging Policy Issues." Congressional Research Service Reports. 2007. http://www.ncseonline.org/NLE/CRSreports/07May/RL33971.pdf

[35] MIT: Deutch, John, et al., "The Future of Coal." 2007. http://web.mit.edu/coal/

The issue of cost and cost recovery for $CO_2$ pipelines may also challenge the existing regulatory structure. For example, an expansion of the pipeline network may also bring out issues that are similar to those seen in developing regional electric transmission networks: if $CO_2$ pipelines are regional in nature, will cost recovery be at the federal or state level? Uncertainty created from variations in state and federal regulation of $CO_2$ pipelines may lessen the level of attraction of $CO_2$ pipelines for capital investment. As the network develops from a series of intrastate pipelines to a network of interstate pipelines, the different economic regulation of $CO_2$ as a commodity or as a waste across state lines may create complexities for pipeline operators. Operators may repeatedly have to negotiate or litigate siting, pipelines access, and rate "pancaking" issues. Coordinated efforts to create coherent economic $CO_2$ regulation on at least a regional basis will likely be crucial to the development of an expanded $CO_2$ pipeline network.

Another issue in the siting of $CO_2$ pipelines is the potential health impact in the event of a leak. The health concern focuses on $CO_2$ and other substances that act as asphyxiants. To mitigate health risks, the DOT regulates interstate $CO_2$ pipeline safety through the Pipelines and Hazardous Materials Safety Administration (PHMSA). The agency applies nearly the same safety requirements to $CO_2$ pipelines as it does to pipelines carrying liquids such as crude oil and gasoline. Analysts have shown that mile-for-mile, $CO_2$ pipelines appear to be safer than the other types of pipelines regulated by the DOT.[36] However, some safety and health concerns including consequence modeling for handling supercritical $CO_2$ must be addressed during the permitting process. Public acceptance of an expanded $CO_2$ pipeline network will require resolution of these safety and health concerns.

The pathway to permitting $CO_2$ pipelines can be problematic and time consuming, as is sometimes the case with natural gas pipelines or electric transmission lines. Outreach and education of the public will be important to avoid unnecessary delays or prevention of $CO_2$ pipeline installations, since public opposition to $CO_2$ pipelines can halt or delay construction even when all permits have been granted.

## Conclusion

Because coal continues to be critical to this Nation's economic security and the reliability of the electric system, Commissions need to be well informed about the range of issues that must be considered as a prerequisite for the deployment of a new generation of coal plants with carbon capture capabilities. To comply with increasingly stringent environmental requirements, objective and comprehensive analyses will be necessary to properly develop and implement capture technologies, transport infrastructure, and storage capabilities. At every step of the way, regulators will need to consider economic, environmental, and health impacts of CCS.

The assessment of the current state of CCS technology will vary depending upon the portion of the process under consideration. Capture technologies are largely known, but not commercialized beyond a number of industrial operations. While portions of CCS regulatory policies are still in developmental stages, there may be appropriate models that can be utilized in the short term to begin the development of new regulations. Government, academia, industry, and non-governmental groups are all investing in research to advance CCS technologies and policies. Further work is needed to move CCS from an experimental/exploratory phase to practical implementation.

[36] National Council for Science and the Environment, "Carbon Dioxide ($CO_2$) Pipelines for Carbon Sequestration: Emerging Policy Issues." http://www.nationalcoalcouncil.org/Documents/JUNE25EXECSUMMARY.pdf

## RESOURCES USED FOR THIS PRIMER

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