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Expediting CCS Development: Challenges and Opportunities

Charles Hopf

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THE NATIONAL COAL COUNCIL

Expedited CCS Development: Challenges & Opportunities

March 18, 2011

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U.S. DEPARTMENT OF ENERGY
The Honorable Steven Chu, Ph.D.
U.S. Secretary of Energy

The National Coal Council is a Federal Advisory Committee to the U.S. Secretary of Energy.
The sole purpose of The National Coal Council is to advise, inform, and make recommendations
to the Secretary on any matter requested by the Secretary relating to coal or the coal industry.

THE NATIONAL COAL COUNCIL

In the fall of 1984, The National Coal Council (NCC) was chartered and in April 1985, the NCC became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner and, in turn, lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy. The NCC is chartered by the U.S. Secretary of Energy under the Federal Advisory Committee Act. The purpose of the NCC is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

Members of the NCC are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The NCC is headed by a Chair and Vice-Chair who are elected by the NCC members. The NCC is supported entirely by voluntary contributions from its members. It receives no funds whatsoever from the Federal Government. By conducting studies at no cost, which might otherwise have to be done by the Department, it saves money for the government. The NCC does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The NCC does not represent any one segment of the coal or coal-related industry nor the views or any one particular part of the country. It is instead a broad, objective advisory group with an approach that is national in scope.

Matters which the Secretary of Energy would like to have considered by the NCC are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by the NCC at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the start-up of the NCC.

Expedited CCS Development: Challenges & Opportunities

Prepared for

The United States Department of Energy

Prepared by

THE NATIONAL COAL COUNCIL

March 18, 2011

The Secretary of Energy
Washington, DC 20585

June 1, 2010

Mr. Michael G. Mueller
Chair, National Coal Council
1730 M Street NW, Suite 907
Washington, DC 20036

Dear Mr. Mueller:

I am writing to request that the National Coal Council (Council) conduct a new study on the deployment of carbon capture and storage (CCS) technologies that build on the work you have done in the recent past by focusing on the management of emissions of carbon dioxide from both the existing and new fleet of coal-based electricity generating plants. This study will provide additional recommendations to assist the Department of Energy in managing a research, development and demonstration program that will allow the country to achieve President Obama's goal of an 83 percent reduction in CO_2 emissions by 2050.

The proposed scope of the report should tackle issues surrounding the widespread, cost-effective deployment of CCS in the post-2020 timeframe. Some of the issues to pursue include: (1) viable strategies for industry to deploy CCS technologies; (2) technical areas that merit Federal support to expedite deployment; (3) a feasible timeline for moving forward with low-carbon coal technologies; and (4) the impacts that legal and regulatory policies pose on the deployment of CCS technologies. Please offer a study completion date upon receipt of this letter.

In closing, I look forward to the Council's recommendations that directly relate to the broad deployment of economically competitive CCS technologies. As the United States is a leader in both technology development and coal reserves, I welcome this important and timely advice from the Council regarding the development of low-carbon technologies for our coal industry.

Sincerely,

Steven Chu

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Summary of Terminology, Abbreviations, and Acronyms

AEF	The Committee on America's Energy Future
ARRA	American Reinvestment and Recovery Act
ASME	American Society of Mechanical Engineering
BACT	Best Available Control Technology
CA	Carbonic Anhydrase
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Use, and Storage
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO_2	Carbon Dioxide
Council	National Coal Council
CSLF	Carbon Sequestration Leadership Forum
DME	Dimethyl ether
DOE	U.S. Department of Energy
EIA	Energy Information Agency
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
FGD	Flue Gas Desulfurization
FLPMA	Federal Land Policy and Management Act
FMLA	Federal Mineral Leasing Act
GHG	Greenhouse Gas
GPSP	Great Plains Synfuels Plant
GW	Gigawatt
ICCS	Industrial CCS Program
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IOGCC	Interstate Oil & Gas Compact Commission
Interagency	Interagency Task Force on CCS
kWh	Kilowatt Hour
MGA	Midwest Governors Association
MIT	Massachusetts Institute of Technology
MVA	Monitoring, Verification, and Accounting
MWh	Megawatt Hour
NCC	National Coal Council
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
RCI	Rotterdam Climate Initiative
RCRA	Resource Conservation & Recovery Act
RCSP	Regional Carbon Sequestration Program
Secretary	U.S. Secretary of Energy
SCR	Selective Catalytic Reduction
SDWA	Safe Drinking Water Act
SO_2	Sulfur Dioxide
U.S.	United States
UIC	Underground Injection Control
UNFCCC	United Nations Framework Convention on Climate Change
USDW	Underground Source of Drinking Water
WRI	World Resources Institute

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The following volunteers made significant contributions to the development the 2011 National Coal Council report.

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Executive Summary

Electricity is the lifeblood of modern society and the key to a higher quality of life around the world. In fact, the National Academy of Engineering has identified electrification as the "most significant engineering achievement of the 20th Century." Coal is the ongoing bulwark of electricity generation in the United States, providing the reliable and cost-effective power that has enabled America's dramatic socioeconomic advances since World War II. In coming decades, the continued use of coal is essential for providing an energy supply that supports sustainable economic growth in the context of climate policy goals, such as President Obama's goal for an 83 percent reduction in greenhouse gas (GHG) emissions by 2050.

Carbon capture and storage (CCS) technologies have been widely recognized as the link for realizing both the benefits of coal and the need for reducing GHG emissions. Ongoing research and development efforts are advancing the technology, but a range of issues must be addressed before CCS processes are commercially acceptable for coal-based electric generating units. It is with that context that Secretary of Energy Steven Chu requested the National Coal Council (NCC or Council) to conduct a study that "…should tackle issues surrounding the widespread, cost-effective deployment of CCS in the post-2020 timeframe."

This report examines issues related to the expedited development and deployment of CCS systems to coal-based generating units by evaluating challenges and opportunities pertaining to each aspect of the technology: capture, transportation, and geologic storage. Overall, the study determined that the current CCS demonstration program in the United States, although robust, has not progressed fast enough and is not on pace to significantly advance CCS development in the near-term due to technical and equally important non-technical obstacles. However, the study also determined that the United States, and in particular the Department of Energy (DOE), is in the best position to accelerate current efforts and overcome these development hurdles.

Challenges to CCS development and deployment can broadly be categorized into technical, financial, and regulatory areas. In terms of technical issues, key development concerns include the fact that commercial-scale CCS processes have *not yet* been demonstrated on a coal-fired generating unit. The current progress of the DOE CCS development program in bringing full-scale demonstration online is insufficient - large-scale, *operating* CCS demonstration projects representing a diversity of capture processes and geologic settings are needed in the near-term to expedite development. Another technical challenge is the need for a greater set of reliable analytical tools for evaluating, designing, and monitoring geologic storage opportunities. As these and other technology challenges are addressed, the solution will not be as simple as one-size-fits-all, especially for retrofit projects to the existing coal fleet where unit-specific factors will require a suite of CCS process and design options.

Related to technology concerns are challenges driven by the cost of CCS projects. Federal incentives are critical for enabling first-mover CCS projects at coal-based generating units; however, such funding does not guarantee that a project will become a reality, as evidenced by the number of projects cancelled despite receiving significant funding awards. CCS projects will be inherently expensive for coal-based generation due to the size of the process, impacts to the generating unit, and associated risks, all of which are compounded by the technology being in an early stage of development. While cost considerations tend to focus on the capture process, pipeline transportation and geologic storage development costs will also be significant. Beneficial CO_2 use or conversion opportunities, such as enhanced oil recovery (EOR), can offset a portion of development costs. However, without a regulatory driver and greater certainty with respect to the management of long-term liability risks, obtaining funding or cost-recovery assurance will continue to be a significant development challenge.

Non-technical challenges related to regulatory and permitting requirements also pose a risk to expedited development, in particular with respect to the time it takes to obtain the necessary approvals and the potential cost to ratepayers. Although many of the relevant permitting programs are well established, the process of obtaining permits to *begin* construction, including obtaining required approvals from state utility commissions, can take years to complete. Consider development of even a modest CO_2 pipeline network, which would require a significant amount of baseline field evaluations to be performed to assess potential impacts to environmental (water, endangered species, wetlands, etc.) and cultural (architectural, archeological, etc.) resources. Much work is required before these evaluations can begin. For example, the scope of field evaluations is dependent on the selection of pipeline corridor options, which is dependent on the selection of potential injection well locations, which is dependent on data from an initial geologic characterization program. A significant financial and time investment is required for this entire process to be completed, which impacts the cost, schedule, and viability of a project. Other regulatory challenges relate to the scale of CCS projects, unique environmental permitting issues, the need for public outreach programs, and uncertainties related to pore-space ownership and the management of long-term liability of the geologic storage site.

While these technical, financial, and regulatory challenges to expedited CCS development are significant, the United States has a broad foundation of tools to address them, including an extensive amount of experience in capturing, transporting, and geologically injecting CO_2 for industries not related to coal-based generation. This experience spans more than 40 years and includes a CO_2 pipeline network of over 3,600 miles, along with over 14,000 CO_2 injection wells that have been permitted primarily in support of EOR operations. To date, approximately 560 million tons of CO_2 have been used for this purpose. In addition, the DOE operates the most comprehensive and robust CCS research and development program in the world, which provides the base knowledge and ongoing data needed for targeting development where advancements are most needed. Historically, the United States, in large part through the efforts of DOE, has addressed the need for clean coal technologies with great success for other emissions - a success that can be built upon for developing the next generation of clean coal technologies using CCS.

If the policy of the United States is to balance the continued use of coal with the need to significantly reduce GHG emissions, then subsequent policies and leadership are in need of greater focus in order to take advantage of the full strength of baseline knowledge and resources that are available to accelerate CCS development. The DOE is in a unique position to provide leadership in addressing all of these development challenges. Certainly, the DOE's CCS research and development program will continue to be essential for addressing technology concerns. Equally as important is the depth and value of knowledge the DOE possesses on CCS development issues, which will continue to be very beneficial in informing the regulatory and policy development process with practical insight on the opportunities, challenges, risks, and realities of CCS technology for the coal-based generation fleet.

The report evaluates challenges to CCS development, along with opportunities for the DOE to address these challenges. The report is structured as follows:

- Chapter 1: The Context - Expedited CCS Development for Coal-Based Generation
- Chapter 2: Expediting the Deployment of Carbon Capture & Low Carbon Coal Technologies
- Chapter 3: Expediting the Deployment of CO_2 Transport, Storage & Reuse
- Chapter 4: CCS Deployment Timeline
- Chapter 5: Legal and Regulatory Policies

Overall, this report finds that the continued use of coal within the context of clean coal technologies such as higher efficiency in power plants and CCS processes provides the opportunity to significantly reduce GHG emissions. Policies and leadership should take advantage of the full strength of baseline knowledge and resources that are available to both increase average efficiency and accelerate CCS development. The DOE is in a unique position to provide leadership in addressing these technical, financial, and regulatory development challenges. Certainly, the DOE's CCS research and development program will continue to be essential for addressing technology concerns. Equally as important is the depth and value of knowledge the DOE possesses on CCS development issues, which will continue to be very beneficial in informing the regulatory and policy development process with practical insight on the opportunities, challenges, risks, and realities of CCS technology for the coal-based generation fleet. Key findings and recommendations from each chapter are summarized below.

Chapter 1: The Context - Expedited CCS Development for Coal-Based Generation

Key Findings

- Coal will continue to be the cornerstone of the energy portfolio of both the United States and the world because it is abundant, affordable, widely distributed, secure and versatile.

- Clean coal technologies, including CCS technologies, are the only way the world can achieve significant GHG emission reductions in the context of sustained economic growth.

- President Obama has set the goal of maintaining economic growth and achieving an 83% reduction in GHG emissions by 2050.

- Clean coal technologies have successfully addressed other emission challenges for coal-based generation, and through continued advancements will be able to address the development challenges for CCS and other low-carbon coal technologies.

- Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050.

Recommendations

- While the Council fully supports the DOE's current research, development and demonstration programs for CCS technologies, it recommends that the DOE expand and expedite its leadership roll in developing these technologies.

- The Council recommends that the DOE aggressively expand and accelerate the near-term development (2015-2020) of integrated commercial scale CCS demonstration projects for coal-based generation.

Chapter 2: Expediting the Deployment of Carbon Capture & Low Carbon Coal Technologies

Key Findings

- Commercial-scale CCS technology has not yet been demonstrated on a coal-based electric generating unit in the United States.

- Federal government policy support is critical to advancing the development of CCS technology. Without continued government support, it is highly unlikely that a sufficient number of large-scale CCS demonstrations will occur in the near-term.

- Most large-scale CCS demonstration projects are currently in the design and engineering phase and many are awaiting review and approval through the National Environmental Policy Act (NEPA) process. In order to significantly advance development, many more operating CCS projects are needed.

- CO_2 capture from coal-based generation can be divided into three general categories: pre-combustion, post-combustion, and oxy-combustion. Development of all three is needed to achieve significant CO_2 emissions reductions across the coal generation fleet.

- Both technical and non-technical challenges must be addressed in order to expedite the development and deployment of CCS technology to coal-based generating units.

- Key technical considerations impacting the development of capture systems include those related to integration with the plant steam cycle, pre-treatment requirements of the combustion gas for other emissions, and opportunities for efficiency improvements. Retrofit considerations are generally more complicated because existing coal-based generating units were not designed with the thought of integrating CCS technology.

- Keys to evaluating the feasibility of a CCS retrofit project are whether the age of the unit and technology, efficiency, and equipment conditions warrant such a high-cost and long-life retrofit. De-rating of the existing unit (CCS auxiliary power requirements), space constraints, existing emission controls, proximity to geologic storage, and regulatory issues are also critical considerations.

- The cost to install CCS technology at an existing coal-based power plant will likely exceed the original installed cost of the entire plant. Coal-based generation with CCS, while expensive, may still be the most cost-effective option when compared to the cost of other generating technologies. CCS retrofit systems may very well be only cost-justified on the newest and most efficient generating units.

- There are many emerging CO_2 capture technologies that have provided promising results at the research phase of development. These projects are considered high risk and are not likely to progress without continued support from the Federal government.

- Some low-carbon coal technologies, such as partial capture and increased unit efficiencies, present practical and cost-effective opportunities for near-term CO_2 reductions from the existing coal-based generation fleet.

Recommendations

- In order for CCS technology to advance at the pace needed to achieve long-term emission reduction goals, the Council recommends that the DOE aggressively expand current policies and financial incentives, as well as develop new programs to support the development of a variety of capture technologies.

- The Council recommends that the DOE expand its leadership role in the development of GHG reduction policies by aggressively assessing and communicating the challenges and opportunities for CCS technology on retrofit and new coal-based generation projects to policy makers and the general public.

- The Council recommends that the DOE aggressively expand efforts to support the development of a suite of low-carbon coal technologies, including increased plant efficiency opportunities and partial CO_2 capture technologies. This includes a review of all overlapping and conflicting regulations set forth in Chapter 5.

Chapter 3: Expediting the Deployment of CO_2 Transport, Storage & Reuse

Key Findings

- For wide-spread deployment of CCS technology to occur on the United States coal-based generation fleet, which is widely dispersed across the country, an extensive pipeline network will be needed to handle the large volumes of CO_2 captured and to support facilities that lack local geologic storage capacity.

- Financing an extensive pipeline network will likely be a significant challenge as current estimates are approximately $1.5 million per mile. EOR applications can partially offset this cost. However, for CCS projects using non-EOR geologic storage, the cost for pipeline development will be a significant consideration.

- One option to complement an expansion of the CO_2 pipeline network in the United States is the hub concept that is being evaluated in Europe as part of the Rotterdam Climate Initiative (RCI). The hub concept may have a niche application to the United States, which may focus on surface pipelines, rather than the waterway systems under consideration for the RCI.

- A larger potential reservoir of EOR opportunities for CO_2 appears to exist. Currently, over 50 million tons of CO_2 per year are used for EOR. Based on estimates for the residual oil zone concept, the capacity could be several times this amount.

- To significantly move beyond EOR-related storage, it is imperative to understand the behavior of CO_2 stored in saline formations going forward since these geologic units represent the largest and best storage capacity in the near-term (to complement EOR) and for the long-term (as the primary storage reservoir).

- The DOE has implemented a systematic and logical approach to assessing geologic formations and to ensuring that adequate and diverse pore space is available for CO_2 storage. While this effort has been substantial, more information is needed for a broader portfolio of geologic settings.

- The design and evaluation of geologic storage systems is currently an empirical simulation and modeling effort that will not advance substantively until data can be collected from more operating integrated CCS projects.

- A project-specific initial geologic characterization is critical to design the geologic storage system, which determines the number of injection and monitoring wells required, the target depth for injection and the spacing between wells. Subsequently, the storage design influences the design of the pipeline network. All of these design variables, along with the need to perform the initial characterization, add complexity, cost, and time to the development process.

- Non-EOR beneficial CO_2 use/conversion technologies are currently insufficient to support the volume of CO_2 that could be captured from coal-based generation. Of these technologies, synthetic transportation fuels production offers the potential to have a material impact on the volume of CO_2 captured from a broad-based CCS program.

Recommendations

- The Council recommends that the DOE support efforts by other agencies in the Executive Branch to address non-technical CO_2 pipeline development challenges related to financing, siting, permitting, and public outreach.

- The Council recommends that the DOE monitor the development of the European hub concept and evaluate opportunities to apply this concept in the United States.

- The Council recommends that the DOE continue and expand near-term efforts to evaluate geologic storage formations to address "information gaps" that exist by completing a diverse suite of studies to characterize storage classes and by conducting small- and large-scale field tests. Results will provide the knowledge base necessary to support future commercialization of carbon storage technologies and the proper application of monitoring, verification, and accounting (MVA) tools for various geologic storage classes.

- The Council recommends that the DOE aggressively expand programs to support the development of CCS-related MVA tools, as well as the gathering of data to allow the upgrade of both simulation and modeling programs. Both are essential to improving the design and management of geologic storage systems.

- The Council recommends that the DOE continue its current CO_2 geologic sequestration demonstration program by expanding and accelerating the number of projects in operation by 2015.

- The Council recommends that the DOE continue to evaluate the worldwide development of beneficial CO_2 use and conversion technologies, and to provide funding support for expediting the development of the most viable opportunities among these.

Chapter 4: CCS Deployment Timeline

Key Findings

- The findings and recommendations for CCS development presented in the 2009 NCC report remain applicable and have been reinforced by other studies, including the 2010 Interagency Task Force (Interagency) Report on CCS and the 2009 National Research Council report titled "America's Energy Future: Technology and Transformation."

- The three reports are unanimous in recognizing the need for large-scale integrated CCS demonstration projects as a prerequisite for commercial adoption of the technology. Both the NCC and National Research Council reports call for an initial 5-10 GW equivalent of CCS capacity to be operated for approximately five years. These projects would need to span a range of configurations to verify the performance and cost of CCS over the expected scope of commercial applications.

- Progress has been made in addressing the recommendations of the 2009 NCC report, but the pace is insufficient for the development needed to deploy CCS to coal-based generation at the rate necessary to meet President Obama's goal of an 83% reduction in GHG by 2050.

- The annual CCS capacity additions from 2020 to 2050 that would be required to meet the 2050 GHG emission reduction goal would rival the coal-based generation capacity additions of the 1970's and 1980's, which averaged approximately 11 GW per year.

- The current DOE CCS development program, although robust by world standards, has not moved fast enough and is not on pace to have the level of impact hoped for by 2020. At the current rate, CCS technologies will continue to be in an early development stage by 2020.

- The suite of ten large-scale integrated demonstration projects currently being funded by the DOE was analyzed in terms of scope, diversity, likelihood of proceeding to completion, and timing. That analysis concludes that the program has too few non-EOR projects and that, on the basis of the past experience with the DOE's large-scale demonstration programs, it is unlikely that more than two or three projects of the existing suite will initiate the injection of 1 million tonnes of CO_2 per year into geologic formations (excluding EOR) by 2020.

- If CCS technology is to be commercially available for coal-based generation by 2020, then the success rate of active projects must improve and the quantity and diversity of large-scale storage demonstration projects must be expedited and accelerated in the near time. The DOE is in the best position to lead this effort.

Recommendations

- The Council recommends that the DOE continue to evaluate and promote CO_2 storage opportunities for EOR applications, while expanding efforts to evaluate storage opportunities in saline and other geologic formations that are not associated with EOR processes.

- The Council recommends that the DOE expand and accelerate its current CCS development programs in order to implement the number of near-term demonstration projects (2015-2020) required to facilitate the rate of CCS deployment necessary to meet the President's stated GHG emission reduction goals for 2030 and 2050.

Chapter 5: Legal and Regulatory Policies

Key Findings

- While it seems unlikely that federal GHG legislation will be enacted in the near future, the U.S. Environmental Protection Agency (EPA) has begun and intends to broaden the regulation of GHG emissions by expanding the applicability of existing Clean Air Act programs.

- The EPA's approach is multifaceted and, at a minimum, will expand consideration of CCS technologies in the development of applicable projects. For example, the EPA has expanded the applicability of the preconstruction Prevention of Significant Deterioration (PSD) and Title V permit programs to GHG. The EPA also issued draft, non-binding guidance regarding whether and how CCS should be evaluated as a Best Available Control Technology (BACT), which concludes that while CCS is a "promising technology," the EPA does not believe it will be a technically feasible BACT option in most cases. Additionally, the EPA recently announced its intent to propose New Source Performance Standards (NSPS) for GHG emissions from power plants in July, 2011.

- Some existing regulatory programs, which may currently apply to CCS projects, will add requirements and risk considerations that could affect the design, schedule, cost, and viability of CCS projects. For example, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and Resource Conservation & Recovery Act (RCRA) create an unnecessary regulatory and/or liability regime for geologic injection and storage.

- A broad scope of permitting and regulatory programs apply to the development of each of the capture, transportation and geologic storage aspects of a CCS project. The process of performing baseline studies for preparing applications and working through the regulatory process to receive final approvals can range from months to years. This can result in significant cost, design, and schedule impacts, which will challenge efforts to expedite the development and deployment of CCS technology to the coal-based generation fleet.

- Since CCS is likely to play an increasingly important role in environmental regulatory decisions for the foreseeable future, regulatory and legal policy will need to be adapted to facilitate the timely and practical development and deployment of that technology.

- Led by many States and the EPA, an appropriate legal and regulatory framework for CCS is starting to take shape. The States' role in CCS regulation should not be underestimated given their historical success in safely regulating comparable injection and storage activities.

- Many States have adopted comprehensive regulations to address long-term geologic storage issues related to pore-space ownership and liability that should be sufficient to enable the permitting of early mover CCS projects.

- Given the number of pore space owners likely to be encountered when siting a CCS project, any requirement to expand the obligation to acquire pore space beyond constitutional requirements will create a significant development barrier.

- The management of long-term liability risks is a critical consideration for CCS projects. In terms of supporting the broad deployment of CCS across the coal-based generation fleet, uncertainty regarding long-term liability options remains a challenge.

- The DOE must continue to play a leading role in supporting policies that regulate CCS in a manner that protects human health and the environment, while enabling worthwhile projects to be financed, developed and operated without unnecessary legal impediments.

Recommendations

- To align and avoid an overlap of regulatory programs applicable to CCS projects and to accelerate CCS development, the Council recommends that the DOE support exempting appropriately permitted CO_2 injection and long-term storage from CERCLA and RCRA.

- The Council recommends that the DOE support policies that accelerate the permitting and regulatory approval process for deploying CCS technologies to existing and new coal-based generating plants, including policies to reduce barriers within the PSD and other programs that are inadequately designed to regulate CCS projects. This also includes streamlining the NEPA review process for CCS projects.

- The Council recommends that the DOE support policies encouraging the development of permitting programs for CCS facilities that would provide that the issuance of the permit for such a facility expressly grants the permittee the right to inject and sequester CO_2 into those portions of a geologic strata that do not contain coal, or oil and gas or other minerals in commercial quantity and do not have a current or reasonably foreseeable use.

- The Council recommends that the DOE support policies to clarify the requirements that apply to CO_2 injection and storage on Federal lands by, for example, stipulating pore space ownership and amending the Federal Land Policy and Management Act (FLPMA) and the Federal Mineral Leasing Act (FMLA) to explicitly allow long-term CO_2 storage under Federal leases.

- The Council recommends that the DOE support policies that would provide that during the construction and operational phases of a CCS project, the private sector should remain subject to both operational responsibilities and liabilities imposed by otherwise applicable law, except that such legislation should limit liability for trespass where the facility is subject to a valid permit applicable to that geologic sequestration.

- The Council recommends that the DOE support policies that would provide that during the post-closure phase of a CCS project, and after regulations have determined that the project meets applicable reporting requirements and poses no threat to human health or the environment, liability should be transferred away from the private sector. Various alternative methods for accomplishing this transfer have been offered at both the Federal and state level.

Chapter 1: The Context - Expedited CCS Development for Coal-Based Generation

1.1 Key Findings

- Clean coal technologies will continue to be the cornerstone of the energy portfolio of both the United States and the world because it is abundant, affordable, widely distributed, secure and versatile.

- Clean coal technologies, including CCS technologies, are the only way the world can achieve significant GHG emission reductions in the context of sustained economic growth.

- President Obama has set the goal of maintaining economic growth and achieving an 83% reduction in GHG emissions by 2050.

- Clean coal technologies have successfully addressed other emission challenges for coal-based generation, and through continued advancements will be able to address the development challenges for CCS and other low-carbon coal technologies.

- Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050.

1.2 Recommendations

- While the Council fully supports the DOE's current research, development and demonstration programs for CCS technologies, and recommends that the DOE expand and expedite its leadership roll in developing these technologies.

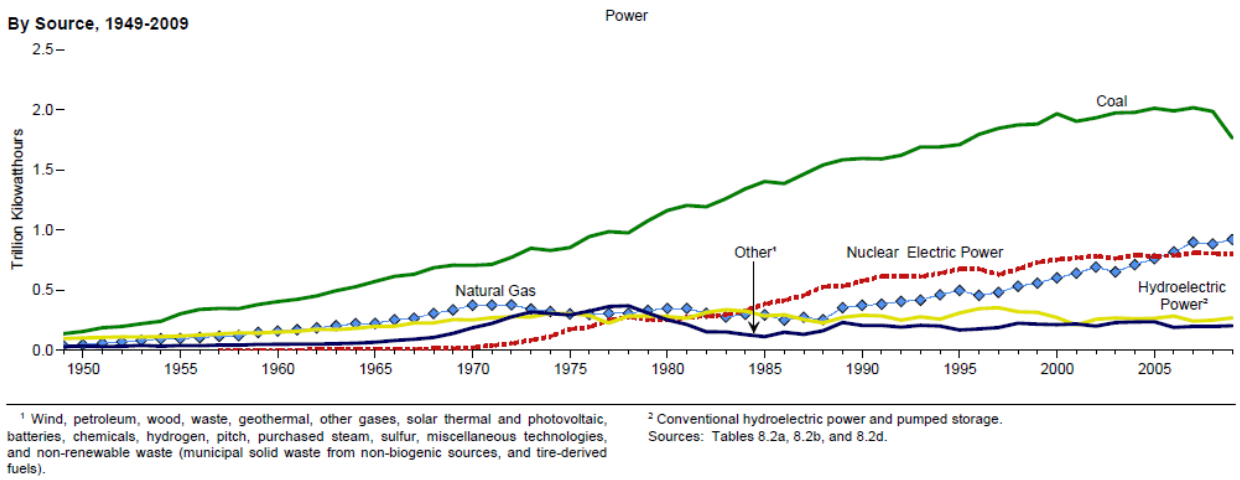
- The Council recommends that the DOE aggressively expand and accelerate the near-term development (2015-2020) of commercial scale CCS demonstration projects for coal-based generation.

1.3. The Continued Importance of Coal to the United States

Coal plays a central role in the domestic energy portfolio and has been the bulwark of reliable and cost-effective electricity generation that has and will continue to benefit America's dramatic socioeconomic advances since World War II, which have been powered by coal-based electricity as shown in Figure 1.1 from the Energy Information Administration (EIA). Secretary of Energy Chu has spoken to the continued importance of coal by noting that:

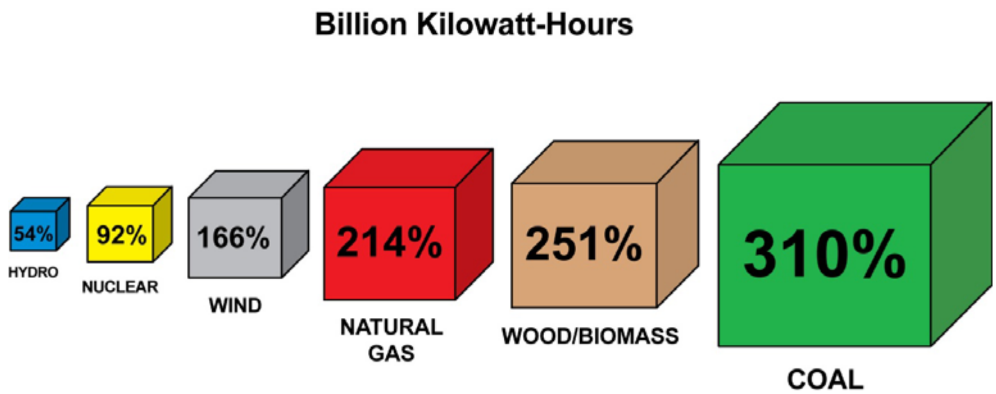
> "prosperity depends upon reliable, affordable access to energy. Coal…is likely to be a major and growing source of electricity generation for the foreseeable future…. We must make it our goal to advance carbon capture and storage technology to the point where widespread, affordable deployment can begin in 8 to 10 years." (2009)

Figure 1.1: Coal is the foundation of electricity in the United States
(EIA Annual Energy Review, 2010)



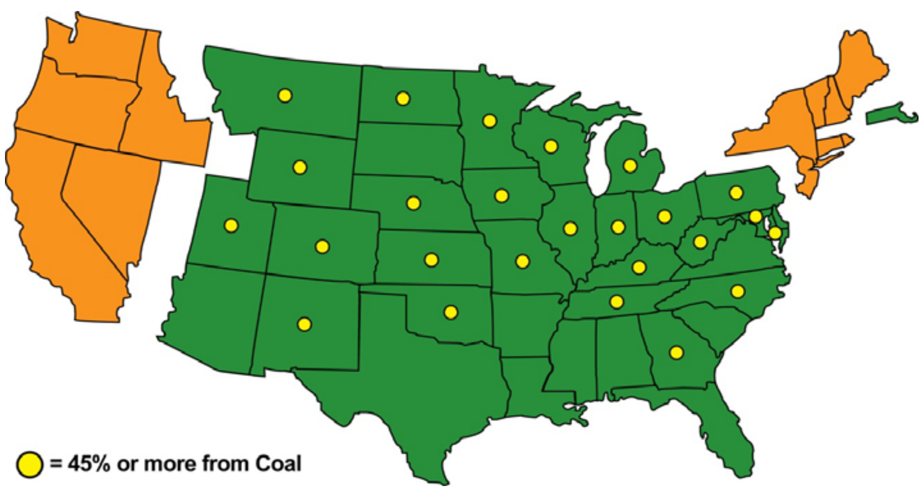
Data from the EIA Annual Energy Review indicate that this historic trend continues with coal-based units providing nearly half of the electricity generated in the United States today (2010). Going forward, coal will continue to provide the majority of electricity in the United States and around the world. The EIA estimates that coal will lead the way in supplying the incremental increase in worldwide electricity over the next 25 years as shown in Figure 1.2.

Figure 1.2: Projected Incremental Sources of Electricity through 2035
(EIA Annual Energy Outlook, 2010)



Further, coal is embedded in the socioeconomic fabric of American society. As shown in Figure 1.3 below, 36 states obtain at least 25% of their electricity from coal, with 26 of those states obtaining 45% or more of their power from coal (EIA Annual Energy Outlook, 2010).

Figure 1.3: Percent of Electricity from Coal
(green-shaded states receive at least 25% from coal)



According to data from the U.S. Census Bureau, the states identified above that receive at least 25% of their electricity from coal account for:

- 215 million people (70% of U.S. population)
- 70% of gross domestic product
- 75% of manufacturing jobs
- 80% of agricultural sales

Coal is irreplaceable in the United States power system. Replacing the existing coal-based generating fleet with other energy sources would be a significant, costly, and prolonged undertaking that would require an equivalent of any one of the following:

- Natural gas: An additional 17 trillion ft^3 annually (three times that produced by Texas)
- Nuclear: 310 new nuclear plants (104 plants are currently operating in the U.S.)
- Hydro: Equivalent to the power from 550 new Hoover Dams
- Wind: Twice the capacity that the *entire world* is projected to have by 2035

Improved efficiency of both generation technologies and end user applications would also play an important role in any such strategy.

Coal will continue to play a key role in generating electricity in the United States, providing affordable, reliable and increasingly clean energy. Coal's contribution to America's energy security is a mainstay of socioeconomic stability - the United States has 29% of the world's coal (EIA International Energy Outlook, 2010). The National Research Council concluded:

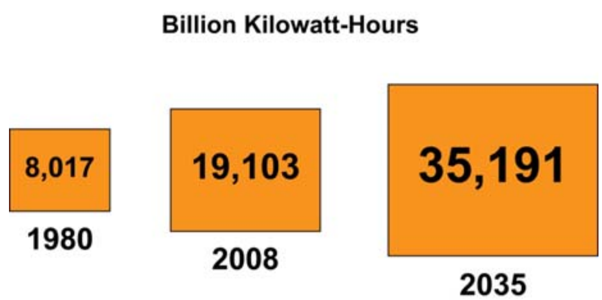
> "U.S. recoverable reserves of coal are well over 200 times the current annual production of 1 billion tonnes, and additional identified resources are much larger. Thus, the coal resource base is unlikely to constrain coal use for many decades to come." (2009)

1.4. The Continued Importance of Coal to the World

Electricity is the lifeblood of modern society and the key to a higher quality of life around the world. People living in societies with greater access to electricity are more likely to survive childhood, live longer, eat better, drink cleaner water and be more highly educated than those without such access. Electricity is central to a safe and clean environment, providing illumination, a means to control pollution, and the energy needed for infrastructure development in both rural and urban areas. In fact, the National Academy of Engineering identified electrification as the "most significant engineering achievement of the 20th Century" (2003). Additionally, the Global Energy Network Institute has stated that "Every single one of the United Nations' Millennium Development Goals requires access to electricity as a necessary prerequisite" (2008).

Given the importance of electricity, it is not surprising that demand for more power is a steady drumbeat across the globe. For example, electricity is the foundation the world's electronic communication system, which currently includes over *two billion* users of the Internet, a number that expands daily, with China alone is adding 6 million users of the Internet per month-- equivalent to the population of Dallas-Fort Worth (Boston Consulting Group, 2010). In addition, the International Energy Agency (IEA) has projected that by 2030, worldwide electricity consumption from household electronic equipment alone could increase to 1,700 billion kilowatt hours (kWh), requiring the addition of at least 280 gigawatts (GW) of new generating capacity-- equivalent to the entire electric power system of Japan (2010). Figure 1.4 highlights the growth in worldwide electricity consumption:

Figure 1.4: The Rise of Electricity Generation
(EIA Annual Energy Outlook, 2010)



Despite this dramatic growth in generation, the extent of electricity deprivation is a continuing blight on the search for a better world. Approximately 1.5 billion people lack access to electricity, while another two billion have minimal access (IEA, 2010). In other words, almost 12 times the population of the United States lacks full access to electric power. The reality of this energy poverty was the reason for the following two goals contained in the December 18, 2009 Copenhagen Accord, which in turn is based upon the 1992 United Nations Framework Convention on Climate Change (UNFCCC):

- The need to "bear in mind that social and economic development and poverty eradication are the first and overriding priorities of developing countries."
- The need for the nations of the world to meet the growing challenge of climate change and "cooperate in achieving the peaking of global and national emissions as soon as possible."

Developed nations, including the United States, which is a party to both the Copenhagen Accord and the UNFCCC, agree that the world needs more electricity at affordable prices and produced in an environmentally acceptable manner. Today, most of the world's electricity is generated through the use of coal. Coal will continue to be the cornerstone of the energy portfolio needed to meet world's growing demand for electricity. Coal is the world's most abundant fossil fuel-- accounting for approximately 65% of global reserves (EIA International Energy Outlook, 2010). In addition, coal is widely distributed, secure, affordable and versatile in use, which is crucial to meeting the energy demands of the developing and developed world.

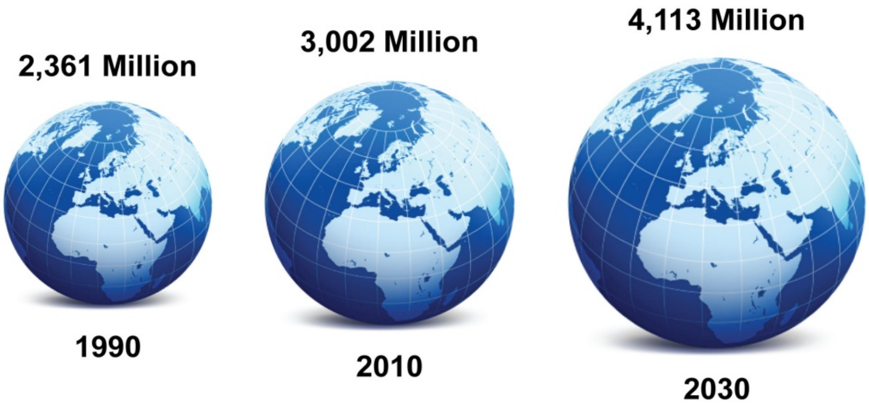
In addition, the world needs coal not only to produce power, but also to manufacture goods such as steel and cement, which are essential to a rapidly urbanizing world. For example, the United Nations estimates that by 2035 over 60% of the world's population will live in cities whose infrastructure is developed and maintained by the use of steel, cement, and other materials, which cannot be produced in a timely or cost-effectively manner at the quantities demanded without the use of coal as an energy source (2010). In fact, over 80% of the world's steel is produced using coal (World Coal Institute, 2009). Therefore, more cities means a greater demand for steel, which in turn means a greater demand for coal.

With a high probability that peak oil supply capacity will occur in the next several decades (if it has not already occurred) the conversion of coal to liquid fuel will be an increasingly important component for meeting the world's energy needs. For example, while the Republic of South Africa is the current world leader in this technology, China sees this future and has moved strongly forward in the construction of coal to liquid facilities.

Beyond its central role within the global energy context, the value of coal in electricity production is the hallmark of its continuing contribution to humanity. Data from the EIA International Energy Outlook indicates that in 1971, coal accounted for 40% of power generation around the world. By 2000, its contribution was still about 40%. In 2035, however, coal is expected to provide 43% of the world's electricity.

In terms of absolute numbers, coal's global contribution is even more impressive. For example, in 1971, coal produced 2,103 billion kWh of electricity, yet by 2005 coal produced 7,152 billion kWh. By 2035, coal is projected to produce over 15,000 billion kWh - more than gas, nuclear, wind and solar *combined*. In essence, coal has been and will continue to be the mainstay of electricity generation throughout the world. Figure 1.5 below depicts the number of people worldwide who depend on coal for electricity.

Figure 1.5 Coal's Ever Growing Role
(EIA, International Energy Outlook 2010)
Population of countries that depend on coal for at least 40% of electricity



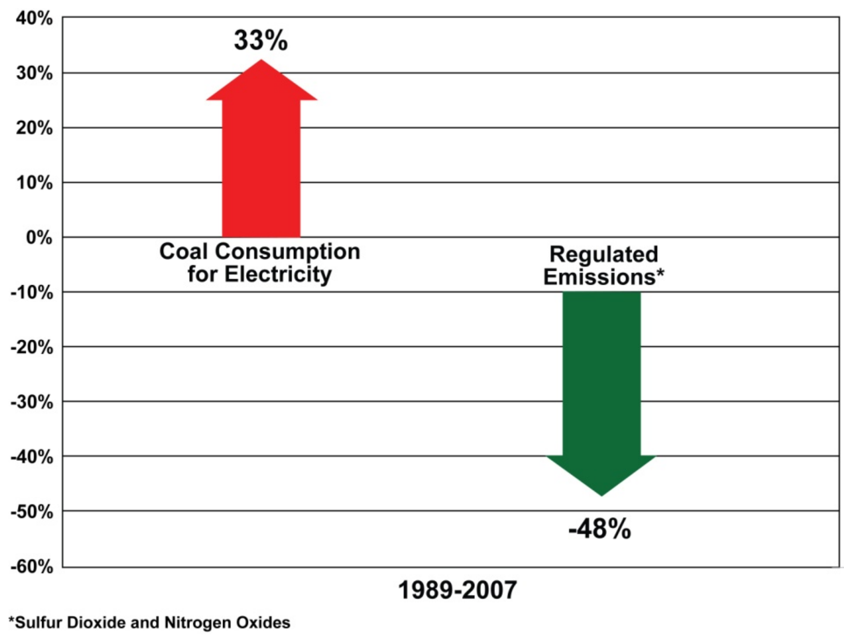
Entire countries with populations of hundreds of millions (some entering into the billions) are depending upon coal to generate much of their electricity in the future. In looking to a future with a dramatic growth in coal-based electricity, it is necessary to first turn to Asia where the growing dependence on coal for new electricity generation is stunning. By 2035, China and India will obtain 74% and 51% of their electricity from coal, respectively. The rationale is straightforward-- coal is where the people are. China and India combined have 42% of the world's population, but only 2% of the oil and natural gas. However, these two countries have 21% of the world's coal (BP, 2010).

As these numbers and projections indicate, coal's story is far from told. Despite its distinguished history of supporting socioeconomic progress around the world, coal is really a fuel of the future. As the 21st century advances, vast multitudes of people will increasingly rely on coal to meet the bulk of the electricity required for their rapidly expanding march toward modernization. Meanwhile, the more developed countries will continue to rely upon coal to meet the increasingly complex electricity and reliability needs of modern society.

1.5 The Next Generation of Clean Coal Technologies

President Obama has set the goal of maintaining economic growth and achieving an 83% reduction in GHG emissions by 2050. As efforts are made to constrain GHG emissions, the amenability of coal to advanced clean technologies will be an increasingly important attribute that will allow the world to continue to take advantage of its immense coal reserves. In the area of electricity generation, the variety of low carbon coal technologies being developed presents opportunities and will be necessary to achieve significant emission reductions across this sector. Among this suite of low carbon coal technologies, CCS technologies and improved plant efficiency will be a key part of any strategy to meet the level of CO_2 reductions being targeted. Clean coal technologies work. Since 1989, the electric power industry in the United States has invested almost $100 billion to reduce emissions with marked success as shown in Figure 1.6 (Hewson, 2008).

Figure 1.6: Success of Clean Coal Technologies
(EIA Annual Energy Outlook, 2010)



Over the past few decades, the United States has made huge advances in reducing emissions of criteria pollutants (particulate matter, sulfur dioxide (SO_2), carbon monoxide, lead, ozone, and nitrogen oxides (NO_x)) and their precursors, while substantially increasing the electricity produced from coal-based generation. Secretary Chu has called for the continuing evolution of clean coal technologies into the area of CCS. Clean coal technologies have solved other emissions challenges, and now the creative work of the scientific and engineering community has turned to the management of CO_2.

There is widespread agreement that CCS is essential for fossil fuel-based generation if the world is to meet CO_2 emission reduction goals amid sustained economic growth. In 2010, the IEA identified CCS for power generation as "the single most important new technology for CO_2 savings." Researchers at the Massachusetts Institute of Technology (MIT) have stated that

CCS "is the critical enabling technology that would reduce CO_2 emissions significantly, while also allowing coal to meet the world's pressing energy needs" (MIT, 2010). The Clean Air Task Force has been even more direct: "No credible technical body has found that adequate CO_2 emissions are possible without widespread use of CCS" (2009). In mid-2010, MIT reaffirmed that achieving an approximate 83% reduction in GHG emissions by 2050 "would probably require" the complete decarbonization of the power sector, including natural gas power generation. Given this widespread support, policy leaders around the world have stressed the importance of developing and implementing CCS programs:

- In June 2010, the G8 summit concluded: "We encourage the IEA to develop work on an International Platform for low-carbon technologies, in order to accelerate their development and deployment. Carbon capture and storage can play an important role in transitioning to a low-carbon emitting economy" (2010).

- In August 2010, President Obama's Interagency Task Force on CCS concluded: **"**CCS can greatly reduce CO_2 emissions from new and existing coal- and gas-fired power plants [and] play an important role in achieving global GHG reduction goals" (2010).

The broad scope of CCS-related resources, experience, and expertise in the United States provides a strong foundation for expediting its development and deployment to coal-based generation and other processes. As an example, for over 40 years CO_2 has been successfully captured, transported, and geologically stored primarily for EOR processes in the United States. Because these efforts have not been at the scale associated with the coal-based generation fleet, significant development changes remain before expedited CCS deployment to these geological resources can occur. DOE programs are leading the world in the research, development and demonstration of CCS technologies. Although these DOE programs and other ongoing and planned projects are advancing the technology for coal-based generation, efforts will need to be expanded and accelerated in the near-term if CCS is to be available to significantly contribute to any longer-term GHG reduction strategy.

1.6 Foundation for the 2011 National Coal Council Report

Pursuant to the continued and increased focus by the United States and world leaders on the need for developing CCS technologies, on June 1, 2010 Secretary of Energy Chu requested the NCC to:

> "…conduct a new study on the deployment of … CCS technologies that builds on the work you have done in the past by focusing on the management of emissions of CO_2 from both existing and new fleet of coal-based electricity generating plants"

The current study is a continuation of a series of NCC reports over the past decade that provide a systematic technological and regulatory path to cleanly and efficiently realize the full potential of domestic coal resources. Throughout, studies conducted by the NCC have consistently supported CCS development:

- 2000 NCC Report: "it is imperative that CO_2 sequestration and generation efficiency become high priorities for Department of Energy research."
- 2003 NCC Report: "The Department should expedite research on a wide range of CO_2 capture options and expand the core R&D and demonstration programs."
- 2006 NCC Report: "The U.S. must develop strategies to adopt CCS technologies…by ardently pursuing the required research, development & demonstration."
- 2007 NCC Report: "It is imperative that research, development and demonstration efforts move forward quickly on a portfolio of technologies to reduce or capture and store CO_2 emissions."
- 2009 NCC Report: "CCS technologies must be developed and made commercially available."

Entitled "Low-Carbon Coal: Meeting U.S. Energy, Employment and CO_2 Emission Goals with 21st Century Technologies," the 2009 NCC report provided an assessment of state-of-the-art CCS technologies. It covered a wide range of issues related to CO_2 reduction, five of which are particularly critical to the current report:

- Timeline and costs for commercial-scale CCS deployment
- Retrofitting the existing coal-based generating fleet to increase efficiency and decrease CO_2 emissions
- Technologies for the capture of CO_2
- Securely transporting and storing CO_2
- Legal and regulatory issues

The 2009 NCC report provided technical descriptions, cost estimates and timelines for the research, development and commercial-scale deployment of CCS technologies that would be needed to achieve the President's 2050 GHG emission reduction goal. The report addressed CO_2 capture technologies, pipeline transportation, geologic storage, and beneficial use/conversion technologies. It also evaluated how CCS technologies may be integrated with a next generation of higher efficiency coal-based generating units.

The 2009 NCC report concluded that the United States and the world will not only continue to use coal, but will use it in increasing amounts. Domestically, such an increase must occur within the context of the President's 2050 GHG emission reduction goal. The widespread deployment of CCS will require large investments and take time, but it will pay significant dividends in providing a path to achieving emission reductions *and* assuring the availability of sustainable clean energy in a growing economy.

This 2011 NCC report meets the Secretary's request by providing further information on the key issues surrounding deployment of CCS technologies. In general, the current study is designed to support the role of the United States as a leader in both technology development and utilization of coal reserves. Specifically, the report focuses on approaches which will:

- Expedite the deployment of CO_2 capture and other low carbon coal technologies;
- Expedite CO_2 transport, storage and use/conversion technologies;
- Enhance the CCS development timeline; and
- Identify key legal and regulatory policies to facilitate deployment

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Chapter 2: Expediting the Deployment of Carbon Capture & Low Carbon Coal Technologies

2.1 Key Findings

- Commercial-scale CCS technology has not yet been demonstrated on a coal-based electric generating unit in the United States.

- Federal government policy support is critical to advancing the development of CCS technology. Without continued government support, it is highly unlikely that a sufficient number of large-scale CCS demonstrations will occur in the near-term.

- Most large-scale CCS demonstration projects are currently in the design and engineering phase and many are awaiting review and approval through the NEPA process. In order to significantly advance development, many more *operating* CCS projects are needed.

- CO_2 capture from coal-based generation can be divided into three general categories: pre-combustion, post-combustion, and oxy-combustion. Development of all three is needed to achieve significant CO_2 emissions reductions across the coal generation fleet.

- Both technical and non-technical challenges must be addressed in order to expedite the development and deployment of CCS technology to coal-based generating units.

- Key technical considerations impacting the development of capture systems include those related to integration with the plant steam cycle, pre-treatment requirements of the combustion gas for other emissions, and opportunities for efficiency improvements.

- Retrofit considerations are generally more complicated because existing coal-based generating units were not designed with the thought of integrating CCS technology.

- Keys to evaluating the feasibility of a CCS retrofit project are whether the age of the unit and technology, efficiency, and equipment conditions warrant such a high-cost and long-life retrofit. De-rating of the existing unit (CCS auxiliary power requirements), space constraints, existing emission controls, proximity to geologic storage, and regulatory issues are also critical considerations.

- The cost to install CCS technology at an existing coal-based power plant will likely exceed the original installed cost of the entire plant. Coal-based generation with CCS, while expensive, may still be the most cost-effective option when compared to the cost of other generating technologies. CCS retrofit systems may very well be only cost-justified on the newest and most efficient generating units.

- There are many emerging CO_2 capture technologies that have provided promising results at the research phase of development. These projects are considered high risk and are not likely to progress without continued support from the Federal government.

- Some low-carbon coal technologies, such as partial capture and increased unit efficiencies, present practical and cost-effective opportunities for near-term CO_2 reductions from the existing coal-based generation fleet.

2.2 Recommendations

- In order for CCS technology to advance at the pace needed to achieve long-term emission reduction goals, the Council recommends that the DOE aggressively expand current policies and financial incentives, as well as develop new programs to support the development of a variety of capture technologies.

- The Council recommends that the DOE expand its leadership role in the development of GHG reduction policies by aggressively assessing and communicating the challenges and opportunities for CCS technology on retrofit and new coal-based generation projects to policy makers and the general public.

- The Council recommends that the DOE aggressively expand efforts to support the development of a suite of low-carbon coal technologies, including increased plant efficiency opportunities and partial CO_2 capture technologies. This includes a review of all overlapping and conflicting regulations set forth in Chapter 5.

2.3 Introduction

Ongoing and announced demonstration and commercial-scale projects for coal-based generation units are advancing the development of a variety of capture technologies. A continuation and expansion of such projects in the near-term is essential for expediting the long-term (post-2020) deployment of CCS. This chapter focuses on the capture aspect of the technology, while Chapter 3 considers transportation, geologic storage, and beneficial use/conversion issues.

2.4 Current Development of Carbon Capture Technologies for Coal-Based Generation

CO_2 capture from coal-based generating units can be divided into three general categories: pre-combustion, post-combustion, and oxy-combustion. Common to all three categories is the process of capturing/concentrating the CO_2 from the other major constituents in the flue gas or syngas into a form that can be geologically stored or beneficially used/converted. The fundamental difference in the three approaches is how the CO_2 is concentrated. Each process has its own advantages, disadvantages, and applicability to various coal-based generation technologies. Within each category is a broad array of alternative and developing processes, wherein lie the future opportunities to reduce capital costs and power consumption. Because of a diversity of technology and site-specific considerations across the coal-based generation fleet, it is likely that all three capture options will be required to achieve significant CO_2 emissions reductions across this sector.

a. Pre-Combustion CO_2 Capture

Pre-combustion capture technologies are applicable to coal-based gasification processes, including coal-based integrated gasification combined cycle (IGCC) technology for generating electricity. There are two operating IGCC power plants in the United States, with other projects at various levels of development. CO_2 capture from gasification-based power generation is accomplished during the syngas cleaning process. Although CO_2 capture has been demonstrated on a commercial scale with coal gasification for other industries, it has not yet been demonstrated in coal-based IGCC applications. However, some IGCC units are being planned in the United States that will incorporate CO_2 capture into the plant design, and two operating coal-based IGCC plants in Europe are being retrofit with CO_2 capture slipstream pilot plants. CO_2

capture from IGCC could be accomplished using chemical solvents, physical solvents, hybrid solvents or membranes. A discussion of each category follows.

Chemical Solvents

Chemical solvents utilize an acid-base reaction between CO_2 (the acid) and the solvent (the base) to transfer CO_2 and other acid gases from the gas phase to the liquid phase. Chemical solvents are typically amines, which are nitrogen-based compounds, such as mono-ethanol amine, di-ethanol amine, methyl-di-ethanol amine, or specially formulated compounds for specific processes. Ammonia (ammonium carbonate as the active reagent) would also be considered a chemical solvent. Chemical solvents are reused by the application of heat, a process that liberates the captured CO_2 and produces a concentrated CO_2 gas stream that, after additional processing, could be geologically stored or beneficially used/converted. The amount of heat needed for reusing the amine can be significant and is an important consideration in the design and development process. Amines have been used for several decades to remove CO_2 and other acid gases (i.e. hydrogen sulfide) from raw natural gas to make the gas suitable for its intended use and for pipeline transportation. Amines have also been used for the removal of sulfur compounds in IGCC applications. Typically, amine systems have a lower capital cost than physical solvents. Chemical solvents for pre-combustion CO_2 capture on coal-based power generation units have not yet been demonstrated at a commercial scale.

Physical Solvents

Physical solvents are typically carbon-based compounds that dissolve CO_2 and other acid gases without chemical reaction. Physical solvents operate on the basis of partial pressure of the acid gas components and the solubility of those compounds in a particular solvent. The performance of physical solvents is typically better at higher pressures and lower temperatures. Physical solvents may be regenerated by the application of heat, a reduction of pressure, or a combination of higher temperatures and lower pressures. Physical solvents are well-suited to the removal of acid gases, including CO_2, in gasification applications due to relatively high pressures. However, physical solvents for pre-combustion CO_2 capture on coal-based generation technologies have not yet been demonstrated at a commercial scale.

Hybrid Solvents

Hybrid solvents are typically proprietary mixtures of chemical and physical solvents. Hybrid solvents have been used in several operating IGCC units for removal of sulfur compounds. Hybrid solvents have not been used for the removal of large amounts of CO_2, such as those associated with coal-based generation. The performance of a hybrid solvent is usually an intermediate between that of a chemical solvent and a physical solvent. Hybrid solvents for pre-combustion CO_2 capture on coal-based generation technologies have not yet been demonstrated at a commercial scale.

b. Post-Combustion CO_2 Capture Technologies

Post-combustion capture refers to the capture of CO_2 in the combustion exhaust gases from conventional coal-based generating units (i.e. pulverized coal or circulating fluidized bed units). This approach offers a retrofit option to the existing fleet and could be applied to new pulverized coal generating units. A significant effort is ongoing to develop the next generation of solvents and other technology options, which offer the promise of reduced energy and cost impacts. Technologies nearest to commercialization are amine-based and ammonia-based solvents. Both are being developed for coal-fired generating units by several technology developers. In fact, various commercial scale processes demonstrations are being planned for coal-based generating units with Clean Coal Power Initiative (CCPI) funding support. To date, commercial scale post-combustion CO_2 capture processes for coal-based generation technologies have not yet been demonstrated.

Amine-Based Solvents

As discussed for pre-combustion capture, amines are widely available compounds that could also be considered for post-combustion CO_2 capture. The primary advantages of amine-based capture technology include decades of experience using such solvents for CO_2 removal from natural gas and synthesis gas, their relatively simple process flow scheme, and the potential ability to remove high levels of CO_2 from the flue gas stream. The primary disadvantages of amines are related to energy requirements (i.e. steam) for regeneration, as well as amine degradation from components in the flue gas, such as SO_2, NO_x and O_2. Also, amines based on formulated or proprietary solvents are usually only available from a single supplier, which can lead to concerns regarding availability and cost. Extensive research is being conducted to improve the cost, efficiency and energy consumption of amine-based processes. To date, amine-based solvents have not yet been demonstrated at a commercial scale for coal-based generating units.

Ammonia-Based Solvents

Ammonia-based solvents are another post-combustion CO_2 capture option for coal-based generating units. These processes utilize ammonia-based solvents that react with CO_2 to form aqueous ammonium carbonate/bicarbonate solutions that can produce high concentration CO_2 gas streams. The solvent is regenerated for reuse by the application of heat. The primary advantages of ammonia technologies are the possibility of lower energy consumption due in part to release (i.e. regeneration) of CO_2 at high pressure and to a greater tolerance of the solvents to other compounds in the flue gas, such as SO_2, NO_x and oxygen. The primary disadvantages of the ammonia technology are the complexity of the operations when compared to other potential capture processes, as well as safety issues in handling ammonia. To date, ammonia-based solvents have not yet been demonstrated at a commercial scale for coal-based generating units.

Emerging and Potential Post-Combustion Capture Options

Other emerging and potential technologies for post-combustion CO_2 capture include membranes, adsorbents, ionic-based solvents, biological solvents, and other proprietary absorbents. These technology options are highly varied in their respective levels of development. None of these options have been demonstrated on a commercial scale at a coal-based generating unit. Note that the following discussion is not all inclusive, but rather provides examples on the diversity of ongoing development research.

Membrane technology involves separating CO_2 from the flue gas on the basis of differing rates of diffusion through a selectively permeable element. The diffusion is driven by the difference in partial pressure and controlled by the selectivity of the membrane, which will only allow the CO_2 to pass through the membrane walls. The potential advantage of membranes for coal-based generation CO_2 capture is their low cost and simple design. The primary disadvantage of membranes is inefficient separation, especially at low CO_2 partial pressures. In addition, membranes that are being developed for flue gas applications would require operating pressures well below atmospheric pressure, which would lead to high compression and operating costs. Membranes are also typically not tolerant of moisture, which is present in flue gas. Additional development is necessary before membrane technology is commercially available for coal-based generation processes.

Solid sorbent processes can be designed to be similar to the processes employed for aqueous solvents. These processes offer the potential advantage of significantly reduced regeneration energies, and thus a much lower overall energy penalty due to much lower heat capacity (i.e. the energy required to change the temperature of a material). There are several different types of solid sorbents being developed that may potentially be applicable to coal-based generation, including amines supported on an inert substrate, carbon based materials, carbonates (usually sodium or potassium carbonate), and novel materials such as metal organic frameworks or zeolitic imidizolic frameworks. These solids can be regenerated by the application of heat, vacuum, and other methods. A National Energy Technology Laboratory (NETL) funded study is evaluating such sorbents at the screening phase from which the most promising materials were selected to be tested at larger scales. To date, several materials have been evaluated using actual flue gas in a one of a kind 1 kW pilot (Sjostrom, 2010). The DOE is currently funding the development of this technology to the 1 MW scale. The primary development barriers are the need for suitable methods to transfer heat to the solid to release the CO_2, an improved tolerance to condensation and sulfur compounds, and a reduced physical attrition rate of the materials.

Considerable development work is occurring in other areas as well, including capture methods that use ionic-based chemical solvents based on amino salts. This technology has not progressed beyond the point of laboratory-scale units and theoretical modeling. However, the solvent exhibits many desirable characteristics, such as low volatility, high stability in the presence of oxygen and sulfur compounds, and is non-flammable. No data has been published on the actual amount of energy needed for regeneration.

Several companies and academic institutions are performing research on using biological catalysts for the capture of CO_2. Much of this research focuses on the biological catalyst carbonic anhydrase (CA), which involves a family of compounds that catalyze CO_2 hydration, and can enable the use of otherwise slow capture solvents with dramatically lower energy losses than current technologies. Existing CA enzymes are prohibitively expensive due to their low activity and short lifetime and high manufacturing costs. Ongoing research is directed toward the development of lower-cost CA with improved activity and stability, and that is amenable to low manufacturing costs.

c. Oxy-Combustion

The oxy-combustion process is similar to the typical coal-based generation combustion technology except that coal is combusted in a mixture of pure oxygen and recycled flue gas rather than in ambient air. The result is that the CO_2 concentration in the flue gas stream is significantly increased because of the reduced amount of nitrogen during combustion. Oxy-combustion processes could increase CO_2 concentrations to about 80% of the flue gas by volume (vs. approximately 13% with conventional air combustion), which could be more conducive for producing a concentrated CO_2 stream for EOR or geologic storage.

One advantage of oxy-combustion is that removal of other criteria pollutants such as NO_x, SO_2, and mercury is expected to be less expensive since the overall volume of flue gas produced (and that must be treated) is lower, requiring smaller sizes for emission control systems. The primary challenges to implementing oxy-combustion are the capital cost and energy consumption for oxygen production, flue-gas recycling, and CO_2 purification and compression. However, even considering these challenges, the Interagency report on CCS noted that new oxy-combustion for CO_2 capture may result in a lower levelized cost of electricity than new pre-combustion or new post-combustion facilities (2010). Although it may not be as straightforward as a retrofit technology, oxy-combustion may also be suitable retrofit option for some existing coal-based generating plants, depending on the unit configuration and existing air emission control equipment.

Critical components for an oxy-combustion facility have been tested at a pilot scale and the world's first commercial-scale oxy-combustion power plant, FutureGen 2.0, is currently under development. FutureGen 2.0 involves converting an existing oil-fired power plant into a coal oxy-combustion unit with CO_2 capture for geologic storage. Continued development work is underway to improve the oxy-combustion process. For example, high flame temperature oxy-combustion is being developed (combustion in the range of 5,000ºF), which would increase the radiant heat transfer from the flame to boiler surfaces resulting in improved process efficiencies and reduced fuel usage. Lower fuel usage reduces both the amount of oxygen needed, which decreases the cost oxygen production, and reduces CO_2 produced per MWh. Although it is being considered for some projects, commercial scale oxy-combustion processes have not yet been demonstrated on coal-based generating units.

2.5 Key Considerations for Expedited CCS Deployment for Coal-Based Generation

The ability to expedite the deployment of CCS technology for coal-based generation will be strongly influenced by the optimization and resolution of a variety of technical and non-technical challenges. Key areas of consideration are presented below, primarily with respect to the capture aspect of the technology.

a. Technical

A variety of common and project-specific technical issues must be considered when evaluating CCS technologies for existing and new coal-based generation. Retrofit considerations are generally more complicated because these facilities were not designed with the thought of integrating CCS technology. However, new coal-based generation units can be designed with plans for CCS technology. Important technical considerations include:

- An evaluation of the impact of steam extraction locations for supplying regeneration heat to the CO_2 capture process. This may include the design of an extraction point for steam in the turbine cycle and space provisions in the plot plan.
- A determination of the concentration of SO_2 and NO_x in the flue gas that is acceptable to support the CO_2 capture process. Select emission controls that will be sufficient.
- An evaluation of optimizations to the boiler heat transfer surfaces that are needed to maximize unit output and reduce parasitic load impact.
- An evaluation of CO_2 transport, geologic storage, and beneficial use/conversion opportunities and challenges, all of which are critical factors in determining the feasibility and design of any CCS project.

b. Retrofit Issues for Existing Coal-Based Generation

When examining the viability of the existing coal-based generation fleet for CCS retrofit potential, several key issues must be considered, including:

- Does the age of the unit, technology, efficiency, and equipment condition, warrant such a high-cost and long-life retrofit?
- Does the existing site have sufficient space to support the installation of CCS equipment?
- Is the unit equipped with sufficient NO_x and SO_2 controls to support the needs of a specific CCS technology?
- Is the unit located in near an acceptable geologic storage, EOR, or other beneficial use/conversion opportunity?

- Is a steam source within the existing plant available for the CO_2 capture system regeneration heat?
- Are there significant regulatory barriers for timely retrofit consideration?

In general, the original design layout of existing coal-based units did not consider the space (footprint) requirements for future emission control retrofit projects, such as selective catalytic reduction (SCR), flue gas desulfurization (FGD) or CO_2 capture systems. SCR systems reside between the steam generator exit and the air heater inlet, and are generally stacked on top of the air heater equipment. FGD systems (especially wet FGD systems) are located at the stack inlet, and in many cases have used all available space surrounding the stack. In the flue gas flow scheme, CO_2 capture systems will typically be located in the clean flue gas stream downstream of the FGD system in the case of conventional wet FGD, or downstream of the baghouse in the case of a dry FGD system. Because of space constraints, the CO_2 capture equipment may need to be located a considerable distance from the FGD system, baghouse or stack, which will impact project design and costs. In the case of a wet FGD system, the ductwork will likely be constructed of alloy materials, which would add significant cost. Design decisions will also be required for how to discharge the treated gas leaving the capture process. Regardless of whether the existing plant stack or a new stack is utilized, this decision-making process will have operational, regulatory, and cost implications.

The concentration of other compounds in the flue gas, such as SO_2 and NO_x, can impact the performance of the CO_2 capture system, and must be evaluated in the design process. CO_2 capture systems must have FGD and SCR upstream of the process. In some cases, the removal efficiency of the FGD and SCR systems will not be adequate for CO_2 capture, and may require additional SO_2 and NO_x controls. For high sulfur coals, sulfur trioxide levels in the flue gas may also be high, requiring additional mitigation measures upstream of the CO_2 capture process. The need for additional flue gas cleanup prior to the CO_2 capture processes will significantly increase project costs.

Existing coal-based generating units were geographically located based on their proximity to fuel supplies, transmission lines, water resources, etc. No consideration was given for the need to handle and dispose of the vast quantities of CO_2 captured by a retrofit CCS system. The proximity of an existing plant to geological storage, EOR, beneficial use/conversion processes, or CO_2 pipeline opportunities are also a significant design and feasibility consideration. Although long distance transport of CO_2 is feasible, the limited CO_2 pipeline network that currently exists would have to be significantly expanded to accommodate widespread use of CCS across the existing coal generation fleet, resulting in additional cost, regulatory, and schedule challenges.

For solvent-based CO_2 capture processes, some amount of energy in the form of steam is needed for the regeneration of the solvent and for processing the CO_2 into a concentrated stream that is acceptable for geologic storage or beneficial use/conversion. Currently operating coal-based generating units may have zero, single, or double reheater systems employed in the steam cycle, and may have varying numbers of feedwater heaters and steam turbine generator designs, all of which have design challenges and opportunities that must be considered. Therefore, a site-specific study is needed to evaluate the feasibility of heat integration options. If heat integration is not an option, then construction of a new steam source will need to be considered, which will add to the cost and complexity.

Retrofit projects may also face permitting challenges that limit the ability to receive timely approvals for installing new emission sources or in modifying existing units as necessary to accommodate the CCS process - all of which have the potential to impact the schedule, cost, and viability of a CCS retrofit project.

c. Financial

The cost to install CCS technology at an existing coal-based power plant will likely exceed the original installed cost of the entire plant. An overall condition assessment of the base power plant is needed to determine if future operating plans for the unit are sufficient to warrant the CCS investment. It may be determined that the cost of CCS technology plus the lifecycle cost of the plant result in unreasonably high costs of electricity. In all instances, however, even these higher costs would need to be weighed against the costs of generating technologies other than those based on coal. Coal-based generation with CCS, while expensive, may still be the most cost-effective solution based upon that analysis. CCS retrofit systems may very well be only cost-justified on the newest and most efficient generating units. In addition, depending on the steam cycle, steam turbine design, steam generator design, emission control systems for NO_x, SO_2, and particulates, the installation of CCS may require very costly upgrades and modifications to the existing plant systems. Even with improvements in CCS technologies and optimized integration into the power plant, commercial-scale CO_2 emissions control will inevitably be expensive. It is unlikely that new and retrofit CCS projects will be successfully deployed without Federal and state incentives or mandates. For regulated electric utilities, demonstration of the project need and cost-effective design to regulators will be a challenge given the current development status of the technology with concerns regarding its effectiveness and impacts on reliability, as well as concerns regarding any increase to the cost of electricity in context with other regulatory and economic drivers. For independent power producers, these challenges may be more pronounced if they are limited in their ability to share the financial and technical risks with their end users.

d. Permitting

Various permitting and regulatory approvals will be necessary for any CCS project to move forward. The time required to obtain these approvals can be significant (months to years), particularly if detailed design of the CCS project is delayed or if project aspects create unique regulatory issues that must be evaluated. The continued and expanded demonstration of multiple CO_2 capture technologies on a commercial scale will help to advance more standardized designs and optimized permitting processes that could reduce the time needed to prepare and process permit applications for all aspects of a CCS project. By encouraging and working with various regulatory agencies to identify opportunities to optimize their review and approval process, the DOE could minimize the impacts to expedited CCS deployment from the permitting process. Chapter 5 discusses opportunities and challenges to the CCS permitting process in more detail.

e. Public Engagement

As new technologies are introduced, people often have more questions and concerns than for more established industries. Public opposition to new technologies can significantly influence technology deployment, as evidenced with technologies like genetically modified organisms in Europe (Loureiro, 2003) and nuclear energy technology in the United States (Yeh, 2009). For CCS technology, the social science literature to date indicates that general public awareness of the technology is low (Ashworth, 2009). However, the fact that general public awareness of CCS may be low does not necessarily mean that CCS technology will be met with public resistance in the United States. This is due to several considerations, including:

- The fact that CO_2 pipelines and geologic injections have existed for decades in some regions of the country for EOR;
- Several major environmental groups in the United States have endorsed the technology;
- The possibility of compensation to some landowners, in the form of payments for use of their pore space, may additionally mitigate concerns;
- The excellent community educational work that has been conducted under DOE's regional sequestration project; and
- The history of the FutureGen program, with cities throughout the United States bidding for the project, suggests that American communities view CCS as an economic development opportunity.

It is important to underscore that effective community engagement is measured by the success of the engagement process and is not contingent upon agreement on the outcome or the design of the CCS project. In some cases effectively engaging communities can help move projects forward with constructive relationships between the developers and communities. Such constructive relationships can help ensure that the first-of-a-kind CCS demonstrations and any later commercial projects advance in such a way that respects local economies, values, ecosystems, and residents. Two recently published resources on this topic are the DOE "Best Practices for Public Outreach and Education for Carbon Storage Projects" (2010), and the World Resources Institutes' (WRI) "Guidelines for Community Engagement on CCS Projects" (2010). The DOE document provides the following ten best practices for those conducting outreach and education on CCS efforts:

- Integrate public outreach with project management
- Establish a strong outreach team
- Identify key stakeholders
- Conduct and apply social characterization
- Develop an outreach strategy and communication plan
- Develop key messages
- Develop outreach materials tailored to the audiences
- Oversee and manage the outreach program for the life of the CO_2 storage operation
- Monitor changes in public perceptions and concerns as a result of the outreach program
- Refine the public outreach program as warranted

The WRI Guidelines are intended to serve as an international source of best practices for regulators (including those in both regulatory policy design and implementation capacities), local decision-makers (e.g., community leaders, citizens, local advocacy groups, landowners, etc), and developers to consider as they plan and proceed with projects. Reflecting the results of an international multidisciplinary stakeholder process, the WRI Guidelines provide guidance on the following elements of a geologic storage project:

- Understanding the local context: the engagement needed will vary based on the local needs of each individual community
- Exchanging project information: exchanging and discussing information is a cornerstone to community engagement, and true engagement must include more than simply providing information
- Identifying engagement level: the level of engagement will vary depending on the specific characteristics of the project as well as the local community context
- Discussing project impacts: an engagement with the community must include discussion regarding the risks and benefits of the project for the local community
- Continued engagement: community engagement should extend over the project lifecycle, and may span many generations

f. Acceptable End Use Options for CO_2

CO_2 transport, geologic storage, and beneficial use/conversion opportunities and challenges are critical site-specific factors that must be considered in determining the feasibility and design of any CCS project. Chapter 3 evaluates these issues in detail.

2.6 Case Studies of Active CCS Projects for Coal-Based Generation

There are currently several ongoing demonstration CCS projects that vary in their scale, scope, and level of completion. For the purposes of this study, questionnaires were completed for several CCS projects under development. This group of projects is not intended to be all-inclusive, but rather was intended to provide specific insights about various CCS demonstration projects that are receiving federal financial support. A summary of these projects is provided in Table 2-1. The completed questionnaires are included in Appendix A.

Table 2-1: Summary of Select Case Studies for CCS Projects Greater than 20 MW in Size

	Pre-Combustion				Post-Combustion			Oxy-Combustion
Project	Hydrogen Energy California IGCC	Mississippi Power / Southern Company Kemper IGCC	Tampa Electric Polk Power Station IGCC	Taylorville Energy Center IGCC Project	AEP – Mountaineer (Commercial Scale Facility)	WA Parish Post-Combustion Capture	AEP – Mountaineer (Validation Facility)	FutureGen 2.0
Location:	Bakersfield, CA	Liberty, MS	Mulberry, FL	Taylorville, IL	New Haven, WV	Thompson, TX	New Haven, WV	Meredosia, IL
Capture Technology	Rectisol	Selexol	Amine	Rectisol	Chilled Ammonia	Amine Solvent	Chilled Ammonia	Oxy- Combustion
Capture Technology Vendor	---	---	BASF	---	Alstom	Fluor	Alstom	Air Liquide and Babcock & Wilcox
Scale (MW)	390 (net)	580 (net)	30-50	TBD, >200	235	60	20	200 (net)
Previous Testing Scale (MW)	N/A	N/A	N/A	N/A	20	50 (from gasification)	1.7	---
Current Project Status	Currently in Design and Engineering Phase	Detailed Design and Construction	Front End Engineering and Design	Detailed Design Complete; Awaiting Project Approval	Front End Engineering and Design	Front Eng Engineering & Design and Other Permitting	Capturing and Sequestering CO_2	Preliminary Engineering
Injecting/Sequestering CO_2	EOR	EOR	Saline	TBD - either EOR or Geological Sequestration	Saline	EOR	Sequestering in Saline	Sandstone Formation
Project Funding Sources	CCPI, Tax Credits, Federal Loan Guarantee	CCPI, Tax Credits, Federal Loan Guarantee	ARRA	Tax Credits, Federal Loan Guarantee	AEP CCPI	CCPI, NRG	AEP, Alstom, EPRI, RWE	ARRA

Although Federal funding of these projects is key to their success, this funding alone does not guarantee that projects will move forward. For example, the Basin Electric project that had been selected for DOE funding was recently tabled. The following observations were made about the projects in Table 2-1:

- Incentives from the Federal government are critical to advancing CCS technology. Without continued assistance, it is highly unlikely that a large number of CCS demonstration projects would progress.
- These projects vary from 20 MW to 580 MW in size. Most of these projects are in the design and engineering phase. However, in order to significantly advance the development of CCS technology, many more operating CCS projects are needed.
- Many of these projects are awaiting review and approval through the NEPA process, which if streamlined for CCS projects would reduce the development timeline.

As is shown in Table 2-1, most of the CO_2 capture case studies are currently in the front end engineering and design phase. The one operating project is the AEP Mountaineer Plant product validation facility. Some of the lessons learned from this project are provided below.

- Footprint: The CO_2 capture technologies require more space than traditional environmental control systems (SCR, FGD, and precipitator). Space available at/around the power plant may be a constraint when considering a CO_2 capture technology retrofit.
- Permitting: The Underground Injection Control (UIC) permit process can be lengthy and requires constant communication with the permitting agency since some of the state agencies do not have experience dealing with CO_2. Plan to start this process early and communicate often with the permitting agency.
- Geology: Geology is not an exact science; engineers who are used to precise calculations need to understand the inherent uncertainty in dealing with geologic structures thousands of feet below surface.
- Stakeholder management: The Mountaineer CCS facility has had over 100 tours including the following organizations: U.S. Congress, state legislative members, DOE, Office of Management and Budget, Government Accounting Office, EPA, State regulatory agencies, State utility commissions, and Non-governmental organizations.
- Communications: The project team held several meetings with employees, community leaders, and hosted an open house for the local community to share project information.
- Intellectual property: It is imperative that companies developing CO_2 capture technologies protect their intellectual property. However, protecting such intellectual property may be difficult under reporting agreements with the governmental agencies such as the DOE and EPA as well as non-governmental agencies such as EPRI, EEI, etc.

Although the Basin Electric CCS project recently was indefinitely suspended by the company, the work performed to date can provide valuable insights into the challenges facing other projects. Therefore, lessons learned from the Basin Electric CCS project are included below.

- Demonstrating CCS will present significant risks for the first projects able to proceed.

- The front-end engineering and design study addresses technical challenges to design the integration of CO_2 capture equipment into the existing plant infrastructure to minimize the risk, but scaling up and getting the proper operating parameters will take time. The financial risk is tremendous – even if an EOR contract is secured, the delivery of CO_2 must be guaranteed creating the need for a backup supply or a financial penalty.

- Storing CO_2 in geological formations will require significant expenses. The site will need to be characterized – Basin Electric's estimates show costs upwards of $50 million. Liability costs are another unknown and could be a show stopper for geological storage.

- Federal cost share for demonstration projects should be a minimum of 50 percent. The Federal government should assume the liability for the first few demonstration projects and conduct development of reasonable long-term liability rules. The Internal Revenue Service 45Q tax incentive for CCS needs to be revised to assure that electric cooperatives and those with limited tax opportunities also may take advantage of the incentive.

Relevant experiences from the development and operation of the Dakota Gasification Company Great Plains Synfuel Plant (GPSP) are also summarized below. Feedback from this and other projects will help mitigate barriers to the expedited development of future projects. The GPSP in North Dakota has been in operation for over 20 years and is the only commercial coal-to-substitute natural gas facility in the United States. Although the process is different from coal-based electric generation technologies, some of the challenges related to the CCS aspects of the GPSP offer valuable lessons to power-related CCS projects. The GPSP delivers a 95% stream of CO_2 via a 205-mile pipeline for EOR operations in Saskatchewan, Canada. Over five million tons of CO_2 have been injected to date, while doubling the oil recovery rate of the oil field. Technical, equipment, and process changes implemented by GPSP have improved efficiency, of which details can be found in the 2006 DOE report on the practical experience gained during the operation of facility (DOE, 2006). Lessons learned from the first 20 years of the plant's operation that are applicable to power-related CCS projects have been excerpted from this report and through conversation with the company, including:

- A synergy is needed between power plant, coal mine, and the CO_2 storage facilities. In this regard, GPSP represents an "energy complex," where a synergistic relationship exists between the GPSP, the Antelope Valley Station power plant, and the Freedom Mine. The close proximity and cooperation between these facilities is an effective model for a future coal gasification plant or broader energy complex.

- Regulatory approvals can be an extensive and time consuming process. For example, the project had to secure permission or agreements from the International Boundary Commission; North Dakota Public Service Commission; North Dakota Water Commission; North Dakota Historical Society; U.S. Army Corps of Engineers; U.S. Department of the Interior/Bureau of Land Management; U.S. Forest Service; Canadian National Energy Board; and over 300 land owners in the U.S. and Canada. Rigorous safety measures were designed into the pipeline, including leak detection systems and a reverse 911 system. Additionally, a subsidiary was formed to own the Canadian portion of the pipeline.

- Although knowledge of the CCs technologies has increased, permitting may continue to be difficult with evolving regulatory programs and political focus.

- Maintaining a good relationship between management and regulatory agencies is essential for managing monitoring, testing, quality control, reporting, and other permitting requirements.

- Frequent, detailed communication with surrounding communities is essential for managing community concerns.

- Healthy communications with landowners can optimize pipeline siting and development.

2.7 Other Low-Carbon Technologies for Coal-Based Generation

Although CCS will be a key part of any strategy to significantly reduce CO_2 emissions from coal-based generation sources, several other low-carbon coal technologies offer the opportunity to reduce CO_2 emissions and potentially expedite CCS deployment. The 2009 NCC report contained a detailed evaluation of various low-carbon coal technologies, including:

- Partial CO_2 capture opportunities
- Efficiency improvements to the existing coal fleet
- Replacement and new coal-based generation that utilize more efficient technologies
- Biomass co-firing
- Integrated fuel cell hybrid power plant
- CO_2 beneficial reuse opportunities
- Coal beneficiation technologies

- Underground coal gasification technologies

Many of the key findings and recommendations for these low-carbon technologies in the 2009 NCC report remain applicable. For example, one key finding from the 2009 NCC report was as follows:

> "Together, the combination of high efficiency retrofits and partial CO_2 capture would result in significant near-term reductions in CO_2 emissions from the existing coal-based generating fleet."

Efficiency improvements to the existing coal-based generation fleet continue to offer a practical, quick, and cost-effective opportunity for significant near-term CO_2 reductions. The 2007 NCC reported discussed a variety of options for improving the efficiency of the existing coal fleet. Likewise, the 2009 NCC report discussed a number of available upgrades for improving the efficiency of the existing fleet, which could reduce CO_2 emissions by 20 to 40 million tons per year. Both reports identify regulatory and permitting issues that present challenges for implementing such efficiency improvements to the existing fleet. The 2007 NCC report specifically noted that efficiency improvements can be technically and economically achieved, but that "regulatory barriers must be addressed including modifying the New Source Review process." These findings and recommendations remain applicable today.

The 2009 NCC report also evaluated partial CO_2 capture (40-60%) technologies in detail. Consistent with the findings of the 2009 NCC report, partial CO_2 capture from the existing coal-based generating fleet continues to offer the opportunity for significant near-term reductions, while affording an avenue for reducing the overall cost, operational impacts, and risks of developing commercially acceptable CCS technologies. The best candidates for partial CO_2 capture processes are existing higher efficiency units that are equipped with sufficient emission controls, have sufficient space to readily accommodate the capture system, and that are located close to geologic storage sites or beneficial use/conversion processes.

Overall, non-CCS low-carbon coal technologies present an opportunity for significant near-term CO_2 emissions from the existing coal-based generation fleet. Continued and expanded economic incentives, along with optimized regulations are necessary to more rapidly drive their development and commercial use. In context with influencing the deployment of CCS, these technologies offer the potential to reduce the amount of CO_2 that must be captured, while adding options for the end use of captured CO_2 - both of which can improve viability on a CCS project-specific basis through potential reductions in cost and operational risks.

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Chapter 3: Expediting the Deployment of CO_2 Transport, Storage & Reuse

3.1 Key Findings

- For wide-spread deployment of CCS technology to occur on the United States coal-based generation fleet, which is widely dispersed across the country, an extensive pipeline network will be needed to handle the large volumes of CO_2 captured and to support facilities that lack local geologic storage capacity.

- Financing an extensive pipeline network will be a significant challenge as current estimates based on current pipeline construction costs are approximately $1.5 million per mile (based on the current experience of Denbury and Worley Parsons). EOR applications can partially offset this cost. However, for CCS projects using non-EOR geologic storage, the cost for pipeline development will be a significant consideration.

- One option to complement an expansion of the United States CO_2 pipeline network is the hub concept that is being evaluated in Europe as part of the RCI. The hub concept may have a niche application to the United States, which may focus on surface pipelines, rather than the waterway systems under consideration for the RCI.

- A larger potential reservoir of EOR opportunities for CO_2 appears to exist. Currently, over 50 million tons per year of CO_2 per year are used for EOR. Based on estimates for the residual oil zone concept, the capacity could be several times this amount.

- To significantly move beyond EOR-related storage, it is imperative to understand the behavior of CO_2 stored in saline formations going forward since these geologic units represent the largest and best storage capacity in the near-term (to complement EOR) and for the long-term (as the primary storage reservoir).

- The DOE has implemented a systematic and logical approach to assessing geologic formations and to ensuring that adequate and diverse pore space is available for CO_2 storage. While this effort has been substantial, more information is needed for a broader portfolio of geologic settings.

- The design and evaluation of geologic storage systems is currently an empirical simulation and modeling effort that will not advance substantively until data can be collected from more operating integrated CCS projects.

- A project-specific initial geologic characterization is critical to design the geologic storage system, which determines the number of injection and monitoring wells required, the target depth for injection and the spacing between wells. Subsequently, the storage design influences the design of the pipeline network. All of these design variables, along with the need to perform the initial characterization, add complexity, cost, and time to the development process.

- Non-EOR beneficial CO_2 use/conversion technologies are currently insufficient to support the volume of CO_2 that could be captured from coal-based generation. Of these technologies, synthetic transportation fuels production offers the potential to have a material impact on the volume of CO_2 captured from a broad-based CCS program.

3.2 Recommendations

- The Council recommends that the DOE to support efforts by other agencies in the Executive Branch to address non-technical CO_2 pipeline development challenges related to financing, siting, permitting, and public outreach.

- The Council recommends that the DOE monitor the development of the European hub concept and evaluate opportunities to apply this concept in the United States.

- The Council recommends that the DOE continue and expand near-term efforts to evaluate geologic storage formations to address "information gaps" that exist (see Table 3.1), by completing a diverse suite of studies to characterize storage classes and by conducting small- and large-scale field tests. Results will provide the knowledge base necessary to support future commercialization of carbon storage technologies and the proper application of MVA tools for various geologic storage classes.

- The Council recommends that the DOE aggressively expand programs to support the development of CCS-related MVA tools, as well as the gathering of data to allow the upgrade of both simulation and modeling programs. Both are essential to improving the design and management of geologic storage systems.

- The Council recommends that the DOE continue its current CO_2 geologic sequestration demonstration program by expanding and accelerating the number of projects in operation by 2015.

- The Council recommends that the DOE continue to evaluate the worldwide development of beneficial CO_2 use and conversion technologies, and to provide funding support for expediting the development of the most viable opportunities among these.

3.3 Introduction

CCS deployment is dependent on the successful development of capture, transport, storage or reuse technologies. The 2009 NCC report projected that to meet President Obama's goal of an 83% reduction in GHG emissions by 2050, the deployment of 360 GW of CCS to coal-based generation would be needed, including the need for 10 large scale demonstration projects by 2016. The investment in CCS for the 360 GW of power was projected to be in the range of $1.2 trillion, excluding the cost of CO_2 transportation and storage, which separately will be significant. It is imperative that as capture technologies evolve, the necessary transportation and storage infrastructure move forward in lock step. The current DOE research, development and demonstration program for geologic carbon sequestration is the most robust in the world and will continue to play a pivotal role in expediting the deployment of CCS. In 2009, NETL estimated that the next generation EOR technology could provide an additional 2 million barrels of oil daily from domestic EOR/CCS programs, which could use the CO_2 generated by approximately 70 of the 360 GW indicated above. This increased domestic oil production provides a potential revenue source to help finance CO_2 capture and transport. Other opportunities to beneficially use and/or convert CO_2 beyond EOR processes will require further development to accommodate a large scale CCS deployment.

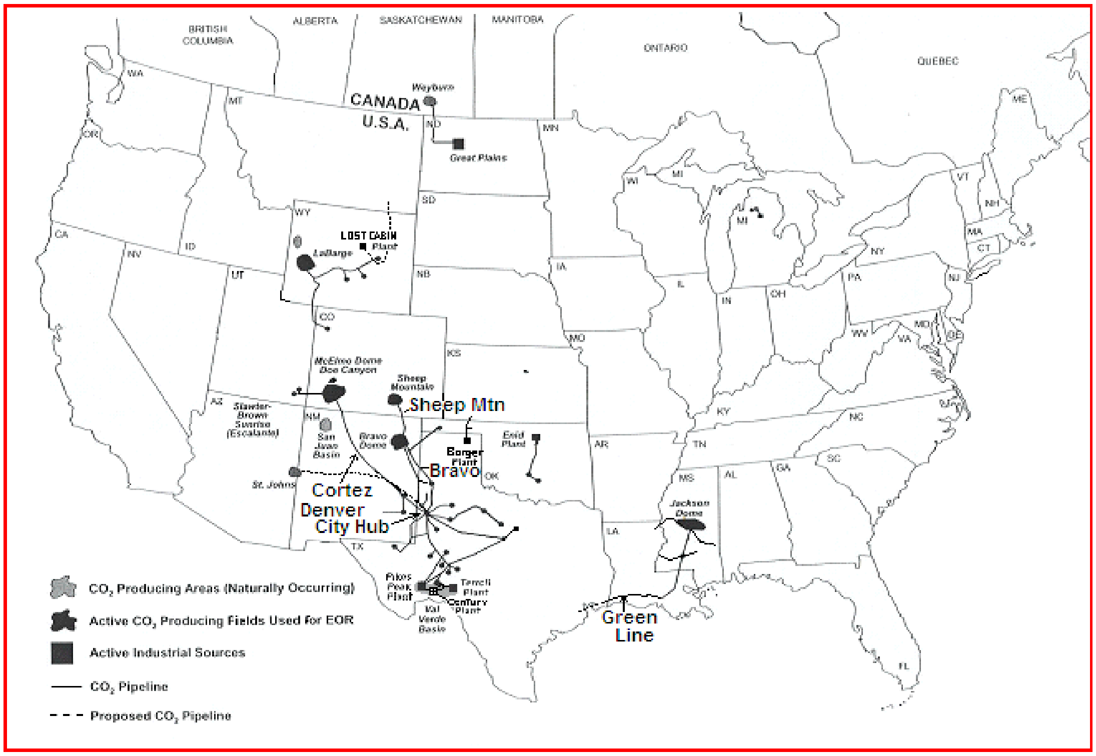
3.4 CO_2 Transport

a. Current vs. Expanded CO_2 Pipeline Network

A critical component to CCS deployment is the infrastructure required to transport CO_2 from the capture process to geologic storage or to beneficial use/conversion processes. For wide-spread deployment of CCS technology to occur on the United States coal-based generation fleet, which is widely dispersed across the country, an extensive pipeline network will be needed to handle the large volumes of CO_2 captured and to support facilities that lack local geologic storage capacity.

Such a network could be achieved, in part, by expanding the existing CO_2 pipeline system (Figure 3.1) that consists of over 3,600 miles of pipeline developed primarily to supply CO_2 to EOR operations from various natural and anthropogenic sources, none of which are coal generation facilities (Marston, 2010). On private lands, to date, the limited number of states with CO_2 pipelines has been responsible for regulating their siting, construction, and operation. Some states have also provided economic incentives for CO_2 pipeline development. As the deployment CCS projects brings pipelines to states without existing provisions for CO_2 management or with minimal experience in regulating such projects, the ability to receive timely regulatory approvals could become a concern.

Figure 3.1: Existing U.S. CO_2 Pipeline Network
(IOGCC, 2010)



The development of an extensive pipeline system to provide sufficient CO_2 transport capacity for coal-based generating units and other sources will take a long period of time, well beyond the 2020 time frame of this study. The development process will likely involve an initial number of large CO_2 capture projects, such as those for coal-based generation units, that will directly connect with a smaller number of injection sites beginning with EOR fields and gradually expanding into non-EOR geologic storage facilities. As the number and dispersion of facilities with CO_2 capture processes expands, so will the need for an expanded pipeline network.

Evaluation of opportunities to expand the existing CO_2 pipeline network is occurring. For example, in 2009, the State of Illinois funded the Midwest CO_2 Pipeline Feasibility Study, which analyzed development of a 740-mile pipeline connecting four planned coal gasification plants in Illinois, Kentucky and Indiana to EOR opportunities in the Gulf Coast states. This study examined two alternative routes and concluded the pipeline could be constructed within four years at a cost of \$1.2 to \$1.4 billion (Denbury Resources, 2010). Potential permitting impediments were evaluated and none were identified. However, a detailed evaluation of the scope of all permits and regulatory requirements for this effort is needed to determine whether timely approvals could be expected that would not significantly impact the project development schedule. Figures 3.2 and 3.3 below display the pipeline expansion considered by this study.

Figure 3.2: Midwest CO_2 Pipeline Feasibility Study
(Denbury Resources, 2010)

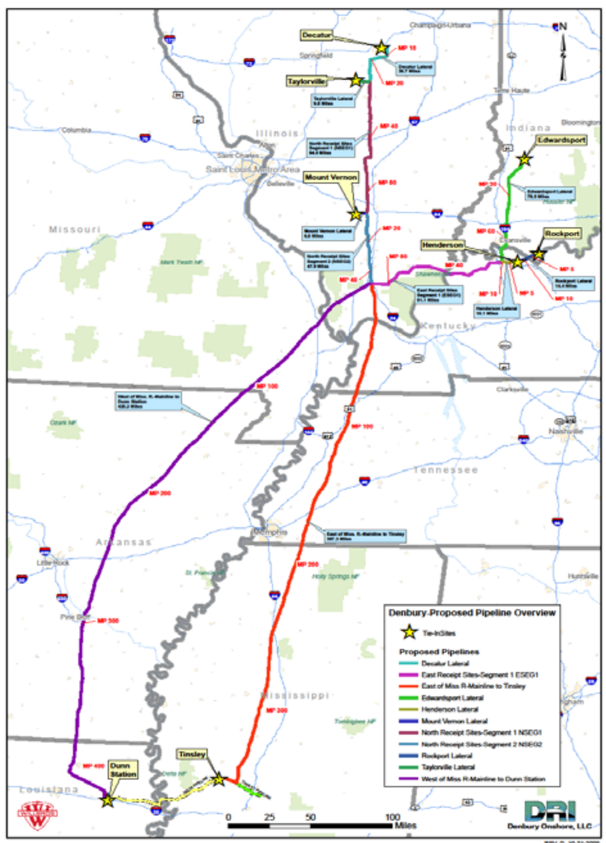
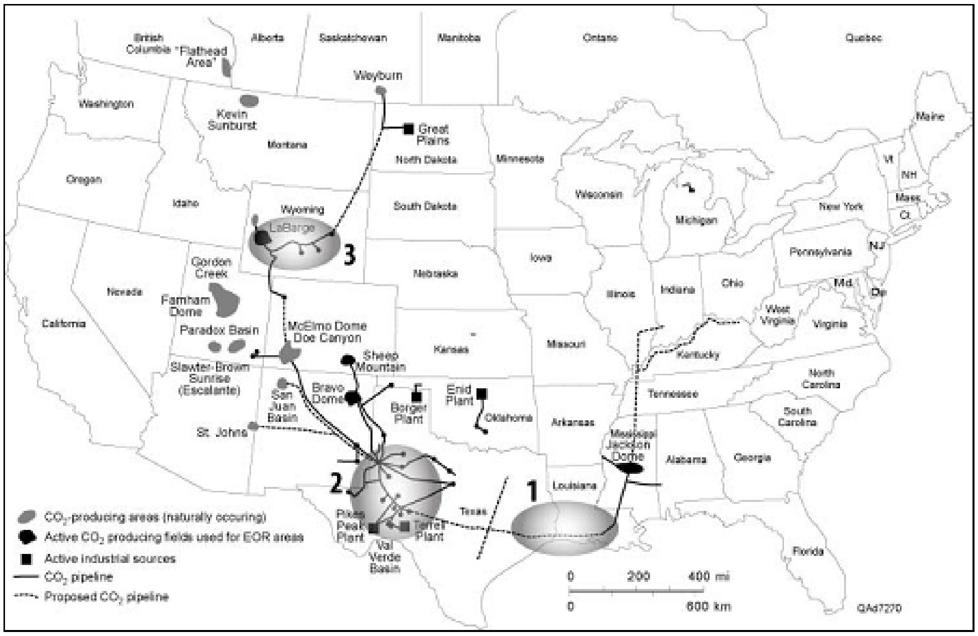


Figure 3.3: Conceptual Expansion of the Midwest System to the West
(Denbury Resources, 2010)



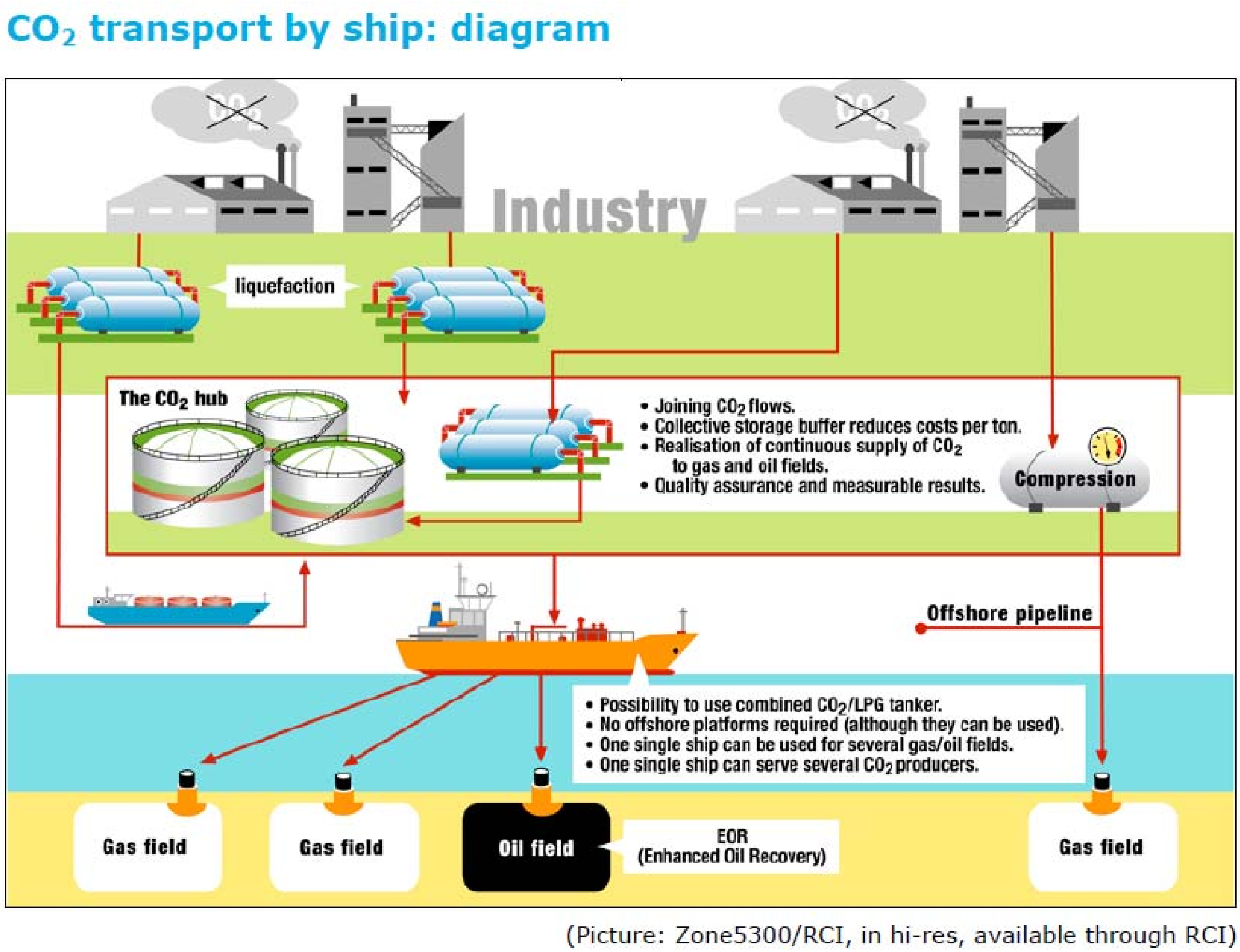
For expedited expansion to occur as necessary to accommodate a broad-based deployment of CCS to the coal-based generation fleet, several development issues must be resolved. For example, new CO_2 sources may require pipeline off-take capacity that is specifically dedicated to receive CO_2 from individual facilities. Failure to accommodate the requirement to ensure the availability of capacity for very lengthy periods could pose significant technical and regulatory barriers to wide-scale commercial deployment. Financing the pipeline network will be a significant challenge as current estimates are approximately $1.5 million per mile (based on current experience of Denbury and Worley Parsons). It is generally believed that the pipeline network could be financed through a combination of project and corporate debt (supported by shipper commitments of CO_2). Federal tax incentives would greatly assist in this build out. In addition, EOR applications could provide a revenue source to offset capture and transport costs. However, a larger challenge is financing CO_2 pipelines for geologic storage in non-EOR applications where no specific commodity price is available to input decision-making. This area requires further regulatory and market development. In the mean time, it is very likely that non-EOR related pipelines for some CCS projects on coal-based generating plants would require substantial government support.

b. Applicability of the European CO_2 Hub Concept

A potential option to complement a build out of the existing United States CO_2 pipeline network is the CO_2 hub concept that is currently being evaluated in Europe as part of the RCI. The hub concept involves aggregating CO_2 from multiple sources through a collection network that utilizes various transportation methods, whereby CO_2 is made available to various storage or beneficial use locations. Transportation methods might include pipelines (onshore or offshore), barges, sea-going vessels, and rail. In the United States, this may more commonly involve pipelines as opposed to waterway transport in Europe. A hub would also have the capability to serve as a temporary storage facility for liquid CO_2. In addition, the hub concept provides the ability to serve CO_2 sources or end-users that may not be able to justify their own large-scale source-to-sink solutions. This shifts the abatement cost curve for sources, resulting in higher volumes that may be captured and removed at a given CO_2 cost.

At the proposed RCI hub, CO_2 would be aggregated from local and remote sources via pipelines and barges, stored in intermediate tanks, and shipped to offshore locations for permanent storage in depleted gas fields. In this scenario, the majority of CO_2 is liquefied and transported to a central liquid CO_2 storage facility before being shipped by sea-going vessel while still in the liquid state. This liquid network will complement CO_2 that is planned to be transported by pipeline to offshore storage from a compression site located at the hub. This arrangement will be optimized for the Rotterdam/North Sea area, but the design could feasibly be adapted for other global locations (although the United States may see more use of the concept with land-based pipeline systems going to CCS hubs). From and within Europe, sea-going vessels could deliver CO_2 to different storage locations and could reach smaller, more remote areas where offshore pipelines would be cost-prohibitive. Under the volume and distance conditions expected in Europe, CO_2 management through the hub and liquid shipping is cost competitive with pipeline transportation and offers the necessary degree of flexibility in routing and managing variations in volumes. Additionally, while the economics of pipeline transportation are developed, the liquid shipping economics are expected to improve as the concept is implemented over time (RCI, 2010). Figure 3.4 summarizes the European hub concept.

Figure 3.4: European Hub Concept
(RCI, 2010)



CO_2 hubs (water-based or pipeline-based) in the United States could be particularly valuable in the period before a fully developed pipeline network is realized. Transportation of CO_2 by waterway may be cost competitive with pipeline transportation in unique locations and may also provide the ability to access multiple markets or storage sites without tying capital investments to one location. It also allows for variations in volume on the supply and receiving side of the network. To the extent that the hub concept would expand the access and cost-effectiveness of storing CO_2 in depleted offshore oil fields, then public acceptance, permitting, and risk management associated with CCS may be easier to address compared to onshore opportunities. For smaller onshore aggregation or use, transport by rail cars would also be a potential option. The Gulf Coast has an existing and growing CO_2 pipeline system that utilizes a hub concept that could be expanded as new CO_2 sources become available. The FutureGen 2.0 project, given its proximity to other potential CO_2 sources, offers another near-term consideration for applying the hub concept in the United States Other possible hub locations might include the East Coast, Chicago, Los Angeles, and the San Francisco Bay. Some areas, such as Los Angeles, may be attractive waterway hubs because transport of CO_2 by pipeline in this area would not easily be achieved. Smaller terminals may be possible in certain areas where CO_2 from smaller sources could be aggregated for transport via short pipelines, barge, or rail to local geologic storage site or beneficial use/conversion processes.

Close coordination between industry and governmental authorities will be necessary to determine, on a case-by-case basis, the optimal and most economical strategy to capture, aggregate, transport, store, and/or beneficially use CO_2. Implementation of the CO_2 hub concept will require overcoming the critical mass required to begin an actual project, which will not be as simple as linking a single CO_2 source to a single storage site or beneficial use process. The potential benefits could be significant, in particular, for areas requiring flexibility in the CO_2 transport network.

The concept of regionally centralized CO_2 geologic storage locations has been considered by the United States as a means to accommodate a broad-based GHG reduction program. For example, U.S. Senator Jeff Bingaman has previously proposed the use of regional storage sites to support CCS projects, which would have merit in providing centralized locations of storage for large CO_2 sources that are widely dispersed across the United States (2009) Further consideration of this regional approach in context with lessons learned from the RCI program may offer opportunities to accelerate the deployment of CCS technologies.

c. CO_2 Transport – Development Challenges

Key challenges related to the development of the CO_2 transportation infrastructure required to accommodate a broad deployment of CCS to coal-based generation include:

- CO_2 Purity: As discussed in the 2009 NCC report, more analysis is needed on the impacts of impurity levels in CO_2 streams from a plant and a pipeline perspective in order to optimize cost impacts.

- Financial: Capital and operating cost recovery guidelines may be needed as projects move forward, especially in regulated states.

- Siting: Pipeline siting requires the need to obtain rights-of-way for development, which can be a time consuming and difficult process depending on landowner negotiations and whether eminent domain must be pursued.

- Pipeline Specifications: Industry design codes (e.g., ASME B31.4) may need to be reviewed to provide more consistent guidance for designing and operating CO_2 pipelines.

- Communication: Public support will help facilitate the timely development of CCS technologies. In conjunction with the development of CCS, programs should be implemented to proactively engage the public on the nature of CO_2, its risks and the outstanding safety record of the existing CO_2 pipeline industry.

- Permitting: The time required to obtain the necessary permits and regulatory approvals for CO_2 pipelines and injection wells could add significant time to the deployment schedule of CCS projects. Chapter 5 discussed permitting issues in more detail.

3.5 CO_2 Storage

a. CO_2 Storage – Historic vs. Future Needs

The United States has over forty years of experience with using CO_2 in EOR applications, with approximately 14,000 CO_2 injection wells having received permits, primarily in the South and Southwest (i.e.. Texas, Mississippi, Alabama). Currently, approximately 50 million metric tons of CO_2 are used annually for EOR in the United States, with a total of approximately 560 million metric tons having been used to date (Marston, 2010). The use of CO_2 for EOR is currently limited by the availability of CO_2 (over 80% of the CO_2 used for EOR purposes is naturally occurring and the remainder comes from natural gas separation plants). Estimates indicate that in the near-term, the amount of CO_2 available for EOR purposes could expand significantly depending on the availability of additional infrastructure for transport to areas where tertiary oil recovery efforts are warranted. Based on this, EOR remains a very viable CO_2 storage approach with significant upside potential. In fact, if residual oil zones exist as currently postulated, then the available geologic capacity for EOR related CO_2 storage would significantly increase. As a result, the projected volume of CO_2 captured from various coal-based generation CCS projects currently under development could be used for primarily EOR purposes, assuming the project-specific location, technology, and cost-effectiveness considerations are acceptable.

Beyond 2020 and as CO_2 capture increases, it will be necessary to have significantly more non-EOR geologic storage platforms ready. With respect to geologic storage potential, the

DOE has separately documented that the United States has ample geologic storage capacity in any number of reservoir types to manage the volumes of CO_2 that might be captured from a broad-based CCS program for centuries.

b. CO_2 Storage Considerations for Expedited CCS Deployment

To move beyond EOR, CCS technical challenges exist primarily in understanding potential geologic storage opportunities like saline reservoirs. It is imperative to understand the behavior of CO_2 stored in saline formations going forward since these geologic units represent the largest and best storage capacity in the near-term (to compliment EOR) and for the long-term (as the primary storage reservoir). CO_2 storage strategies beyond EOR opportunities are currently at the pilot/demonstration stage and will need to be tested for several years to gain empirical data. The results from those efforts will need to be integrated with experience from around the world in order to deploy an effective large scale CCS program.

Moving forward with CCS development will require the integrated development of capture, transportation, storage and monitoring systems. Various near-term integrated CCS projects are being planned in the United States (see Chapter 2). The projects include the scale up of AEP's Mountaineer project in West Virginia and Alabama Power/SECARB's Plant Barry project in Alabama. In addition, there are other planned projects that include carbon capture integrated with EOR, including Mississippi Power Company's Kemper County IGCC project, the FutureGen 2.0 oxy-combustion project in Illinois, the Summit Texas Clean Energy project in Texas, and the Hydrogen Energy California (HECA) IGCC project in California.

In order to prepare for future deployment of fully integrated CCS projects across the coal generation fleet, it is necessary for such projects to become a reality and for a broader portfolio of current early deployment projects to emerge from the perspective of both a technology option and a geologic setting. From a CO_2 storage perspective, deployment challenges for CCS include both a better characterization of the different reservoir classes and types, as well as various legal, liability, and permitting issues, which are covered in Chapter 5. The DOE has implemented a systematic and logical approach to assessing geologic formations and to ensuring that adequate and diverse pore space is available for CO_2 storage. This effort is well summarized in 2010 NETL report titled "Geologic Storage Formation Classifications: Understanding Its Importance and Impacts on CCS Opportunities in the United States."

NETL's goal is to characterize the different depositional environments with drilling, subsurface geophysics, chemical analysis, and geomechanical analysis and to conduct both small scale (less than 500,000 tonnes) and large-scale (over 1 million tonnes) injections of CO_2. An overview of the storage projects, including the storage formation classes involved, that have been complete or are underway in 2010 is provided in Table 3.1 below. While the effort to date has been substantial, a number of key gaps remain.

Table 3.1: Field Activities in Different Geologic Storage Formation Classes
(NETL Regional Carbon Sequestration Partnership Program website, 2009)

	High Potential					Medium Potential				Lower or Unknown Potential	
Large Scale Field Tests (over 1 million tonnes)	-	1	-	-	1	3	-	1	-	-	-
Small Scale Field Tests (less than 0.5 million tonnes)	3	2	4	1	2	-	-	2	-	5	1
Site Characterization	1	-	8	6	-	3	3	2	2	-	1
Geologic Storage Formation Classes	Deltaic	Shelf Clastic	Shelf Carbonate	Strandplain	Reef	Fluvial Deltaic	Eolian	Fluvial & Alluvial	Turbidite	Coal	Basalt (LIP)

Notes:
The number in the cell is the number of investigations per depositional environment.
Site Characterization – Characterize the subsurface at a location with the potential to inject at least 30,000,000 tons of CO_2.
Reservoir potentials were inferred from petroleum industry data and field data from the sequestration program

In order to effectively understand CCS at early mover storage sites, a very effective and extensive MVA tool box is needed. The DOE is supporting research on a broad range of MVA tools with the goal that many will emerge as cost-effective candidates for commercial applications. Others may prove to be too costly or not robust enough for commercial use, but may be important in the verification of more conventional MVA tools. The DOE has set targets for MVA tools with respect to measurement performance, but it should also establish criteria for cost of implementation and robust operations. Industry, both in the United States and globally, along with the DOE need to closely collaborate in the testing of MVA solutions between now and 2020 to develop a useful commercial approach to CO_2 management in a CCS application. For example, more data and evaluation tools are needed to assess the boundary conditions of geologic storage.

A greater availability of cost-effective and accurate tools are needed for performing initial geologic characterizations and for designing the storage aspect of a CCS project. For some current projects, the initial geologic characterization process can be an expensive and time-consuming effort. However, the information obtained from this process is critical to design the geologic storage system for a specific project, with consideration to a number of factors, including the quantity of wells needed, the target depth for injection, the spacing between wells, along with the design of associated monitoring wells. This design will influence the design of the pipeline or transportation network as well. All of these variables add complexity, cost, and time to the development process.

Simulation and computational design is important and will continue to be a key tool in the management of stored CO_2. The computational and simulation tools need to be calibrated and tested against actual data as the data are gathered and modified as necessary. Models are iterative and model simulation needs to be verified against data as they become available. While it may not be possible to incorporate results from different geologic settings in an "idealized" model, CO_2 storage data collected domestically and worldwide can be synthesized to improve current simulation and modeling efforts. To better understand the iterative nature of the predictive tools and the data gathering tools addressed above, the below logic applies:

- The burden of proving permanence of CO_2 storage is based on rock properties and the associated engineered features (i.e., wells).
- If characterization and fluid flow modeling is correct, 100% of the CO_2 injected is stored.
- It is currently impossible to directly monitor the storage volume to the precision needed to show that the modeling is correct.
- MVA becomes the means to prove permanence of storage using the formation characteristics tied to a sensitivity analysis of uncertainties of input data and modeling.
- Once the uncertainties with significant implications to permanence are understood, a MVA strategy can be refined to verify the correctness of the model predictions (>99% over a 1,000 years).

- This effort will be iterative with a learning curve that will increase certainty of results as the currently planned testing goes forward both within the regional partnerships and with the currently planned integrated CCS projects.

c. Biological Carbon Storage

Optimized and expanded use of biological resources offers the potential to significantly offset CO_2 emissions by promoting and adopting beneficial land use practices that enhance biological carbon storage by vegetation and soil. These resources, albeit finite, have a potential to store significant amounts of carbon. In a 2007 report, the Congressional Budget Office estimated that biological carbon storage has the potential to store 40 to 60 billion metric tones of CO_2 over a 50-year period.

d. CO_2 Storage – Development Challenges

Key development challenges related to the geologic storage of CO_2 in support of the broad-based use of CCS on coal-based generation include:

- Knowledge of Local Geology: The design and evaluation of geologic storage opportunities is currently an empirical simulation and modeling effort that will not advance substantively until data can be collected from more operating integrated CCS projects. Obtaining this information for the currently active large-scale demonstration projects is an expensive and time-consuming effort. But it is necessary for designing the well scheme and pipelines necessary to support an individual CCS project.

- Geologic Evaluation Tools and Data: Data from the DOE regional partnerships and planned integrated CCS projects in the United States and around the world are imperative to developing a sound and defendable CCS program. The need to expand the development of geologic storage opportunities beyond EOR applications, as well as into the 2020 time frame, requires setting up real CCS "first mover" projects in the near-term. Such an effort will provide data to establish a CCS platform that starts as a backup to EOR and then moves into a primary storage role.

- CCS Experience: The current portfolio of active projects in the DOE Geologic Sequestration Demonstration program is insufficient to provide the data required to evaluate storage in geologic formations at a level necessary to support an expedited broad-based deployment of CCS across the existing coal generation fleet. Both industry and the DOE need to be proactive to ensure that the CCS platform is available when needed. At this point, insufficient data are available to completely define the simulation and modeling tools and the MVA techniques that are needed to ameliorate risks.

3.6 Non-EOR Beneficial CO_2 Use and Conversion

a. Beneficial Use and Conversion Opportunities

Non-EOR beneficial CO_2 use technologies are currently insufficient to support the volume of CO_2 available from capture processes for coal-based generation. However, various technologies under development offer potential opportunities. Both the 2007 and 2009 NCC reports discuss these technologies in more detail, resulting in various findings and recommendations that remain applicable. For example, the 2007 NCC report categorized and discussed beneficial use technologies related to industrial consumption, material production, and biological conversion, while noting that these technologies "*could* provide important niche uses of CO_2 in the future." In addition, the 2009 NCC report found that "beneficial use technologies face both technical and economic hurdles to scale-up and to achieve widespread deployment."

This trend continues as more research and development is needed to advance these technologies to the point that they are viable alternatives that can support the quantities of CO_2 that could be supplied from coal-based generation. Of the technologies being developed, the synthetic transportation fuels production and related processes offer the potential to have a material impact on the volume CO_2 captured from a broad-based CCS program. In particular, beneficial use processes involving algae derived biofuels and the production of methanol and dimethyl ether (DME) represent leading areas of potential, large scale use of CO_2. Current developments related to fuels production include a Carbon Recycling International plant in Iceland that will produce 13 million gallons of fuel per year by 2013. In addition, Mitsubishi Heavy Industries is currently building a DME plant in Iceland using geothermal power which will be operational in 2014. Volvo is investing heavily in DME fueled engines for trucks with commercial engines expected within 5 years. The work being done in Iceland with methanol and DME is worthy of note because if technical and cost competitive issues are resolved, the existing market is large. The large quantities of CO_2 needed to turn algae into fuels like diesel could also be substantive, but the current development horizon for algae technologies exceeds ten years. The demand and availability of other beneficial uses of CO_2 (i.e., food packaging, cement) are not sufficient at present to support the large volumes of CO_2 that could be captured from coal-based generation.

Overall, non-EOR beneficial use technologies are not currently available to support the amount of CO_2 supplied from capture processes at coal-based generating facilities. A strong need exists for a more structured development program for these potential technologies. The following recommendation from the 2009 NCC report remains valid and would help to provide structure and focus for development of these technologies:

> "The Council recommends that the DOE spearhead the cataloguing of available information to compare and contrast beneficial use technologies and conduct tests to determine which are the most promising. This would expedite the determination of which alternatives are most economically attractive, based on the specific circumstances of a company or plant."

b. Clean Energy Ministerial – Carbon Capture, Use and Storage Action Group

Carbon capture, use, and storage (CCUS) from coal utilization has been identified by world government groups that the United States participates in as one of several clean energy technologies that are necessary to promote the growth and sustainable development of a low-carbon economy. The following describes the inclusion of CCUS among the clean energy technologies being evaluated by the Major Economies Forum on Energy and Climate and the Clean Energy Ministerial.

The Major Economies Forum on Energy and Climate was established in 2009, in part, to advance the supply of clean energy, while reducing GHG emissions. The group includes 17 major economic countries, including the United States In July 2009, the group formed the Global Partnership in order to:

- drive transformational low-carbon technologies;
- increase and coordinate public sector investment in advancing these technologies;
- remove barriers, establish incentives, and work to aggressively accelerate deployment; and
- advance action on CCUS; and high-efficiency/low-emissions coal technologies.

One outcome of the Global Partnership was the issuance in December 2009 of a Technical Action Plan for CCUS. The report, among other things, discusses barriers to CCS development, describes best practices for advancing CCS, and recommends specific actions to accelerate deployment. An offshoot of the Global Partnership is the formation of the Clean Energy Ministerial. The Clean Energy Ministerial is comprised of energy ministers and stakeholders from over 23 countries for the purpose of collaborating on actions designed to accelerate the deployment of clean energy technologies. Secretary Chu hosted the first ministerial meeting in July 2010, which established several initiatives to pursue prior to the 2011 ministerial meeting. Among these initiatives is the formation of a CCUS Action Group that is tasked with preparing a Global Strategic Initiative Implementation Plan to examine key barriers to the deployment of CCUS. The Plan will develop recommendations for overcoming CCUS barriers by focusing on issues related to strategic direction, financing, use & storage, regulation, and knowledge sharing.

A primary conclusion from the efforts of the aforementioned groups is the identification of CCUS as a key clean energy technology that is an essential part of any strategy to pursue a sustainable low-carbon future. It will be important for the United States to continue to actively participate and provided leadership in these and other related organizations in order to advance the development and deployment of CCUS technologies in a technically feasible, cost-effective, and timely manner.

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Chapter 4: CCS Deployment Timeline

4.1 Key Findings

- The findings and recommendations for CCS development presented in the 2009 NCC report remain applicable and have been reinforced by other studies, including the 2010 Interagency Report on CCS, and the 2009 National Research Council report titled "America's Energy Future: Technology and Transformation."

- The three reports are unanimous in recognizing the need for large-scale integrated CCS demonstration projects as a prerequisite for commercial adoption of the technology. Both the NCC and National Research Council reports call for an initial 5-10 GW equivalent of CCS capacity to be operated for approximately five years. These projects would need to span a range of configurations to verify the performance and cost of CCS over the expected scope of commercial applications.

- Progress has been made in addressing the recommendations of the 2009 NCC report, but the pace is insufficient for the development needed to deploy CCS to coal-based generation at the rate necessary to meet President Obama's goal of an 83% reduction in GHG by 2050.

- The annual CCS capacity additions from 2020 to 2050 that would be required to meet the 2050 GHG emission reduction goal would rival the coal-based generation capacity additions of the 1970's and 1980's, which averaged approximately 11 GW per year.

- The current DOE CCS development program, although robust by world standards, has not moved fast enough and is not on pace to have the level of impact hoped for by 2020. At the current rate, CCS technologies will continue to be in an early development stage by 2020.

- The suite of ten large-scale integrated demonstration projects currently being funded by the DOE was analyzed in terms of scope, diversity, likelihood of proceeding to completion, and timing. That analysis concludes that the program has too few non-EOR projects and that, on the basis of the past experience with the DOE's large-scale demonstration programs, it is unlikely that more than two or three projects of the existing suite will initiate the injection of 1 million tonnes of CO_2 per year into geologic formations (excluding EOR) by 2020.

- If CCS technology is to be commercially available for coal-based generation by 2020, then the success rate of active projects must improve and the quantity and diversity of large-scale storage demonstration projects must be expanded and accelerated in the near time. The DOE is in the best position to lead this effort.

4.2 Recommendations

- The Council recommends that the DOE continue to evaluate and promote CO_2 storage opportunities for EOR applications, while expanding efforts to evaluate storage opportunities in saline and other geologic formations that are not associated with EOR processes.

- The Council recommends that the DOE expand and accelerate its current CCS development programs in order to implement the number of near-term demonstration projects (2015-2020) required to facilitate the rate of CCS deployment necessary to meet the President's state GHG reduction goals for 2030 and 2050.

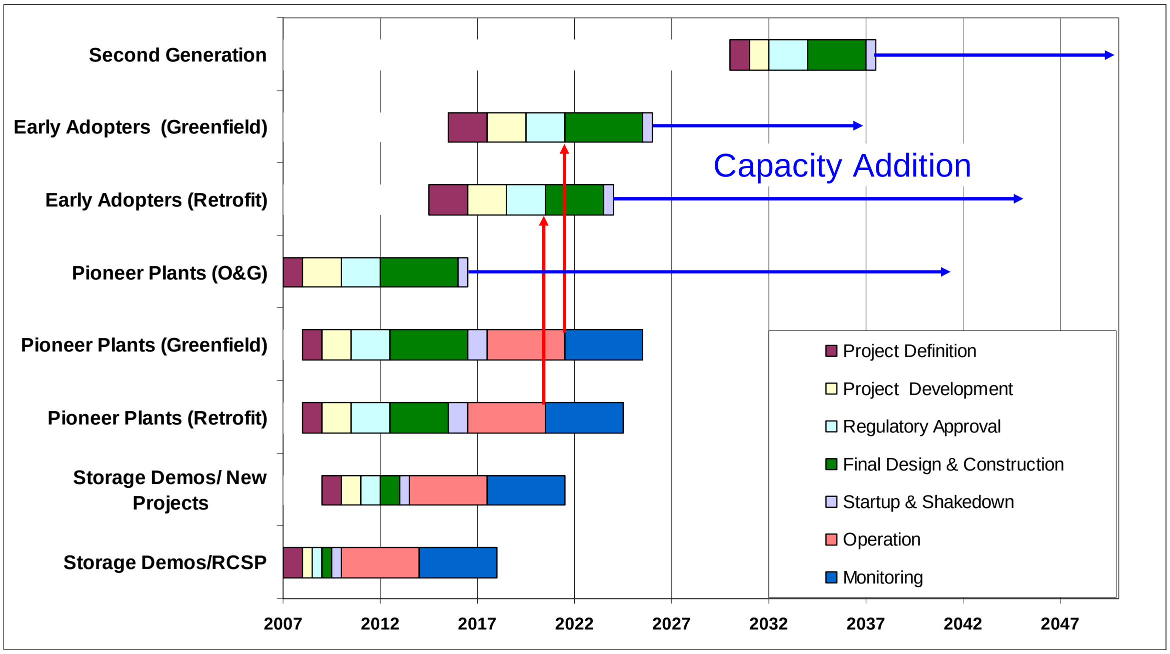
4.3 Introduction

The 2009 NCC report presented a timeline and cost analysis for CCS deployment. The deployment timeline considered the technology demonstration steps necessary to enable a sustained period of construction of coal-based CCS facilities, and a plausible subsequent addition rate of CCS capacity through 2050 in order to meet President Obama's goal of an 83% reduction in GHG emissions. Results of that analysis are summarized below and compared to similar analyses performed by other organizations. The recommendations from the 2009 NCC report, particularly for the early technical development of CCS, are then compared to the status of current CCS projects in the United States to assess whether timely progress toward CCS commercialization is occurring.

4.4 CCS Development – 2009 National Coal Council Report

As shown in Figure 4.1, the timeline model presented in the 2009 NCC report assumed the need for large-scale stand-alone CO_2 storage tests and for the demonstration-at-scale of integrated CCS technology (Pioneer Plants) as a prerequisite for potential owners to commit to widespread deployment (Early Adopters and subsequent capacity addition).

Figure 4.1: CCS Deployment Timeline (NCC, 2009)



The timeline model divided the necessary steps to commercial deployment into these phases:

- Stand-alone CCS storage tests in geologic formations. These are tests of CO_2 injection and post-injection monitoring, particularly in saline formations, but they are not necessarily integrated with an industrial source of CO_2. These include projects underway in Phase III of the DOE's Regional Carbon Sequestration Partnership (RCSP) Program, and detailed characterizations for a number of potential commercial CCS projects.

- Pioneer Plants (greenfield and retrofit) that are at least partially integrated with CCS for electricity generation or some other industrial use of coal. These include projects such as FutureGen, as well as other CCS related projects relying on various financial incentives, including those related to the DOE CCPI program, tax credits, loan guarantees and other incentives, such as oil and gas revenue from EOR projects. The 2009 NCC report described a suite of 20-30 projects that would comprise 5-7 GW of Pioneer Plant capacity, and span a sufficient range of coal types, technologies, and geologic storage sites and geographic regions.

- Early Adopters. Based on a realistic schedule for project inception, design, permitting, construction and operation, the 2009 NCC report determined that a number of Pioneer Plants could be in operation by 2015-2020. This would provide sufficient operating experience to begin to add CCS capacity on a routine basis by 2025 (i.e., initial Early Adopter plants begin construction around 2020 as depicted by the vertical red arrows in Figure 4.1). There is some consensus within the industrial community that approximately 60 GW of cumulative capacity in the Pioneer Plant and Early Adopter phases is necessary to bring the cost of the technology down to acceptable commercial-scale levels.

- Capacity Addition. Once the Early Adopters begin operation, the 2009 NCC report assumes that the pace of CCS capacity additions would increase up to a maximum annual build rate (e.g., 10 GW/year). For comparison, in the 1970s and 1980s, the United States added an average of approximately 11 GW/yr of coal-based power plant capacity, with a maximum of 15.4 GW in any one year (EIA, Annual Electric Generator Report, 2009). Some of the CCS additions will be retrofits, which are limited in the model by a maximum net retrofit capacity (e.g., 90 GW). It is expected that costs will continue to decline with experience, and that advanced "second generation" technologies with lower capital cost and lower levelized cost of electricity, and potentially lower heat rate and higher CO_2 capture percentage may become available in later years.

As discussed in detail in the 2009 NCC report, these assumptions result in a cumulative capacity calculation as depicted in Figure 4.2 for retrofit and new applications for saline, EOR and enhanced coal bed methane storage. This includes Pioneer Plant projects, which were assumed to continue in operation as commercial facilities.

Figure 4.2: Cumulative CCS Capacity Over Time (NCC, 2009)

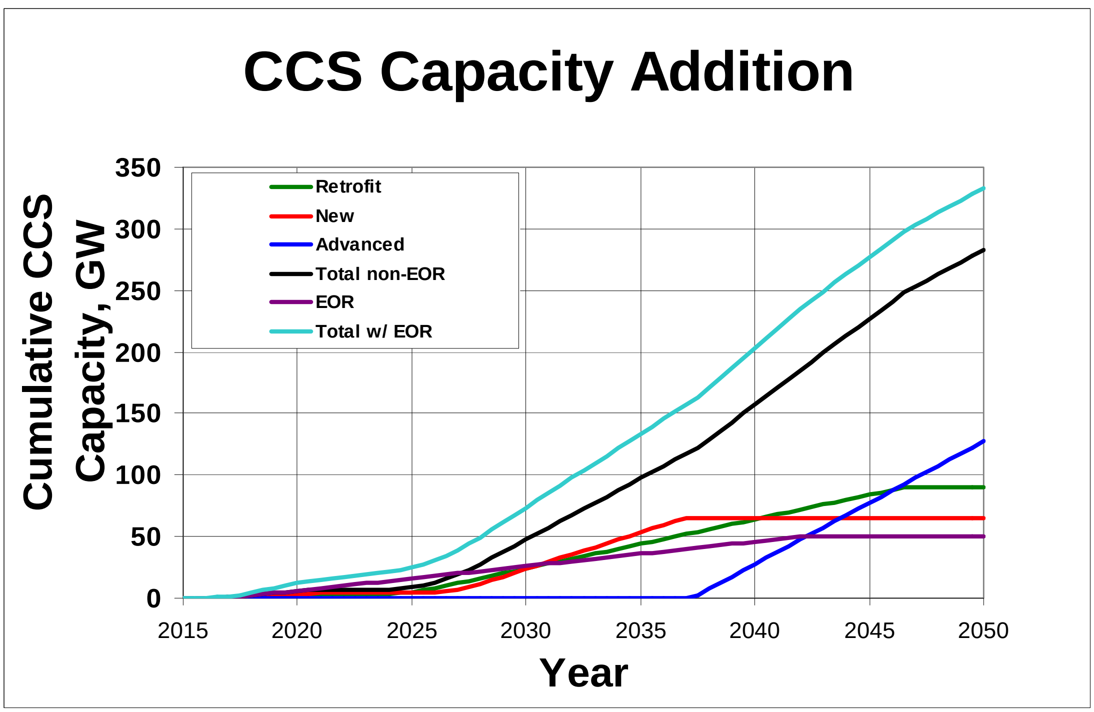


Figure 4.2 shows greenfield and retrofit capacity in the Pioneer Plant and Early Adopter phases, and plots EOR capacity separately. The results suggested that with an immediate start to

the Pioneer Plant phase, 60 GW of Pioneer and Early Adopter CCS capacity could be in operation by around 2030, and that the existing coal-based capacity in the United States of approximately 300 GW could be replaced by 2050. However, it is important to note that the model attempts to define a maximum rate of CCS capacity addition over time, based on the timing of the Pioneer Plant phase and subsequent annual capacity addition limits. This supposes that policies exist to fund the Pioneer Plant phase and that sufficient financial incentives are available for the Early Adopters. Although some programs are currently in place, such as FutureGen and the CCPI programs, that are conceptually aligned with the Pioneer Plant phase, a key question remains as to whether these programs are funded at the level it would take to build 5-7 GW of CCS-equivalent capacity in a timely manner.

For simplicity, the analysis in the 2009 NCC report did not explicitly take account of factors like financing, regulatory, permitting, legal, liability, land use, and infrastructure development, all of which must be resolved to allow for the kind of rapid expansion of CCS capacity modeled in the Early Adopter and later stages. All of these factors are influenced by a number of variables, which have the potential to add significant technical, financial, regulatory, and schedule considerations that may impact the timing and viability of an individual project. In effect, the analysis assumes that these factors are dealt with in a timely manner so as to not impede the ability to reach and sustain a maximum annual CCS build rate.

4.5 CCS Development – 2010 Interagency Task Force on CCS Report

In August 2010, the Administration released the "Report of the Interagency Task Force on Carbon Capture and Storage" written at the request of President Obama. The goal of the task force:

> "was to develop a comprehensive and coordinated Federal strategy to speed the commercial development and deployment of carbon capture and storage technologies in line with the Administration's goals for climate protection. The Task Force, co-chaired by the Department of Energy and the Environmental Protection Agency, was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016." (Interagency, 2010)

To a large extent, the Interagency report echoes the conclusions reached in the 2009 NCC deployment timeline analysis that CCS must be demonstrated on an initial suite of large-scale installations (the Pioneer Plants) before there will be sufficient confidence in its performance and cost to justify wide-spread deployment. Specifically the Interagency report found that:

> "large-scale demonstrations of CO_2 capture technologies are very important for encouraging the successful commercial deployment of CCS… While industrial CO_2 separation processes have been commercially available for some time, they have not been deployed at the scale required for large power plant applications. The CO_2 capture capacities for current industrial processes are typically an order of magnitude smaller than the capacity required for a typical power plant.
>
> A concern regarding CO_2 capture technologies is whether they will safely and reliably work when applied to coal-based power generation. Based on previous experience of CO_2 capture technologies in industrial applications, it would appear that these systems should be effective at larger scale in power generation applications. However, until these systems are constructed and successfully demonstrated at full scale, uncertainty over the technology's performance and cost yield a substantial risk premium for early projects.
>
> Primarily as a result of technical risk, there are also economic and financial risks associated with application of CO_2 capture technologies to coal-based power generation. Acquiring adequate financing for early adoption of CO_2 capture systems could be difficult until there is a positive track record of cost and performance."

The Interagency report does not present a commercial CCS deployment timeline, but notes that:

> "existing Federal programs are being used to deploy at least five to ten large-scale integrated CCS projects. These projects, expected to be online by 2016, are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities."

These existing projects are discussed in more detail in Chapters 2 and 3. With regard to subsequent commercial CCS deployment, the Interagency report provides a detailed discussion of various technical, legal and financial hurdles and makes recommendations for climate change policy. However, it does not provide a plan for any CCS installations beyond the "five to ten" projects cited, or roughly through the Pioneer Plant phase, as described in the 2009 NCC report. Indeed, one of the report's key recommendations is that:

> "DOE should determine if early projects will sufficiently demonstrate an adequate breadth of capture technologies and classes of storage reservoirs to enable widespread cost-effective CCS deployment. This assessment will allow the Administration to target any remaining technology gaps in a manner consistent with addressing market failures."

4.6 CCS Development – 2009 National Research Council Report: "America's Energy Future: Technology and Transformation"

In December 2009, the National Research Council released a study titled "America's Energy Future: Technology and Transformation." The purpose of the study was to assess "the status of energy-supply and end-use technologies in the United States, both at present and over the next two to three decades. It is intended to inform the development of wise energy policies by our nation's decision makers and to provide the technical underpinnings for more detailed explorations of key energy-policy options…" The Committee on America's Energy Future (AEF) that conducted the study and wrote the report notably included Dr. Steven Chu, who later resigned from the panel to become Secretary of Energy, and Dr. James Markowsky, who subsequently became DOE's Assistant Secretary for Fossil Energy.

The report discusses the technical and economic aspects of coal-based electricity generation with CCS and presents a timeline for commercialization "based on the assumptions that advanced coal technologies with CCS technologies are developed successfully and deployed at a rate that the committee judges to be 'aggressive but achievable'- that is, in line with maximum historical deployment rates" (National Research Council, 2009). The essential elements and timing of this AEF timeline are similar to the phases of CCS deployment presented in the 2009 NCC report. Specifically, the AEF Committee presents:

- A demonstration period (equivalent to the Pioneer Plant phase described in the 2009 NCC report) which lasts until 2020. The goal is to gain confidence in "various" capture and storage technologies and to develop state and federal regulations for underground CO_2 storage. By 2020, about 10 GW of coal power with CCS would be operating, mainly as demonstration plants.

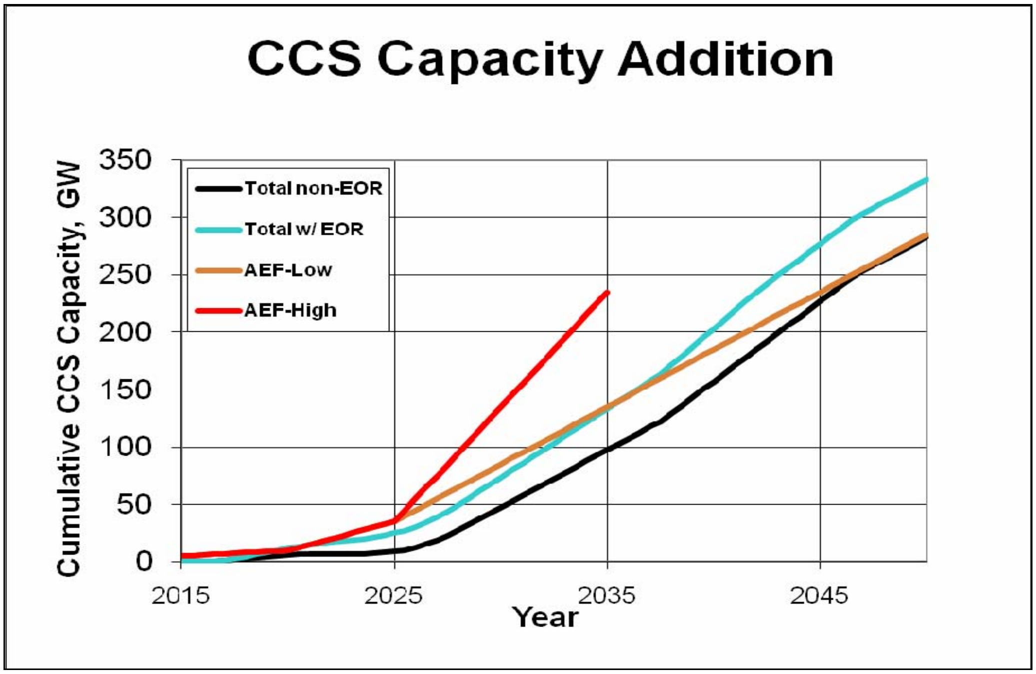
- The second period described in the AEF report corresponds to the Early Adopter phase of the 2009 NCC report. According to the AEF report, from 2020 and 2025 about 5 GW of new capacity could begin operating per year, and, from 2025 to 2035, an installation rate of 10 and 20 GW/yr "seems aggressive but achievable." According to the AEF report, "In 2035, the amount of coal power with CCS would reach either 135 GW or nearly twice that value - 235 GW."

- In the third period, corresponding to the Capacity Addition phase of the NCC study, the same rate of construction (i.e., 10-20 GW/yr) of new coal plants with CCS "might continue from 2035 to 2050."

Figure 4.3 compares the overall CCS capacity addition rates presented in Figure 4.1 above from the 2009 NCC report with CCS addition rates of the AEF report. The "Low" and

"High" scenarios correspond to CCS addition rates of 10 GW/yr and 20 GW/yr respectively in the period following 2025.

Figure 4.3: Comparison of 2009 NCC Report and AEF CCS Development Timelines
(NCC, 2009 and National Research Council, 2009)



The overall CCS addition rate through 2050 in the "AEF-Low" scenario is similar to the 2009 NCC analysis, although it is significantly more aggressive in the early years, particularly between 2020 and 2025. The difference results from an assumption in the NCC analysis that potential owners would not decide to begin construction on a commercial "Early Adopter" CCS facility until the Pioneer Plants and associated CO_2 storage facilities (i.e., the AEF demonstration plants) have been operated for several years (until about 2020). Given the time needed for construction, this extends the startup of the first Early Adopter facilities to about 2025.

The "AEF-High" scenario assumes that 20 GW of new CCS capacity is added annually starting in 2025. Several factors argue against such a high construction rate. First, this is much more than the historic addition rate of coal-based generating units, even during the high growth period of the 1968 to 1985, when 10.9 GW/yr of new capacity was came on line. Second, the high-growth period of the 1970s and early 1980s was preceded by 15 years in which an average of 5.0 GW/yr of coal-fueled plants was added, thus allowing the industrial construction capacity to grow (EIA, 2009). Third, the plants built during this period were much simpler than current coal-based generating facilities, even without the added complexity of CO_2 transportation and storage. Fourth, based on recent trends, permitting of any new coal-based generation plant, regardless of combustion technology or emission control equipment, is significantly more complicated because of regulatory requirements and public interest. As a result, it will be challenging for *any* new coal-based generation project to receive the regulatory and permitting approvals necessary for timely development. These permitting challenges are more pronounced considering the approvals necessary for a large rate of capacity addition of new coal-based generation. As the both the 2009 NCC and AEF reports note, these are not predictions, but analyses of potential maximum rates of CCS adoption. They assume that the necessary public policy, legal and regulatory mechanisms are in place to support build rates of this magnitude.

4.7 CCS Development 2010 NETL CCS RD&D Roadmap

In December 2010, NETL issued a report regarding its CCS RD&D roadmap. The NETL report does not concern deployment per se, but outlines an RD&D strategy to develop advanced technologies that NETL believes will be necessary for widespread CCS deployment. Noting in the introduction that "one of President Obama's objectives is to reduce United States GHG emissions to 20 percent below 1990 levels by 2020," NETL says that the "DOE envisions having an advanced CCS technology portfolio ready by 2020 for large-scale demonstration that provides for the safe, cost-effective carbon management that will meet our Nation's goals for reducing GHG emissions." In Chapter 1, NETL states that its program corresponds to an "overall timeline for the RD&D effort, which involves pursuing advanced CCS technology from the fundamental/applied stage through pilot-scale so that full-scale demonstrations can begin by 2020. The RD&D effort will produce the data and knowledge needed to establish the technology base, reduce implementation risks by industry, and enable broader commercial deployment of CCS to begin by 2030."

There might appear to be a discrepancy between the NETL roadmap report, which calls for large scale demonstrations to begin by 2020, and the Interagency report, which relies on the set of ten existing projects (discussed in Chapter 3 of this report) that it expects to begin by 2016. However, the ten existing projects will demonstrate what NETL refers to as "current" CCS technology, while the focus of the NETL program is on developing more cost-effective second generation technology. The 2010 NETL roadmap report notes that:

> "There are commercially-available CO_2 capture technologies that are being used in various industrial applications. However, at their current state of development these technologies are not ready for widespread deployment on coal-based power plants. The three primary reasons for this are: (1) they have not been demonstrated at a large enough scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support CO_2 capture would significantly decrease power generating capacity; and (3) if successfully scaled-up, they would not be cost effective at their current level of process development."

> "Near-term efforts focus on two parallel RD&D paths. The first path is to demonstrate (i.e., learn-by-doing) that the scale-up of first generation CO_2 capture technologies is achievable so that commercial deployment can begin by 2020. This effort is currently underway through the CCPI and ICCS demonstrations. The second path is to continue development of advanced second and third generation CO_2 capture technologies that can significantly decrease the parasitic loads and improve the cost-effectiveness of CCS and be ready for full-scale demonstration by 2020 and enable commercial deployment by 2030."

This underscores a fundamental problem of near-term deployment of CCS to achieve President Obama's goal as stated in the NETL report of a 20% reduction in GHG emissions by 2020 (note that the United States commitment to 2020 is now memorialized in the Copenhagen Accord). In NETL's analysis, the five to ten near-term CCS projects currently at various stages of implementation are not expected to demonstrate technology that is sufficiently cost-effective to support broad commercial deployment. Therefore, the NETL RD&D program focus is on a second generation of technology that could be demonstrated beginning in 2020, and commercialized by 2030. The 2009 NCC report also assumes a second generation of CCS technology that could begin to be deployed around 2030. However, the 2009 NCC report assumed that approximately 60 GW of cumulative CCS capacity can and should be added prior to that as part of the Pioneer Plant and Early Adopter phases. The 2009 NCC report assumed that extensive practical experience in the construction and operation of these early CCS facilities, along with research and development advances of the kind envisioned by the DOE will be necessary for widespread deployment.

4.8 Critical Assessment of the Adequacy of the DOE CCS Development Program

As concluded by the 2009 NCC report, the 2010 Interagency report on CCS and the 2009 National Research Council America's Energy Future: Technology and Transformation report, five to ten large-scale integrated CCS projects will need to be underway by 2015 for the technology to be commercial ready by 2020. In this context, large-scale is considered greater than 1 million tonnes per year of CO_2. The current DOE research, development and demonstration program for CCS is the most robust and ambitious in the world for advancing the technology. This program is comprised of several elements, including the CCPI, the Industrial CCS program (ICCS), the FutureGen 2.0 project, and the RCSP. These programs have announced support for ten major integrated CCS demonstration projects, which are summarized below in Table 4.1. Other DOE efforts to support CCS development include financial incentives through tax credit and loan guarantee programs. The following evaluates the adequacy of these programs in collectively achieving the advancements needed for CCS technology on coal-based generation to be commercially ready in the near-term.

Table 4.1: DOE's Major CCS Demonstration Projects
(NETL – Coal and Power Systems Major Demonstrations Website, 2010)

Program	Project	Description	Total Cost	DOE Share	Storage Type	Project Size CO_2 tonnes/ yr
CCPI Round II	Mississippi Power – Kemper Co. IGCC	Transport gasifier, Selexol, 60% capture	$2.98B	$270MM	EOR	3.0 million
CCPI Round III	HECA IGCC	GE gasifier, Rectisol capture	$2.8B	$408MM	EOR	2.0 million
CCPI Round III	Basin Electric*	Retrofit HTC Purenergy capture*	$287MM	$100MM	EOR	1.0 million
CCPI Round III	Summit Power – Texas Clean Energy Project	Siemens gasifier, Selexol capture	$1.7B	$450MM	EOR	3.0 million
CCPI Round III	AEP Mountaineer Project	Retrofit Alstom chilled ammonia, 235 MW slip stream	$668MM	$334MM	Saline formation	1.5 million
CCPI Round III	NRG	Retrofit Fluor Econamine FG Plus capture, 60 MW slip stream	$334MM	$167MM	EOR	0.4 million
Industrial CCS	ADM	Retrofit ethanol plant, Dow Alstom amine capture	$208MM	$141MM	Saline formation	1 million
Industrial CCS	Air Products	Retrofit steam methane reformer, vacuum pressure-swing absorption capture	$431MM	$284MM	EOR	1 million
Industrial CCS	Leucadia	New petcoke to methanol plant, Rectisol capture	$436MM	$261MM	EOR	4.5 million
FutureGen	FutureGen 2.0	200 MWe B&W oxy-combustion	To be Determined	$1.048B	Saline Formation	1.0 million
*Project was tabled indefinitely by Basin Electric Power Cooperative in December 2010.						

Key to assessing the adequacy of the projects in Table 4.1 is a consideration of the size of the projects, diversity of capture and storage processes, and development challenges based on the recent experiences of other demonstration programs. With respect to size, nine of the ten are considered to be large-scale demonstrations (defined here as $\geq$ 1 million tonnes per year of CO_2). These projects represent a diversity of capture processes, but only three are non-EOR CCS projects, an area in particular where more demonstration projects are in demand. Of the nine projects large-scale, how many will go to completion or to the point of beginning injection during the decade? The prospect of success for the FutureGen 2.0 project is unique among these projects because it has a very high level (80%) of federal funding. Many of the remaining eight large-scale sequestration projects listed in Table 4.2 will not be completed, if past experience is an indicator. As shown in Table 3, Rounds I and II of the CCPI were focused on improvement in efficiency, abatement of conventional emissions, and development of IGCC technology. These are areas that could bring immediate economic benefit to the host generating plant. Of the twelve projects selected, six were terminated prior to contract signing; three made it to completion, and three remain active (but one of the "active" projects has been stalled). This is a "batting average" of no more than 50% for projects focused on technologies that can have an immediate economic benefit to the host generating facility. Round III was focused on CCS and it maintained the requirement of 50% or greater private cost share. Any near-term economic benefit to the host is uncertain for a retrofit-CCS project, unless the CO_2 produced is used for EOR purposes. EOR-CCS projects are very complex and difficult to finance; these factors contributed to Basin Electric Power Cooperative's announcement in December 2010, more than five years after selection for award, that it was tabling its project indefinitely. The Mississippi Power Company Kemper County project, which includes EOR and partial CO_2, capture, has received both a CCPI Round II award and Federal loan guarantee, but is not scheduled to come on line until 2014. This is more than nine years after initial selection for award of the Orlando Gasification project, which was later cancelled and whose funding was transferred to the Mississippi Power project. (NETL – Coal and Power Systems Major Demonstrations Website, 2010) Further, even with significant economic support from DOE, large-scale CCS projects face a number of development challenges. For example, the DOE has awarded $2.58 billion in loan guarantees and $417 million in tax incentives to the Tenaska Taylorville coal-to-SNG and co-production power project, which is being designed with CCS technology; but despite these incentives, the Illinois State Senate voted in January 2011 against cost-recovery for the project, and the future of the project is uncertain (Tenaska, 2011).

Table 4.2: Fate of Projects Selected for Clean Coal Power Initiative Awards
(NETL – Coal and Power Systems Major Demonstrations Website, 2010)

Round I, focused on improvements in efficiency and environmental performance. Eight projects selected; five withdrawn, discontinued, or negotiations ceased; three complete (Neuco, Toxecon, Great River Energy).
Round II, focused on IGCC and advanced flue gas clean-up. Four projects selected; one withdrawn; three active (Mississippi Power, Mesaba, Pegasus). (It is noteworthy that the Mississippi Power Company project includes partial capture of CO_2 and sequestration via EOR. It is also noteworthy that the "active" Mesaba project appears to be stalled.)
Round III, focused on CCS. Round IIIa. Two projects selected; one recently tabled indefinitely (Basin Electric); one active (Hydrogen Energy California). Both are EOR. Round IIIb. Three projects originally selected; one withdrawn; two originally selected projects active (Summit EOR, American Electric Power – saline formation). One project selected to replace the one withdrawn is active (NRG – EOR).

Thus, by 2015, the maximum number of large-scale non-EOR geologic CO_2 sequestration projects that will be underway in the United States will be three, and then, only if all three projects proceed in a timely manner. On the basis of the past experience with the DOE's large-scale demonstration programs, it is likely that no more than four of the CCPI and ICCS projects will proceed to completion, and those could easily take five or more years to get started. Therefore, if "commercial readiness" of CCS technology for coal-based generation means to be available by 2020, then the success rate of active projects must improve and the quantity and diversity of large-scale demonstration projects must be expanded and the program must be accelerated in the near time. The DOE is in the best position to lead this effort.

The nine Phase III regional carbon sequestration projects under the RCSP are listed in Table 4.3. In the 2009 NCC report, the proposed CCS deployment timeline depended on an immediate start to these and perhaps other large-scale sequestration-only projects to gain longer-term experience with CO_2 storage and monitoring than will be available from the integrated projects which, as discussed above, will not begin operations until mid-decade at best. However, costs and the limited availability of DOE funding have combined to force most of these regional projects to be EOR and to be smaller than 1 million metric tonnes of CO_2 per year. In fact, only two of the nine regional projects are at a scale of 1 million metric tonnes per year or more and are non-EOR. Of those, one is not in the United States (it is located in northern Canada) and involves the injection of CO_2 containing 15% or more hydrogen sulfide. The other (Cranfield) involves the injection of CO_2 into the water ring of an oil- and gas-containing dome structure that has been pressure-depleted by past production of hydrocarbons. Although this project is not technically EOR, it is very similar in that the reservoir for injected CO_2 has been created by the displacement of hydrocarbons. The bottom line is that the current regional project portfolio contains one large non-EOR project that will inject mixed acid gases in northern Canada, one large project that differs slightly on a geologic structural basis from EOR, and several smaller EOR projects.

Table 4.3: Currently Planned Injection Tests for RCSP Phase III.
(NETL – RCSP Website, 2010)

RCSP	CO_2 Source	CO_2 Injected	Injection Start	Geologic Formation	Storage Type
MGSC	ADM ethanol fermentation plant	1 MMT over 3 years	2011	Mt. Simon sandstone, Illinois Basin, IL	Saline
MRCSP	Natural gas processing plant	1 MMT over 4 years	2011-12	St. Peter/Bass Island sandstone and carbonate, MI	Saline
PCOR	Natural gas processing plant	1 to 2 MMT/y for 20 years	2014	Elk Point Formation carbonate, Alberta Basin, Alta. Canada	Saline - cosequestration
PCOR	Natural gas processing (Bell Creek injection site)	Up to 1MMT/y for 20 years	2012	Cretaceous Muddy sandstone, Bell Creek, MT	EOR
SECARB	Jackson Dome (natural)	1.5 MMT over 1.5 years	4/1/2009	Lower Tuscaloosa, Cranfield, AL	Saline (oil field)
SECARB	So. Co. Plant Barry coal plant	125 kT/y for 3 years	2011	Paluxy Formation sandstone and shale. Lower Tuscaloosa, Citronelle Dome, AL	Saline
Big Sky	Kevin Dome (natural)	250 kT/y over 4 years	2013-16	Duperow dolomite, Williston Basin, MT	Saline
SWP	Triassic Sinbad and Permian White Formations (natural)	Up to 1 MMT over 3 years	2012	Navajo sandstone, Gordon Creek Field, UT	Saline
WESTCARB	Uncertain	Uncertain	Uncertain	Uncertain	Uncertain
**Plans subject to change due to regulatory, liability, or other challenges.					

The United States federal RD&D program on geologic CO_2 sequestration is the most robust and ambitious in the world. Is it sufficient to ensure commercial readiness of geologic CO_2 sequestration by 2020? Based on the results of the efforts to date, the answer is "probably not". The program is strongly focused on EOR, surely driven by costs for non-EOR sequestration and the availability of CO_2. Based on past performance, it is likely that many of the currently identified projects will either never proceed to the injection of large volumes of CO_2, or will go forward much later than originally planned. Bottom line, it appears unlikely that more than two or three projects of the existing suite of identified projects will initiate the injection of 1 million tonnes of CO_2 per year into geologic formations (excluding EOR) by 2020. Therefore, an acceleration and expansion of the quantity and diversity of CO_2 storage projects is needed in the near time if "commercial readiness" of CCS technology for coal-based generation is to be available by 2020. As noted above for large-scale integrated CCS projects, the DOE is in the best position to lead this effort.

4.9 Next Steps

All of the analyses of CCS deployment discussed above are unanimous in the recognizing the need for a variety of large-scale integrated CCS projects as a prerequisite for commercial adoption of the technology. Both the 2009 NCC and 2009 National Research Council reports call for 5-10 GW of equivalent CCS capacity to be in operation for a period of about five years. These projects would need to span a range of configurations to verify the performance and cost of CCS over the expected scope of commercial applications. As the 2009 National Research Council report says:

> "A suite of projects can be designed to clarify the costs, risks, and environmental impacts of carbon storage. This would enable a determination of whether such plants can become significant contributors to the U.S. power system in a carbon constrained world. Successful demonstration will require projects spanning the many types of coal, using several capture strategies, at a variety of storage sites, at both power and synfuel plants, and with storage both in deep saline aquifers and in hydrocarbon-bearing seams."

In its 2009 report, the NCC presented one attempt to populate such a suite of projects. The universe of projects as shown in Table 4.4 would, if distributed over 5-7 GW of equivalent capacity, result in 20-30 projects. The goal was to design a suite of projects to demonstrate a range of capture technologies, utilize coals from all the major United States coal basins, demonstrate both new and retrofit applications, and to include a sufficient number of projects to allow storage in a diversity of geological/geographic settings. The DOE has identified seven regions of the country in its RCSP, so that 20-30 projects would allow for 3-4 in each region. An emphasis on CO_2 storage in saline formations is needed because the presumption is that storage in oil and gas reservoirs (i.e., EOR) is an established technology. Therefore, while EOR projects coupled with carbon capture at industrial facilities is valuable for demonstrating carbon capture technology, it does not enhance our knowledge of CO_2 storage in saline formations, which will be necessary for widespread application of CCS in the United States or elsewhere. The DOE has estimated that EOR has the potential to accommodate as much as 50 GW of equivalent coal capacity for a period of time (DOE, 2008).

Table 4.4: CCS Pioneer Plant Categories
(NCC, 2009)

Capture Location	Technology	Unit size (MW)	Flue Gas Treated (MWe)	% CO_2 Capture of Gas Treated	Fuel[1]	Storage Geology	Technical Risk
Pre comb	New IGCC Oxygen	250 – 600	250- 600	≥75	B/S/PC	Saline	High
Pre-comb	New IGCC Air	250 – 600	250- 600	≥75	S/L	Saline	High
Post-comb	New PC/FBC Scrubber	200 – 600	200 – 300	≥90	Any	Saline	Medium
Post-comb	New PC/FBC Scrubber	200 – 600	200 – 600	≥90[2]	Any	Saline	High Operational
Post-comb	Retrofit PC/FBC Scrubber	400 – 1,300	200 – 400	≥90	Any	Saline	Medium
Post-comb	Retrofit PC/FBC Experimental	200 – 1,000	50	≥ 60	Any	Saline	High Technology
Oxy-comb	New PC/FBC	100 – 150	100 – 150	≥90	Any	Saline	Medium/High Operational Risk
Oxy-comb	New FBC	50 – 100	50 – 100	≥90	Any	Saline	Medium/High Operational Risk
Any				≥90	Any	Oil & Gas	Medium
Note 1: B = Bituminous, S=Subbituminous, L = Lignite, PC = Petroleum Coke							

In summary, the findings and recommendations for CCS development that were presented in the 2009 NCC report remain applicable and have been reinforced through the recent analyses in the Interagency and the National Research Council reports. Although progress has been made to address the recommendations of the 2009 NCC report, a much more ambitious program must be realized in the near-term if the expedited deployment of CCS on coal-based generation is to occur at the rate necessary to meet President Obama's goal of an 83% reduction in GHG's by 2050. As discussed in Section 4.8 of this current report, the group of 10 integrated CCS projects currently under development in the United States (the same 10 as identified by the Interagency report) falls well short of the range and diversity of carbon capture technologies and storage configurations needed to sufficiently advance its development in the near-term. The emphasis of these projects is too heavily on EOR applications, and it is likely that many of them will not be completed (in fact, two have already announced some hesitation). This reinforces the need, as recommended by the Interagency report, that "DOE should determine if early projects will sufficiently demonstrate an adequate breadth of capture technologies and classes of storage reservoirs to enable widespread cost-effective CCS deployment. This assessment will allow the Administration to target any remaining technology gaps in a manner consistent with addressing market failures."

4.10 References

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Chapter 5: Legal and Regulatory Policies

5.1 Key Findings

- While it seems unlikely that federal GHG legislation will be enacted in the near future, the EPA has begun and intends to broaden the regulation of GHG emissions by expanding the applicability of existing Clean Air Act programs.

- The EPA's approach is multifaceted and, at a minimum, will expand consideration of CCS technologies in the development of applicable projects. For example, the EPA has expanded the applicability of the preconstruction PSD and Title V permit programs to GHG. The EPA also issued draft, non-binding guidance regarding whether and how CCS should be evaluated as a BACT, which concludes that while CCS is a "promising technology," the EPA does not believe it will be a technically feasible BACT option in most cases. Additionally, the EPA recently announced its intent to propose NSPS for GHG emission from power plants in July, 2011.

- Some existing regulatory programs, which may currently apply to CCS projects, will add requirements and risk considerations that could affect the design, schedule, cost, and viability of CCS projects. For example, the CERCLA and RCRA create an unnecessary regulatory and/or liability regime for geologic injection and storage.

- A broad scope of permitting and regulatory programs apply to the development each the capture, transportation and geologic storage aspects of a CCS project. The process of performing baseline studies for preparing applications and working through the regulatory process to receive final approvals can range from months to years. This can result in significant cost, design, and schedule impacts, which will challenge efforts to expedite the development and deployment of CCS technology to the coal-based generation fleet.

- Since CCS is likely to play an increasingly important role in environmental regulatory decisions for the foreseeable future, regulatory and legal policy will need to be adapted to facilitate the timely and practical development and deployment of that technology.

- Led by many States and the EPA, an appropriate legal and regulatory framework for CCS is starting to take shape. The States' role in CCS regulation should not be underestimated given their historical success in safely regulating comparable injection and storage activities.

- Many States have adopted comprehensive regulations to address long-term geologic storage issues related to pore-space ownership and liability that should be sufficient to enable the permitting of early mover CCS projects.

- Given the number of pore space owners likely to be encountered when siting a CCS project, any requirement to expand the obligation to acquire pore space beyond constitutional requirements will create a significant development barrier.

- The management of long-term liability risks is critical consideration for CCS projects. In terms of supporting the broad deployment of CCS across the coal-based generation fleet, uncertainty regarding long-term liability options remains a challenge.

- The DOE must continue to play a leading role in supporting policies that regulate CCS in a manner that protects human health and the environment, while enabling worthwhile projects to be financed, developed and operated without unnecessary legal impediments.

5.2 Recommendations

- To align and avoid an overlap of regulatory programs applicable to CCS projects and to accelerate CCS development, the Council recommends that the DOE support exempting appropriately permitted CO_2 injection and long-term storage from CERCLA and RCRA.

- The Council recommends that the DOE support policies that accelerate the permitting and regulatory approval process for deploying CCS technologies to existing and new coal-based generating plants, including policies to reduce barriers within the PSD and other programs that are inadequately designed to regulate CCS projects. This also includes streamlining the NEPA review process for CCS projects.

- The Council recommends that the DOE support policies encouraging the development of permitting programs for CCS facilities that would provide that the issuance of the permit for such a facility expressly grants the permittee the right to inject and sequester CO_2 into those portions of a geologic strata that do not contain coal, or oil and gas or other minerals in commercial quantity and do not have a current or reasonably foreseeable use.

- The Council recommends that the DOE support policies to clarify the requirements that apply to CO_2 injection and storage on Federal lands by, for example, stipulating pore space ownership and amending the FLPMA and the FMLA to explicitly allow long-term CO_2 storage under Federal leases.

- The Council recommends that the DOE support policies that would provide that during the construction and operational phases of a CCS project, the private sector should remain subject to both operational responsibilities and liabilities imposed by otherwise applicable law, except that such legislation should limit liability for trespass where the facility is subject to a valid permit applicable to that geologic sequestration.

- The Council recommends that the DOE support policies that would provide that during the post-closure phase of a CCS project, and after regulations have determined that the project meets applicable reporting requirements and poses no threat to human health or the environment, liability should be transferred away from the private sector. Various alternative methods for accomplishing this transfer have been offered at both the Federal and state level.

5.3 Regulation of CCS Facilities

CCS facilities are being developed to help meet the goals of reducing GHG emissions. While CCS is currently not a mandatory practice, the EPA is working quickly to regulate GHG emissions and CCS may soon be a requirement, or at least a feasible option. For example, in 2010, the EPA indicated in its draft PSD guidance for GHG emissions that CCS was an "available" technology. Further, the EPA announced in 2010 its intent to propose in July 2011 NSPS to control GHG emissions from power plants.

As common with many new technologies, the development, deployment and use of CCS will be regulated through a host of regulatory programs, many of which remain largely under development. The following highlights challenges and opportunities within some of these regulatory programs.

a. Regulation of CO_2 Capture Process

In general, the timeline for obtaining all required permits from application preparation to receipt of final permits has the potential to range from months to years depending on the complexity of the project, public input, and agency resources. To the extent federal or state agency approvals are needed to support project funding, these aspects would also add scope and time to the CCS development process. Examples include the NEPA process for federally supported projects, and the rate recovery process for projects regulated by state utility commissions. In general, obtaining approval for either funding mechanism could require at least one to two years. It is important to note that the Obama Administration, in its Interagency Task Force report, committed to work to consolidate and simplify the permitting process for CCS projects.

Another consideration is whether a proposed CO_2 capture technology would require significant modifications to an existing energy source that might involve changes to the combustion and/or steam systems. Such activities may trigger the applicability of the New Source Review/PSD air permitting program, which would add significant complexity and time to the permitting process for a proposed CCS project. Effective January 2, 2011 under the PSD program, any proposed project that is classified by regulation as a major new source or major modification to an existing source will be required to perform a BACT analysis for controlling GHG. Other than extending the permitting schedule, it is unclear if or how the requirement to perform a GHG BACT analysis would impact the design, feasibility, performance expectation, or technology selection for a CCS project. In late 2010, the EPA issued draft, non-binding guidance on GHG permitting under the PSD program, which indicated that CCS should be considered as an "available" technology in Step 1 of the standard BACT analysis process. The EPA cautioned that CCS would likely be eliminated as a control technology later in the BACT process due to grounds such as commercial availability and economic factors.

The deployment of CCS technology on new and existing coal-based generation could face a number of new or unique permit considerations that could significantly extend the approval timeline. For example, the EPA regulations currently require continuous emission monitoring systems on coal-based generation units for quantifying emissions and demonstrating compliance with certain limits. CO_2 is one of the parameters monitored and is used to derive an overall heat input value for the unit. This heat input value is needed to demonstrate compliance with other emission limits designed as pounds (emissions) per amount of heat input (million British Thermal Units – mmBtu). Updates to the current emissions monitoring process and regulatory guidelines are needed to account for the removal of CO_2 by the capture process and to provide regulatory consistency across permitting jurisdictions.

b. Regulation of CO_2 Injection

On December 10, 2010, the EPA issued the final injection well regulations under the Safe Drinking Water Act's (SDWA) UIC program that would apply to CO_2 geological sequestration wells. The rule is designed to primarily protect underground sources of drinking water (USDW). The SDWA mandates that each state must have an UIC program.[1] The final rule established a new UIC well class - Class VI - for wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage. The final rule also specifies that geologic sequestration could occur via a UIC Class II well, which is currently used for EOR purposes, if certain circumstances are met. The final rule sets minimum technical criteria for the permitting, geologic site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure of Class VI wells for the purposes of protecting underground sources of drinking water USDWs. Significantly, the SDWA was enacted to protect public health through regulations designed to protect USDWs.[2] The SDWA does not grant authority to EPA to regulate other potential legal impediments to CCS such as pore space rights and long-term liability.

To complement the UIC Class VI program, EPA issued the Final Mandatory Reporting of Greenhouse Gases from Carbon Dioxide Injection and Geologic Sequestration Rule in November 2010. Subpart RR of this rule requires CCS facilities to report GHG data annually. This rule requires CCS facilities to develop and implement a site-specific monitoring, reporting and verification plan, and to report the amount of carbon dioxide sequestered using a mass balance approach.[3] Compliance with this rule will allow geologic sequestration operators to provide proof of sequestration, eliminating yet another a barrier to CCS.

c. Regulation of Wastes and Hazardous Substances in the CO_2 Injectate

While CO_2 itself is not hazardous, there is uncertainty about the nature of constituents and by-products of CO_2 streams. For example, for purposes of the Class VI well rule discussed above, the EPA has defined "CO_2 stream" as "CO_2 that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from source materials and the capture process, and any substances added to the stream to enable or improve the injection process."[4] This definition recognizes that a "CO_2 stream" is not likely to consist of 100% CO_2.

According to the EPA, CO_2 is not a hazardous substance under CERCLA.[5] Thus, geologic sequestration of CO_2, in and of itself, should not give rise to CERCLA liability. Absent additional clarification of CERCLA, sequestration of CO_2 could give rise to CERCLA liability if the CO_2 stream contained constituents that are CERCLA hazardous substances from the source materials or the capture process or if the CO_2 stream reacted with groundwater to produce a CERCLA hazardous substance. CERCLA contains an exemption for federally permitted releases that could, in theory, affect release reporting and cleanup liability, but application of that exemption in the CCS context is unclear.

Similarly, the EPA has not listed any CO_2 streams as a "listed" hazardous waste under the RCRA. Thus, for RCRA hazardous waste jurisdiction to apply to a CO_2 stream, it would have to be "characteristically" hazardous – *i.e.*, meet one or more objective criteria set out at 40 C.F.R. §§ 261.20-261.24 for toxicity, corrosivity (*i.e.*, pH), ignitability, reactivity. The EPA has stated, however, that if the CO_2 stream meets one or more of these objective criteria, the stream itself would be deemed hazardous and regulated as such under RCRA. The EPA has also stated that it intends to propose in 2011 a conditional exemption from RCRA for certain CO_2 streams when injected into the subsurface for purposes of sequestration.

Accordingly, consideration should be given to changing both the RCRA and CERCLA programs to exempt appropriately permitted injection and long-term storage activities from coverage under those laws.

d. Regulation of Storage

Consistent with the recommendations of the model CCS rules of the Interstate Oil & Gas Compact Commission (IOGCC), a growing number of states have enacted laws that separately govern the act of storage itself. These laws generally have the following aspects: (1) requirement that the owner or operator of the prospective storage site obtain a storage permit, issuance of which is dependent upon a plethora of factors, including detailed geologic studies of the prospective site, demonstration of access to pore space rights, assessment of a variety of relevant environmental end points, public communications, and compliance with all applicable environmental laws; (2) monitoring and reporting to relevant state authorities while operations are continuing; (3) monitoring and reporting for a period of time (typically ten years) after injections have ceased; (4) issuance by the state of a certificate of completion thereafter, if the site meets relevant regulatory standards; and (5) some form of stewardship program following issuance of the certificate of completion – typically a industry-funded trust fund. These actions, and others like them, offer some of the best examples of actions being taken to address obstacles to the development of CCS projects. These requirements supplement, but do not supplant the UIC Class VI requirements discussed above.

e. Regulation of CO_2 Transportation

Once CO_2 has been captured there are several ways to transport it. These CO_2 transportation methods include: pipelines, tanker or railway car, ship and truck. This discussion will focus on the barriers and opportunities that apply to the use of pipelines for CO_2 transportation because currently pipelines are perceived to be among the most economically viable options for the long-term transportation of bulk CO_2 within the United States.

Siting

Existing United States CO_2 intrastate and interstate pipelines have primarily been constructed for the use of CO_2 in EOR, as discussed in Chapter 3. These pipelines were sited under state law with minimal federal role. This pipeline network has functioned well and experienced incremental growth over the years based upon this regulatory model. Several states have recently enacted new laws to provide additional siting authority of CO_2 pipelines – a trend which is expected to continue. The large-scale build out of CO_2 pipeline infrastructure throughout the United States, as discussed above, might entail the need for federal siting authority for interstate CO_2 pipelines.

Certificate of Need

CO_2 pipeline operators need to consult with the states to determine whether a certificate of need must be obtained. Following the lead of the IOGCC recommendations, several states have already adopted statutes that specify such a requirement for CO_2 pipelines. The federal government is not involved in this process.

Right of Way Acquisition

Acquiring a right of way[6] across public and private property is necessary for the development and construction of CO_2 pipelines. Currently the federal government only regulates right of way acquisition across federal lands. States independently regulate right of way acquisition. Condemnation rights are also state-specific. Some states have enacted regulations that provided condemnation authority to developers of CO_2 pipelines.

Safety

The federal government currently regulates interstate CO_2 pipeline safety. Several states have adopted the federal standards for purposes of the safety regulation of intrastate CO_2 pipelines. Separate and apart from these federal and state regulatory regimes, pipeline operators typically impose their own CO_2 compositional requirements both to maintain pipeline integrity and to meet the needs of specific EOR fields (since the existing CO_2 pipeline network services the EOR industry). The safety record of the existing CO_2 pipeline network is impeccable. At the moment, with the exception of additional state adoption of the federal safety standards, there appears to be little need for additional safety regulation of CO_2 pipelines.

Environmental Permitting

Like the development of any pipeline project, several environmental permits are required to develop CO_2 pipelines, including those dealing with protection of surface and ground waters, soil, cultural resources, biological resources, and others. Permitting of both interstate and intrastate pipelines generally is well understood and will not be repeated here. There are no special environmental permits that are specifically required for CO_2 pipelines, and it is important to realize that CO_2 is relatively innocuous compared to the other materials that are currently transported throughout the United States by pipeline (oil and natural gas, for example, both of which are flammable). However, given the large-scale build out of CO_2 pipelines that is expected to accompany the development of CCS (see Chapter 3 above), it is anticipated that the magnitude of related siting and construction could result in significant project costs and schedule delays.

5.4 Pore Space

a. Introduction to Pore Space Ownership and Acquisition

Geologic sequestration has the potential to affect subsurface private property rights to the extent that CO_2 is injected into the pore space of a geologic formation that is or may be used for another purpose. Pores exist in all geologic formations, including deep saline formations and those used for EOR. For Federal lands, legislation was introduced in the 111th Congress that again would have codified the default rule – namely, that the Federal government, which is the owner of the surface estate, also owns the pore space. In the United States, where private property rights are rooted in the common law and federal and state constitutions, pore space ownership is a state-specific matter. Significant activity is occurring around the country in the development of property issues related to CCS projects. Among these initiatives are the following:

Louisiana

In 2009, the Louisiana Legislature passed new CCS legislation. This bill authorizes expropriation by the state or certain corporations engaged in CCS for a storage facility and for pipelines for transportation.[7]

Montana

The Montana legislature passed CCS legislation in 2009, which established a CCS regulatory framework and addressed pore space ownership.[8] Unless otherwise documented, the surface owner owns the pore space for geologic carbon sequestration. The bill also protects the existing rights of mineral owners and does not change common law regarding surface and mineral rights.

North Dakota

In 2009, Senate Bills 2139 (pore space and property issues) and 2095 (CO_2 storage operational issues) were enacted into law. This legislation creates a legal and regulatory framework for CCS, while addressing pore space and property issues relevant to CCS, including placing title to pore space in all strata underlying the surface with the owner of the overlying surface estate. If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the state may require that the pore space owned by non-consenting owners be included in a storage facility and subject to geologic storage. This is accomplished through the amalgamating provision, which is similar to unitization, requiring the consent of 60% of the property owners.[9]

Wyoming

In 2009, Wyoming passed three bills to address ownership and liability issues related to geological storage of CO_2. H.B. 57 clarifies that mining and drilling rights will be prioritized over geologic sequestration activities.[10] H.B. 58 provides that the injector holds the title and liability for sequestered CO_2 and all other materials injected during the sequestration process.[11] H.B. 80 establishes a procedure for unitizing geologic sequestration sites, whereby pore space rights from multiple parties would be aggregated for the purposes of a carbon storage project as long as 80 percent of the parties approve the project. This suite of bills complements that which was passed in 2008.[12] H.B. 89 specified ownership of pore space.[13] The 2008 legislation declared that the ownership of all pore space in all strata below the surface lands and waters of the state is declared to be vested in the owners of the surface above the strata. H.B. 90 established an operational regulatory program.[14]

Kansas

In 2007, Kansas established the authority to develop rules for CCS facilities. Proposed administrative regulations issued in March 2009 address operational requirements for an environmental permitting program. Among those requirements is that the applicant must hold necessary property and mineral rights and own financial instruments that demonstrate financial responsibility. Kansas law does not define who owns pore space.[15]

IOGCC

In 2007, the IOGCC issued its model program for the storage of CO_2 in geologic formations. With respect to property rights, the IOGCC model program provides that an applicant should acquire the property rights to use pore space in the geologic formation for storage.[16] While much of the IOGCC's program addresses the need to acquire property rights through negotiation or eminent domain, the model program specifically notes that the IOGCC is less concerned about what mechanism is used to acquire those rights and is more concerned that all necessary property rights be acquired by valid, subsisting and applicable state law.

b. Pore Space Acquisition Options

Because the plume from a single large-scale CCS project can be expected to migrate a significant distance underground, there is a potential for a large number of property owners to be involved. While much attention has thus far been given to who holds the ownership rights to the pore space in the United States, much less attention has been given to whether the intended use of pore space for CO_2 sequestration, particularly in deeper formations, would necessitate the need to acquire pore space rights. Under existing law, the cost of acquiring the right to use the pore space presents a significant barrier to the development of commercial scale CCS. In order to understand how pore space acquisition is being handled around the country, it is necessary to review some of the more significant state level activities addressing the property rights related to CCS. The discussion will then turn to the six possible options that have been identified for addressing property. The discussion will also include an analysis with respect to the law related to the circumstances under which the U.S. Constitution requires that a property owner be compensated for the use of property. The DOE can be helpful in addressing this barrier by beginning the process of communicating the challenges that a general property acquisition requirement presents and by offering alternatives to such a requirement.

Based upon a survey of proposals by other states and organizations, six alternatives have been identified related to the nature and extent of the obligation of an operator of a facility engaged in the geologic sequestration of CO_2 to acquire the property rights for that purpose. Those six alternatives are as follows:

<u>Option 1. Existing Law</u>

In absence of new legislation to address the ownership and acquisition of property rights, a CCS operator and regulatory agencies would be left to resolve property rights issues under existing law. While this approach necessarily assumes that new legislation is not undertaken, many existing laws do not address what property rights are necessary to sequester CO_2. In addition, current law in most states requires a title search of existing property instruments to determine property ownership, which can be time-consuming and expensive. In the likely event that all the necessary property cannot be acquired through negotiation, a condemnation action or forced unitization must be commenced. In many jurisdictions, eminent domain is not currently authorized for any party other than utilities already having the power of eminent domain. Where eminent domain is approved, compensation to land owners is likely to be variable.

Option 2. Streamline Existing Law

Streamline existing law by including some or all of the following suggestions: (1) allow the use of tax records (updated to include transactions occurring in the past year) or other alternative methods to identify pore space ownership; (2) use Administrative Law Judge's (or create a specific special master) as a first step in setting compensation; (3) expand the scope of existing eminent domain authority; (4) allow companies (in addition to existing utilities) the right to acquire the property rights and operate such facilities; (5) clarify who owns pore space under various scenarios; and (6) protect operators from common law claims (*e.g.* trespass) where CO_2 moves onto property not yet acquired. While streamlining existing law is likely to require legislative action, and compensation for all property owners, simplification of the title search would provide some structure for controlling compensation. This approach would not change existing ownership of pore space, but rather would create a presumption of ownership in certain circumstances and allow that presumption to be rebutted, thereby protecting the rights of the owners. Neither does this approach address the "windfall" value that may be created for the use of pore space for CO_2 sequestration.

Option 3. Public Use

The Midwest Governors Association (MGA) has proposed that a state either unitize pore space or declare the subsurface below 2,500 feet not associated with hydrocarbon development to be accessible for public use. A fixed fee per acre will be provided for the use of the pore space. Eminent domain would be authorized.[17] This option has not yet been enacted into law by any state. Such an approach if undertaken would eliminate much of the uncertainty associated with determining the identity of the owner of the pore space and would simplify compensation since it would be set at a nominal amount. A principal concern about such an approach is the uncertainty that is created to the extent that compensation is set below "fair market value." The issue of whether a legislative declaration of pore space below 2,500 feet constitutes a taking, which would trigger payment of just compensation, has not yet been tested. Due to variations in geology, the strata available for CO_2 sequestration may dip causing a depth line to pass in and out of a given stratum, potentially complicating the issue. The operator would still be required to bear the burden of determining ownership of pore space and of taking the right to use the pore space, even if sequestration does not materially impair the pore space owner's use.

Option 4. Unitization

Unitization of pore space rights has also been suggested by the MGA and has been enacted into the laws of North Dakota and Wyoming.[18] The concept has not been applied to an actual CCS operation. Unitization would mandate that pore space rights can be used for CCS if a majority of rights are obtained by consent. Compensation for those additional rights is required and must be determined. This approach has the obvious benefit of providing an alternative to the enactment of new laws expanding the powers of eminent domain. States desiring to pursue this approach would need to enact legislation similar to that which has been adopted in North Dakota and Wyoming. In addition, such a program would need to address the fact that historically, unitization has assumed continued payment to the property owner. With CCS, there is no apparent, continual revenue stream or "product" beyond the operational stage of the project. Indeed, the Wyoming program apparently does not address how the affected property owners will be compensated. The price paid for the use of the pore space must be sufficient to entice a majority of the pore space owners to voluntarily relinquish the pore space for this to work effectively. It presumes an arms length/fair transaction between the parties, which may not always be the case.

Option 5. Permit Authorization

The Carnegie Mellon CCSReg Project has offered a comprehensive regulatory framework for geologic sequestration based upon the balancing of the interests of private property owners with the public benefit of geologic sequestration, thereby, reducing the possibility of interference with other productive non- geologic sequestration uses of the subsurface that are also in the public interest.[19] This framework should enable UIC regulators to permit geologic sequestration projects and allocate use of subsurface pore space under an expanded version of the UIC program. Under this framework, regulators would consider the trade-offs between private interests and the public benefit of a proposed geologic sequestration project, determining the safest, most efficient and equitable use of the pore space, including non-geologic sequestration uses. This framework should increase the potential for either avoiding most subsurface property disputes outright, or resolving them at the outset in a stable and predictable environment that is fair and equitable to all affected parties. If such an approach were to be undertaken care would need to be exercised to be certain that an approval by UIC regulators to allow the sequestration of CO_2 in that pore space would not be a *per se* physical taking of property that requires compensation.[20]

Such a process would have the distinct advantage of addressing property issues during the permitting process and minimizing the transaction and other costs associated with requiring that pore space rights be obtained for CO_2 sequestration. If such an approach were to be pursued it would likely need to be joined with the power of eminent domain to address those instances in which a pore space right might need to be taken.

Option 6. Reverse Rule of Capture

Based upon the current application of the UIC program, the Ohio federal district court case involving the underground migration of a hydrocarbon plume, and the experience of the State of Florida with the underground injection of treated municipal wastewater, one option would be to establish a program that does not call for the taking of pore space rights.[21] In Florida, property rights are generally not taken in connection with its extensive treated municipal waste disposal via the UIC program nor are they taken in connection with the underground injection of hazardous waste (however this often occurs on public land or offshore).[22] Under this approach sequestration projects may be able to sequester CO_2 into pore space where they have no surface or mineral ownership interests. While using the reverse rule of capture would eliminate the need to acquire the property rights to pore space, this approach might require characterization of this activity more as waste (and not commodity) management, which may create RCRA implications. Only a minority of states has adopted the reverse rule of capture rule and it is unclear whether states other than Ohio would follow this rule.

c. Pore Space Acquisition Recommendation

In order to expedite the commercial development of CCS it will be important to establish a regulatory program that places no additional requirement on property acquisition beyond constitutional mandates. This can be accomplished by the development of a CCS programs that provide that the issuance of the permit for CCS facilities expressly grants the permittee with the right to inject and sequester CO_2 into those portions of a geologic formation that do not contain coal, or oil and gas, or other mineral in commercial quantity and do not have a current or reasonably foreseeable use.

5.5 Long-Term Stewardship

There is widespread agreement among policymakers and legal experts that a mechanism must be developed to manage risks and liabilities during the post-closure stewardship phase of a geologic storage site. It is understood that, although the risks of geologic storage sites are expected to rapidly decrease once site operations cease (because, for example, the storage reservoir is no longer actively pressurized), project developers, investors and the public need to know that geologic storage sites will be appropriately monitored indefinitely. Corporations do not last forever, nor do governments for that matter, and insurance is not currently available during the post-closure stewardship phase. The EPA's new Class VI UIC rule also does not explicitly impose liability requirements during the post-closure stewardship phase, nor does the SDWA authorize the EPA to transfer site responsibilities from one party to another.

In 2007, the MIT published "The Future of Coal," an interdisciplinary study which considered the role coal would play "in a world where constraints on carbon emissions are adopted to mitigate global warming." The researchers concluded that CCS is not without risk of liability that could be associated with adverse health, safety, and environmental consequences. The researchers divide liability associated with CCS into two distinct categories operational liability and post-injection liability and conclude that operational liability associated with CO_2 capture, transport, and injection is best managed within the same framework used by the existing oil and gas industries. The researchers concluded that a new regulatory and liability framework will be needed to manage post-closure liability risks. The researchers "suggest that industry take financial responsibility for liability in the near-term, i.e. through injection phase and perhaps 10-20 years into the post-injection phase. Once certain validation criteria are met, government would then assume financial responsibility, funded by industry insurance mechanisms, and perhaps funded by set-asides of carbon credits equal to a percentage of the amount of CO_2 stored in the geological formation."

On September 25, 2007, the IOGCC issued its model program for the storage of CO_2 in geologic formations. The IOGCC model program is premised on the belief that the regulation of CO_2 geological storage should be left to regulation by the states, rather than the EPA. Under the IOGCC approach, an operator would be obligated to monitor the project to assure its integrity following completion of the project. At the completion of that period, title to the facility would be transferred to the state and the operator and all generators of CO_2 injected would be released for all regulatory liability and any posted performance bonds would also be released. The IOGCC is considering the possibility of expanding the liability release to include common law tort liability. As part of the inducement for a state to allow liability transfer, the program establishes a trust fund which would assess a fee on each ton of CO_2 injected. The trust fund provides the financial resources for the state to take title to the project at the end of its operating life. IOGCC also suggests the authorization for cooperative agreements for use in connection with projects that extend beyond state boundaries.

Following the recommendations of the IOGCC, states are taking the lead on enacting statutory programs to address site responsibilities during the post-closure stewardship phase. They are doing so by enacting statutes that provide for the creation of industry-funded trust funds that take responsibility for site operations and liabilities upon issuance of a certificate of completion by the appropriate regulator, be it federal or state. This trend of state enactment of IOGCC-based trust funds laws is expected to continue, events that the DOE should continue to encourage. Among the more significant state initiatives addressing liability transfer include:

<u>Louisiana</u>

The Louisiana Geologic Sequestration of CO_2 Act was passed by the Louisiana Legislature in June 2009.[23] This bill provides that 10 years after injection has ended, or any other time frame established by rule, a certificate of completion of injection operations must be issued on a showing that the reservoir is reasonably expected to retain mechanical integrity and the CO_2 will reasonably remain emplaced, at which time the ownership of the remaining project including the stored CO_2 transfers to the state. At that time the storage operator, generators of the CO_2, the owners of the CO_2, and all other owners otherwise having an interest must be released from any and all regulatory duties or obligations and any other liability associated with or related to the storage facility.[24]

A trust fund is created by the Act to be used solely for the purposes of: (1) operational and long-term inspecting, testing, and monitoring; (2) remediation of mechanical problems; (3) repairing mechanical leaks; (4) plugging and abandoning remaining wells; and (5) contracting for private legal services. The Act provides the ability to create site specific trust accounts for each transferred site for the purpose of providing a source of funds for long-term maintenance, monitoring, and site closure assessment and provides rulemaking authority to set fees.[25]

Montana

The Montana legislature has considered several pieces of CCS legislation. S.B. 498, passed in 2009, establishes a CCS regulatory framework that transfers ownership and liability of the CCS facility from the operator to the state The bill provides that the geologic storage operator is liable for the operation and management of the CO_2 injection well, the storage reservoir, and the injected or stored CO_2, prior to project completion and transfer of title. The operator must furnish an adequate bond or other surety to guarantee that all requirements of the state are met.[26] The completion and transfer of ownership and liability from the operator to the state is a process that takes 30 years: (1) 15 years after injection of CO_2 ends, a certificate of completion is issued to the operator if the operator is in full compliance of all rules; and (2) for a period of an additional 15 years after the certificate of completion is issued, the operator must continue adequate monitoring of the wells and reservoir and continue to accept all liability. [27]

Following the 15-year period of required monitoring and verification, if the operator has title to the storage reservoir and the stored CO_2, it may transfer the title to the state if the operator meets all requirements. Once the title is transferred to the state, the state is granted all rights and interests in, and all responsibilities associated with, the geologic storage reservoir and the stored CO_2. The transfer releases the operator from all regulatory requirements and liability associated with the reservoir and the stored CO_2. At this time, all bonds or other surety posted by the operator must be released and the state will be responsible for all monitoring and management of the reservoir and stored CO_2.[28] If the operator does not transfer title to the state, the operator accepts liability indefinitely for the reservoir and the stored CO_2.[29]

North Dakota

In 2009, S.B. 2095 was enacted authorizing the Industrial Commission Authority to regulate the operations of a storage facility.[30] Pursuant to that law, the storage operator has title to the CO_2injected into and stored in a storage reservoir. The storage operator holds title until the Commission issues a certificate of project completion. While the storage operator holds title, the operator is liable for any damage the CO_2 may cause, including damage caused by CO_2 that escapes from the storage facility.[31] After project completion and application for closure, the Commission will consider issuing a certificate of project completion. Such certificate may not be issued until at least 10 years after CO_2 injections have ended. The criteria set for making such a determination include whether: the operator is in full compliance; all pending claims regarding the operation have been addressed; the reservoir is reasonably expected to retain the CO_2 stored in it; the reservoir is stable; the facility is in good condition; and all wells are plugged and equipment removed and reclamation work finished.[32]

Once a certificate is issued, title to the storage facility and to the stored CO_2 is transferred without payment of any compensation to the state. Title acquired by the state includes rights and interests in the CO_2. The storage operator and all persons who generated any injected CO_2 are released from all regulatory requirements and other liability associated with the storage facility. Any bonds are released. Monitoring and managing the storage facility is the state's responsibility to be overseen by the Commission until such time as the federal government assumes responsibility for the long-term monitoring and management of storage facilities.[33]

<u>Kansas</u>

In 2007, Kansas established the authority to develop rules for CCS facilities. Proposed administrative regulations issued in March 2009 address operational requirements for an environmental permitting program. Among those requirements is that for the applicant to obtain a post-closure determination, the facility operators must demonstrate that the plume and storage pressure have stabilized. Upon written approval of post-closure status, the operator would plug the remaining monitor wells at which point the CO_2 storage facility permit would be revoked and any financial assurance instrument would be released. All future remediation or monitoring activities would be performed by the state.[34]

5.6 Financial Structure and Incentives for Projects with CCS

Financing structures and incentives are needed to address the key challenges and present opportunities for advancing the commercial development of CCS technologies for coal-based generation units. Government involvement can facilitate installing CCS features in conjunction with industrial facilities, at least during the early years of the technology's development. At the federal level, there have been a number of different proposals to facilitate CCS deployment by reducing the cost, including the following:

- Tax credits for geologic sequestration of CO_2 and storage in conjunction with EOR
- Loan guarantees or "GHG savings bonds" for commercial-scale projects with innovative technologies
- Investment tax credits

- Grants for commercialization and deployment of CCS technologies
- Grants and tax credits for research to reduce the cost of CCS technologies
- A "wires charge" on electric utility customers to capitalize a CCS research, development and deployment fund over 10 years
- Bonus allowances or revenue from a cap and trade program

a. Legislation to Address CCS Risk Management

The proposed support mechanisms mentioned above each can serve an important function, but they are not created equally. High capital costs and the uncertainty regarding the development CCS projects for a coal-based generation unit are dependent on "one-of-a-kind" circumstances, such as the lack of demonstrated commercial scale capture processes and limited data on potential geologic storage formations. The issues are potentially compounded by market competition; meaning investors may expect a premium, demand quicker recovery, or both. The application of an incentive during the early stages of the development of a project is more critical to CCS deployment than the use of incentives that are evenly spread over time. This is not to say that incentives over time are not valuable but, those that are front loaded are more useful.

There is consensus that a suite of financing tools, not just subsidies but risk management mechanisms or policy, is needed for the government to mobilize private capital and facilitate widespread deployment of CCS. There will be varied circumstances for the deployment of CCS projects, requiring varied tools such as those described above. Focusing on supporting a few early plants, as the DOE has done, will help to develop operational history and a risk profile that could be expected to yield the cost-effective and technically feasible advancements necessary for commercial acceptance, while make financing more readily available and reduce risk premiums.

Operation of additional equipment and the possibility that operation may be disrupted - for example, if the storage facility were found not to provide sufficient containment - gives CCS projects a higher risk profile, increasing the difficulty of acquiring capital, particularly in a credit constrained financing landscape. Substantial work is being done to reduce various costs - for example, by devising new technologies, such as better solvents or membranes that will provide for more efficient capture and compression.

CCS costs affect differently situated potential developers in different ways. A regulated utility that can gain State utility commission approval for recovery of CCS costs through customer rates may be more favorably positioned to proceed with a project involving CCS than a merchant generator competing for customers in the open market. The merchant generator's ability to recover investment in the plant will depend on selling power in the market. Both the regulated utility and the merchant generator face a different set of financing conditions and project risks compared to an electric cooperative or public power entity. Below are some considerations for specific types of project developers.

b. Regulated Utilities

Regulated utilities pursuing rate base recovery for generating facilities with CCS would be required to obtain approval from state utility commissions. In states with traditional rate regulation, utility commissions universally are obligated to approve the recovery of only those costs that are just and reasonable. In some states, this amounts to a two-tiered approval process whereby a proposed project must first obtain a certificate of need, and secondly must obtain acceptable cost recovery through demonstration that the technology selection and related costs are prudent.

Thus far, reaction in the States to CCS and CCS-ready features for proposed generating facilities has been one of reluctance, illustrating the importance of government support in reducing capital costs up front. State consideration of CCS cost recovery has had a certain "chicken and egg" quality, with the Commonwealth of Virginia arguing, for example, that it was "reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for [AEP] to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers."[35] In another example, Mississippi initially rejected rate recovery for Southern Company's Kemper County facility, despite substantial cost reductions through federal incentives. The State subsequently approved cost recovery, but imposed a cost cap limiting the potential effects on ratepayers. Additionally, Indiana has placed similar limits on cost recovery for Duke's 600 MW IGCC at Edwardsport.

States with regulated retail rates often have dispatch order priority agreements or requirements under which the cheapest power supplies run the most often and more expensive supplies run less frequently, which keeps rates low for consumers. The added costs of CCS may cause cost recovery to take longer under such a dispatch order priority system.

c. Public Power

Public power facilities are financed by debt, rather than by equity investment. Public power entities are able to issue tax exempt bonds to raise capital for qualifying projects, such as new generation facilities. The market for the debt will depend on the likelihood of repayment, which in turn depends on the project risks. Long-term contracts to purchase the power address the repayment risk. In recent years public power entities have teamed on large-scale power projects, both with each other and with commercial sector entities, in order to spread risks and to arrange multiple power purchase contracts that in aggregate provide a sufficient basis to secure bond financing.

d. Merchant Generators

Like regulated utilities, merchant generators finance facilities through a combination of debt and equity. They compete in the market based on the cost of delivering reliable power. Thus, as with regulated utilities, merchant power producers benefit from subsidies that reduce the up-front inputs into the cost of power, particularly the capital cost of the facility.

Merchant facilities generally are likely to be financed with a higher proportion of debt than regulated utility facilities. The size of CCS facilities is too large for typical venture capital investment. Debt financing drives the considerations for the types of government assistance needed. A predictable cash flow to service debt is thus a top consideration. Yet higher capital and production costs, as well as the increased risk of down time, raise the risks for debt financing. Some merchant developers have opted to pursue IGCC projects, which can produce valuable streams of gases, including CO_2, which can be sold for industrial purposes, thus providing additional revenues or economic value.

While a loan guarantee or direct loan appears to offer little lift on economics, such government debt may provide "threshold" credit support, i.e., a make or break mechanism for a riskier, early deployment project to move forward, in addition to offering a way to monetize the national strategic value (domestic supply, avoided energy imports, GHG emissions savings, etc.) related to progress on a large-scale advanced technology that no single project can capture.

e. List of key risks

Key risks affecting CCS have been analyzed and measured through discussions with various parties deploying or considering deploying CCS, including project developers, energy companies, financiers, and risk managers. Table 5.1 below lists top ranking technical, policy and financing risks, calculated as a factor of the likelihood respondents gauged of a risk occurring, and the impact on the project proceeding if the risk did occur.

Table 5.1: Top Ranking CCS Development Technical, Policy and Financial Risks[36]

#	Risk Type	Business Case Risk Description
1	Financial	Capital costs (+ parasitic load) with CCS run too high relative to competing baseload
2	Policy	Electricity rate regulation fails to offer dispatch preference or incentives for CCS
3	Market / Financial	Credit financing constraints result in difficult terms (more equity, short debt tenor)
4	Policy	Uncertain regulation on CO_2 emissions results in low economic value for CCS
5	Market / Financial	Natural gas prices remain lower making coal with CCS uneconomic
6	Policy	Incentives for CCS operations (allowances, tax credits) are inadequate for costs
7	Market / Financial	Volatility of (or lack of) carbon allowance prices hinders financing
8	Policy	Water use regulations threaten coal plant operations with CCS (shutdowns)
9	Policy	Lack of clarity about liability for long-term stewardship of CCS hinders financing
10	Market / Financial	Long-term demand growth fails to justify investment in baseload units
11	Technical	Technical performance problems lead to excessive repairs and downtime
12	Policy	Older coal units are allowed to run longer posing competitive challenges
13	Market / Financial	Imported coal prices rise or see more volatility raising costs
14	Technical/ Financial	Transport of CO_2 proves too costly or logistically difficult
15	Policy	Lack of public recognition or acceptance of value of CCS hinders permitting
16	Technical	Injection and storage encounters operating problems triggering higher costs
17	Market / Financial	Interest rates rise threatening financing terms and costs

The vast majority of financing for large projects with CCS will be provided by debt, not equity. Debt financing dictates a credit rating framework for evaluating risks to revenues and cash flows for such projects, whether on balance sheet as corporate debt, or whether financed as a stand-alone project. To offer a lender's perspective, the Carbon Sequestration Leadership Forum (CSLF) Financing Task Force invited lenders to participate in two roundtables conducted in 2010. Those meetings made clear that projects typical will entail multiple actors negotiating and managing critical risks at critical stages of the commercial-scale effort. The complexity of an energy project with integrated CCS means that public–private risk-sharing must be *negotiated* and adjusted with the development and deployment of the technology over time. Insights from these workshops are reflected in Table 5.2, which identifies financial considerations for CCS development.

Table 5.2: Financial Considerations for CCS Development
(CSLF Workshop, 2010)

Major Set of Issues	Lead Responsibility
Clear long-term policy and regulatory framework for the whole CCS chain	Government
Confidence that policy and regulations will not be adversely modified	Government
Strong financial support (CCS is fundamentally uneconomic without it)	Government
Co-completion with alignment of interests in all areas of the chain	Project participants
Proven capture technology (not experimental first units)	Project participants
Understanding economics and risks of capture and storage technology	Participants & Govt
Project break-even versus other competitive suppliers, particularly natural gas	Participants & Govt

Legislating a cap on GHG emissions is *not* sufficient to address other major uncertainties for investors, namely operating risks and parasitic load, and long-term liability related to CO_2 leakage or mobilization of groundwater contaminants. Instead, such a cap could actually move investment away from projects that use coal, pet-coke and heavy fossil resources, whether for power generation or other energy-intensive sectors (e.g., steel, cement, refining). Moreover, a cap and trade regime could actually increase volatility of revenues and debt coverage for such projects, which chills investment.

Lastly, IEA and CSLF, in cooperation with the Global CCS Institute, hosted a forum, "Financial Structure and Incentives for Projects with CCS," in 2009 to better identify critical commercial gaps for promoting deployment of CCS. The roundtables arranged for the CSLF Financing Task Force by the CCS Alliance (Washington, D.C.) and the Carbon Capture and Storage Association (London, UK) provide an additional lens through which to see the recommendations brought forward by the Commercial Gaps experts workshop led by IEA. Two sets of recommendations from the CSLF are summarized in Table 5.3 below. Of note is the extent that these recommendations have evolved in a relatively short period of time.

Table 5-3: CSLF Recommendations for CCS Development[37]

Recommendations to CSLF governments from CSLF "Bridging Gaps" Workshop (Sept. 2009):	Recommendations seen through lens of CSLF Finance Roundtables (Jan. & Apr. 2010):
1. Develop project implementation partnerships with industry	1. CCS is not economic. Public – private investment partnerships are essential as technology unfolds.
2. Encourage "first movers" by moderating investment risks	2. Public and private sector must *negotiate* risk-sharing, tailored to specific project features.
3. Provide adequate public funding (justified to meet emissions goals)	3. Public funding can take many forms: loans, tax credits, grants, capacity payments, "green bonds."
4. Accelerate progress on storage regulation, characterization and pipeline infrastructure	4. Regulatory clarity, such as for long-term liability, for leakage, characterization and infrastructure must be in place to mobilize investment at large scale
5. Conduct community outreach (on benefits / risks)	5. Community outreach is needed not only on risks, but benefits, like regional development, and use of domestic resources.
6. Work with industry to promote best practices, knowledge sharing and regulatory framework development	6. Experience with CCS across industries can promote best practices, knowledge sharing and regulatory insights. Other industries, e.g., chemicals, fuels, may wield better economics for integrating CCS.
7. Support demonstration projects in developing countries	7. Projects in developing countries can enhance engineering, system experience.

In conclusion, a suite of financial mechanisms is critical for CCS development, but government incentives early in the development and construction phases is most important. Addressing the financial barriers to CCS will encourage its widespread deployment.

5.7 References

[1] 42 U.S.C. § 300h.

[2] *See* U.S. EPA publication, *Understanding the Safe Drinking Water Act*, at http://www.epa.gov/safewater/sddwwa/pdfs/fs_30ann_sdwa

[3] Mandatory Reporting of Greenhouse Gases from Carbon Dioxide Injection and Geologic Sequestration Rule, 75 Fed. Reg. 75060 (Dec. 1, 2010).

[4] See, Final Rule Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geological Sequestration (GS) Wells, at 225, available at, http://www.gpo.gov/fdsys/pkg/FR-2010-1210/pdf/2010-29954.pdf (Dec. 10, 2010).

[5] 73 Fed. Reg. 43,492, 43,504 (July 25, 2008). (42 U.S.C. §§ 9601 to 9675)

[6] Black's Law Dictionary (9th ed. 2009) , **right-of-way. 1.** The right to pass through property owned by another. • A right-of-way may be established by contract, by longstanding usage, or by public authority (as with a highway). Cf. EASEMENT. [Cases: Easements 1.] **2.** The right to build and operate a railway line or a highway on land belonging to another, or the land so used. [Cases: Railroads 69.] **3.** The right to take precedence in traffic. [Cases: Automobiles 154, 171(4); Highways 99;] **3.** The strip of land subject to a nonowner's right to pass through. — Also written *right of way*. Pl. **rights-of-way.**

[7] Louisiana R.S. 30:1101 through 1111. See LA. REV. STAT. ANN. §§ 1101-1111 (West 2009)

[8] See S. B. 498, 61st Leg. (Mont. 2009).

[9] See, S. B. 2139, 61st Leg. Reg. Sess. (N.D. 2009).

[10] See H.B. 57, 60th Leg., Gen. Sess. (Wyo. 2009).

[11] See H.B. 58, 60th Leg., Gen. Sess. (Wyo. 2009).

[12] See H.B. 80, 60th Leg., Gen. Sess. (Wyo. 2009).

[13] See H.B. 89, 59th Leg., Gen. Sess. (Wyo. 2008).

[14] See H.B. 90, 59th Leg., Gen. Sess. (Wyo. 2008).

[15] KAN STAT. ANN. §§55-1637 through 1640.

[16] See Interstate Oil and Gas Compact Commission, CO2 Storage: A Legal and Regulatory Guide for the States, at http://iogcc.publishpath.com/Websites/iogcc/pdfs/Road-to-a-Greener-Energy-Future.pdf (Dec. 2007).

[17] *See* Midwestern Governors Association, *Preliminary MGA Geologic Carbon Storage Utility Design Recommendations, at* http://www.midwesterngovernors.org/CCS/Meeting1/MGA_Preliminary_Geologic_Carbon_Storage_Utility_Design_Recommendations_September_2009.pdf (Sept. 2009)

[18] *See* Midwestern Governors Association, *Preliminary MGA Geologic Carbon Storage Utility Design Recommendations, at* www.midwesterngovernors.org/CCS/Meeting1/MGA_Preliminary_Geologic_Carbon_Storage_Utility_Design_Recommendations_September_2009.pdf (Sept. 2009). S. B. 2139, 61st Leg. Reg. Sess. (N.D. 2009). H.B. 80, 60th Leg., Gen. Sess. (Wyo. 2009).

[19] *See* The Carnegie Mellon CCSReg Project, *Policy Brief: Regulating Carbon Dioxide Pipelines for the Purpose of Transporting Carbon Dioxide to Geologic Sequestration Sites, at* http://www.ccsreg.org/pdf/PipelineTransport_07013009.pdf (Sept. 13, 2009)

[20] In its Preliminary Report to the Legislature July 1, 2010, the West Virginia CCS Working group favored the approach of both dedicating certain pore space below 2,500 ft to public use and provide CCS owners operators with access to the pore space through the permitting process. *See* Preliminary Report, *available at*, http:// www.dep.wv.gov/executive/Documents/WVCCS_Working_Group_Preliminary-Report_Final_(C18211971)1.pdf.

[21] *See Baker v. Chevron USA, Inc.*, 2009 WL 3698418 (S.D. Ohio Nov. 4, 2009)

[22] *See* David W. Keith et al., *Regulating the Underground Injection of CO2, at* http://www.ucalgary.ca/~keith/papers/73.Keith.ESTRegulatingCCS.e.pdf (Dec. 2005).

[23] *See* LA. REV. STAT. ANN. §§ 30:1101–30.1111.

[24] *See* LA. REV. STAT. ANN. § 30:1109.A(1).

[25] *See* LA. REV. STAT. ANN. § 30:1111.

[26] *See*, S.B. No. 498. *available at* http://data/opi.mt.gov/bills/2009/billpdf/SB0498.pdf. This bill amends the following sections of MONT. CODE ANN. 70-30-105, 75-5-103, 75-5-401, 77-3-430, 82-10-402, 82-11-101, 82-11-

104, 82-11-111, 82-11-118, 82-11-122, 82-11-123, 82-11-127, 82-11-136, 82-11-137, 82-11-161, 82-11-163, 82-11-201, 82-11-204, 82-11-205, and 82-11-214, MCA; and providing effective dates.

[27] *Id.*

[28] *Id.*

[29] *Id*.

[30] *See* N.D. CENT. CODE § 38-22-03.

[31] *See* N.D. CENT. CODE § 38-22-16.

[32] *See* N.D. CENT. CODE § 38-22-17.

[33] *Id; see also* Telephone Interview with Lynn Helms, Director, North Dakota Industrial Commission, Department of Mineral Resources (Nov. 23, 2009).

[34] KAN STAT. ANN. §§55-1637 through 1640.

[35] Virginia State Corporation Commission, Final Order in the Application of Appalachian Power Company, Case No. PUE-2009-00030, July 15, 2010, p.20.

[36] - Source - CCS Alliance Risk Study prepared for CSLF Financing Task Force, April 6, 2010. [A.D. Paterson, F.E. Eames, M.D. Pineda]; www.ccsalliance.net

[37] Sources: IEA, Global CCS Institute, CCS Alliance

Appendix A

Case Study Questionnaires

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

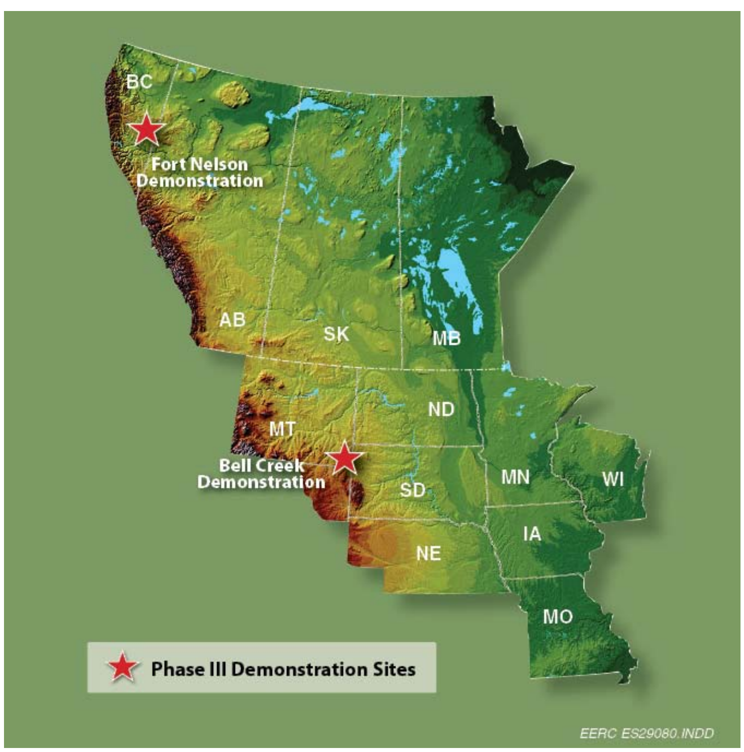
I. Brief Project Description:

Name, Location, and Major Sponsor(s):

DOE NETL RCSP Program and numerous other partners:

- **Fort Nelson Test Site; northeastern British Columbia, Canada; DOE NETL and Spectra Energy.**
- **Bell Creek Test Site; southeastern Montana; DOE NETL and Denbury Resources, Inc.**

PCOR Partnership Phase III Demonstration Sites



Capture Technology (Include Vendor):

- **The Fort Nelson Gas Plant uses an amine system to separate its acid gases from the raw gas stream. The specific amine technology is not currently public information. According to Environment Canada's National Pollutant Release Inventory, DEA (diethanolamine) has been used; the plant converted the process amine in the E/F trains to MDEA in August 2002.**

- **The Lost Cabin Gas Plant uses the Selexol process to selectively remove first H_2S and then CO_2 from the raw natural gas. The plant is one of only two reported locations (the other being the LaBarge Gas Plant) that utilizes Selexol for removal of H_2S and CO_2 from natural gas. The Selexol process is owned and licensed by Dow Chemical, although it is available through several vendors, including UOP LLC. The specific vendor used at the Lost Cabin plant is not available.**

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):

- **Both demonstrations will be employing approximately 1 million tons of CO_2/year. CO_2 for both sites is from natural gas processing facilities – no coal is involved.**

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

- **Fort Nelson Test Site: feasibility and planning stages (preliminary engineering).**

- **Bell Creek Test Site: Denbury Resources is in the detailed engineering and procurement phase.**

Expected Duration:

- **Both sites are expected to operate approximately 20 years.**

Current Project Key Milestones:

- **Fort Nelson injection could commence as early as 2014.**

- **Bell Creek injection is scheduled for late 2012.**

Target Completion Date:

- **Fort Nelson target completion date is 2034.**

- **Bell Creek target completion date is 2032.**

Other Comments:

- **Our original plans were to source the CO_2 from one gas processing facility for the Fort Nelson site and one conventional coal-fired power plant, but project delays forced us to abandon the coal-fired project, and replace it with the Lost Cabin gas plant.**

II. Previous Use of Capture Technology (Please send a picture if possible):

Scale (see description for scale above): **Not applicable (NA)**

Duration: **NA**

Location: **NA**

Was the CO_2 sequestered? **NA**

III. Sequestration Description:

Sequestration Dates (Beginning and End):

- **Fort Nelson Test Site: Anticipated sequestration to start in 2014 and end in 2034.**
- **Bell Creek Test Site: Anticipated sequestration to start in 2012 and end in 2032.**

Sequestration Rate (tonnes CO_2/yr):

- **Fort Nelson Test Site: Up to 2 Mt/yr of sour CO_2 (95% CO_2 and 5% H_2S)**
- **Bell Creek Test Site: Approximately 1 Mt/yr CO_2 for simultaneous CO_2 sequestration and enhanced oil recovery (EOR).**

Total Amount of CO_2 to be Sequestered During Project:

- **Fort Nelson Test Site: Planned to store approximately 40 million tonnes CO_2**
- **Bell Creek Test Site: Planned to store approximately 20 million tonnes CO_2**

Storage Site Name and Estimated Capacity:

- **Fort Nelson Test Site and capacity in direct vicinity is greater than 200 million tonnes.**
- **Bell Creek Test Site and capacity greatly exceeds planned 20 million tonnes of injection.**

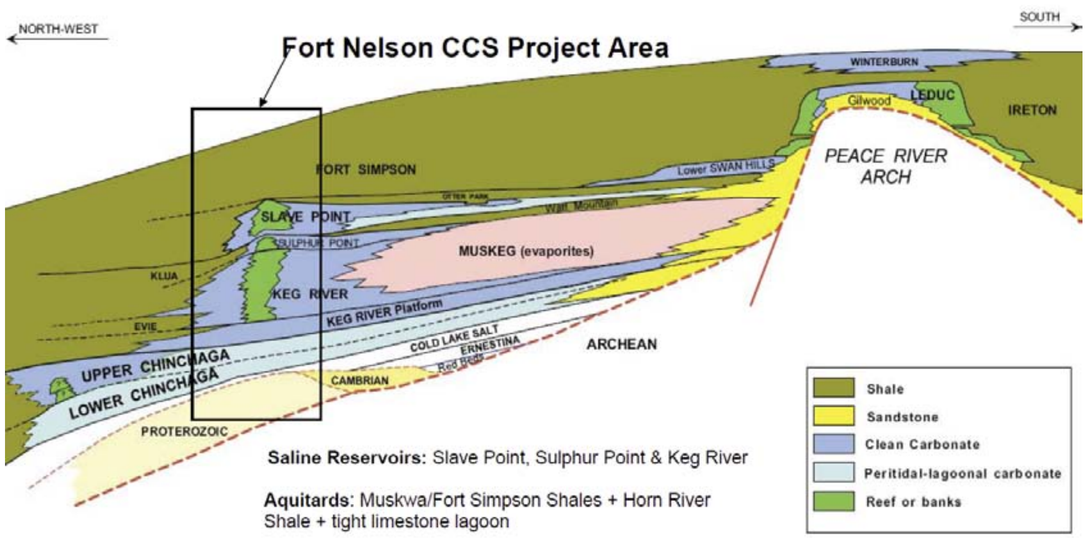
Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):

- **Fort Nelson: Saline Aquifer**
- **Bell Creek: EOR**

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?

- **Fort Nelson Test Site: CO_2 will be injected over 7200 feet underground into the carbonate rocks (limestone and dolomite) in the Elk Point Group. The proposed injection zone is capped by 1800-foot -thick Fort Simpson and Muskwa shale.**

Fort Nelson Project Site Cross Section (Figure Courtesy of Spectra Energy)



- **Bell Creek Test Site: Injected into oil bearing rock in the Muddy Sandstone formation at a depth of 4,400 feet. Target reservoir has an average permeability of 900 md, porosity average is 24%. Gross reservoir thickness is 25-30 feet.**

Source of CO_2 (if not capture project):

Gas processing facilities for both projects

Expected CO_2 Purity and Other Major Components:

- **Fort Nelson: sour CO_2 (95% CO_2 and 5% H_2S)**
- **Bell Creek: assumed to be pipeline quality, essentially pure CO_2**

Expected Wellhead Pressure During Injection:

TBD

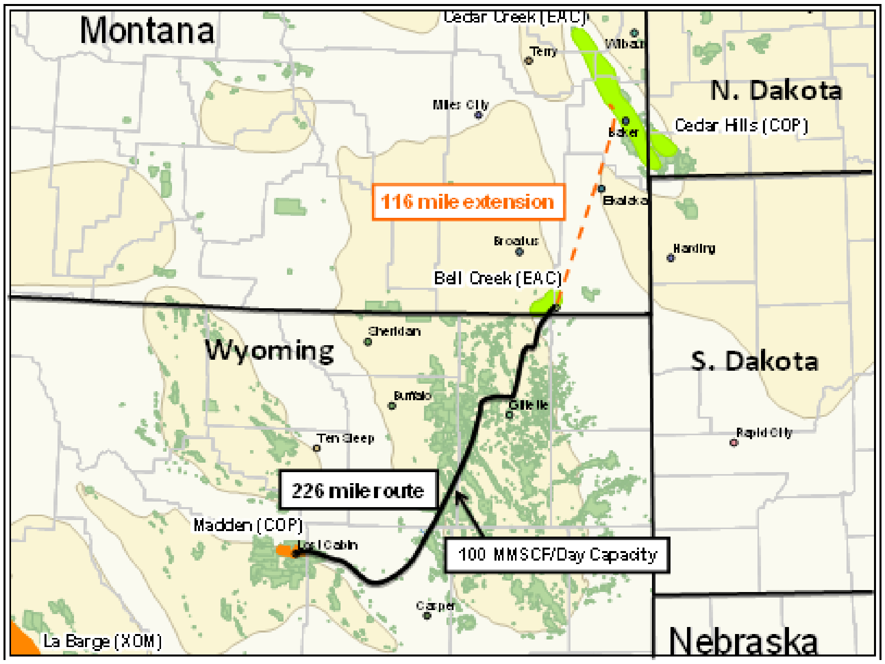
Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):

TBD

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)

- **Fort Nelson: The supercritical CO_2 would be transported via pipeline approximately 9 miles from the gas processing facility to the injection site. The pipeline would be owned by Spectra Energy.**
- **Bell Creek: The CO_2 would be transported 226 miles from the Lost Cabin gas plant to the Bell Creek oil field. The pipeline would likely be owned by Denbury Resources.**

Pipeline route from the Lost Cabin gas plant to the Bell Creek oil field and proposed extension into Cedar Creek Anticline. (Figure courtesy of Denbury Resources, Inc.)



IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	Fort Nelson – Environmental Questionnaire (EQ) was submitted March 2008. Categorical Exclusion (CX) received June 2008. A revised EQ was sent in February 2009 and a CX received the same month. Bell Creek – EQ anticipated to be submitted April 2011.
Air	To be determined (TBD)*
Water	TBD
Solid Waste	N/A
Public Utility Commission (etc)	TBD
Drilling, etc.	TBD
Local (County, Municipal, Zoning boards, etc)	TBD
Other	

***The Fort Nelson project is in the preliminary engineering phase. Permitting plans will be developed as the project progresses. The Bell Creek project is in the detailed engineering/procurement phase. A permitting action plan will be in place August 2011.**

V. Project Funding Sources

Federal Government Incentives:

- **Both the Fort Nelson and Bell Creek projects are supported by inclusion in the US DOE RCSP program. Fort Nelson is applying for additional support through the province of British Columbia and the Canadian federal government. Significant additional funding for both projects has been provided by the commercial partners.**

Grants and Other Sources of Funding (CCPI, etc.):

Tax Credits: **Unknown at present time.**

Government Insured Loans: **Unknown at present time.**

State Incentives: **Unknown at present time.**

Long term liability for CO_2: **Unknown at present time.**

Tax Increment Financing District: **Unknown at present time.**

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

- **See General Comments, Section VII., below.**

Key Lessons Learned to date

- **Monitoring, verification, and accounting (MVA) programs can be developed that are unobtrusive to commercial operations and are both technically and cost effective.**

- **Tertiary-phase EOR is the primary near-term opportunity for managing CO_2 in the PCOR Partnership region.**

- **EOR demand for CO_2 exceeds near-term supply.**

- **Outreach activities are critical to the success of CO_2 storage projects and must be conducted at every level, from local communities to nationwide venues.**

- **Natural gas-processing facilities represent a key near-term source of CO_2.**

- **If CO_2 supply surpasses EOR demand, saline aquifers are available throughout the region to meet sequestration demand.**

- **Regulatory and legal issues are constantly changing in this topic area and represent key challenges to CO_2 storage technologies.**

- **The economics of CCS from conventional coal-fired power plants are not viable absent regulatory drivers or substantial incentives.**

VII. General Comments and Other Information:

- **Our intention was to source at least one of our Phase III large-scale demonstrations with CO_2 from a conventional coal-fired power plant. The cost of capture, regulatory uncertainty, and fundamental economics precluded this from occurring. The PCOR Partnership region has the ideal geology and socioeconomic conditions for CCS should carbon management become a commercial reality.**

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s): WESTCARB Northern California CO_2 Reduction Project, Solano County, California, with C6 Resources, LLC

Capture Technology (Include Vendor): to be determined; emissions to be supplied by Shell's refinery in Martinez, CA

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): not applicable

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) preliminary project assessment

Expected Duration: 10 years (2 years pre-operations, planning, permitting and construction, 3-5 years injection, 3-5 years post-injection monitoring)

Current Project Key Milestones: project risk assessment, including technical, financial, regulatory, and scheduling

Target Completion Date: project completion 2018; assessment phase completion 2011

Other Comments: Based on project risk assessment and other analyses, it became clear, within the current policy environment, that WESTCARB's partner, C6 Resources, could not make a business case to its corporate owner, Shell, to pursue the project at this time.

II. Previous Use of Capture Technology (Please send a picture if possible): not applicable

Scale (see description for scale above): Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): target dates for injection: 2015 begin; 2018 end; sequestration monitoring would continue for several years past injection

Sequestration Rate (tonnes CO_2/yr): injection rate: 250, 000 tonnes per year

Total Amount of CO_2 to be Sequestered During Project: 750,000 to 1,000,000 tonnes injected

Storage Site Name and Estimated Capacity: Montezuma Hills; unknown

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): saline

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? Domengine, Hamilton, Anderson, and Martinez sandstones, thicknesses vary from 50 to 1000 feet, 8,400 to 14,000 ft. depth to top, est. 20 percent porosity, est. 20 millidarcy permeability

Source of CO_2 (if not capture project): capture at oil refinery

Expected CO_2 Purity and Other Major Components: not determined

Expected Wellhead Pressure During Injection: not determined

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): C6 Resources, LLC

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) yes; at commercial-scale, the project would require a pipeline from the refinery to the sequestration site of approximately 30 miles, which would be owned by C6 Resources.

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	**prepared**
Air	**undetermined**
Water	**undetermined**
Solid Waste	**undetermined**

Public Utility Commission (etc)	**Not applicable**
Drilling, etc.	**applied**
Local (County, Municipal, Zoning boards, etc)	**applied**
Other	

V. Project Funding Sources

Federal Government Incentives: none

Grants and Other Sources of Funding (CCPI, etc.): WESTCARB receives funding through the Dept of Energy's NETL Regional Carbon Sequestration Partnership Program; cost share is provided by the industry partner (C6 Resources, LLC) and the California Energy Commission; C6 Resources also received a Phase I ARRA ICCS grant

Tax Credits: none

Government Insured Loans: none

State Incentives: none

Long term liability for CO_2: undetermined

Tax Increment Financing District: undetermined

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

Timing of the project relative to the pace of incorporating CCS into GHG emissions reduction policy in California and continued regulatory and legal uncertainty led C6 Resources, LLC to a decision to not pursue the project at this time.

Key Lessons Learned to date

The public and regulatory outreach aspects of this project were highly successful. Outreach to the communities in the area of the sequestration project was accomplished through open houses and presentations at local community events and service organization meetings; meetings were also held with local and county officials as well as state and federal agencies involved in permitting. The project also identified the importance of providing an understanding of and proactively addressing monitoring for any potential induced seismic activity.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s): WESTCARB Kimberlina Project, Kimberlina, California, with Clean Energy Systems

Capture Technology (Include Vendor): not applicable; Clean Energy Systems uses a patented oxycombustion-firing technology which produces a relatively pure CO_2 stack gas.

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 170 MW thermal

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) preliminary project assessment

Expected Duration: 10 years (2 years pre-operations, planning, permitting and construction, 3-5 years injection, 3-5 years post-injection monitoring)

Current Project Key Milestones: project risk assessment, including technical, financial, regulatory, and scheduling

Target Completion Date: project completion 2018; assessment phase completion 2011

Other Comments: Based on project risk assessment, it became clear, within the current policy and fiscal environment, that financing was unlikely to become available to Clean Energy Systems at the Kimberlina site to complete the project within the schedule for CO_2 delivery to the WESTCARB project

II. Previous Use of Capture Technology (Please send a picture if possible): Clean Energy Systems' gas generator (5 MWe) is pictured below

Scale (see description for scale above): 5MWe

Duration: ongoing for testing and demonstration purposes

Location: Kimberlina, CA

Was the CO_2 sequestered? no

Clean Energy Systems' Oxy-Combustion 5MWe Gas Generator

III. Sequestration Description:

Sequestration Dates (Beginning and End): target dates for injection: 2013 begin; 2015 to 2017 end; sequestration monitoring would continue for several years past injection

Sequestration Rate (tonnes CO_2/yr): injection rate: 230,000 tonnes per year

Total Amount of CO_2 to be Sequestered During Project: 700,000 to 1,000,000 tonnes injected

Storage Site Name and Estimated Capacity: Kimberlina; unknown

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): saline

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? Vedder Sandstone, several hundred feet thickness, varying across the basin; 7000 ft. depth to top, 10-40 percent porosity, 0.2-10 Darcy permeability

Source of CO_2 (if not capture project): capture

Expected CO_2 Purity and Other Major Components: not determined

Expected Wellhead Pressure During Injection: not determined

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): Clean Energy Systems

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) no

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	**prepared**
Air	**undetermined**
Water	**Not applicable**
Solid Waste	**Not applicable**
Public Utility Commission (etc)	**applied**
Drilling, etc.	**prepared**
Local (County, Municipal, Zoning boards, etc)	**undetermined**
Other	

V. Project Funding Sources

Federal Government Incentives: none

Grants and Other Sources of Funding (CCPI, etc.): WESTCARB receives funding through the Dept of Energy's NETL Regional Carbon Sequestration Partnership Program; cost share is provided by the California Energy Commission and industry partners (Schlumberger and Clean Energy Systems)

Tax Credits: none

Government Insured Loans: none

State Incentives: none

Long term liability for CO_2: undetermined

Tax Increment Financing District: undetermined

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

Timing of the project relative to the economic downturn and the slowed pace of GHG emissions reduction policy in California led to Clean Energy Systems inability to construct a power plant in time to meet WESTCARB's schedule for CO_2 delivery.

Key Lessons Learned to date

The risk assessment exercise that project staff undertook under the guidance of Schlumberger proved invaluable in identifying risks to the project across the spectrum from technical (geologic and engineering), financial, to legal and regulatory. The financial risk was highlighted during this session as high-risk, high impact; to date, this issue remains unresolved, although WESTCARB and Clean Energy Systems continue to explore options for a CCS project at other sites where economics might be more favorable.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

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I. Brief Project Description:

Name, Location, and Major Sponsor(s):

Name: Southwestern U.S. Commercial-Scale Geologic CCS Deployment

Location: Gordon Creek Field, Edge of Uinta Basin, Central Utah, USA

Major Sponsor: Major sponsors beyond NETL include Thunderbird Energy Corporation

Capture Technology (Include Vendor):

All CO_2 for this deployment is sourced from a natural CO_2 reservoir, and thus capture technology will not be utilized.

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):

1,000,000 tons (909,091 tonnes) per year of CO_2 or ~2750 tons per day of CO_2 which is derived from about 825 tons (750 tonnes) per day of coal.

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

The project is currently in the preliminary engineering design stage, and transitioning to detailed engineering.

Expected Duration:

The deployment test is expected to take place over a 10-year period, including 1 year for site development and construction, 3 to 4 years of active injection, and 5 to 6 years of post-injection monitoring, verification and accounting (MVA) activities.

Current Project Key Milestones:

The current key project milestones including drilling of initial site characterization wells and verifying the amount of natural CO_2 in place within source reservoirs.

Target Completion Date:

The target completion date of active injection activities is September 30, 2015. The target completion date of post-injection MVA activities is September 30, 2020.

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible):

Scale (see description for scale above): N/A

Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): October 1, 2011 to September 30, 2020 (official project ending date)

Sequestration Rate (tonnes CO_2/yr): up to 1,000,000 tons (909,091 tonnes) per year

Total Amount of CO_2 to be Sequestered During Project: approximately 2,900,000 tons (2,640,000 tonnes)

Storage Site Name and Estimated Capacity: Gordon Creek Field, Utah – minimum capacity of 10,000,000 tons

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Saline

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? Navajo Sandstone; 300 feet minimum thickness; 8400 feet depth to top; estimated average permeability 10^{-14} m^2; estimated average porosity 10%.

Source of CO_2 (if not capture project): N/A (Natural CO_2 from the Triassic (Sinbad) and Permian (White Rim) formations.

Expected CO_2 Purity and Other Major Components: 97% pure; nitrogen, light hydrocarbon, and other trace elements make up remaining 3%

Expected Wellhead Pressure During Injection: 2200 psi

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): State of Utah

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: no (All pipelines will be within the Gordon Creek Unit and from the source to injection location and expected to be less than 2 miles total)

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	Sept 30, 2011
Air	Sept 30, 2011
Water	Sept 30, 2011
Solid Waste	Sept 30, 2011
Public Utility Commission (etc)	Sept 30, 2011
Drilling, etc.	Sept 30, 2011
Local (County, Municipal, Zoning boards, etc)	Sept 30, 2011
Other	

V. Project Funding Sources

Federal Government Incentives:

Grants and Other Sources of Funding (CCPI, etc.): NETL Regional Parnerships Program

Tax Credits:

Government Insured Loans:

State Incentives: State royalties on produced CO_2 waived

Long term liability for CO_2: Limited liability (indemnification) offered by State of Utah.

Tax Increment Financing District: Carbon County, Utah

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.): Securing liability for short- and long-term is, by far, the most challenging issue. Other challenges include minimal existing reservoir characterization data and reconciling pore space ownership under current state and federal laws.

Key Lessons Learned to date: The key lessons we have learned are (1) a mechanism for long-term liability must be established if commercial sequestration is to go forward, whether through a tax-supported community fund or other means, and (2) existing financial incentives in the form of tax credits* are insufficient for industry to instigate commercial sequestration or testing. Other financial incentives, or otherwise a law that requires sequestration, must be created, if sequestration is to proceed at any significant scale.

*Effectively $10/ton for CO_2 injected for enhanced hydrocarbon recovery (EOR) and $20/ton for deep saline or non-EOR sequestration.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

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I. Brief Project Description:

Name, Location, and Major Sponsor(s):

Name: Southeast Regional Carbon Sequestration Partnership (SECARB) Anthropogenic Test

Location: Citronelle, Alabama

Major Sponsors: U.S. Department of Energy, National Energy Technology Laboratory, Southern Company, Alabama Power Company, Denbury Resources Inc., Electric Power Research Institute, Advanced Resources International, Mitsubishi Heavy Industries, and the Southern States Energy Board (program management).

Capture Technology (Include Vendor): Advanced amine technology, post-combustion slip stream (Vendor: Mitsubishi Heavy Industries and Southern Company Services)

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 25MW, 500 tpd at 100%

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.): Detailed engineering, procurement, and construction.

Expected Duration: 10 years

Current Project Key Milestones:

2008: Regional Characterization

2009: Site Selection and Characterization

2010: Permitting, Infrastructure Development, and Site Monitoring (Baseline)

2011-2014: Injection Operations

2015-2017: Site Monitoring and Closure

Target Completion Date: September 30, 2017

Other Comments: N/A

II. Previous Use of Capture Technology (Please send a picture if possible):

Scale (see description for scale above): N/A

Duration: N/A

Location: N/A

Was the CO_2 sequestered? N/A

III. Sequestration Description:

Sequestration Dates (Beginning and End): 2011-2014

Sequestration Rate (tonnes CO_2/yr): ~ 125,000 tonnes CO_2/yr

Total Amount of CO_2 to be Sequestered During Project: 375,000 tonnes CO_2

Storage Site Name and Estimated Capacity: Citronelle Dome, South Alabama. Volumetric analysis indicates that the CO_2 storage capacity of Cretaceous-age sandstone units in the study area is between 12.9 and 51.9 billion U.S. short tons (Gt).

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Saline Formation

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? The injection target is the Cretaceous-age Paluxy Formation. It is a coarsening-upward succession of variegated shale and sandstone. The individual sandstone bodies fine upward and contain shale at the top. The Paluxy is approximately 1,100 feet thick, and depth to the top is approximately 9,410 feet. Regionally, the formation has an average permeability of 130 mD and 23% porosity.

Source of CO_2 (if not capture project): Slip stream captured from coal-fired power plant

Expected CO_2 Purity and Other Major Components: CO_2 purity ~99.7%

Expected Wellhead Pressure During Injection: 2,000-3,000 psia

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): Denbury Onshore LLC

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) Denbury Resources Inc. is constructing a fit for purpose and dedicated pipeline to transport the CO_2 from Plant Barry to the geologic storage site in Citronelle Dome. The distance of the pipeline is approximately 12 miles.

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	EA Under Review
Air	N/A
Water (UIC permit is issued through the MDEQ water program)	UIC Preparation
Solid Waste	N/A
Public Utility Commission (etc)	N/A
Drilling, etc.	Undetermined
Local (County, Municipal, Zoning boards, etc)	N/A
Other	N/A

V. Project Funding Sources

Federal Government Incentives: N/A

Grants and Other Sources of Funding (CCPI, etc.): The Southeast Regional Carbon Sequestration Partnership is funded through a Cooperative Agreement with the DOE/NETL. The capture unit and pipeline are separately funded. Industry cost share of at least 20% is provided for all governmental funding.

Tax Credits: N/A

Government Insured Loans: N/A

State Incentives: N/A

Long term liability for CO_2: Denbury Resources Inc.

Tax Increment Financing District: N/A

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.): N/A

Key Lessons Learned to date: N/A

VII. General Comments and Other Information: N/A

National Coal Council 2010 Study: Case Study Data Collection

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I. Brief Project Description:

Name, Location, and Major Sponsor(s):

Name: Southeast Regional Carbon Sequestration Partnership (SECARB) Early Test

Location: Cranfield, Mississippi

Major Sponsors: U.S. Department of Energy, National Energy Technology Laboratory, The University of Texas at Austin Bureau of Economic Geology, Denbury Resources, Inc., and Southern States Energy Board (program management).

Capture Technology (Include Vendor): N/A (Utilizing natural CO_2 from Denbury's Jackson Dome)

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): To date, the project partners have monitored the injection of 2.2 million metric tons CO_2 (>1 million metric tons/year)

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) Injection has been underway since July 14, 2008; under Phase III since April, 2009.

Expected Duration: 36 months

Current Project Key Milestones: Post-injection monitoring be completed by December 2010.

Target Completion Date: July 2012

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible): N/A

Scale (see description for scale above): N/A

Duration: N/A

Location: N/A

Was the CO_2 sequestered? The project is geologic sequestration.

III. Sequestration Description:

Sequestration Dates (Beginning and End): July 14, 2008 – July 2012

Sequestration Rate (tonnes CO_2/yr): > 1 million metric tons CO_2/year

Total Amount of CO_2 to be Sequestered During Project: Approximately 4 million metric tons

Storage Site Name and Estimated Capacity: Cranfield Field. Capacity calculation will be the result of research (not available at this time).

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Stacked Storage: Saline storage in water leg of oil and gas reservoir under CO_2 EOR.

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity: The Lower Tuscaloosa Formation D-E is the injection target. The formation is approximately 65 feet thick at a depth of 10,300 feet. Its average permeability is 100 mD and average porosity is 22%.

Source of CO_2 (if not capture project): Jackson Dome (natural source)

Expected CO_2 Purity and Other Major Components: >99% CO_2, methane

Expected Wellhead Pressure During Injection: 3,000 psi

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): Denbury Onshore LLC

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) 100 miles Denbury commercial system

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	April 2009
Air	NA
Water	NA
Solid Waste	NA
Public Utility Commission (etc)	NA
Drilling, etc.	March 2009
Local (County, Municipal, Zoning boards, etc)	NA
Other Mississippi Oil and gas board	Injection/production

V. Project Funding Sources

Federal Government Incentives: N/A

Grants and Other Sources of Funding (CCPI, etc.): The Southeast Regional Carbon Sequestration Partnership is funded through a Cooperative Agreement with DOE/NETL. Partners contribute matching funds of 20% or more.

Tax Credits: N/A

Government Insured Loans: N/A

State Incentives: N/A

Long term liability for CO_2: Denbury Onshore LLC

Tax Increment Financing District: N/A

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.): CO_2 availability limits progress.

Key Lessons Learned to date: Commercial EOR is ready to accept large volumes of CO_2

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s): The primary source of funding for the Phase III project is DOE/NETL. Other, non-federal members of the MRCSP can be found listed at www.mrcsp.org.

Capture Technology (Include Vendor): No capture is required in the proposed MRCSP Development Scale CO_2 injection test.

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): Goal is 1 million metric tonnes of CO_2 injected over an approximate four-year period. This is equivalent to about 30 MW(e) of bituminous base load generation capacity.

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) Engineering

Expected Duration: 10 years total for Phase III with four years of injection

Current Project Key Milestones: Injection: start in late 2011, end in late 2015. End of monitoring and closure in 2019

Target Completion Date: 2019

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible):
MRCSP has not used capture technology in any of its tests thus far.

Scale (see description for scale above):

Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): Late 2011 to late 2015 (injection phase)

Sequestration Rate (tonnes CO_2/yr): Approximately 250,000 metric tonnes per year

Total Amount of CO_2 to be Sequestered During Project: 1 million metric tonnes

Storage Site Name and Estimated Capacity: MRCSP Phase III Development Scale Test

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Saline/carbonate

What is the target formation's name (St. Peter/Bass Islands), **lithology** (sandstone/carbonate), **thickness** (~1000 ft), **depth to top** (~8500 feet for St. Peter), **permeability** (TBD)**, and porosity** (TBD)?

Source of CO_2 (if not capture project): Natural gas processing

Expected CO_2 Purity and Other Major Components: 99+%

Expected Wellhead Pressure During Injection: ~1500 – 2000 psig

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): TBD

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) No

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	EA summer 2011
Air	None
Water	None
Solid Waste	None
Public Utility Commission (etc)	None
Drilling, etc.	End of 2010
Local (County, Municipal, Zoning boards, etc)	End of 2010
Other	

V. Project Funding Sources

Federal Government Incentives: None

Grants and Other Sources of Funding (CCPI, etc.): Cooperative Agreement with NETL

Tax Credits: None

Government Insured Loans: None

State Incentives: None

Long term liability for CO_2: TBD

Tax Increment Financing District: NA

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical -- Formations of interest for sequestration often are not well documented prior to digging test well and conducting seismic assessment**, financial –** Obtaining private funding for cost share challenging in the context of no active carbon market**, regulatory –** CO_2 is new to many regulators and, therefore, requirements are uncertain and may not be well tailored to needs**, etc.)**

Key Lessons Learned to date Detailed geologic assessment and characterization plan including test well and seismic assessment important prior to implementation. Outreach to key stakeholders is key prior to beginning field work. Early and regular contact with regulators is important throughout the design and characterization process.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

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I. Brief Project Description:

Name, Location, and Major Sponsor(s):

Illinois-Basin Decatur Project, Midwest Geological Sequestration Consortium (MGSC)

Decatur, Illinois

U.S. Department of Energy through the RCSP and the Illinois Office of Coal Development

Capture Technology (Include Vendor):

Direct capture from ethanol fermentation

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):

Mw not applicable; will capture and inject 1 million tonnes over 3 years

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

Injection well complete, observation well currently drilling, compression dehydration facility complete in March 2011, injection April 2011

Expected Duration:

Injection: 2011-14; post-injection monitoring: 2014-2016

Current Project Key Milestones:

Draft final permit modification due December 2011; compression facility complete March 2011, Injection initiated: April 2011

Target Completion Date:

Injection complete 2014; monitoring complete 2016

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible):

Not applicable

Scale (see description for scale above):

Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End):

April 2011- March 2014

Sequestration Rate (tonnes CO_2/yr):

335,000

Total Amount of CO_2 to be Sequestered During Project:

1 million tonnes

Storage Site Name and Estimated Capacity:

Illinois Basin Decatur Project; 10->50 million tonnes

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):

Saline reservoir

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?

Mount Simon Sandstone; sandstone; 1,650 ft; 5,544 ft; mostly 80->200 md and greater; 15-25 percent porosity

Source of CO_2 (if not capture project):

Ethanol fermentation

Expected CO_2 Purity and Other Major Components:

99.9 percent pure

Expected Wellhead Pressure During Injection:

1,400 psi under long term operating conditions

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):

Archer Daniels Midland Corporation

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)

Yes. Approximately 6,000 ft total length, entirely on-site, 6 inch, 2,000 psi working pressure, owned by Archer Daniels Midland Corporation

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	**2008**
Air	**na**
Water	**na**
Solid Waste	**na**
Illinois EPA final modification to 2009 permit	**March 2011**
Drilling, etc.	**2009,2010**
Local (County, Municipal, Zoning boards, etc)	**na**
Other	

V. Project Funding Sources

Federal Government Incentives:

Grants and Other Sources of Funding (CCPI, etc.):

DOE Regional Carbon Sequestration Partnership Program; Illinois Clean Coal Institute

Tax Credits:

Government Insured Loans:

State Incentives:

Long term liability for CO_2:

Site owner

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

State regulatory authorities dealing with UIC permits unfamiliar with CO_2 as an injectant; they are also unfamiliar with innovative monitoring well concepts.

Key Lessons Learned to date

Allow more time than you thought for permitting.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s): Kevin Dome, Kevin – Sunburst area, MT. Major sponsors Vecta Oil and Gas, Schlumberger Carbon Services

Capture Technology (Include Vendor): None

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): N/A natural source

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.): Application nearly complete, will submit to DOE in November 2010

Expected Duration: 8 yrs

Current Project Key Milestones: Application in preparation; milestones subject to negotiation

Target Completion Date: Jan 2019

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible): N/A; natural CO_2 source

Scale (see description for scale above):

Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): Jan 2013 through Dec 2016

Sequestration Rate (tonnes CO_2/yr): 250,000 / yr

Total Amount of CO_2 to be Sequestered During Project: 1,000,000 tonnes

Storage Site Name and Estimated Capacity: Duperow Formation, 15-59 GT in central MT, 25-100 GT in Williston Basin

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Saline Formation

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? Duperow, dolomite, ~500 ft thick but porosity zone in injection region is ~100 ft thick at a depth of 3400 ft. Formation is significantly deeper to the east

Source of CO_2 (if not capture project): Kevin Dome natural accumulation

Expected CO_2 Purity and Other Major Components: 98%

Expected Wellhead Pressure During Injection: 1500psi

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): Injection will occur on Montana State Trust Lands. Ownership will be accepted by State of Montana.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) A pipeline will be constructed from the compressor station to the injection site – a distance of ~ 6 miles.

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	**06/11**
Air	**06/11**
Water	**06/11**
Solid Waste	**06/11**
Public Utility Commission (etc)	**06/11**

Drilling, etc.	**06/11**
Local (County, Municipal, Zoning boards, etc)	**06/11**
Other - UIC	**01/12**

V. Project Funding Sources

Federal Government Incentives:

Grants and Other Sources of Funding (CCPI, etc.): Regional Partnership Phase III

Tax Credits:

Government Insured Loans:

State Incentives:

Long term liability for CO_2: State of Montana allows transfer of liability after 30 yrs

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s):
Taylorville Energy Center IGCC Project
Christian County Generation, LLC
(Joint Venture of Tenaska and MDL Holding Company)
Christian County, Illinois

Capture Technology (Include Vendor):
Pre-combustion capture process utilizing water-gas shift reactor and Rectisol

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):
The proposed project would gasify Illinois Basin Bituminous Coal to produce synthetic natural gas that would be used to generate electricity through a combined cycle process (IGCC) or that would be sold and sent offsite via pipeline.

Detailed design continues. Final specifications on the capture rate, amount of CO_2 reduced, and options for disposing of the captured CO_2 are to be determined.

CO_2 capture design: $\geq$ 50% reduction

Schlumberger completed a study in February 2010, *"Carbon Storage Feasibility Study: Taylorville Energy Center,"* which used the following assumptions:

- Case 1: 3,410,000 tonnes per year CO_2 sequestered
- Case 2: 2,274,000 tonnes per year CO_2 sequestered

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

February 2010:	Completed Front-End Engineering & Design
February 2010:	Christian County Generation submitted *Facility Cost Report* to the Indiana Commerce Commission
September 2010:	Indiana Commerce Commission submitted an *Analysis of the Taylorville Energy Center Facility Cost Report* to the Illinois General Assembly
To be determined:	The Illinois General Assembly will review the Commerce Commission Report and determine whether the Taylorville Project qualifies for cost-recovery per the Illinois Clean Coal Portfolio Standard Law.
To be determined:	Results of the General Assembly decision will determine the tasks and schedule for completing the project, which is currently targeted to begin operation in 2015.

II. Previous Use of Capture Technology (Please send a picture if possible): Unknown

Scale (see description for scale above):
Duration:
Location:
Was the CO_2 sequestered?

III. Sequestration Description:

Detailed design continues. Final specifications on the capture rate, amount of CO_2 reduced, and options for disposing of the captured CO_2 are to be determined.

Sequestration Dates (Beginning and End):
To be determined.

Sequestration Rate (tonnes CO_2/yr):
Schlumberger completed a study in February 2010, *"Carbon Storage Feasibility Study: Taylorville Energy Center,"* which used the following assumptions:

- Case 1: 3,410,000 tonnes per year CO_2 sequestered
- Case 2: 2,274,000 tonnes per year CO_2 sequestered

Total Amount of CO_2 to be Sequestered During Project:
To be determined.

Storage Site Name and Estimated Capacity:
Two-options under consideration:

EOR Option: Work with Denbury Onshore, LLC to expand existing CO_2 pipeline network from Gulf Coast to Illinois. To be determined where and how CO_2 from the Taylorville project would be used. .

Sequestration Option: Geologic sequestration at or near the plant site.

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):
EOR and geologic sequestration are both under consideration.

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?

Schlumberger completed a study in February 2010, *"Carbon Storage Feasibility Study: Taylorville Energy Center,"* which considered the following:

- CO_2 would be sequestered in the Mt. Simon sandstone formation
- The Mt. Simon formation near the project site has the following characteristics:
  - located approximately 5,615 – 6,916 feet below the surface
  - thickness is 1,110 to 1,500 feet.
  - Eau Claire shale formation is the cap rock and greater than 200 feet thick
  - porosity and permeability data not provided in report

Source of CO_2 (if not capture project): Not applicable.

Expected CO_2 Purity and Other Major Components:
Schlumberger completed a study in February 2010, *"Carbon Storage Feasibility Study: Taylorville Energy Center,"* which considered a CO_2 purity of 98%;

Expected Wellhead Pressure During Injection:
Schlumberger completed a study in February 2010, *"Carbon Storage Feasibility Study: Taylorville Energy Center,"* which considered a wellhead pressure of 2,100 psi.

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):
Two-options under consideration:

EOR Option: Work with Denbury Onshore, LLC to expand existing CO_2 pipeline network from Gulf Coast to Illinois. Under this scenario, Denbury would assume ownership of CO_2 at the plant boundary.

Sequestration Option: Geologic sequestration at or near the plant site. Ownership and liability to be determined.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)
Technical details to be determined.

Two-options under consideration:

EOR Option: Work with Denbury Onshore, LLC to expand existing CO_2 pipeline network from Gulf Coast to Illinois. The length of this extension is to be determined. Under this scenario, Denbury would assume ownership of CO_2 and pipeline at the plant boundary.

Sequestration Option: Geologic sequestration at or near the plant site. Estimated that pipeline would be approximately 7.5 miles in length. Ownership and liability to be determined.

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

NEPA (EIV, EIS)	Notice of Intent – 4/2011 Target Final EIS - unknown
Air	Permit issued in 2007
Water	Unknown
Solid Waste	Unknown
Public Utility Commission (etc)	Unknown
Drilling, etc.	Unknown
Local (County, Municipal, Zoning boards, etc)	Unknown
Other	

V. Project Funding Sources

Federal Government Incentives: Tax credits, Federal loan guarantee. See below

Grants and Other Sources of Funding (CCPI, etc.):

Tax Credits:
2010 DOE Investment Tax Credit: $417 million

Government Insured Loans:
Pursuing DOE loan guarantee

State Incentives:
Pursuing cost-recovery the Illinois Clean Coal Portfolio Standard Law

Long term liability for CO_2:
Two-options under consideration:

EOR Option: Work with Denbury Onshore, LLC to expand existing CO_2 pipeline network from Gulf Coast to Illinois. Under this scenario, Denbury would assume ownership of CO_2 at the plant boundary.

Sequestration Option: Geologic sequestration at or near the plant site. Ownership and liability to be determined.

Tax Increment Financing District: Unknown.

VI. Key Development Challenges and Lessons Learned To be determined.

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information:

Questionnaire completed based on information contained in the following resources:

1. Illinois Commerce Commission Report to Illinois General Assembly – Taylorville Facility Cost Analysis – September 1, 2010.

2. Taylorville Energy Center Facility Cost Report
February 2010
www.cleancoalillinois.com/report/index.php

3. Carbon Storage Feasibility Study: Taylorville Energy Center
February 2010
www.cleancoalillinois.com/report/index.php

National Coal Council 2010 Study: Case Study Data For the TECO Plant

Brief Project Description: The Tampa Electric Power Station is located near Fort Meade, in Florida. It is a nominal 250 megawatt integrated gasification combined cycle (IGCC) system. The station utilizes pet coke and coal mixture as the fuel.

According to a company news release, TECO plans to work with RTI over the next six months to finalize the project details. Upon completion of the final agreements, RTI will design, construct and operate the pilot plant that will capture a portion of the plant's CO2 emissions to demonstrate the technology.

Capture Technology: The proposed technology RTI intends to apply is the solid sorbent pre-combustion CO_2 capture from syngas. It will utilize warm gas cleanup with the sorbent. RTI is currently investigating Lithium Ortho-silicate ($LiSiO_4$), Lithium Magnesium, and MgO sorbents. It is developing a fluidized version of the sorbent to facilitate sorbent transport between the adsorption and stripping columns, while improving the heat transfer coefficient of the sorbent bed. RTI in cooperation with the Shaw Group of URS, could also apply the sorbent enhanced, water-gas shift technology.

Scale (MW): The announced size of the slip-stream to be treated is approximately 30%. That represents a 75 MW slip-stream to capture the CO_2 emissions from a nominal 250 MW IGCC plant. The plant uses petroleum coke and coal to produce syngas.

Expected Duration: The expected duration of the test is stated as one year. The project is expected to sequester approximately 300,000 tons of CO2 in a saline formation more than 5,000 feet below the Polk power station.

Other Comments:

Previous Testing Description (Please send a picture if possible):

Scale: RTI conducted bench scale testing of various sorbents to operate at warm gas conditions.

Duration: Not known

Location: Not known

Sequestration Description: see below

Sequestration Rate (tons CO_2/yr): The project is expected to sequester approximately 300,000 tons of CO2 in a saline formation more than 5,000 feet below the Polk power station.

Total Amount of CO_2 to be Sequestered During Project: The amount of CO_2 to be captured and sequestered is stated as 300,000 tons.

Storage Site Name and Estimated Capacity: The storage site selected for sequestration is a saline formation more than5,000 feet below the Polk IGCC power plant. The plant is located on State Road 37. It occupies 4,300 acres.

Type (EOR, Saline Aquifer, etc.): The type of sequestration site identified is a saline formation.

Current Project Key Milestones: The design and construction of the proposed CO_2 capture and sequestration pilot plant is expected to start in approximately six months by RTI, a contractor selected by the National Energy Technology Laboratory of the US Department of Energy. Plant operation is planned to start in 2013.

Target Completion Date: According to RTI, the selected contractor, upon completion of the final agreements, the pilot plant is expected to be completed and operational by2013.

Additionally, RTI has plans to subcontract the Shaw Group to design and build a sulfur removal demonstration unit at the TECO plant.

Target Air Permit: Not known

Target NEPA or Other Required Pre-Startup Reporting: Not known

Federal Government Incentives: DOE contract through NETL

Grants and Sources of Funding (CCPI, etc.): CCPI funding

Tax Credits: Not known

Government Insured Loans: Not known

State Incentives: Not known

Ownership of CO_2 After Injection to Sequestration Site (if applicable): Not available

TIF District: Not known

Power Purchase Agreements: TECO will continue to generate and sell power.

General Comments and Other Information: TECO's Polk power station occupies 4,300 acres on State Road 37. The plant previously has been named the cleanest coal-fired power plant in North America. It is also one of only two operating IGCC units in the United States.

The power station, located near Fort Meade, is a 250-megawatt integrated gasification combined cycle (IGCC) unit.

According to a company news release, TECO plans to work with RTI over the next six months to finalize the project details. Upon completion of the final agreements, RTI will design, construct and operate the pilot plant that will capture a portion of the plant's CO2 emissions to demonstrate the technology.

Construction of the pilot plant, which is designed to capture the CO2 from a 30 percent side stream of the coal-fired plant's syngas, would be completed in 2013, the release states. Syngas, a synthetic gas generated by the gasification of coal and petroleum coke, is used as a fuel in the plant's combustion turbine to create electricity.

The CO2 capture and sequestration demonstration phase would take place over a one-year period. The project is expected to sequester approximately 300,000 tons of CO2 in a saline formation more than 5,000 feet below the Polk power station.

"Tampa Electric has been an industry leader in reducing carbon dioxide emissions since 1998," company Vice President Tom Hernandez said in the news release. "We are pleased to partner with RTI on the development of these innovative technologies and to continue to be on the forefront of tomorrow's clean coal technology."

RTI, working with the U.S. Department of Energy's National Energy Technology Laboratory, has also awarded a contract to the Shaw Group to design and build a sulfur removal demonstration unit at the Polk power station. According to the TECO release, the sulfur removal unit is expected to significantly reduce the capital and operating costs of an integrated gasification combined cycle plant equipped with carbon capture technology.

TECO's Polk power station occupies 4,300 acres on State Road 37. The plant previously has been named the cleanest coal-fired power plant in North America. It is also one of only two operating IGCC units in the United States.

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s):
Mississippi Power Company / Southern Company
Kemper IGCC Project
Kemper County, Mississippi

Capture Technology (Include Vendor):
Pre-combustion capture process utilizing water-gas shift reactor and Selexol

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):

IGCC unit:	nominal 580 MW (net)	
Lignite-coal fired unit:	580 tons/hour	
	13,800 tons/day design	
CO_2 capture design:	67% reduction	
	~8,709 tonnes/day	(9,600 tons/day)
	~2.3-2.7 million tonnes/yr	(2.5-3.0 million tons/yr)

High CO_2 reduction designs considered, but not selected due to concerns regarding the design and operation of combustion turbines with higher concentrations of hydrogen in the syngas, as well as economic feasibility.

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

2010 – 2012:	Detailed IGCC plant design
2010 – 2014:	Construction of IGCC plant (site-prep currently occurring)
2011 – 2013:	Construct linear facilities, including pipelines.
2^{nd} quarter 2014:	Commence Operation

II. Previous Use of Capture Technology (Please send a picture if possible): Not Applicable

Scale (see description for scale above):
Duration:
Location:
Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End):
IGCC project expected to commence operation in the 2^{nd} Quarter 2014.
Beginning and ending dates for sequestration to be determined.

Sequestration Rate (tonnes CO_2/yr):

~8,709 tonnes/day	(9,600 tons/day)
~2.3-2.7 million tonnes/yr	(2.5-3.0 million tons/yr)

Total Amount of CO_2 to be Sequestered During Project:
To be determined.

Storage Site Name and Estimated Capacity:
To be determined.

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):
EOR

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?
To be determined.

Source of CO_2 (if not capture project): Not applicable.

Expected CO_2 Purity and Other Major Components:
99% CO_2 purity; <10 ppm H_2S; <35 ppm Total Sulfur Compounds

Expected Wellhead Pressure During Injection:
To be determined. Pipeline pressure 2,100 psi.

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):
To be determined.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)
Ownership to be determined.
Pipeline would connect with existing CO_2 pipeline network near Heidelberg, MS.
Pipelines to be located underground.
~ 61 miles of pipeline estimated
Diameter estimated to be 12-18 inches
Design operations: 2,100 psi; 95 deg F;

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	Final – 2010
Air	Final – 2008
Water	Unknown
Solid Waste	Unknown
Public Utility Commission (etc)	Final – 2010
Drilling, etc.	Unknown
Local (County, Municipal, Zoning boards, etc)	Unknown
Other	

V. Project Funding Sources

Federal Government Incentives: CCPI, tax credits, Federal loan guarantee. See below

Grants and Other Sources of Funding (CCPI, etc.):
2007 CCPI Award: $270 million

Tax Credits:
National Energy Policy Act of 2005 Investment Tax Credits
2006 Award: $133 million
2010 Award: $279 million

Government Insured Loans:
DOE Loan Guarantee

State ~~Incentives~~:
Mississippi Public Service Commission approval in 2010 for project cost-recovery

Long term liability for CO_2:
To be determined.

Tax Increment Financing District:
To be determined.

VI. Key Development Challenges and Lessons Learned - To be determined.

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information:

Questionnaire completed based on information contained in the following resources:

1. U.S. Department of Energy – Final Environmental Impact Statement for Kemper Project
   May 2010
   www.netl.doe.gov/technologies/coalpower/cctc/EIS/eis_kemper.html

2. Mississippi Public Service Commission Docket
   Case # 2009-UA-14
   www.psc.state.ms.us/

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s):
Hydrogen Energy International, LLC
(Joint Venture of BP Alternative Energy North America, Inc. and Rio Tinto Hydrogen Energy, LLC)
Hydrogen Energy California IGCC Project
Kern County, California

Capture Technology (Include Vendor):
Pre-combustion capture process utilizing water-gas shift reactor and Rectisol

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow):

IGCC unit:	nominal 390 MW (gross); 250 MW (net)	
Petcoke only firing:	2,820 tons/day	
Petcoke & Western Bituminous blends:	3,197 tons/day	
CO_2 capture design:	$\geq$ 90% reduction	
	6,622 - 6,713 tonnes/day	(7,300-7,400 tons/day)
	2 million tonnes/yr	(2.2 million tons/yr)

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

2010-2012:	Design and Engineering
Mid-2011:	Complete Permitting
2012:	Commence Construction
2015:	Complete Construction
Throughout 2015:	Commissioning and Initial Startup
2016:	Commence Operation

II. Previous Use of Capture Technology (Please send a picture if possible): Not Applicable

Scale (see description for scale above):
Duration:
Location:
Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End):
IGCC project expected to commence operation in the September 2015.

Sequestration Rate (tonnes CO_2/yr):

6,622 - 6,713 tonnes/day	(7,300-7,400 tons/day)
2 million tonnes/yr	(2.2 million tons/yr)

Total Amount of CO_2 to be Sequestered During Project:
To be determined.

Storage Site Name and Estimated Capacity:
Elk Hills Field.

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):
EOR

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?
Stevens oil reservoirs within the Monterey sandstone formation.
The Monterey formation is located ~4,500 to 10,000 feet below surface.
Stevens reservoir:

- average thickness:	450 feet
- average porosity:	20%
- average permeability:	32.2 mD

Cap Formation: Reef Ridge Shale in the Miocene formation

Source of CO_2 (if not capture project): Not applicable.

Expected CO_2 Purity and Other Major Components:
97% CO_2 purity;

Expected Wellhead Pressure During Injection:
Well head pressure: 2,000 to 3,000 psi
Pipeline pressure 1,500 – 2,800 psi.

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):
Hydrogen Energy International will own the pipelines and CO_2 transported to the EOR site where ownership will transfer to Occidental of Elks Hills, Inc.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)
Hydrogen Energy International will own the pipelines and CO_2 transported to the EOR site where ownership will transfer to Oxy Elk Hills, Inc.
Pipelines to be located underground.
~ 4 miles of pipeline estimated
Diameter estimated to be 12 inches
Design operations: 1,500 - 2,800 psi;

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	Notice of Intent – 4/2011 Target Final EIS - unknown
Air	Unknown
Water	Unknown
Solid Waste	Unknown
Public Utility Commission (etc)	Unknown
Drilling, etc.	Unknown
Local (County, Municipal, Zoning boards, etc)	Unknown
Other	California Energy Commission Approval: May 2011

V. Project Funding Sources

Federal Government Incentives: CCPI, tax credits, Federal loan guarantee. See below

Grants and Other Sources of Funding (CCPI, etc.):
2010 CCPI Award: $308 million

Tax Credits: Unknown

Government Insured Loans: Unknown

State Incentives: Unknown

Long term liability for CO_2:
Hydrogen Energy International will own the pipelines and CO_2 transported to the EOR site where ownership will transfer to Occidental of Elks Hills, Inc.

Tax Increment Financing District: Unknown.

VI. Key Development Challenges and Lessons Learned - To be determined.

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information:

Questionnaire completed based on information contained in the following resources:

1. U.S. Department of Energy – Notice of Intent for HECA Project
   April 2010
   www.netl.doe.gov/publications/others/nepa/FR%20HECA%20NOI%204-6-10%20EIS-0431.pdf

2. California Energy Commission – Application for Certification
   May 2009
   www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/revised_afc/index.php

3. Hydrogen Energy California – Project Website
   Accessed October 2010
   www.hydrogenenergycalifornia.com

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy, the National Coal Council is preparing a study that focuses, in part, on demonstration-scale CO_2 capture and/or sequestration projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting the following information: specific government sponsored incentives that are essential to completion of your project and, to the extent known key issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects, which might be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

I. Brief Project Description:

Name, Location, and Major Sponsor(s): Antelope Valley Station (AVS) Carbon Capture and Sequestration Project

Capture Technology (Include Vendor): HTC Purenergy/Doosan-Babcock

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 120 MWs

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) Evaluation of the completed Front End Engineering and Design Study

Expected Duration: Month of October

Current Project Key Milestones: Take Business Plan to the Board of Director's to get approval or non-approval for Notice to Proceed – next key milestone

Target Completion Date: Fourth quarter, 2014 if Board approves final notice to proceed

Other Comments: The Notice to Proceed approval will be challenging due to the increased project cost, the cost to capture the CO_2 plus the challenge of securing a committed Enhanced Oil Recovery (EOR) contract.

II. Previous Use of Capture Technology (Please send a picture if possible): Pilot plant at SaskPower's Boundary Dam Power Station

Scale (see description for scale above): 4 tons per day CO_2

Duration: 1987 to present

Location: Near Estevan Saskatchewan, Canada

Was the CO_2 sequestered? No, the CO_2 is captured and released

III. Sequestration Description: Primary objective is enhanced oil recovery sequestration while as a contingency plan Basin Electric has been investigating injection into a geological formation.

Sequestration Dates (Beginning and End): Commercial operating date to end of project life (20 + years).

Sequestration Rate (tonnes CO_2/yr): 1,000,000 tons CO_2/yr

Total Amount of CO_2 to be Sequestered During Project: Assuming 20 yr project life, 20,000,000 tons.

Storage Site Name and Estimated Capacity: Undetermined

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Primary Objective is EOR however geological formation is being investigated as well.

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? EOR will be site specific. If geological formation, the Broom Creek formation is the most likely.

Source of CO_2 (if not capture project): N/A

Expected CO_2 Purity and Other Major Components: Virtually all CO_2 with ppm amounts of water and other components

Expected Wellhead Pressure During Injection: Dependant on site

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): If EOR, the oil field operator. If geological sequestration, Basin Electric.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) Undetermined for EOR, however, geological sequestration could require a short pipeline - distance of approx. 10 miles

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.) If Notice to Proceed is granted by the Board, an EA would be needed to be complete before procurement or construction of the project. The following are approximate times.

Environmental Permits & Approvals	Target Dates

NEPA (EIV, EIS), EA	**Up to two years**
Air	**6 month-1 year**
Water	**3 months**
Solid Waste	**3-6 months**
Public Utility Commission (etc)	**Pipeline site approval- one year**
Drilling, etc. geological formation	**2 year development**
Local (County, Municipal, Zoning boards, etc)	**1 year**
Other - North Dakota Industrial Commission - oil & gas division	**Permits of EOR/geological formation injection – post EA – 1 year**

V. Project Funding Sources

Federal Government Incentives: Clean Coal Power Initiate – selected to negotiate a cooperative agreement worth $100 Million. Negotiations on hold until Board make its Notice to Proceed decision.

Grants and Other Sources of Funding (CCPI, etc.): North Dakota Industrial Commission - $2.7 million from the Lignite Energy Research Fund

Tax Credits: Internal Revenue Code (IRC) 45Q would be a possibility; however, because of the way IRC is structured, Basin Electric would not be able to utilize the credits

Government Insured Loans: $300 million Rural Utility Service loan approved for the project

State Incentives: Sales tax exemption on equipment, reduction in coal conversion tax (in lieu – property tax) for AVS Unit One, no sales tax on carbon dioxide sales.

Long term liability for CO_2: Basin Electric would need to assume the liability for CO_2 release from geological storage, but the liability for EOR sales would reside with the oil company.

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.) Demonstrating carbon capture and storage will present huge risks for the first to proceed. The FEED study does address the technical challenges to design the integration of the carbon capture equipment into the existing plant infrastructure to minimize the risk, but scaling up and getting the proper operating parameters will take time. The financial risk is tremendous – if an EOR contract is secured, the delivery of CO_2 must be guaranteed creating the need for a backup supply or a financial penalty. Storing the carbon dioxide in geological formations will create huge expenses.

The site will need to be characterized – Basin Electric has had estimates that could cost upwards of $50 million for our project. Liability costs is another unknown and could be a show stopper for geological storage.

Key Lessons Learned to date

Federal cost share should be a minimum of 50 percent. The Federal government should assume the liability for the first few demonstration projects and conduct development of reasonable long-term liability rules. The IRC 45 Q tax incentive needs revisions to assure cooperatives and those with limited tax appetite can take advantage of the credit. The overall project costs are more than originally conceived, the cost to capture a ton of CO_2 have increased from original projections and the time for completion of the project have lengthen considerably.

VII. General Comments and Other Information:

National Coal Council 2010 Study: Case Study Data Collection

At the request of the United States Secretary of Energy the National Coal Council (NCC) is preparing a study that focuses, in part, on demonstration-scale CO_2 capture projects. Although it is important that we can provide as much information to the Secretary as possible, please do not include any information that cannot be shared with the general public. We are specifically requesting information related to issues (regulatory and other) that are causing or could cause problems or delays in your project and similar projects that could be addressed by the Secretary of Energy or the government in general. Finally, we request that you avoid, to the greatest extent possible, technical jargon so that the information can be readily understood by the lay person. Thank you in advance for your contribution. If you have any questions, please don't hesitate to contact the Chapter 2 lead, Holly Krutka (hollyk@adaes.com, 303-962-1949).

Brief CO_2 Capture and Storage **Project Description:**

The AEP and Alstom Mountaineer CO2 Product Validation Facility is designed to treat a 20 MWe slipstream of combustion flue gases from an existing coal-fired boiler that are taken downstream of the existing selective catalytic reduction (SCR) and wet flue gas desulfurization (WFGD) systems. The project scope includes CO2 capture, compression, and storage in two geologic reservoirs with injection wellheads located on the plant property. AEP and Alstom worked together to develop the capture system using Alstom's Chilled Ammonia Process (CAP) and AEP contracted Battelle to develop the geologic storage system. The Mountaineer PVF captured CO2 for the first time on September 1, 2009 and injected CO2 for the first time on October 1, 2009 becoming the first ever integrated CCS system on a coal fired power plant. It is capable of capturing and storing 100,000 metric tonnes per year of CO2.

Capture Technology: (describe reagent, vendor, and process)

In Alstom's Chilled Ammonia Process (CAP), incoming flue gas is cooled to drop water out of the gas stream, decrease the volume of flue gas, and promote the chemical reactions in the absorber. The cooled flue gas is sent to the absorber where the CO2 reacts with an ammonia based reagent liquid to form ammonium bicarbonate. The flue gas slipstream, with most of the CO2 removed, is sent back to the stack for discharge. The ammonium bicarbonate solution formed in the absorber is sent to the regenerator under pressure. In the regenerator, the solution is heated using a reboiler thereby reversing the reaction and releasing CO2 for storage; the reagent is returned to the cycle. At the CAP exit, a compressor increases the CO2 pressure to approximately 1,500 psi, where it transitions from a gas to liquid and is piped to the geologic storage equipment.

Storage Technology: The geologic storage equipment starts off with a pump that can increase the CO2 pressure from approximately 1,500 psi to 3,000 psi (if required). The CO2 is then piped to one of two injection wells that inject into saline reservoirs, the Rose Run Sandstone at approximately 7,800 ft below surface and the Copper Ridge B-Zone at approximately 8,200 ft below surface. Additionally, there is extensive monitoring equipment to safely monitor the CO2 characteristics and behavior.

Scale (MW): (Scale is defined as the Net MW_e (net) size that represents the % of full load gas flow to the process.)

20 MWe

Expected Duration:

The PVF started operations on September 1, 2009 and will run for 1-5 years.

Other Comments:

Previous Testing Description (Please send a picture if possible):

Scale (MW): (Scale is defined as the MW_e (net) size that represents the % of full load gas flow to the process.

Alstom conducted lab scale testing at SRI in California and constructed two 1.7 MWe pilot facilities that captured the CO2 and released it back to the stacks.

Duration:

The lab scale facility operated for several months. The 1.7MWe pilot facility each operated for 12-18 months.**Location:**

Lab scale: SRI, California (synthetic gas)

1.7 MWe: We Energies Pleasant Prairie Power Plant (PRB coal)

1.7MWe: E. On Karlshamm Facility (oil)

(Is the CO_2 released back to the atmosphere or compressed for storage?)

Pilot facilities: relased back to the atmosphere.

Mountaineer Product Validation Facility: compressed for storage.

Sequestration Description: ***(Some of the Sequestration projects did not have capture upstream, do we want these included?)***

Sequestration Rate (tons CO_2/yr): (Tons or Tonnes?) MT PVF: 100,000 tonnes/yr

Total Amount of CO_2 to be sequestered during project: 100,000-500,000 tonnes total. Through August 2010, the PVF captured approximately 21,000 tonnes of CO2 and injected approximately 15,000 tonnes of CO2. Initial injectivity into the Copper Ridge formation was better than expected whereas initial injection into the Rose Run formation was less than expected. The Rose Run formation injectivity improved over time but it is still less than initially expected. AEP is conducting annual maintenance and well workover activities in the Fall of 2010 and will continue injecting CO2 to validate and further test the injection potential of both formations.

Storage Site Name and Estimated Capacity: Mountaineer Plant

Rose Run Sandstone (~7,800 ft below surface): 100,000-300,000 tonnes/yr

Copper Ridge B-Zone (~8,200 ft below surface): 100,000-400,000 tonnes/yr

Type (EOR, Saline Aquifer, etc.): Saline Aquifer

Current Project Key Milestones:

Sep 1, 2009 – Captured CO2 for the first time

Oct 1, 2009 – Stored CO2 for the first time

March 2011 – Complete initial performance testing

Target Completion Date: Will run the facility for 1-5 years, but no longer than May 4, 2014 when the Underground Injection Control (UIC) permit expires.

Target Air Permit: (Air permit applies to capture system and not sequestration project)

N/A – did not require an air permit modification since 20 MWe slipstream is less than 1.5% of 1,300 MWe Mountaineer Power Plant flue gas stream.

Target NEPA or Other Required Pre-Startup Reporting:

Not applicable.

Federal Government Incentives:

None

Grants and Sources of Funding (CCPI, etc.):

None**Tax Credits:**

TBD

Government Insured Loans:

None

State Incentives:

None

Other Funding Methods:

AEP - ~$76M

Alstom – primary (amount confidential)

EPRI – secondary (amount confidential)

RWE – secondary (amount confidential)

Ownership of CO_2 after Injection to Sequestration (or EOR) Site (if applicable):

AEP

TIF District: What does this mean?

Power Purchase Agreements:?

N/A

General Comments and Other Information:

For geologic storage of CO_2, there are several questions and concerns that need to be addressed before programs are implemented on a commercial scale basis, such as:

- Who owns the rights to the pore space in the geologic reservoirs thousands of feet under ground? How can those rights be acquired and /or utilized to support commercial storage projects?
- Are uniform federal standards needed to govern storage requirements in order to facilitate the use of interstate formations?
- How will liability protection be handled during project operation, post-closure, and ultimately during the long-term stewardship period?
- What are the risks and liability complications for situations when CO_2 or pressure effected zone from one source combines underground with CO_2 or pressure effected zone from other source(s)?

MT PVF Lessons learned:

- Foot print: The CO2 capture technologies take up more space than traditional environmental control systems (SCR, FGD, and precipitator) since they treat a larger percentage of the flue gas. Space available at/around the power plant may be a constraint when considering a CO2 capture technology retrofit.

- Permitting: The UIC permit process can be a lengthy process that requires constant communication with the permitting agency since some of the state agencies do not have experience dealing with CO2. Plan to start this process early and communicate often with the permitting agency.

- Geology: Geology is not an exact science; engineers that are used to precise calculations need to understand there is a lot more uncertainty dealing with geologic structures thousand of feet below surface.

- Stakeholder management: The MT PVF has had well over 100 tours including members from the following organizations: US Congress; State Senators and Representatives; DOE; OMB; GAO; EPA; state regulatory agencies; state utility commissions; non government organizations; local, state, and federal media; environmental groups; and universities. The CCS validation and demonstration projects generate a lot of interest from external stakeholders that must be accounted for in staffing and communications management.

- Communications: The project team held several meetings with AEP employees, community leadership, and even hosted an open house for the local community to put out information about the project. We believe this helped ease people’s concerns about this First of a Kind (FOAK) project.

- Intellectual property: It is imperative for the companies developing the CO2 capture technologies to protect their intellectual property so they are not as forthcoming with their process information as governmental agencies (DOE, EPA, etc..) and non-governmental agencies (EPRI, EEI, etc…) would like.

Future Projects:

In addition to the PVF, AEP entered into an agreement with the DOE on February 2, 2010 to design, build and operate an approximately 235 MWe slip stream CCS facility at the Mountaineer Power Plant. The commercial scale facility, MT CCS II, will process the flue gas to capture 90% of the CO_2 using the Alstom Chilled Ammonia Process (CAP) and compress, transport, inject and store 1.5 million tonnes per year of the captured CO_2 into deep saline reservoirs. The DOE is cost sharing 50% of the project costs up to $334M.

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I. Brief Project Description:

Name, Location, and Major Sponsor(s): Antelope Valley Station (AVS) Carbon Capture and Sequestration Project

Capture Technology (Include Vendor): HTC Purenergy/Doosan-Babcock

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 120 MWs

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) Evaluation of the completed Front End Engineering and Design Study

Expected Duration: Month of October

Current Project Key Milestones: Take Business Plan to the Board of Director's to get approval or non-approval for Notice to Proceed – next key milestone

Target Completion Date: Fourth quarter, 2014 if Board approves final notice to proceed

Other Comments: The Notice to Proceed approval will be challenging due to the increased project cost, the cost to capture the CO_2 plus the challenge of securing a committed Enhanced Oil Recovery (EOR) contract.

II. Previous Use of Capture Technology (Please send a picture if possible): Pilot plant at SaskPower's Boundary Dam Power Station

Scale (see description for scale above): 4 tons per day CO_2

Duration: 1987 to present

Location: Near Estevan Saskatchewan, Canada

Was the CO_2 sequestered? No, the CO_2 is captured and released

III. Sequestration Description: Primary objective is enhanced oil recovery sequestration while as a contingency plan Basin Electric has been investigating injection into a geological formation.

Sequestration Dates (Beginning and End): Commercial operating date to end of project life (20 + years).

Sequestration Rate (tonnes CO_2/yr): 1,000,000 tons CO_2/yr

Total Amount of CO_2 to be Sequestered During Project: Assuming 20 yr project life, 20,000,000 tons.

Storage Site Name and Estimated Capacity: Undetermined

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): Primary Objective is EOR however geological formation is being investigated as well.

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? EOR will be site specific. If geological formation, the Broom Creek formation is the most likely.

Source of CO_2 (if not capture project): N/A

Expected CO_2 Purity and Other Major Components: Virtually all CO_2 with ppm amounts of water and other components

Expected Wellhead Pressure During Injection: Dependant on site

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable): If EOR, the oil field operator. If geological sequestration, Basin Electric.

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership) Undetermined for EOR, however, geological sequestration could require a short pipeline - distance of approx. 10 miles

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.) If Notice to Proceed is granted by the Board, an EA would be needed to be complete before procurement or construction of the project. The following are approximate times.

Environmental Permits & Approvals	Target Dates

NEPA (EIV, EIS), EA	**Up to two years**
Air	**6 month-1 year**
Water	**3 months**
Solid Waste	**3-6 months**
Public Utility Commission (etc)	**Pipeline site approval- one year**
Drilling, etc. geological formation	**2 year development**
Local (County, Municipal, Zoning boards, etc)	**1 year**
Other - North Dakota Industrial Commission - oil & gas division	**Permits of EOR/geological formation injection – post EA – 1 year**

V. Project Funding Sources

Federal Government Incentives: Clean Coal Power Initiate – selected to negotiate a cooperative agreement worth $100 Million. Negotiations on hold until Board make its Notice to Proceed decision.

Grants and Other Sources of Funding (CCPI, etc.): North Dakota Industrial Commission - $2.7 million from the Lignite Energy Research Fund

Tax Credits: Internal Revenue Code (IRC) 45Q would be a possibility; however, because of the way IRC is structured, Basin Electric would not be able to utilize the credits

Government Insured Loans: $300 million Rural Utility Service loan approved for the project

State Incentives: Sales tax exemption on equipment, reduction in coal conversion tax (in lieu – property tax) for AVS Unit One, no sales tax on carbon dioxide sales.

Long term liability for CO_2: Basin Electric would need to assume the liability for CO_2 release from geological storage, but the liability for EOR sales would reside with the oil company.

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.) Demonstrating carbon capture and storage will present huge risks for the first to proceed. The FEED study does address the technical challenges to design the integration of the carbon capture equipment into the existing plant infrastructure to minimize the risk, but scaling up and getting the proper operating parameters will take time. The financial risk is tremendous – if an EOR contract is secured, the delivery of CO_2 must be guaranteed creating the need for a backup supply or a financial penalty. Storing the carbon dioxide in geological formations will create huge expenses.

The site will need to be characterized – Basin Electric has had estimates that could cost upwards of $50 million for our project. Liability costs is another unknown and could be a show stopper for geological storage.

Key Lessons Learned to date

Federal cost share should be a minimum of 50 percent. The Federal government should assume the liability for the first few demonstration projects and conduct development of reasonable long-term liability rules. The IRC 45 Q tax incentive needs revisions to assure cooperatives and those with limited tax appetite can take advantage of the credit. The overall project costs are more than originally conceived, the cost to capture a ton of CO_2 have increased from original projections and the time for completion of the project have lengthen considerably.

VII. General Comments and Other Information:

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I. Brief Project Description:

Name, Location, and Major Sponsor(s): FutureGen 2.0; Meredosia, IL; Ameren Energy Resources and the FutureGen Industrial Alliance

Capture Technology (Include Vendor): Oxycombustion process by Air Liquide and Babcock & Wilcox

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 200 MWe (net)

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.) Preliminary Engineering

Expected Duration: 30 years

Current Project Key Milestones: Procurement and Construction expected to begin second quarter of 2012 with target completion in the fourth quarter of 2015

Target Completion Date: Q4 2015

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible):

Scale (see description for scale above):

Duration:

Location: Pilot tested coal-fired oxy-combustion with this technology in Alliance, OH

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): Beginning 2015, minimum 30 year injection period

Sequestration Rate (tonnes CO_2/yr): initially 1.3 million tons/year (90% of plant emissions)

Total Amount of CO_2 to be Sequestered During Project: 39 MMT over 30 years from the Meredosia plant

Storage Site Name and Estimated Capacity: permitted to accept 100-500 MMT of CO2

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.): sandstone formation

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity? Mount Simon

Source of CO_2 (if not capture project):

Expected CO_2 Purity and Other Major Components:

Expected Wellhead Pressure During Injection:

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	
Air	
Water	
Solid Waste	
Public Utility Commission (etc)	
Drilling, etc.	
Local (County, Municipal, Zoning boards, etc)	
Other	

V. Project Funding Sources

Federal Government Incentives:

Grants and Other Sources of Funding (CCPI, etc.): $1 Billion ARRA funding

Tax Credits:

Government Insured Loans:

State Incentives:

Long term liability for CO_2: State of Illinois

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information: On October 6, 2010 the FutureGen Industrial Alliance announced details of the process that will lead to the selection of the final storage site for the CO2 in Illinois.

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I. Brief Project Description:

Name, Location, and Major Sponsor(s): Air Products, NETL, Port Arthur, TX

Capture Technology (Include Vendor): Air Products, VSA

Scale (Defined as the net MW size or by tpd of coal use that represents the % of full load CO_2 gas flow): 1,000,000 TPY

Current Project Status: (Preliminary Engineering, Detailed Engineering, Procurement, Construction, etc.)

Expected Duration:

Current Project Key Milestones:

Target Completion Date:

Other Comments:

II. Previous Use of Capture Technology (Please send a picture if possible):

Scale (see description for scale above):

Duration:

Location:

Was the CO_2 sequestered?

III. Sequestration Description:

Sequestration Dates (Beginning and End): 2012

Sequestration Rate (tonnes CO_2/yr):

Total Amount of CO_2 to be Sequestered During Project:

Storage Site Name and Estimated Capacity:

Type (EOR, Saline Aquifer, Depleted Oil or Gas Reservoir, etc.):

What is the target formation's name, lithology, thickness, depth to top, permeability, and porosity?

Source of CO_2 (if not capture project):

Expected CO_2 Purity and Other Major Components:

Expected Wellhead Pressure During Injection:

Ownership of CO_2 after Injection to EOR or Sequestration Site (if applicable):

Does the Project Include a Pipeline Longer than 0.5 Miles (locations off-site)? If so, please describe pipeline: (Distance, ownership)

IV. Permitting (capture, transport, and sequestration) Status (Preparation, Applied, Received, Denied, Not applicable, Undetermined, etc.)

Environmental Permits & Approvals	Target Dates
NEPA (EIV, EIS)	
Air	
Water	
Solid Waste	
Public Utility Commission (etc)	
Drilling, etc.	
Local (County, Municipal, Zoning boards, etc)	
Other	

V. Project Funding Sources

Federal Government Incentives:

Grants and Other Sources of Funding (CCPI, etc.):

Tax Credits:

Government Insured Loans:

State Incentives:

Long term liability for CO_2:

Tax Increment Financing District:

VI. Key Development Challenges and Lessons Learned

Key Development Challenges (technical, financial, regulatory, etc.)

Key Lessons Learned to date

VII. General Comments and Other Information:

Appendix B

Study Group Members – 2011 National Coal Council Report

Study Group Members - 2011 National Coal Council Report

Sy Ali	Clean Energy Consulting
Barbara Altizer	Eastern Coal Council
Carol Bailey	Deloitte Consulting
Robert A Beck	National Coal Council
Janos Beer	Massachusetts Institute of Technology
Indrajit Bhattacharya	American Electric Power
Frank Blake	American Electric Power
Frank Burke	Consultant
Luiz Camargo	Northwestern University
Frank Clemente	Penn State University
Kipp Coddington	Mowrey Meezan Coddington Cloud LLP
Mike DeLallo	Worley Parsons
Bill DePriest	Sargent & Lundy
Michael Ducker	U.S. Department of Energy
Daniel M Duellman	American Electric Power
Fred Eames	Hunton & Williams
David M. Flannery	Jackson Kelly, PLLC
Sarah Forbes	World Resources Institute
Janet Gellici	American Coal Council
Larry Grimes	National Coal Council
Bill Harper	Bechtel
Janet Henry	American Electric Power
Robert Hershey	Consultant
Gerald Hill	Southern States Energy Board
Steve Jenkins	CH2MHill
Austin Knight	Air Liquide
Holly Krutka	ADA Environmental Solutions
Klaus Lambeck	Public Utilities Commission of Ohio
Lynn Lednicky	Dynegy
Pam Martin	National Coal Council
Janine Migden-Ostrander	Office of Ohio Consumer's Counsel
Nancy Mohn	Alstom
Ram Narula	Bechtel
John Novak	Electric Power Research Institute
Jerry Oliver	Global Tech Management Services
Bill Olson	Worley Parsons
Fredrick Palmer	Peabody Energy
Bob Purgert	Energy Industries of Ohio
Masood Ramezan	Leonardo Technologies
Don Schneider	FirstEnergy Solutions Corp
Curtis R Sharp	American Electric Power
Brian D Sherrick	American Electric Power
Greg Slone	Office of Ohio Consumer's Counsel
David Stopek	Sargent & Lundy
P.V. Sundareshwar	South Dakota School of Mines & Technology
Laura Swingle	Jackson Kelly, PLLC
Sherry Tucker	Denbury
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