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Harnessing Coal's Carbon Content to Advance the Economic, Environment and Energy Security

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National Coal Council

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Executive Summary

"The implementation of clean, state-of-the-art coal-based technologies will help insure America's energy security," ***The Blueprint for a Secure Energy Future***, The White House, March 2012

The purpose of this report is to respond to a request to the National Coal Council (NCC) from the Secretary of the U.S. Department of Energy (DOE) to conduct a new study focused on the capture of carbon dioxide (CO_2) emissions from the combustion of fossil fuels for power generation and from using coal to make alternative fuels, chemical and other products, or synthetic natural gas. The Secretary also requested that the study address the storage of CO_2 and its use for enhanced oil recovery (EOR) or the production of other products. Our study shows that advanced coal technology, coupled with capturing carbon emissions for use in EOR, could lead to annual revenues of $200 billion in industry sales and $60 billion in federal, state, and local taxes, and to the creation of over one million jobs. Further, we could reduce our imports of petroleum by over 6 million barrels per day (bbl/d), thereby increasing our energy independence, and reduce carbon emissions equivalent to almost 100 gigawatts (GW) of coal-based electric power.

Introduction

Vision

More than any other nation, America can control its own energy destiny. Coal is the foundation of that control. Almost 30% of the world's coal reserves are in the United States. Our nation stands at the threshold of a unique opportunity to deploy clean coal technologies to more fully use domestic coal resources in order to accomplish a full range of socioeconomic and environmental goals. Our leadership in deploying these technologies would benefit the global community as well. In a future world of 8.5 billion people in 2035, the U.S. Energy Information Administration's (EIA) projected 50% increase in energy consumption will require President Obama's "all of the above" energy resources – oil, gas, renewables, and nuclear – but coal will continue to be the cornerstone, providing more incremental energy over the next 25 years than any other single fuel. As MIT Professor Ruben Juanes recently confirmed, "We should do many different things, but one thing that's not going away is coal."

The NCC has identified its vision for coal in earlier reports. First, coal's abundance and widespread distribution present powerful means to produce electricity reliably and affordably. Second, coal's versatility allows conversion to liquid transportation fuels, substitute natural gas (SNG), and chemicals. Third, improving coal's environmental performance through advanced coal technologies coupled with CO_2 capture and EOR will not only make it possible to meet

climate policy goals but also open the door to the beneficial use CO_2. Finally, the dynamic activity associated with deploying advanced coal, carbon capture, and EOR technologies will stimulate the economy, provide jobs, revive established industries, and create new ones. But, without a facilitating regulatory regime in place to assure proper integration of these three elements, attaining these benefits will remain elusive as all nations struggle to meet the rising tide of energy demand amid higher prices, uncertainty, international tension, and the need to improve our global environment.

Coal-Based CO_2 and Petroleum Independence

Clean coal technologies work. The National Energy Technology Laboratory (NETL) concludes that "Technologies… have helped to dramatically reduce potentially harmful emissions, even as coal use for electricity generation has risen substantially." Now, the creative gaze of the scientific and engineering communities turns to carbon capture, utilization, and storage (CCUS). Private sector companies have already demonstrated that underground storage of CO_2 is more than a waste disposal business as shown by the success of EOR technology. The emergence of CO_2 as a commodity enables society to fully unlock the value of advanced, low emission coal technologies.

The use of CO_2 for EOR is the CCUS approach providing the greatest potential for economic and environmental pay offs over the next several decades. DOE-sponsored research found that "next-generation" CCUS and EOR technologies would enable the economic recovery of 67 billion barrels of "stranded oil" which could be produced assuming an $85/barrel oil price. In addition, there is emerging recognition that the Residual Oil Zone (ROZ) resources are enormous, and could yield yet another 33 billion barrels for a total of at least **100 billion barrels** of oil that would otherwise remain unavailable.

But, the *sine qua non* of such recovery is the availability of adequate amounts of CO_2. New EOR projects are being delayed due to a lack of CO_2. Advanced Resources International (ARI) estimates that as much as 20 billion metric tons of CO_2 will be needed to produce this recoverable resource, and, if potential ROZ production is included, the required CO_2 exceeds 33 billion metric tons. However, only about 2 billion metric tons of CO_2 will be available from natural sources and natural gas processing. Coal-based CCUS technologies can help meet this 31 billion metric ton shortfall to enable our nation to produce our own petroleum resources and avoid reliance on imported oil that severely impacts our trade balance of payments and national security.

Aspirational Case for Increased Petroleum Production from Coal

Regardless of the scenario, large-scale development of CO_2 EOR will require massive amounts of CO_2, economically derived from large concentrated stationary sources, e.g., coal generation along the Ohio River, one of the regions hit hardest by the national decline in manufacturing. These large supplies of CO_2 are available at such coal-based power plants and also at potential coal conversion facilities like coal-to-liquids (CTL) plants. Many of the 320 GW of existing coal-based generation units can serve as the foundation for the vast amounts of CO_2 required,

pending development of adequate pipelines and infrastructure. And, since coal generation will continue to be the leading source of electric power, it will provide a steady, affordable, and reliable source of CO_2.

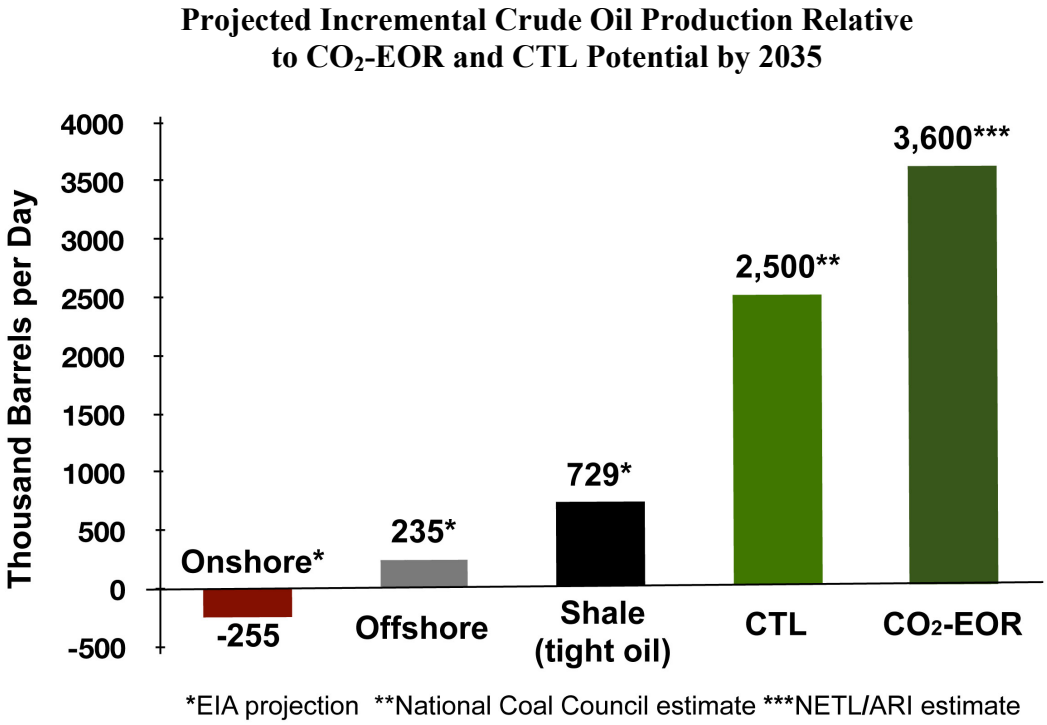
In order to develop a point of reference, an Aspirational Case for enhanced petroleum production using CCUS EOR technologies is presented in this report that draws from sources such as previous work by the NCC as well as work by the National Academy of Sciences (NAS) and ARI/NETL. In essence, such an Aspirational scenario through 2035 posits:

- continued reliance on America's extensive fleet of coal power plants
- continued national consumption of petroleum for transportation fuels and chemicals of at least 15 million bbl/d
- development of 100 GW of coal-based generating capacity with capability to capture CO_2 over the next two decades, about half retrofits and half new builds
- CTL facilities with carbon capture capability to produce 2.5 bbl/d of liquid transportation fuels
- utilization of over 500 million metric tons of coal-based CO_2/year to produce 4 million bbl/d of domestic petroleum through CO_2 EOR for over 40 years

Kuuskraa (ARI) estimates that using captured CO_2 for EOR petroleum production would offset the emissions of approximately 100 GW of coal based power plants that would consume at least 300 million tons of coal per year. Since CO_2 used in EOR operations is effectively retained in the oil reservoir, minimal CO_2 would be emitted from the 100 GW of coal-based units. Approximately 475 million tons of coal per year would be needed to produce 2.5 million bbl/d of synthetic fuels or chemicals through CTL technologies. Therefore, a total coal supply of almost 800 million tons per year – perhaps 600 million of which would be new demand – would be needed for the Aspirational Case. Our national coal consumption would rise to over 1,700 billion tons per year based on EIA projections.

Benefits from Coal-Based CO_2 Use

The reward from implementing the Aspirational Case would be highly significant. Our nation would benefit from domestic production of more than an additional 6 million bbl/d of oil that would not need to be imported – more than twice the current production of Venezuela. Additional jobs would be created through the EOR deployments and the increased coal production. The figure below illustrates coal's potential role in meeting our needs for crude oil compared to others sources. There is little doubt that the potential production of oil from CO_2 EOR could far surpass other projected domestic sources of oil supply. Thus, by 2035, the powerful tandem of CO_2 EOR and CTL could provide almost 30% of our projected liquid fuel consumption and enhance America's energy security for decades.



Outlook for Production of Substitute Natural Gas from Coal

The Council has studied the production of SNG from coal in earlier reports (2006, 2008, 2009) and found this technology to be viable under favorable market conditions. In the current gas markets in the United States, the interest in SNG has waned because of the belief that shale gas has permanently institutionalized the expectation of increased natural gas supply at low prices. But the unknowns relating to shale gas abound. Regarding supply, long term questions on environmental impacts, deliverability, cost and price stability remain unanswered. Paralleling these unknowns, factors increasing the demand for gas further cloud the future – liquefied natural gas (LNG) export facilities are being built, the chemical industry is rejuvenating, gas vehicles are entering the market and gas-based generation capacity is growing.

In short, the gas market of today is not the gas market of tomorrow and predictions of the future supply and price of gas have a high level of uncertainty. Longer term, the probability is that LNG at the global level will be precariously tied to the price of oil, similar to the current situation in Asia where LNG prices have exceeded $17/mmbtu during the first half of 2012. As the U.S. enters this global market, LNG prices will gain increasing significance in policy decisions relating to cost and energy security. To counteract these escalating costs of LNG, China is already converting hundreds of millions of tons of coal to SNG and related products. China also plans to use such new technologies as hydromethanation to continue to convert coal to SNG at scale.

The Council's previous studies have shown that over 4,000 billion cubic feet of pipeline quality SNG can be produced utilizing 325 million tons of coal. SNG with CCUS has significantly lower

greenhouse gas (GHG) emissions than LNG production. SNG facilities would create thousands of jobs in the mining and gas production sectors and enhance national security.

Findings

Advanced coal technologies coupled with carbon capture and EOR are key to achieving deep reductions in GHG emissions for electric power generation and for producing transportation fuels and chemicals. These achievements can be realized at affordable cost. A wide range of other benefits, opportunities, and issues has been identified in our report and are summarized below:

- **Significant benefits result from implementing coal-based CCUS EOR technologies:** Implementing the Aspirational Case will create new industries, revitalize a large number of U.S. industry sectors, manufacturing, and technology, and create numerous professional technical and skilled jobs. Over the next two decades, the Aspirational Case will annually generate nearly $200 billion in industry sales, over 1 million jobs, and $60 billion in federal, state, and local government tax revenues. If "Advanced Coal/CCS/EOR" were a company, it would rank 5th on the Fortune 500.

- **CCUS can expand domestic oil production:** Recent pioneering EOR projects are dramatically expanding the view of commercial oil reservoir targets, including the ROZ. With what we now know, a U.S. contribution to global carbon storage could be occurring at a much faster pace. This process would not only be a major stride toward achieving climate change goals, but also provide insurance against economic and energy security crises. CO_2 EOR can almost immediately assist with the two challenges of: 1) providing revenue for plants that capture carbon and 2) identifying candidate regions where CO_2 can be permanently stored.

- **Integrated deployment of CCUS EOR can bring widespread economic development:** Essentially undeveloped, the source potential in the Midwest for petroleum recovery is equal to the Gulf Coast and Texas combined. It is important for those states involved to proactively help to remove barriers and align surface and subsurface resources. Multi-plant pipeline systems connecting multiple sources to multiple fields offer significant flexibility and provide a better overall strategy to linking sources and EOR sinks than close coupled systems.

- **CCUS EOR deployment would reduce emissions of CO_2:** Because of the size of the U.S. coal-based generation fleet, retrofitting operating units for capture of CO_2 from the flue gas represents a major opportunity for reducing CO_2 emissions and for providing CO_2 for EOR. The findings indicate that CO_2 captured at many existing U.S. coal power plants could provide large volumes of CO_2 for pipeline transportation to EOR fields.

- **New electricity and CTL coal plants should be strategically sited:** Coproduction plants would be a viable route for providing synfuels in regions where new electricity supplies are needed and would provide a strong basis for economic revitalization of regions such as the Ohio River Valley, an area where many coal power plant retirements

have been announced. New coal-fired power plants will be more efficient, and the CO_2 capture process would be integrated into the plant steam cycle. These new plants should be strategically located near existing or new CO_2 pipelines.

- **A national network of CO_2 Pipelines is needed:** The Permian Basin in West Texas is where CO_2 EOR could be expanded most quickly, but the Ohio River Valley region offers the greatest near-term potential for providing CO_2 for EOR – underscoring the national need for establishing long trunk East-West CO_2 pipelines complementing those already built or being planned (e.g., Rockport-Tinsley).

- **CTL synfuel plants offer benefits of coproduction, inexpensive carbon capture, and high quality fuels:** Stand-alone synfuel plants and coproduction synfuel plants (e.g., plants producing fuels and electricity) offer the lowest capture cost of all the technologies considered, coal or natural gas. These technologies are commercially ready and economically attractive at current world oil prices. Coal/biomass coprocessing plants will significantly expand the use of domestic coal. Synfuel and coproduction plants that capture CO_2 for EOR markets and coprocess modest quantities of biomass with coal would provide liquid transportation fuels with near-zero levels of sulfur and other contaminants.

- **Coal-based CCUS power plants are more economical than natural gas power plants:** Per climate policy goals, carbon capture must be implemented at natural gas power plants as well. For a design capacity factor of 85%, the capture cost for Natural Gas Combined Cycle (NGCC) power plant with carbon capture is relatively high at $57/metric ton. If, as a result of dispatch competition, a typical capacity factor of this plant plants turns out to be 40%, the capture cost would increase to $100/metric ton. Overall, these plants: (a) are likely to fare poorly in economic dispatch competition and (b) would offer very low Internal Rate of Return on Equity (IRRE) values and (c) would have high levelized cost of electricity (LCOE) rates at all examined CO_2 selling prices.

- **CCUS EOR should be recognized as a valid carbon emissions control technology:** Emissions of CO_2 from new and modified coal-fired power plants and other major stationary sources of GHGs are regulated under a variety of federal Clean Air Act (CAA) permitting and emission control programs. Those facilities will only be able to sell their CO_2 for EOR if the U.S. Environmental Protection Agency (EPA) recognizes that activity as a form of emissions control under the CAA.

- **CCUS EOR should be treated as a Class II injection process:** Similarly, CO_2 EOR operators will only be willing to purchase CO_2 from facilities whose emissions are regulated under the CAA if they are not penalized. More specifically, CO_2 EOR operators need to be able to quantify the permanent storage of such CO_2 while continuing to operate their wells under Class II of the federal Safe Drinking Water Act's Underground Injection Control (UIC) program when they purchase coal-derived CO_2.

- **SNG from coal is a viable option:** As demonstrated in a number of previous Council reports, the production of SNG from coal can be an important economically viable option for future gas supplies not only in the United States but also globally.

Recommendations to the Secretary of Energy

The NCC offers the following recommendations to the Secretary of Energy as an outcome of the study:

- **Regulatory Certainty**: Regulatory certainty is necessary for the development of a robust CCUS/EOR industry. The Council recommends that the appropriate federal, state, and local regulatory agencies, with coordination and cooperation from industry, work with the Secretary of Energy to develop a stable and consistent regulatory framework to promote CCUS/EOR technology applications. When this regulatory environment is established, industry will work to develop the necessary implementation technologies for CCUS/EOR.

- **Demonstration Projects**: The DOE has proven its leadership capabilities on regional CO_2 storage projects. Based on these past successes, the NCC recommends that the Energy Secretary meet and work with a wide range of stakeholders (including, but not limited to, coal, electricity generation, petroleum production, chemical manufacturers, and other stakeholders) to find new and innovative ways to develop financial support to create demonstration/early mover projects. Lessons learned from developing Nth-of-a-kind (NOAK) plants will reduce the CO_2 capture costs and promote growth in CCUS/EOR application. Accelerating the widespread deployment of CCUS/EOR technologies will allow the economic benefits to the nation presented in this report to be realized more rapidly.

- **Future Workforce**: Education and training programs are needed to develop the necessary work force with the appropriate skills for implementation of a robust CCUS/EOR industry. While it is incumbent upon industry and the appropriate educational entities to work together to develop and implement such programs, support and encouragement from the Energy Secretary on this educational need is recommended.

- **State Development and Regulatory Practices**: Regulations on the state level will be required to support the concurrent use of CO_2 for EOR and storage of CO_2. Such regulations must be based both on commercial viability and environmental protection. Rules adopted by the state of Texas can be used as a template for other states new to deploying EOR technologies. The Interstate Oil and Gas Compact Commission (IOGCC) has considerable experience in this forum. The Energy Secretary should work with the IOGCC group and similar resources to develop regulatory recommendations for concurrent EOR and CO_2 storage. Under his leadership, a national work group of states and industry representatives could be established to provide expert advice regarding regulations pertinent to the industries involved.

- **Long Distance CO_2 Pipelines**: In order to develop a long distance pipeline network for transport of captured CO_2, regional, large-scale coal-based capture projects must be developed. Industry and the Energy Secretary should collaborate to develop pipeline network scenarios that will incentivize the development of these long distance pipelines.

- **Promotion of EOR Deployment**: The DOE, through the Regional Carbon Sequestration Partnerships, along with private industry, environmental groups, and other appropriate stakeholders, should work together to promote CO_2 emissions capture technologies, CO_2 pipeline construction, and wide-scale deployment of EOR technologies. The DOE is uniquely situated to coordinate this effort that would expedite the implementation of CCUS/EOR in candidate areas of the country thereby speeding and enhancing economic development in these areas.

- **Coproduction Technologies for Liquids from Coal and Biomass**: The advantages of CCUS/EOR technologies will help increase the economic viability of CTL industries in the U. S. The technologies involved in CTL production are mature, thereby presenting reduced technology risks, but would benefit from opportunities that reduce the financial cost of such plants, thereby reducing the financial risk. The Energy Secretary should work with interested parties in the private sector, to develop pathways whereby commercial-scale coproduction plants would be built and demonstrated. Coproduction technologies could include the inclusion of biomass as part of the feedstock.

- **Continued Support for Developing Advanced Coal Technologies**: Industry will continue to conduct research on, and development of, advanced coal technologies as well as work to reduce the cost of capturing CO_2 emissions from coal-based electricity generating plants. The Secretary should assist in coordinating the private sector R&D effort, including recommending congressional support for federal cost sharing and conducting information exchange workshops and meetings with stakeholders, so that advanced coal technologies can be deployed more rapidly in commercial scale operations.

- **Deployment of EOR Technologies**: The Energy Secretary should take advantage of the numerous opportunities he has available to promote the deployment of CCUS/EOR in both domestic and international venues. With this support, and with that of private industry, CCUS/EOR technologies will be a commercial success.

Concluding Comments

Coal is the cornerstone of electricity production in the United States, but that is only the beginning of the story. CCUS presents a powerful opportunity for the U.S. to take even greater advantage of the Nation's vast coal resources to affordably meet energy needs, reach climate policy goals, create new businesses, revive established operations, create jobs, and enhance national energy security. The recognition that CO_2 is a valuable commodity that can be utilized to create wealth for the American people is a sea change in the way we will view coal and other fossil fuels going forward. Adding the "U" to CCS (carbon capture and storage) is the crucial step toward the business model that will unlock the full value of coal for future generations.

Chapter 1: Energy, Socioeconomic, and Regulatory Context

This chapter has two main themes which are presented in the text as Part 1 and Part 2. Part 1 presents an overview of the role of advanced coal technology in meeting energy demand and promoting economic security through electricity generation, coal conversion and particularly CO_2 EOR. Part 2 addresses key regulatory issues which must be resolved if the great promise of CO_2 EOR is to be realized in the United States.

Part 1: Overview of Advanced Coal Technology

1.1 Emissions are Reduced in Advanced Coal Technology Systems

Advanced coal technologies work. NETL (2011) concludes: "Technologies…have helped to dramatically reduce potentially harmful emissions, even as coal use for electricity generation has risen substantially." Specifically, over the last several decades, consumption of coal to produce electric power in the United States has increased over 180%, but regulated emissions such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter have decreased 82%, 88%, and 96% respectively. Now, the creative gaze of the scientific and engineering communities has turned to CO_2, the capture of which the International Energy Agency (IEA, 2010) has labeled "the most important technology option for reducing direct emissions in industry."

Increased efficiency at supercritical and ultra-supercritical coal-based power plants is leading to significant reductions in emissions. Coal gasification power processes could reduce the formation of CO_2 by 40% or more, per unit of output, compared to today's conventional coal-burning plant (DOE, 2012). Related research anticipates increasingly greater efficiency, lower costs, and reduced emissions. The DOE has also created seven regional partnerships to advance technologies for capturing and permanently storing GHGs that contribute to global climate change. These partnerships have become important components of the continuing trek toward 90% capture with moderate increases in electricity costs.

In essence, new advanced coal technologies are both emerging and being refined to not only reduce CO_2 production but also to use it beneficially. CO_2 is a valuable byproduct of fossil fuel consumption and coal will serve as the primary source to obtain adequate supplies for CCUS. As the European Center for Energy and Resource Security (2011) recently noted, "CO_2

should not be looked at as a waste product...it can have economic value." The wealth creating opportunities will soon supersede the view that the geological sequestration of CO_2 is more than a waste disposal business.

The present report pursues this concept of utilization and responds directly to the Secretary of Energy's request for a study that focuses on CCUS, especially as it relates to the use of CO_2 for tertiary operations (EOR). CO_2 EOR is the CCUS approach providing the greatest economic pay off over the next several decades. Synfuel and coproduction facilities using coal also provide affordable modes of producing liquid fuel, and in the case of the latter, producing electricity as well. These technologies are all powerful pathways toward climate policy goals, economic growth, and greater oil production. The underlying theme of the CCUS initiative is to develop a process driven by business economics: "By putting the captured CO_2 to use, CCUS provides an additional business and market case for companies or organizations to pursue the environmental benefits of CCS" (DOE, 2012).

Moreover, as the International Energy Forum (2012) points out, CO_2 EOR is of particular promise because it will be a "catalyst," accelerating commercial deployment of CO_2 reduction technologies such as CCS. The National Resources Defense Council (2012) states "CCS needs to be ready to scale up substantially by 2020 and EOR could make it happen." The large-scale deployment of CCS is crucial for the world to meet climate change mitigation targets. Such deployment "is an element of any least-cost approach to reducing CO_2 emissions while meeting growing domestic energy demands and addressing energy supply challenges" (CCUS Action Group, 2011).

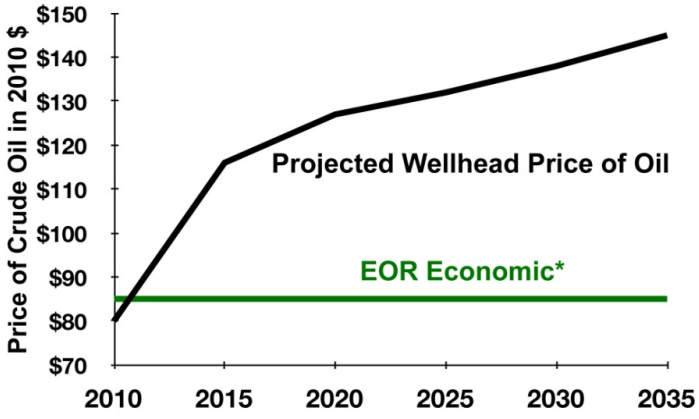
CO_2 EOR is already an established technology in the United States with over 125 projects providing more than 5% of domestic oil production. In 2012, the process will yield some 350,000 bbl/d through the injection of almost 60 million metric tons of CO_2 transported over 4,000 miles of pipeline. Various studies have indicated that CO_2 EOR can be greatly expanded in the United States to the level of millions of bbl/d. This expanded supply of oil would improve the balance of trade by reducing dependence on oil imports, stimulate the economy, create jobs, and generate substantial tax revenues.

The CO_2 EOR process provides the primary means to utilize ever larger volumes of CO_2 for societal benefit. The U.S. reserve potential for tertiary recovery is great and exists in dozens of states – from Texas to California to Ohio to Mississippi. In fact, about half of the reservoirs in

the contiguous United States are amenable to CO_2 EOR. In a report for NETL, ARI (2012) found that next-generation technology will enable the economic recovery of 67 billion barrels of "stranded oil" assuming an oil price of $85/barrel. And that is clearly the world we face. The EIA (2011) has projected that oil prices will exceed $100/barrel to the 2035 forecast horizon (see Figure 1.1).

Figure 1.1: CO_2 EOR Production is Increasingly Economical

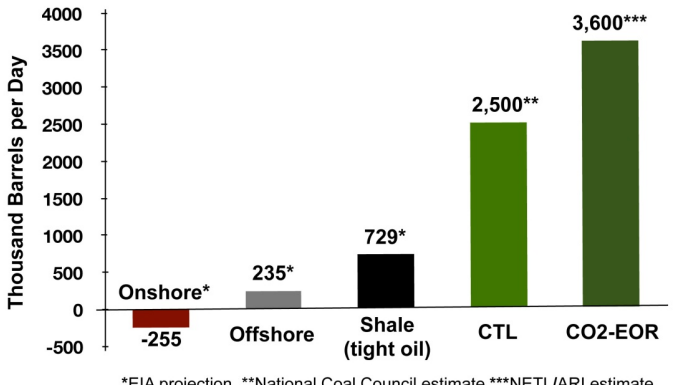
(EIA, International Energy Outlook, 2011)



"In 2035, the average real price of crude oil in the Reference case is about $145 per barrel in 2010 dollars, or about $230 per barrel in nominal dollars," EIA, 2011

Development of this vast resource over a 50-year period would yield an average of upward of four million bbl/d. Even with the current excitement over the tight oil (shale) resources, there is little doubt that the potential output from CO_2 EOR could far surpass other projected domestic sources of oil supply in the United States (see Figure 1.2). Further, as the Council has noted in previous reports, 475 million tons of coal a year can be converted into at least 2.5 million bbl/d (CTL). Thus, by 2035, the tandem of CO_2 EOR and CTL could provide close to 30% of our projected liquid fuel consumption and enhance America's energy security for decades.

Figure 1.2: Projected Incremental Crude Oil Production Relative to CTL and CO_2-EOR Potential



Tight oil production is projected to peak at 1.3 million bbl/d and not provide more than 7% of U.S. demand through 2035

As impressive as these numbers are, however, it must be noted that the ARI estimates generally do not include potential from ROZ production. The scale of the ROZ resource is not known but, independently, both Trentham (Pickett, 2012) and Meltzer (2012) have indicated the ROZ may contain over 100 billion barrels. As for the nationwide resources, Meltzer has left the question open-ended: "It is Very Clear to Us Now that ROZ Targets are Immense – But Just How Large are They?"

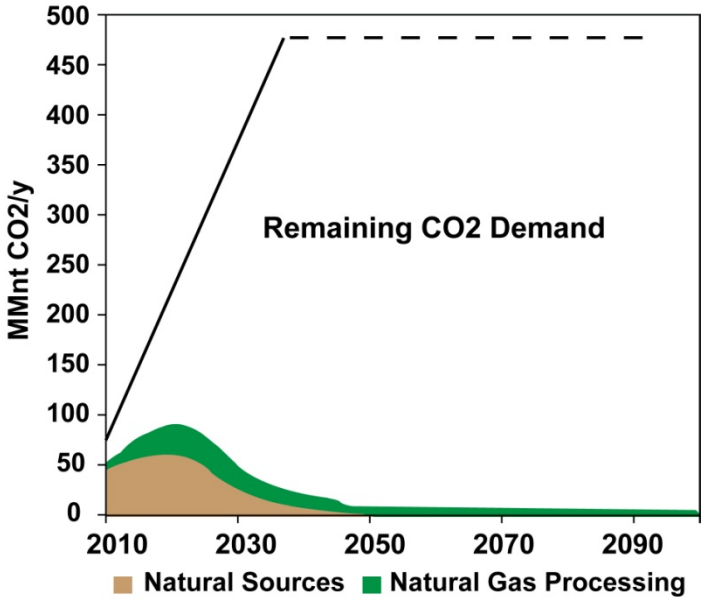
In recent work, Kuuskraa (2012) estimated that the U.S. ROZ could contain over 33 billion barrels of oil economically recoverable with next-generation CO_2 EOR technology. The additional resource would take the ARI estimate of oil recoverable through CO_2 EOR at $85/barrel to 100 billion barrels – an average of over 4 million bbl/d for more than half a century.

1.2 Coal Can Meet CO_2 Demand at Scale

The *sine qua non* of CO_2-based EOR is the availability of adequate amounts of CO_2. Lack of availability has been and continues to be a major constraining factor in greater CO_2 EOR production. Tracy Evans, former President of Denbury Resources, confirms that "The single largest deterrent to expanding production from CO_2 EOR today is the lack of volumes of reliable and affordable CO_2" (Gunther, 2012). In key areas such as the Permian Basin, CO_2 supply is severely constrained and prices have reached over $35/ton. New projects are being delayed due to a lack of CO_2. In essence, the market will remain supply constrained and be dictated by the rate at which carbon capture deployment enables new supplies of CO_2 EOR.

Industry experience indicates that one metric ton of CO_2 will produce one to four barrels of oil depending on the reservoir and the EOR techniques employed by the operator. Expansion of the recoverable volumes of oil using anthropogenic CO_2 (using ARI 2011 estimates) is projected to create by 2035 an additional 67 billion barrels of oil using approximately 18 billion metric tons of CO_2 stored in geologic formation through EOR. The benefits will be enormous. Storing 500 million metric tons of CO_2 a year would equate to removing over 80 million vehicles from America's roads.

Figure 1.3: CO_2 Supply and Demand



"The only way to increase oil production from EOR is to boost supplies of CO_2 EOR from man-made sources in a manner suitably calibrated to the full potential of EOR," National Enhanced Oil Recovery Initiative (NEORI), 2012

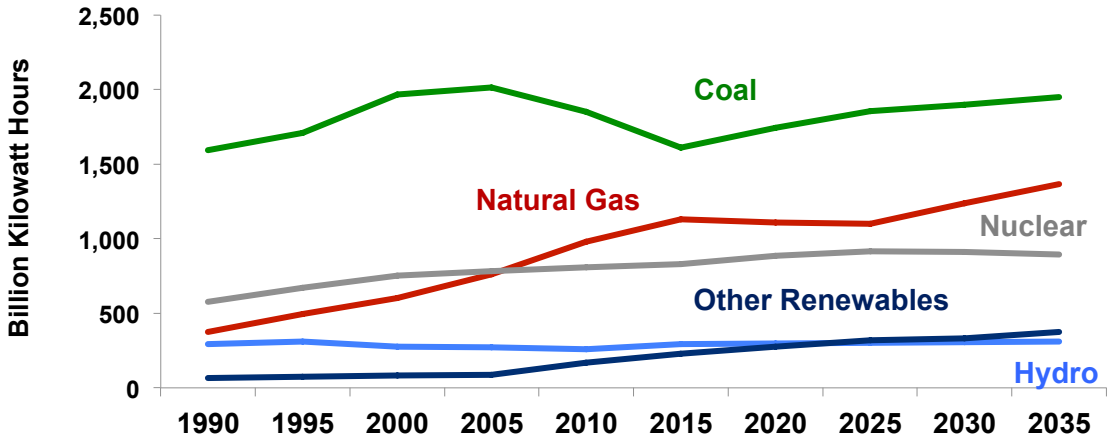
If potential ROZ production is included per Kuuskraa, required CO_2 reaches 33 billion metric tons. Regardless of the scenario, large-scale development of CO_2 EOR will require massive amounts of CO_2, economically derived from large concentrated stationary sources, e.g., coal generation along the Ohio River Valley, one of the regions hit hardest by the national decline in manufacturing. These large supplies of CO_2 are available at such coal-based power plants and also at potential coal conversion facilities like CTL plants. Coal consumption is a leading source of man-made CO_2 and can serve as the foundation for the vast amounts required. And, since coal generation will continue to be the leading source of electric power in the United States, it will provide a steady, affordable, and reliable source of CO_2 (see Figure 1.4). The Midwestern Governors Association (MGA) has posited CO_2 EOR as especially viable for the 12-state MGA region. In essence, the Midwest could serve as the emerging focal point of broader CO_2 EOR for five main reasons:

- large stationary sources of CO_2 in the form of coal power plants
- vast reserves of oil in place
- substantial storage areas
- need for revitalization of manufacturing sector
- manufacturing base for the heavy equipment needed for CO_2 EOR (i.e., compressors, steel, recycle plants)

The MGA expects that even with increases in production of alternative energy sources coal will "remain a large supplier of energy for the Midwest in the years ahead" (ARI, 2009).

Figure 1.4: The Continuing Leadership Role of Coal in Power Generation

(EIA, Annual Energy Outlook, 2012)



Specker and his colleagues (2009) have indicated that over 180 GW of coal-fired boilers 300 megawatts (MW) plus are candidates for capture retrofit in the United States. In *America's Energy Future* (2009), the NAS indicated that through a combination of: (a) CCS retrofitted and repowered coal plants and (b) new coal generation with CCS "the entire existing coal power fleet could be replaced by CCS coal power... 10 GW of demonstration fossil-fuel CCS plants could be operating by 2020... 5 GW per year could be added between 2020 and 2025, and a further 10–20 GW per year from 2025..." Further, research at the DOE (2012) anticipates substantial improvements in clean coal technologies are on the way for coal plants that incorporate CCUS:

- Cost of generating electricity could be reduced up to 37%
- Efficiency increased by up to 43%
- Cost of avoiding CO_2 emissions reduced by as much as 82%
- Cost of capturing CO_2 reduced by as much as 82%

In a recent presentation, Kuuskraa (2012) indicated the captured CO_2 emissions from a large segment of this new coal fleet could be accommodated by EOR projects throughout the

nation, pending construction of adequate pipelines and adequate infrastructure (development processes which would strongly stimulate the manufacturing sector). The far ranging benefits of CO_2 EOR CO_2 argue for a "source to sink" pipeline network capable of transporting vast amounts of CO_2 from largely stationary sources to oil fields across the country (see Figure 1.5).

Figure 1.5: Demand for CO_2 – Number of 1 GW Size Coal-Fired Power Plants

(Advanced Resources International, 2012)

Reservoir Setting	Number of 1GW Size Coal-Fired Power Plants***	
	Technical	Economic
L-48 Onshore	170	90
L-48 Offshore/Alaska	31	14
Near-Miscible CO2-EOR	5	1
ROZ**	34	28
Sub-Total	**240**	**133**
Additional From ROZ "Fairways"	**86**	**43**

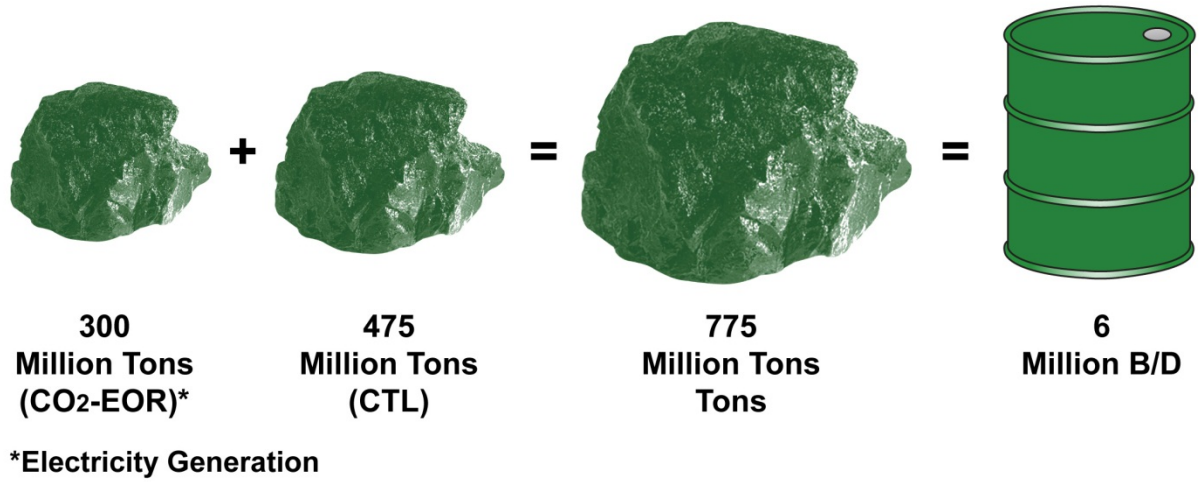
*At $85 per barrel oil price and $40 per metric ton CO2 market price with ROR of 20% (before tax)
**ROZ resources below existing oilfields in three basins; economics of ROZ resources are preliminary
***Assuming 7 MMmt/yr of CO2 emissions, 90% capture and 30 years of operation per 1GW of generating capacity; the U.S. currently has aproximately 309 GW of coal-fired power plant capacity

"CO_2 EOR ...can accommodate a major portion of the CO_2 captured from coal-fired power plants for the next 30-40 years," Kuuskraa, 2012

In order to develop a point of reference, an Aspirational Case is presented based upon previous work by the Council as well as the work by the NAS and by Kuuskraa/ARI/NETL. In essence, such an Aspirational scenario posits: (a) continued reliance on America's extensive fleet of coal power plants, (b) the development of 100 GW of coal-based generating capacity with CCS over the next two decades, about half retrofits and half new builds, (c) CTL facilities with CCS to produce 2.5 million bbl/d of transportation fuels, and (d) the utilization of over 500 million metric tons of CO_2 a year to produce 4 million bbl/d through CO_2 EOR for over 40 years. Assuming, as Kuuskraa (ARI) suggests, that coal accounted for enough CO_2 through EOR to offset the emissions of upwards of 100 GW of coal capacity, over 300 million tons of coal would be required. Adding the 475 million tons needed for 2.5 million bbl/d through CTL means coal demand of almost 800 million tons – perhaps 600 million of which would be new demand,

taking total coal consumption to over 1,700 billion tons per EIA projections. The reward, however, would be great – over 6 million bbl/d – double what the UAE produced in 2011 (see Figure 1.6).

Figure 1.6: More Coal = More Liquid Fuel Security



The coal endowment of the United States can surely meet this new demand:

> ***"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,"***
>
> **National Academy of Sciences, 2009**

As research presented elsewhere in this report demonstrates – and as supporters of CCUS have argued extensively – these activities will enable new industries to be created and established businesses to expand:

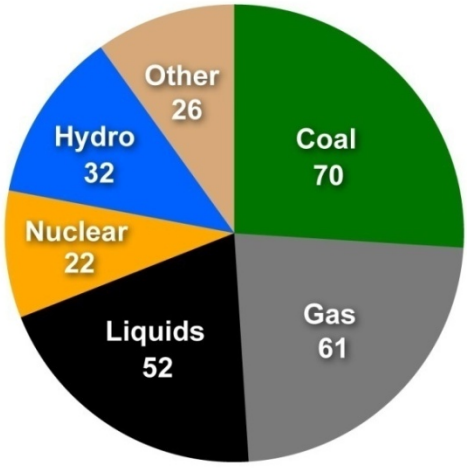
> **"A conceptual Ohio CO_2 pipeline was developed and mapped to reflect planned CO_2 sources and depleted oil fields that could be viable for EOR... (this) CO_2 pipeline and EOR activity in the state of Ohio would positively impact 13,000 establishments and 136,000 employees. This represents 2.5 percent of all Ohio workers," (see Pew Center on Global Climate Change, 2008)**

1.3 Scale of Societal Growth Sets the Context

While the magnitude of producing 67 billion barrels of oil using 20 billion tons of captured CO_2 and utilizing an additional 15-20 billion tons of coal appears daunting, one must remember the rising tide of growth that looms ever larger in the United States – and across the globe. The world grows apace and the scale of that growth is unprecedented. By 2030, less than 20 years from now, the planet will be home to over 8.5 billion people, the global economy will exceed $140 trillion, and energy consumption will approach 725 quadrillion British Thermal Units (Btu) (EIA, 2011). Importantly, as these macro trends continue to unfold, affordability, availability, and reliability will keep coal the most rapidly growing energy source (see Figure 1.7).

Figure 1.7: Incremental Energy Demand through 2035 in Quadrillion Btu

(IEA, World Energy Outlook 2011)



Over the first three decades of this century, coal's share of global energy consumption will have increased over 105%.

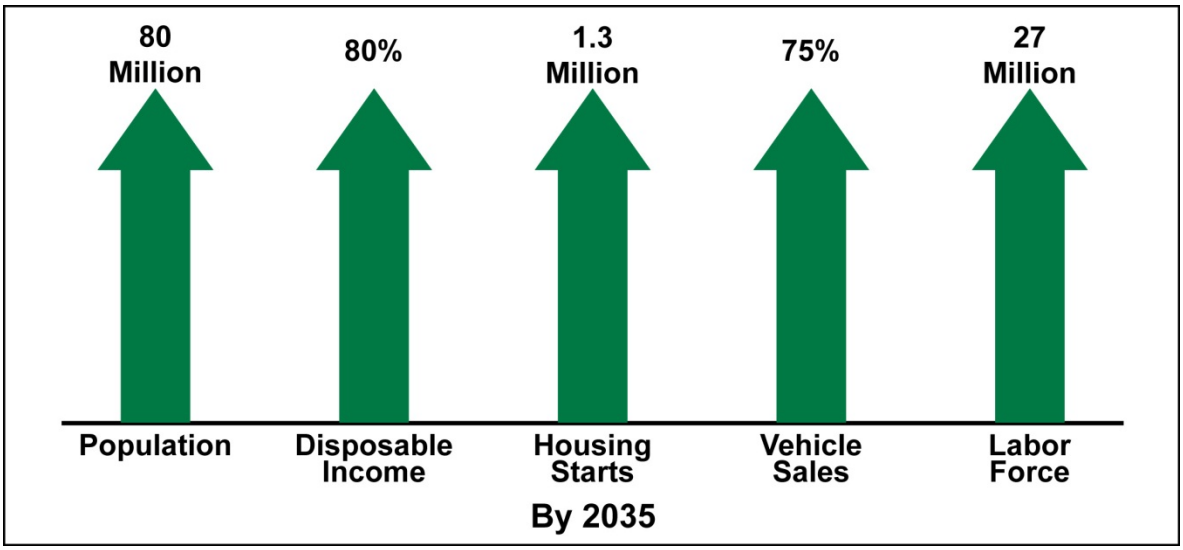
Yet, despite this rapid growth, hundreds of millions of people will be left in the energy backwater, victims of poverty and electricity deprivation. The IEA projects that over 1,030 million people will be "living" without electricity in 2030, or just about two current European Union's worth of humanity. In addition, hundreds of millions more will have extremely limited access to electricity, meaning just a few hours or days a week. For yet others, power will remain dangerously unaffordable.

Within this global panorama, America remains a growing nation (see Figure 1.8). Each year, we add approximately three million people to the population. This actually exceeds the growth of the world at large. Between 2009-2035, the population of the United States will grow 28%. The population of the world will increase only 26% during the same time period**.** More and

more Americans will live in cities. For instance, the number of people living in urban areas in the United States will increase by about 70 million – a population almost equivalent to two Californias.

Figure 1.8: The United States is a Growing Nation: Increases in Just 25 years

(EIA, International Energy Outlook, 2011)



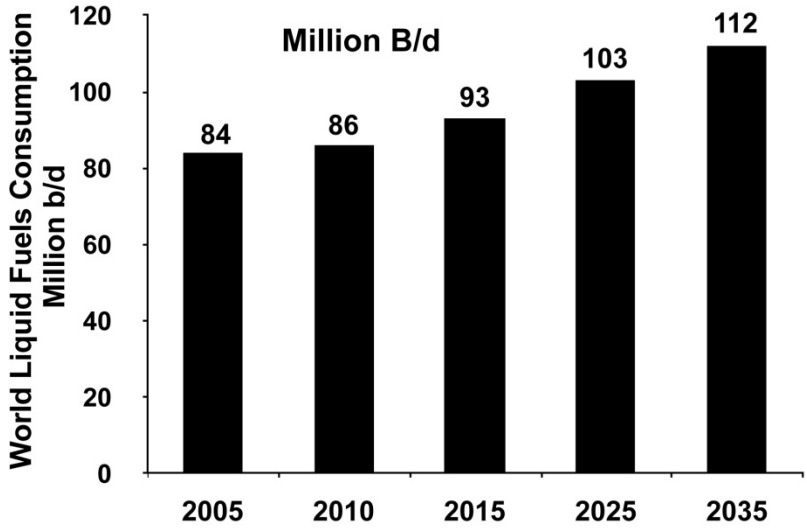
Like the rest of the world, the United States faces the issues of meeting energy demand and economic growth while reaching climate change goals – all within the context of affordability, reliability, and energy security.

1.4 Energy Security Through Coal – Increasing Supplies of Liquid Fuel

The demand for oil grows apace as more nations strive to increase supply to meet the needs of their population (see Figure 1.9). In an era of rapidly rising demand, high levels of geopolitical tension, and tight spare capacity, the price of crude oil is becoming increasingly high and volatile. For the U.S. economy, which is almost entirely dependent on petroleum for mobility, this volatility represents a significant vulnerability. Volatility creates uncertainty, and uncertainty significantly impacts planning and budgetary decisions, resulting in less efficient resource allocations and ultimately preventing the U.S. economy from maximizing its potential.

Figure 1.9: Projected Global Oil Demand

(EIA, International Energy Outlook, 2011)



In 2035, the United States will still account for 20% of global liquid fuel consumption – and depend upon liquids to meet 35% of energy demand

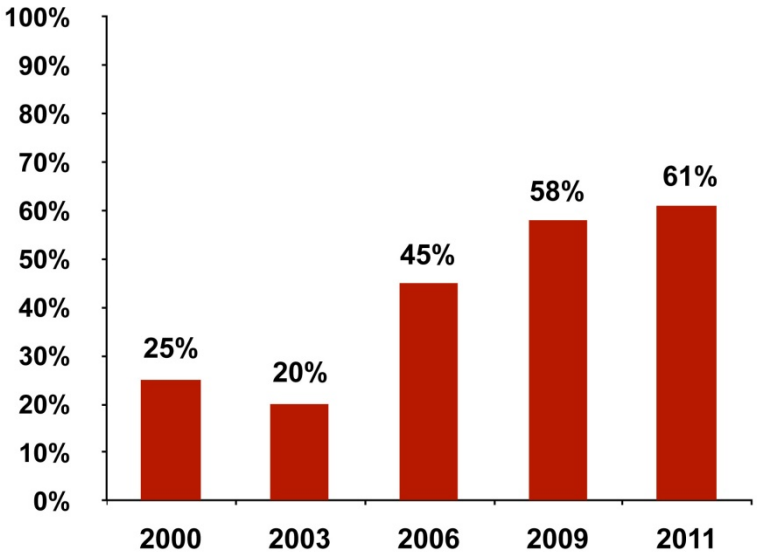
Dependence means loss of control. A key consequence of this dynamic is that "changes in oil supply or demand anywhere tend to affect prices everywhere" (Energy Leadership Council, 2012). For decades, energy security has been a concern for the United States. Every administration since Lyndon Johnson has stressed the importance of a secure supply of energy – particularly oil. As domestic oil production waned in the United States demand increased and imports grew steadily. Higher prices coupled with the risk of imports from unstable and even hostile nations have led to chronic concern about the balance of trade as well as energy security (see Figure 1.10). By 2010, the United States imported over half of its oil. In fact, importing nations around the world have been paying an increasingly heavy price. Professor Ruud Weijermars, of the University of Texas Bureau of Economic Geology (2012), reports "last year, oil-importing nations jointly transferred $5 billion per day to oil exporting ones."

In his turn, President Obama has called for a 33% reduction in oil imports by 2025 – approximately 3.5 million bbl/d fewer barrels of foreign oil. As the competition for global liquid supply increases, future world production is largely dependent upon forces outside our control. To meet global oil demand by 2030, the IEA's required investment estimates have been consistently escalating. For example, in 2004, the IEA concluded that the world oil system needed $3 trillion by 2030; in 2007, it was $5.4 trillion; and in 2010, $6.5 trillion. The IEA's *World Energy Outlook 2011* now reports that $10 trillion is needed to meet projected demand

from 2011-2035, with the capital intensive upstream sector accounting for 85%. Sunken economies and spreading resource nationalism continue to make these investments less likely.

Figure 1.10: Petroleum as a Percentage of the U.S. Trade Deficit

(Bureau of Economic Analysis, 2012)



"Increasing domestic oil supplies through EOR will not only improve energy security, it will reduce trade deficits, strengthen the overall health of our economy and reduce CO_2 emissions," NEORI, 2012

In 2001, the average U.S. household spent approximately $1,750 dollars on gasoline, equivalent to 4.2% of the median household income. Over the following six years, as oil prices marched steadily upward, household spending on gasoline increased as well, reaching almost $3,800 in 2008 – or about 7.5% of the median household income. This increase of more than $2,000 per household essentially functioned as a kind of tax, providing no additional consumer value of any kind relative to 2001 (Energy Leadership Council, 2012). These economic losses continued as average household spending on gasoline reached a record $4,060 in 2011, equal to 8.2% of the median household income (Energy Leadership Council, 2012). Coal's support of conversion to liquid fuels and CO_2 EOR can significantly change this situation.

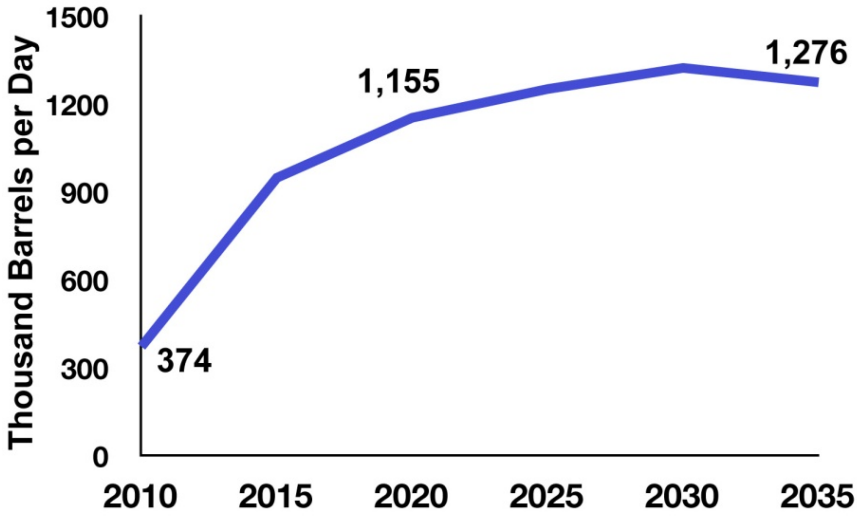
1.5 Tight Oil Has Increased U.S. Production

One significant positive which has emerged in domestic oil production relates to the rise of tight oil from shale formations (see Figure 1.11). These unconventional plays have produced an additional almost 600,000 bbl/d since 2005 and EIA projects another 400,000 bbl/d will be

added by 2020. This is a highly constructive amount but relatively small on the global or even national scale, especially given the fast decline rates for conventional oil.

Figure 1.11: U.S. Tight Oil Production

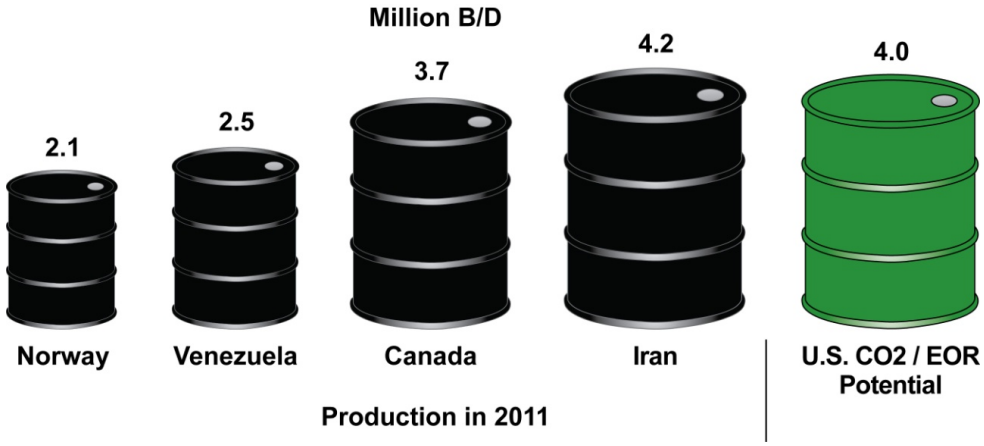
(EIA, International Energy Outlook, 2011)



The long-term value and potential scale of coal supported liquid fuel substantially exceeds the prospects for tight oil. Coal provides the opportunity to dramatically offset many of the current imports and to significantly reduce pressure on the United States regarding competition for oil in global markets. The case for using coal and coal byproducts to produce fuel is greatly enhanced by the difficulties in predicting sources of oil supply as well as price in an increasingly dynamic world. An example of how coal with CCS can significantly improve this energy security situation can be drawn from the very plausible scenario of increased supplies of liquid fuels from coal conversion and EOR: (1) NAS (2009) has indicated that between 2-3 million bbl/d could be obtained through coal conversion to liquid fuels with CCS and (2) ARI (2009) has indicated an incremental 3.6 million bbl/d of liquid fuels can be obtained through CO_2 EOR (see Figure 1.12). Producing an additional 6 million bbl/d through CTL and CO_2 EOR would have a dramatic impact on U.S. liquid fuel supplies.

Figure 1.12: Stranded Oil in the U.S. is a World Class Resource

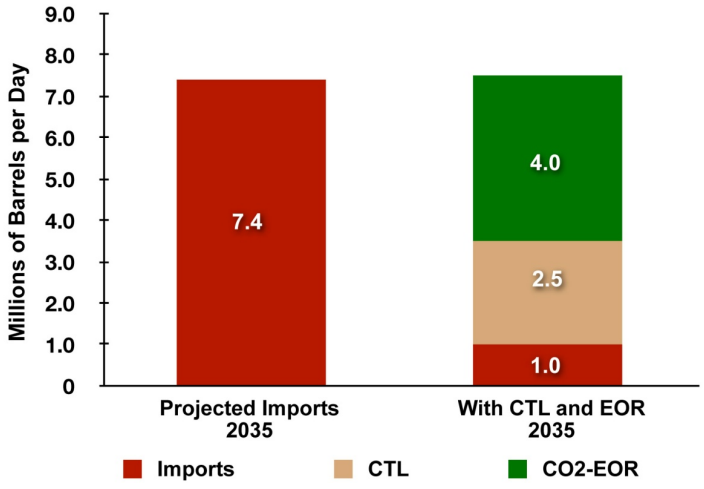
(EIA, 2012)



"Coal-to-liquid fuel production, with or without CCS, is the least expensive option for producing alternative liquid fuels" IEA

Producing such an amount domestically would not only improve U.S. energy security, but the security of the world as well. By 2035, both the EIA and IEA project global consumption to be over 110 million bbl/d, compared to 88 million bbl/d in 2011. While there is some debate over where and how this oil will originate, there is little doubt that the socioeconomic and demographic trends taking place now will dictate demand. In short, liquid fuel demand is more predictable than supply – or price. The abundance, distribution, affordability, stability, and security of coal all place the United States in a very advantageous position. Coal can provide the pathway to meet – and significantly exceed – President Obama's goal for reduced oil imports (see Figure 1.13).

Figure 1.13: The Powerful Impact of Coal Supported Liquid Fuel Production



1.6 The Role of the National Coal Council

Few organizations have been more consistently supportive of CCS development and deployment than the Council. For over a decade, the Council has issued a series of reports delineating how the United States can use coal to solve many of our most pressing energy needs regarding electricity, liquid fuels, and natural gas. These reports deal with a variety of issues but have one common theme – how coal and its byproduct, CO_2, can be used to meet environmental, energy, and economic goals:

- 2000 – "It is imperative that CO_2 sequestration and generation efficiency become high priorities for Department of Energy research."
- 2003 – "The Department should expedite research on a wide range of CO_2 capture options and expand the core R&D and demonstration programs."
- 2006 – "The U.S. must develop strategies to adopt CCS technologies…By ardently pursuing the required research, development & demonstration."
- 2008 – "CCS technologies must be developed and made commercially available."
- 2009 – "Coal-based generation with CCS will enable the U.S. to meet the President's twin goals of an 80% reduction in CO_2 emissions amid sustained economic and employment growth."
- 2010 – "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."
- 2011 – "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."

In terms of CCUS, the Council has been equally supportive: stating in 2011 that CCUS is 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 provide leadership in order to advance the development and deployment of CCUS technologies in a technically feasible, cost effective, and timely manner. These prior recommendations by the Council have been reflected in growing widespread agreement that coal-based technology with CCS is the pathway to

unlocking the full economic value of coal while protecting the environment and enhancing energy independence.

Part 2: Key Regulatory Issues for CO_2 EOR Deployment

2.1 Regulations Will Stimulate Investments in CO_2 EOR

It is widely recognized that a coherent regulatory framework is needed to enable full development of CO_2 EOR and other benefits of coal. Such a framework will require coordinated efforts both within the federal government as well as with the states. This section explains why it is imperative that the Administration recognize that coal-fired power plants and other stationary sources of GHGs may sell CO_2 for use in EOR to satisfy the sources' federal CAA GHG permitting and emission control requirements.

Policies to promote CCUS typically start from the premise that the CO_2 EOR industry, which has been safely injecting and storing CO_2 for decades, will jumpstart CCUS by making use of proven oil and gas reservoirs and infrastructure while providing a critical commercial impetus to CCUS through CO_2 sales and the production of additional oil.[i] This is not to suggest that CO_2 EOR is a panacea that will make CCUS economic or overcome hurdles such as the need to commercially demonstrate CO_2 capture technologies. CO_2 EOR is a capital intensive industry even when natural sources are used, and operating costs and challenges are increased when non-natural sources are contemplated. The Clean Air Task Force has estimated that revenues associated with CO_2 EOR projects are alone insufficient to close what has been described as the "CCS gap."[ii] This said, it is also understood that if any amount of CO_2 is going to be stored for the foreseeable future, it is going to be done by the CO_2 EOR industry.[iii]

2.2 Regulation of Stationary Source GHG Emissions Under the CAA

The CAA regulation of GHG emissions such as CO_2 is based upon the EPA's December 7, 2009 Endangerment Finding, which reached two conclusions. First, that under section 202(a)(1) of the CAA, a mix of six atmospheric GHGs – CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride – constitute "air pollution" reasonably anticipated to endanger public health and welfare. Second, the U.S. Environmental Protection Agency (EPA) determined that these six gases together equal a single "air pollutant" emitted by new automobiles that contributed to harmful "air pollution." Thereafter, the EPA

finalized related actions that ultimately culminated in the agency asserting legal authority to regulate GHG emissions from certain new and modified stationary sources.[iv] The EPA regulates GHG emissions from certain new and modified stationary sources under several CAA programs.

PSD: Under the Prevention of Significant Deterioration (PSD) program, permitting requirements currently cover: (1) new construction projects that emit at least 100,000 tons/year even if they do not exceed the permitting thresholds for any other pollutants and (2) modifications at existing facilities that increase GHG emissions by at least 75,000 tons/year even if they do not significantly increase emissions of any other pollutant.

The PSD program requires regulated stationary sources to implement Best Available Control Technology (BACT) to control GHG emissions. The EPA has recognized that CCUS could be deemed BACT if and when numerous technical and legal hurdles are met in the years ahead, including the commercial demonstration of CO_2 capture technologies in relevant industrial operations.

Title V: Under the title V program, facilities that emit at least 100,000 tons/year CO_2 are required to obtain CAA operating permits.

New Source Performance Standards: On March 27, 2012, the EPA proposed New Source Performance Standards (NSPS) for New Electricity Generating Units (EGUs), *77 Fed. Reg. 22392*. The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW electric to meet an output-based standard of 1,000 pounds of CO_2 per MW which is based on the performance of NGCC technology.

2.3 Regulation of CO_2 EOR

CO_2 EOR operations are subject to numerous environmental requirements, one set of which – those dealing with underground injection – is particularly relevant here. Operating under authority of the federal Safe Drinking Water Act (SDWA), the EPA's UIC program regulates the construction, operating, permitting, and closure of injection wells that place fluids underground for EOR, storage, and disposal. The UIC program is intended to protect Underground Sources of Drinking Water (USDWs). Different levels of regulation, identified by specific well classes, apply depending on the nature of the operations and the fluid(s) being injected.

UIC Class II: UIC Class II wells inject fluids associated with oil and natural gas production, and therefore also apply to CO_2 EOR. Approximately 144,000 Class II wells are in

operation in the United States, most of which are located in Texas, California, Oklahoma, Kansas, and Mississippi. All of these states, along with numerous others, have primacy over the UIC Class II program, which means they have primacy enforcement responsibility after their regulations were approved by the EPA. In order to obtain primacy, these states had to demonstrate to the EPA that their existing oil and gas regulations were "effective" in protecting USDWs.[v] State-based UIC Class II well programs have been protecting USDWs for decades, and CO_2 EOR operators are knowledgeable operating under the applicable regulatory requirements.

UIC Class VI: UIC Class VI wells, in contrast, inject CO_2 for the commercial purpose of "geologic sequestration."[vi] UIC Class VI is a new program and no Class VI wells have been permitted to date. UIC Class VI is a federal program – i.e., it is implemented by the EPA – because no state has yet been granted primacy to implement it.[vii]

In comparison with UIC Class II, compliance with the UIC Class VI well program is overly burdensome, complex, and costly – and more significantly, not conducive to or compatible with CO_2 EOR operations.

For example, CO_2 EOR involves evolving development of a reservoir to take advantage of oil recovery response to the CO_2 injection pattern. Placement of injection wells and producing wells change as the EOR operation matures. The non-commerciality of the Class VI well requirements would prevent an EOR project from even commencing, given the number of injection wells required for such an endeavor.

Further, as an additional example, following the cessation of sequestration injection, the owner or operator of a Class VI well must continue to conduct monitoring of the site, as specified in the EPA-approved post-injection site care and site closure plan, for a default period of at least 50 years.[viii] No such requirement exists under the UIC Class II program nor would it be commercially feasible for an operator to do so. That is why state regulatory schemes include plugging funds for future remediation.

Finally, unless a waiver is granted, injections under Class VI requirements may only occur below the lower most USDWs in a formation – a requirement that could effectively prohibit the use of some CO_2 EOR fields as storage sites altogether. The EPA has published voluminous guidance under the UIC Class VI program, with more guidance expected in the

coming months and years.[ix] That guidance collectively suggests that EPA may disfavor CO_2 EOR under UIC Class II as a carbon storage technology.

To date, none of the published guidance discusses the use of CO_2 EOR under UIC Class II to satisfy stationary CO_2 source permitting or other GHG emission control requirements. The UIC Class VI well program regulations state that "[o]wners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit where there is an increased risk to USDWs compared to Class II operations."[x] The relevant regulator – currently, the EPA unless and until a state seeks and is granted primacy – retained authority for determining if the injection is for production or storage and therefore, if the CO_2 EOR owner/operator must obtain a UIC Class VI permit.[xi] The EPA must weigh nine factors in making that determination.[xii] This provision is helpful because it leaves open the door for sequestration to be conducted under UIC Class II regulations. Unfortunately, however, the provision also creates commercial uncertainty and imposes significant barriers to projects moving forward.

2.4 GHG Emissions Reporting

The EPA has separately finalized GHG emissions reporting regulations that are relevant for CO_2 EOR operations. Formally known as the "Mandatory Reporting of Greenhouse Gases Rule," the regulations were published by the EPA on October 30, 2009.[xiii] As originally finalized, these regulations applied to "Suppliers of Carbon Dioxide" under provisions known as "Subpart PP." Subpart PP reporting is limited to the upstream capture of CO_2, not the subsequent downstream injection or use of that gas. The EPA emphasized that subpart PP is "focused on upstream supply" and does not cover the "use of CO_2 in enhanced oil and gas recovery."[xiv] The EPA further stated that it recognized that not all CO_2 uses are "emissive" to the atmosphere, stating:

> In today's final rulemaking, CO_2 suppliers must provide information on the downstream CO_2 application, if known. The EPA believes information on the end-use will provide some idea of the amounts of CO_2 which are emitted [i.e., released to the atmosphere]. Where that end-use is geologic sequestration (at EOR or other types of facilities), the EPA will need additional information on the amount of CO_2 that is permanently and securely store and on the monitoring and verification methodologies applied. With respect to EOR, the geology of an oil and gas reservoir can create a good barrier to trap CO_2 underground. Because

> these formations effectively stored oil or gas for hundreds of thousands to millions of years, it is believe that they can be used to store injected CO_2 for long periods of time.[xv]

On December 1, 2010, the EPA published new emissions reporting regulations that specifically applied to certain geologic injection activities.[xvi] The new regulations created two new subparts to the basic GHG reporting regulations: (1) subpart RR, which applies to the non-CO_2 EOR geologic sequestration of CO_2 and (2) subpart UU, which applies to the injection of CO_2 for EOR purposes. Subpart RR notably requires the use monitoring, reporting, and verification – or MRV – plans to verify the amount of CO_2 that has been stored.

2.5 Regulatory Impediments to the Use of CO_2 EOR to Satisfy Stationary Source GHG Emission Control Permitting & Requirements Under the CAA

Because it is likely that the use of CO_2 EOR will lead the deployment of CCUS with CO_2 supplies coming from CAA-regulated sources, it is imperative that an appropriate regulatory regime accommodate that outcome while ensuring adequate protection of the environment and public health with adequate margins for safety.

An appropriate regulatory regime is necessary for several reasons. For starters, there is no legal requirement that CO_2 EOR operators acquire CO_2 from anthropogenic sources, particularly those that are subject to GHG emissions controls under the CAA. The purchase and use of CO_2 by a CO_2 EOR operator instead is a private commercial business decision as opposed to the result of a government mandate. If the government burdens the purchase of anthropogenic CO_2 with needless legal and regulatory mandates, particularly when the industry already has been safely and effectively storing large and increasing volumes of CO_2 since the early-1970s, CO_2 EOR operators may pursue other options. Additionally, if CAA-regulated sources do not receive legal recognition for CAA objections of their CO_2 sales to EOR, they will be discouraged if not legally prohibited from engaging in that practice.

Additionally, there is legal and policy tension between the industrial source, which may view its CO_2 EOR operator as a provider of emissions control services, and the CO_2 EOR operator, who owes a duty to its mineral owners to view itself as being in the oil production business as opposed to the CO_2 management/storage business. Unfortunately, the regulatory

regime for CCUS that has emerged in recent years tends to frustrate and hinder, not foster, the use of anthropogenic CO_2 from CAA-regulated sources for EOR:

- ✓ *None of the CAA GHG stationary source programs stipulate that CO_2 EOR under UIC Class II may be used to satisfy GHG permitting or related emission control requirements.* The proposed NSPS for new EGUs is silent on the use of CO_2 EOR to meet the new requirements. The EPA's permitting guidance for the PSD and title V programs, meanwhile, suggests that the "economics of CCUS" could be made more favorable where the CO_2 is "sold for enhanced oil recovery" but likewise falls short in endorsing the practice as a means of CAA compliance.[xvii]

- ✓ *To date, neither the EPA nor any state has issued a PSD or title V permit that recognizes CO_2 EOR conducted under UIC Class II as a means of CAA compliance.*

- ✓ *The EPA has never clarified whether a CO_2 supplier may satisfy its CAA permit or other GHG emission control requirement by ensuring that it sells its CO_2 to an UIC Class II EOR operator that has opted into the Subpart RR Mandatory Reporting of Greenhouse Gases regulations, which include a MRV requirement.* A modest amount of MRV should be sufficient to verify that storage is occurring.

3 Recommendations

The Council strongly recommends that the states adopt CO_2 regulatory injection programs in keeping with the EPA's recognition that CO_2 utilization for EOR is a recognized form of geologic storage. In addition, we urge the Administration take appropriate regulatory actions to clarify that CO_2 EOR as currently conducted under UIC Class II, with or without a modest amount of MRV, constitutes "storage" from the perspective of a stationary source of GHG that is regulated under the CAA.

Experts agree and acknowledge that current CO_2 EOR operations conducted under UIC Class II result in nearly 100% storage. CO_2 EOR is a demonstrated, proven, and commercial technology. By its mere existence, it provides two critical benefits to society: (1) significant incremental oil production from existing fields and (2) the concurrent storage of significant volumes of CO_2. Additionally, the incidental storage of CO_2 volumes in EOR projects is subject to easy verification by mass balancing and management of the CO_2 in a closed, controlled

system. The cumulative reduction in oil imports that could result between now and 2030 would improve the trade balance by nearly $700 billion, resulting in increased state and federal revenues of $190 to $210 billion.[xviii] All of these benefits would be put at risk, if not completely lost, if the EPA ultimately determined that creditable geologic storage may only be conducted under UIC Class VI. UIC Class VI may be suitable for non-EOR deep saline injections but is wholly unworkable for existing and future CO_2 EOR.

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Footnotes (PART 2)

[i] *Sources: Melzer Consulting; "Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage"* (Massachusetts Institute of Technology, July 2009).

[ii] *"EOR-CCUS Policy Needs and Options."* Waltzer, K, Clean Air Task Force, Presentation to the National Enhanced Oil Recovery Initiative, July 12, 2011 (on file with author).

[iii] The Obama Administration supports CO_2-EOR. To that end, the U.S. Department of Energy now refers to CCUS as "Carbon Capture, Utilization and Storage," with "Utilization and Storage" largely understood to mean CO_2-EOR. *See also* "*Report of the President's Interagency Task Force on CCUS*" (2010).

[iv] Many of EPA's actions remain subject to judicial review, including the so-called Tailoring Rule that EPA published on June 3, 2010. *75 Fed. Reg. 31514.* Under that regulation, EPA "tailored" the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHG emissions under the Prevention of Significant Deterioration and title V programs of the CAA. Without the Tailoring Rule, PSD and title V requirements would have applied, as of January 2, 2011, to the 100 or 250 tons per year levels provided under the CAA, greatly increasing the number of required permits, imposing undue costs on small sources, overwhelming the resources of permitting authorities, and severely impairing the functioning of the programs. On March 8, 2012, EPA proposed to maintain GHG permitting thresholds at current thresholds. *77 Fed. Reg. 14226.*

[v] SDWA § 1425(a). In contrast, to obtain primacy over well classes other than UIC Class II, state programs must demonstrate to EPA that their regulations provide effective minimum requirements. Id. § 1422.

[vi] "Geologic sequestration" means the "long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations." 40 C.F.R. § 144.3.

[vii] 76 Fed. Reg. 56982 (Sept. 15, 2011).

[viii] 40 C.F.R. § 146.93(b)(1).

[ix] See http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm.

[x] 40 C.F.R. § 144.19(a).

[xi] 40 C.F.R. § 144.19(b).

[xii] The nine factors are: (1) increase in reservoir pressure within the injection zone(s); (2) increase in CO_2 injection rates; (3) decrease in reservoir production rates; (4) distance between the injection zones and USDWs; (5) suitability of the Class II area of review delineation; (6) quality of abandoned well plugs within the area of review; (7) the owner's or operator's plan for recovery of CO_2 at the cessation of injection; (8) the source and properties of the injected CO2; and (9) any additional site-specific factors as determined by the regulator. 40 C.F.R. § 144.19(b).

[xiii] 74 Fed. Reg. 56260 (2009).

[xiv] 74 Fed. Reg. at 56349.
[xv] *Id.* at 56350 (emphasis added).
[xvi] *Id.* at 75060.
[xvii] *PSD and Title V Permitting Guidance for Greenhouse Gases*, at p. 43, EPA-457/B-11-001 (Mar. 2011).
[xviii] "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage." Advanced Resources International. March 10, 2010.

Chapter 2: Economic, Employment, and Energy Stimulus from Clean Coal Technology Deployment

2.1 Key Findings

- Implementing the Aspirational Case will create new industries, revitalize a large number of U.S. industry sectors, manufacturing, and technology, and create numerous professional and technical skilled jobs.
- By 2030, the Aspirational Case will annually generate nearly $200 billion in industry sales, over 1 million jobs, and $60 billion in federal, state, and local government tax revenues.
- If "Advanced Coal/CCS/EOR" were a company, it would rank 5th on the Fortune 500 and would be significantly larger than such iconic American companies as General Motors, General Electric, Ford, Hewlett-Packard, AT&T, Verizon, and Apple. The sales created are larger than the Gross Domestic Product (GDP) of entire countries, including nations like Romania, Hungary, Kuwait, New Zealand, Ukraine, and Vietnam.
- There is currently a mismatch in the United States between available jobs and required skills, and an important issue that must be addressed is that of whether there will be an adequate skilled workforce available to meet the demands created by the Aspirational Case. If not, various programs may be required to address this problem.
- While most of the jobs created will be for conventional skills and professions, the initiatives will also lead to many new employment opportunities, and new and emerging jobs and skills will be in demand.

2.2 Recommendations

- In order for the Aspirational goals to be achieved, over the next decade, an aggressive RD&D program and related initiatives by government and industry are required and must start soon.
- This is not a free lunch, and the most cost effective and beneficial programs with the highest return on investment to the public and private sectors should be identified and supported.

- Education and training programs must be implemented to ensure that there will be an adequate supply of workers with the appropriate skills to fill the jobs created by the Aspirational Case and related U.S. industrial, manufacturing, and technical initiatives.

2.3 Background

Despite continuing controversies over coal plant development and EPA regulations, the salient fact is that coal will continue to be the mainstay of U.S. electricity production over the next several decades. More importantly, extensive coal development, in combination with rapid expansion of CCS, CO_2 EOR, CO_2 pipelines, CTL, and the associated infrastructure will create a U.S. industrial rebirth and facilitate the creation of new industries, increased industry sales and profits, higher GDP, millions of jobs, and more tax revenues for the federal government and for state and local governments (see the discussion in Section VII). Numerous studies in recent years have indicated the significant potential for coal, CCS, CO_2 EOR, and CTL. For example:

- ARI estimated that the volume of economically recoverable resource from next-generation CO_2 EOR resource of 80 billion barrels is sufficient to support 4 million bbl/d of domestic oil production for over 50 years.
- The National Research Council (NRC) indicated that coal-based generation with CCS can replace the existing coal fleet and provide up to 3,000 Terawatt hours of electricity per year at affordable rates and that the CO_2 captured from these plants would support a robust EOR program providing at least 2 million bbl/d.
- NETL/ARI estimated that 120-130 GW of new CCS coal plants would be required by 2035 to produce about 4 million bbl/d of CO_2 EOR.
- ARI/NRDC estimated that, by 2030, about 70 GW of new CCS coal plants would be required to produce about 3 million bbl/d of CO_2 EOR.
- The DOE's Unconventional Fuels Task Force estimated that the United States could produce about 2.5 million bbl/d of CTL by 2030.
- The Council estimated that the United States could produce about 2.6 million bbl/d of CTL by 2025.

- NETL estimated that the United States could produce about 5.1 million bbl/d of CTL by 2027.
- The Southern States Energy Board (SSEB) estimated that the United States could produce about 5.5 million bbl/d of CTL by 2030.
- SSEB estimated that the United States could produce about 2.8 million bbl/d of CO_2 EOR by 2030.
- NETL estimated that the United States could produce about 2.9 million bbl/d of CO_2 EOR by 2027.

2.4 Economic and Jobs Concepts

2.4.1 Constant Dollar Data

The only meaningful way to compare and analyze historical and forecast data over a long period is to use constant dollar data. Obviously, it would be misleading to equate a dollar expended in 2012 with one forecast to be spent in 2030, since the price level in the latter year will likely be much higher than that of the former year. Aside from the general distortions, use of current dollar data in the analysis would, for example, seriously undercount expenditures early in the forecast period relative to those later in the forecast period. Therefore, throughout this chapter all the estimates given are stated in constant 2011 dollars.

We derived the constant 2011 dollar data (2011=1.00) using the GDP deflators to convert dollar values into 2011 base year estimates. It is preferable in an analysis such as the one conducted here to use the GDP deflators – implicit price deflators (IPD) – instead of the more widely known consumer price index (CPI) deflators.[1]

2.4.2 The Jobs Concept

The jobs issue is a key focus of the current chapter. The "jobs concept" can be subject to misinterpretation and misuse, and it is thus important that it be carefully defined and specified. Specifically, the employment concept used is a full time equivalent (FTE) job in the United States. An FTE job is defined as 2,080 hours worked in a year's time, and adjusts for part time

[1] The IPD, compiled by the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce, is a byproduct of the deflation of GDP, and is derived as the ratio of current-to-constant-dollar GDP (multiplied by 100). It is the weighted average of the detailed price indices used in the deflation of GDP, but they are combined using weights that reflect the composition of GDP in each period. Thus, changes in the implicit price deflator reflect not only changes in prices but also changes in the composition of GDP. It is issued quarterly by BEA.

and seasonal employment and for labor turnover. Thus, for example, two workers each working six months of the year would be counted as one FTE job. An FTE job is the standard job concept used in these types of analyses and allows meaningful comparisons over time and across jurisdictions.

Thus, a "job" created is defined as a job created for one person for one year, and 50,000 jobs created will refer to 50,000 persons employed for one year. It is correct to state that "over a ten year period 500,000 cumulative jobs are created" as long as it is specified that this refers to 50,000 persons each employed for 10 years. Indeed, these distinctions may sound technical, but they are critical to a proper interpretation of the results. Total (direct, indirect, induced) jobs created will be estimated:

- Direct jobs are those created directly in the specific activity or process.
- Indirect jobs are those created throughout the required inter-industry supply chain.
- Induced jobs are those created in supporting or peripheral activities; e.g., in a restaurant across the street from a coal power/CCS plant.
- Total jobs are the sum or all of the jobs created.
- For simplicity, here we include induced jobs in the indirect category.

The total (direct, indirect, and induced) jobs concept is the accepted methodology widely used in studies of this nature and in the peer-reviewed literature.

2.5 The Aspirational Case

2.5.1 Discussion

The Aspirational Case represents a scenario that is ambitious and aggressive but technically feasible. The initial target forecast year for the Aspirational scenario is 2030, recognizing that all technologies and applications will have to ramp up between 2012-2030.

Over the past 25 years or so, U.S. CO_2 EOR output has risen from 30,000 bbl/d in 1986 to a rate of about 350,000 bbl/d in 2012. This represents an annual average growth rate of about 9.4%. The Aspirational Case assumes that U.S. CO_2 EOR production in 2030 will reach 4 million bbl/d (see Figure 2.1). This illustrates an increase in CO_2 EOR of about 3.7 million bbl/d

above the 2011 level by 2030 and requires an annual average rate of growth over the period 2012-2030 of roughly 15%. Thus, the historical annual average rate of growth of EOR will have to increase by about 60%.

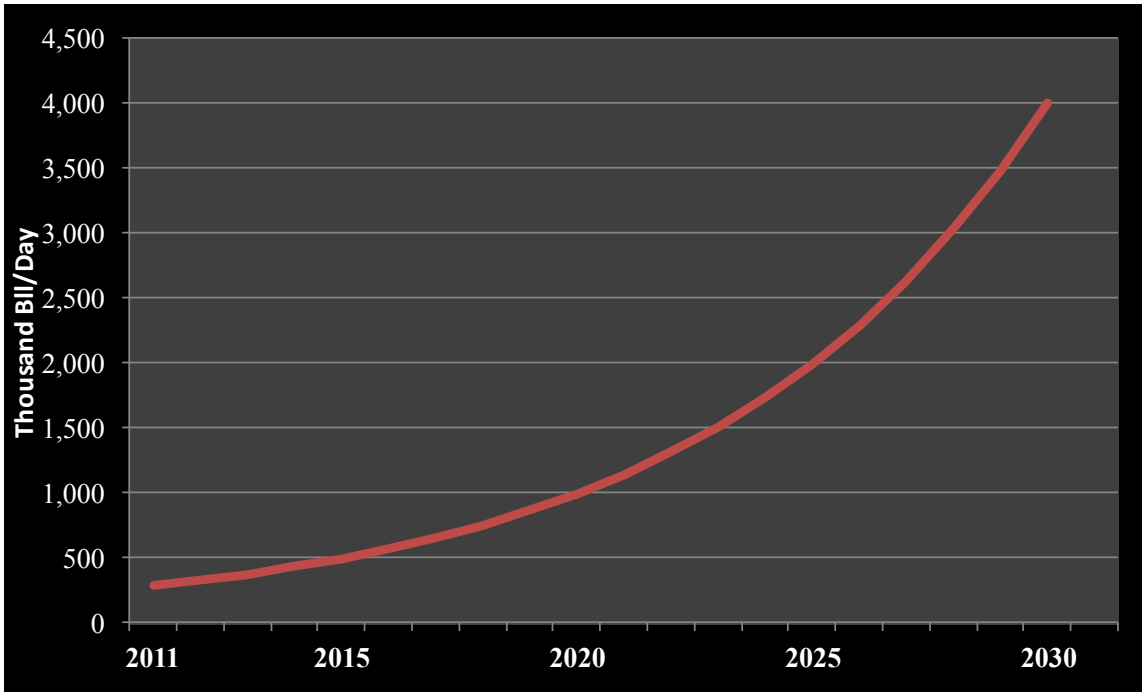
Using the NETL/ARI CO_2 EOR studies, 4 million bbl/d of CO_2 EOR will require about 550 million tons of CO_2/year in 2030. To produce 550 million tons of CO_2/year will require about 100 GW of coal. Thus, by 2030, the Aspirational Case implies 100 GW of coal with CCS.

2.5.2 Aspirational Case Scenario Parameters

On the basis of the above discussion, the basic parameters for the Aspirational Case scenario are discussed below.

Figure 2.1:CO_2 EOR Rate of Growth in the Aspirational Case

(NETL, ARI, *Oil & Gas Journal*, MISI, 2012)



So

2.5.2.1 Construction and Operation of Equipment at Power Plants for Capturing CO_2

Energy Secretary Chu's letter stated that the "study must address the number of jobs that will be created in the construction of equipment at power plants for capturing the CO_2."

Accordingly, here we focus on the economic and jobs impact of new coal plants with CCS and CSS retrofit applications on existing coal plants.[2]

We assume that about 100 GW of CCS coal capacity will be installed by 2030, over the period 2015-2030. We assume that about 50 GW of this capacity will be new plants and that about 50 GW will be CCS retrofits. On the basis of recent studies, the Council assumes the total cost of this will be about $260 billion (2011 dollars).

The economic and jobs impacts of this activity were estimated based on relevant published estimates of the economic and jobs impacts of CCS technologies, advanced coal electric generation with CCS, CCS jobs studies, etc., as well as the economic and jobs profiles of the construction industry (NAICS 23) and elements of the utilities industry (NAICS 22).

New Coal Plants

Assuming the 50 GW of new coal capacity will be installed over the period 2015-2030, an average of about 3.3 GW of new CCS coal plants is constructed each year. This level of construction creates about 4,200 direct jobs and about 5,000 indirect jobs, for a total of about 9,200 jobs annually.

When the new CCS coal plants are completed, about 2,800 permanent direct O&M jobs will be created per 3.3 GW of capacity, as well as another 3,700 indirect jobs. Thus, the total number of permanent jobs (direct plus indirect) will be about 6,500/year. Assuming that the first tranche of new CCS coal plants is completed in 2019 implies that the total number of permanent jobs created in 2030 equals about 101,000.

Therefore, in 2030, about 110,000 total jobs will be created.

CCS Retrofits

About 3.3 MW of coal CCS retrofits will be required each year 2015-2030. This retrofit construction will create about 12,000 jobs (direct plus indirect) annually. The total number of incremental permanent jobs (direct plus indirect) will total about 500 annually. Assuming that these jobs begin in 2018, the total of permanent jobs created in 2030 will be about 7,500.

Therefore, in 2030, the total number of retrofit jobs will be about 19,500.

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[2] We thus do not address the impacts of CCS extraction from natural sources, industrial facilities, natural gas process, ethanol, refineries, ammonia, etc.

Thus, the total number of jobs (direct plus indirect) created in 2030 by new and retrofit coal CCS will be about 130,000. In addition, in 2030 under the Aspirational goal, development of new coal plants and CCS retrofits will generate about:

- $27 billion in industry sales
- $1.2 billion in industry profits
- $7.8 billion in tax revenues ($5.3 billion in federal government tax revenues and $2.5 billion in state and local government tax revenues)

2.5.2.2 Pipeline Construction and Operation for Transporting CO_2

A somewhat geographically limited CO_2 pipeline network already exists in the United States to supply CO_2 for EOR. This infrastructure has been built starting in the early-1970s and currently includes about 4,100 miles of pipelines moving 65 million metric tons of CO_2 each year. Current U.S. CO_2 EOR totals roughly 350,000 bbl/d. This implies that to transport the incremental CO_2 for 3.7 million bbl/d of envisioned here for the Aspirational Case about 46,000 miles of additional CO_2 pipelines would be required. A greater number of larger capacity 24 and 30 inch pipelines would likely be used, thus reducing the miles of pipeline that may be required. However, this may be at least partially offset by the requirement to move CO_2 further to the major CO_2 markets. We therefore here assume that about 40,000 miles of CO_2 pipelines will be required to meet the Aspirational goal of 4 million bbl/d in CO_2 EOR production.

The Aspirational Case assumes that about 36,000 miles of additional CO_2 pipelines will be required by 2030 – an average of about 2,400 miles/year over the period 2016-2030. An illustration of the type of pipeline network that may be required by 2030 is given in Figure 2.2.

The economic and jobs impacts of this activity were estimated based on relevant published estimates of the economic and jobs impacts of pipeline construction and the economic and jobs profile of the oil and gas pipeline and related structures construction industry (NAICS 23712). We estimate that the construction and maintenance of the 2,400 miles/year of additional CO_2 pipelines, 2016-2030, will create about 110,000 total jobs/year. Thus, in 2030, about 110,000 total (direct plus indirect) jobs will be created. In addition, in 2030 under the Aspirational goal, pipeline construction, operation, and maintenance will generate about:

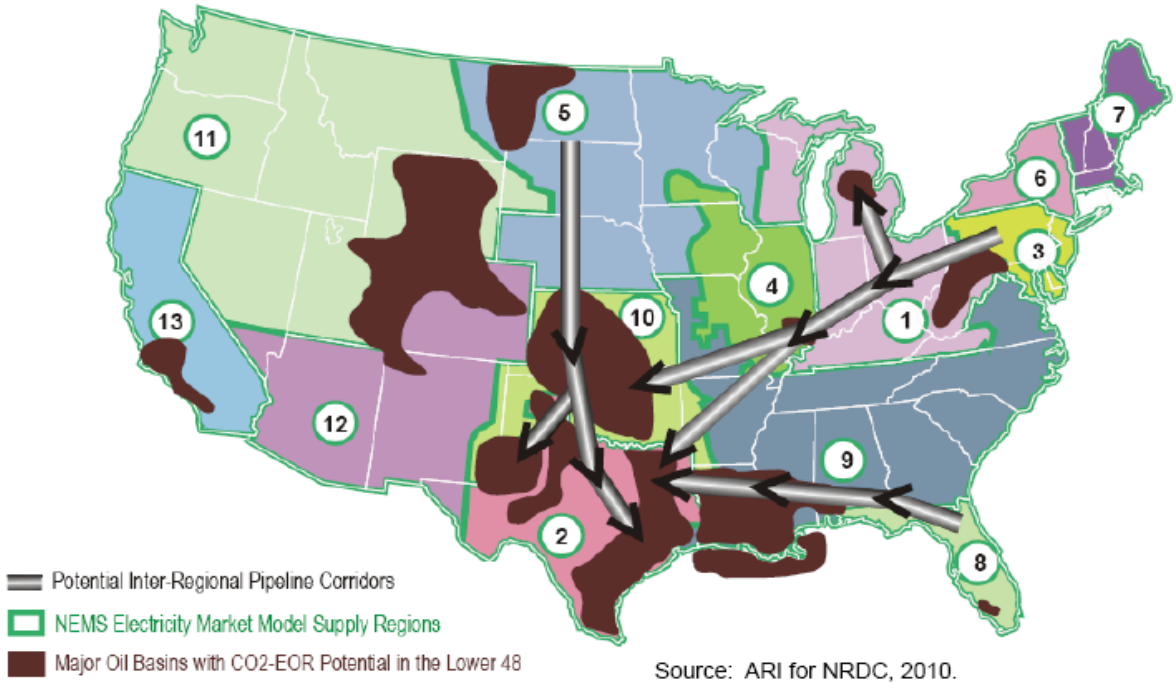
- $7 billion in industry sales
- $420 million in industry profits
- $2.1 billion in tax revenues ($1.4 billion in federal government tax revenues and $700 million in state and local government tax revenues)

2.5.2.3 CO_2 EOR

CO_2 EOR consists of:

- The injection process
- Systems operations
- Monitoring the injection wells

Figure 2.2: How the Required CO_2 Pipeline Network Could Evolve



The Aspirational Case assumes that an incremental 3.7 million bbl/d of CO_2 EOR will be produced by 2030 – about an average incremental 200,000 bbl/d of CO_2 EOR annually over the period 2016-2030. In 2030, production of 4 million bbl/d of CO_2 EOR will require expenditures

of roughly $38 billion. The economic and jobs impacts of this activity is estimated based on relevant published estimates of the economic and jobs impacts of CO_2 EOR.

In 2030, CO_2 EOR expenditures of $38 billion generate in total (direct plus indirect):

- 355,000 jobs
- $60 billion in industry sales
- $3.1 billion in industry profits
- $21.2 billion in tax revenues ($13.1 billion in federal tax revenues and $8.1 billion in state and local government tax revenues)

2.5.2.4 Production of Liquid Transportation Fuels (CTL)

For the Aspirational Case, we assume that in 2030 about 2.5 million bbl/d of CTL is being produced in the United States in 2030. Since no CTL is currently being produced, we assume an annual average incremental CTL production of about 165,000 bbl/d annually over the period 2016-2030. The economic and jobs impacts of this activity are estimated based on relevant published estimates of the economic and jobs impacts of CTL.

In 2030, the Aspirational Case assumes that 2.5 million bbl/d of CTL are being produced. The total expenditures on CTL, including plants under construction will be about $47 billion for construction and about $2.1 billion for O&M. In 2030, the total (direct plus indirect) impact of CTL production, including plants under construction will be about:

- $94 billion in industry sales
- 410,000 jobs
- $3.8 billion in industry profits
- $28.9 billion in tax revenues ($19.1 billion in federal tax revenues and $9.8 billion in state and local government revenues).

2.5.2.5 Production of Feedstocks for Chemical Manufacturing

Private industry and DOE assessments of alternative fuels and utilization processes for replacing natural gas and petroleum as chemical industry feedstocks have identified coal as a potential source of replacement for Olefins (Ethylene, Propylene, Butadiene) and for Aromatics

(Benzene, Toluene, Xylenes). Annual U.S. production of Olefins is currently about 50 million tons and of Aromatics is about 17 million tons.

However, relatively cheap shale gas is currently fulfilling this need without the use of coal, and the interest in producing chemicals from coal has waned in the United States. Yet, the long-term cost and availability of shale gas are still unknowns and the story will play out in coming years. China, however, is steadily proceeding to convert coal to chemicals.

2.5.2.6 Total Economic and Jobs Impacts of the Aspirational Case

Under the Aspirational Case, the total (direct plus indirect) number of jobs created in 2030 (permanent plus construction) is:

- Coal plants (new plus retrofit): 130,000 jobs
- Pipelines: 110,000 jobs
- CO_2 EOR: 355,000 jobs
- CTL: 410,000 jobs

Thus, the total (direct plus indirect) number of jobs created in 2030 under the Aspirational Case, (permanent plus construction) is 1,005,000. The overall economic and jobs impacts are summarized in Table 2.1.

Table 2.1: Summary of the Economic and Jobs Impacts of the Aspirational Case in 2030

(Management Information Services, Inc., 2012)

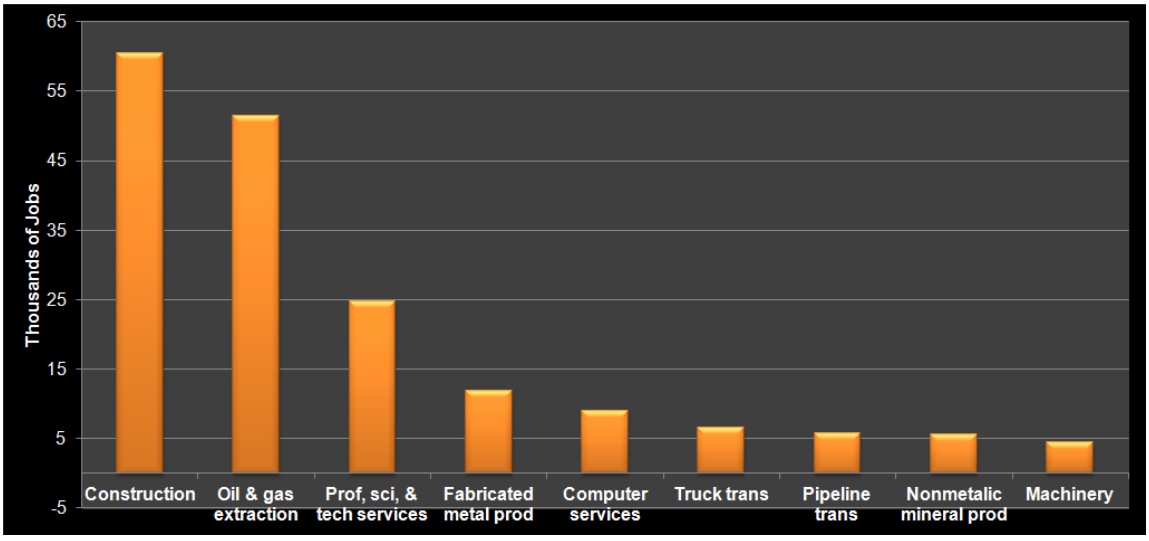
	Sales (billions)	**Profits** (billions)	**Tax Revenues** (billions)	**Jobs** (thousands)
Power Plants	$27	$1.2	$7.8	130
Pipelines	7	0.4	2.1	110
CO_2/EOR	60	3.1	21.2	355
CTL	94	3.8	28.9	410
Total	$188	$8.5	$60.0	1,005

2.6 Requirements Created for Jobs, Occupations, and Skills

The number of jobs created is important, but it is also vital to disaggregate the employment generated by the initiatives into occupations and skills. The jobs generated will be disproportionately concentrated in fields related to the construction, energy, utilities, mining, industrial, technology, and related sectors, reflecting the requirements of the initiatives and their supporting industries. For example, Figure 2.3 and Table 2.2 show the estimated job impacts among major industries created by CO_2 EOR under the Aspirational Case in 2030. It is seen that the most jobs are created in the Construction and the Oil and Gas Extraction industries, followed by the Professional, Scientific and Technical Services, Fabricated Metal Products, and Computer Systems Design and Related Services industries. The jobs created in these five industries comprise 45% of all of the jobs created in 2030 by CO_2 EOR.

Figure 2.3: Jobs Created in 2030 by CO_2 EOR
(Selected Industries)

(Management Information Services, Inc., 2012)



In terms of industry sales and jobs, we found that throughout the forecast period the construction, oil and gas extraction, petroleum and coal products, professional, scientific and technical services, wholesale trade, fabricated metal products, computer systems design, pipeline transportation, and related industries would be major beneficiaries of increased EOR activity. However, while significant, the job estimates must be put into perspective. In 2025, the U.S.

labor force is projected to total 169 million; in 2030, it is projected to total 173 million. Nevertheless, there will be significant job gains resulting from the EOR option.

The Aspirational Case will revitalize large sections of U.S. industry and will create an especially robust labor market and greatly enhanced employment opportunities in many industries and in professional and skilled occupations such as chemical, mechanical, electronics, petroleum, and industrial engineers; electricians; sheet metal workers; geoscientists; computer software engineers; skilled refinery personnel; tool and die makers; computer controlled machine tool operators; industrial machinery mechanics, electricians; oil and gas field technicians, machinists, engineering managers, electronics technicians, carpenters; welders; and others. However, it is also important to note that numerous jobs will also be created at all skill levels for occupations such as laborers, truck drivers, security guards, managers and administrators, secretaries, clerks, service workers, and so forth.

Table 2.2: Top 20 Industries Affected in 2030 by CO_2 EOR – Ranked by Employment

(Management Information Services, Inc., 2012)

Industry	**Jobs Created in 2030** (thousands of jobs)
1. Construction	60.4
2. Oil and gas extraction	51.4
3. Administrative and support services	30.3
4. Miscellaneous professional, scientific and technical services	24.8
5. Other services, except government	14.9
6. Wholesale trade	14.7
7. Fabricated metal products	11.8
8. Retail trade	11.1
9. Federal Reserve banks, credit intermediation, and related activities	9.4
10. Management of companies and enterprises	9.2
11. Computer systems design and related services	9.0
12. Rental and leasing services and lessors of intangible assets	8.8
13. State and local government enterprises	8.6
14. Truck transportation	6.6
15. Waste management and remediation services	6.5
16. Legal services	6.1

17. Pipeline transportation	5.8
18. Nonmetallic mineral products	5.6
19. State and local general government	4.9
20. Machinery	4.5
All other industries	189
Total, all industries	355

Accordingly, the importance of the initiatives for jobs in some occupations is much greater than in others. Some occupations, such as those listed initially above, will benefit greatly from the employment requirements generated by the initiatives. This is hardly surprising, for most of these jobs are clearly related to the construction, energy, utilities, scientific, and industrial sectors. Nevertheless, while workers at all levels in all sectors will greatly benefit from the initiatives, as noted, disproportionately large numbers of jobs will be generated for various professional, technical, and skilled occupations. For example, Table 2.3 and Figure 2.4 show the estimated job impacts among major occupational and skill groups created by CTL under the Aspirational Case in 2030. This table and figure indicate that, while the jobs created are disproportionately for skilled, technical, and professional workers, numerous jobs in all categories are generated. Thus, for example:

- While there are jobs for 1,390 software engineers created, there are also jobs created for 3,700 janitors.
- While there are jobs for 7,500 electricians created, there are also jobs created for 11,650 construction laborers.
- While there are jobs for 1,130 computer programmers created, there are also jobs created for 8,720 truck drivers.
- While there are jobs for 830 mechanical engineers created, there are also jobs created for 2,190 security guards.

2.7 Jobs Required and Skills Available

This section presents a discussion related to the new jobs expected to be available and the required skill sets for these emerging jobs.

2.7.1 Emerging CCS, Carbon Management, and Related Activities Jobs, Occupations, and Skills

The Aspirational Case will create new industry, industries, and industrial rebirth. It will revitalize large sections of U.S. industry, manufacturing, and technology, and will create an especially robust labor market and greatly enhanced employment opportunities in many industries and in professional and skilled occupations. While most of the jobs created will be for conventional skills and professions, the scenario will also will lead to many new employment opportunities as businesses expand to meet the new energy and industrial requirements, and new and emerging jobs and skills will be in demand resulting from the CCS/EOR initiatives. These include specialties such as GIS specialists, carbon capture power plant installation, operations, carbon sequestration plant installation, operations, hydro-geologist, engineering geologist, carbon emission specialist, GHG emissions report verifier, emissions reduction project manager, emissions reduction credit portfolio manager, and others.

Table 2.3: Jobs Created by CTL in 2030

(Selected Occupations)

(Management Information Services, Inc., 2012)

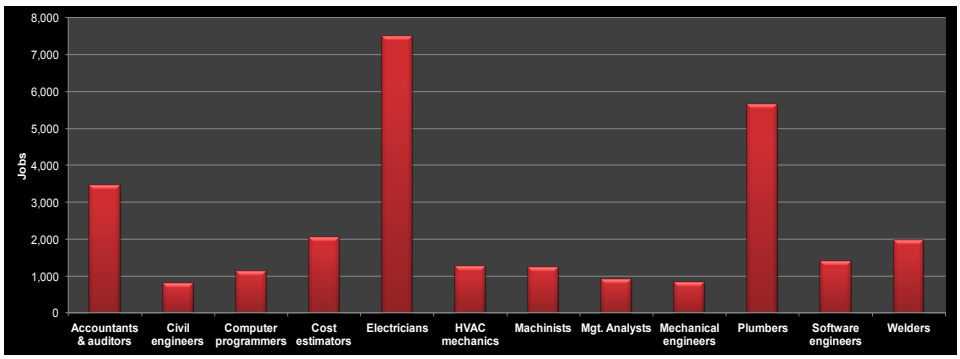
Occupation	Jobs
Accountants and auditors	3,450
Bookkeeping and accounting clerks	6,670
Brickmasons and blockmasons	1,650
Carpenters	6,160
Cashiers	4,630
Cement masons and concrete finishers	2,880
Civil engineers	800
Computer programmers	1,130
Construction laborers	11,650
Cost estimators	2,040
Drywall and ceiling tile installers	1,770
Electricians	7,500

Excavating and loading machine operators	1,380
Executive secretaries and administrative assistants	4,510
First line construction supervisors	7,920
Heating, air conditioning, and refrigeration mechanics	1,240
Industrial engineers	750
Industrial machinery mechanics	1,160
Janitor and cleaners	3,700
Machinists	1,220
Management analysts	910
Mechanical engineers	830
Mobile heavy equipment mechanics	1,030
Operating engineers	5,040
Painters	3,210
Plumbers	5,650
Security guards	2,190
Shipping and receiving clerks	1,980
Sheet metal workers	2,220
Software engineers	1,390
Structural iron and steelworkers	1,070
Truck Drivers	8,720
Welders	1,960
Total, all occupations	425,000

Figure 2.4: Jobs Created by CTL in 2030

(Selected Occupations)

(Management Information Services, Inc., 2012)



Many jobs will be created across a new and wide spectrum of work activities, skill levels, and responsibilities, and some of these currently do not have occupational titles defined in federal or state government occupational classifications and standards. In addition, many of these new jobs require different sets of skills than current jobs, and training requirements must be assessed so that this rapidly growing sector of the U.S. economy and labor market has an adequate pool of trained and qualified job applicants. At some point in the future, many of these occupations will grow in the number of employees classified in the occupation and the federal government will add them to the employment classification system. Until that time, economic and employment analysis and forecasting is usually conducted using the current set of U.S. Department of Labor occupational titles.[3]

Table 2.4 identifies by occupational title some of the new jobs that will be created by the initiatives. The listing of jobs spans a broad range of skills, educational requirements, and salaries. New occupational titles are listed in the first column of the table. The average salary, listed in the second column, represents the average of the starting salary and highest salary for that occupation. Wages may be 15-20% lower at the beginning of employment and may rise to a level 15-20% higher as the person becomes an experienced employee. In addition, wages and salaries are often significantly higher in urban than rural areas.

Table 2.4: Emerging Jobs, Salaries, and Educational Requirements in the Clean Coal, CCS, Carbon Management, and Related Industries

(Management Information Services, Inc., 2012)

Occupational Title	Average Salary	Minimum Education
Carbon capture power plant installation, operations, eng. & mgt.	$69,000	Bachelor's (Engineer)
Carbon sequestration plant installation, operations, eng. & mgt.	$69,000	Bachelor's (Engineer)
Geologist & hydrogeologist	$66,010	Bachelor's (Science)
GIS specialist	$47,380	Bachelor's (Geography)
Director of project development	$138,000	Bachelor's (Business)
Environmental health & safety engineering manager	$76,360	Bachelor's (Science)
Environmental health & safety lead	$81,420	Master's (Science)
Plant technical specialist - safety instrument testing & repair	$64,400	Bachelor's (various)

[3] These are listed in the *2010 Standard Occupational Classification Code*, U.S. Department of Labor, Bureau of Labor Statistics, February 2010.

Safety investigator - cause analyst	$88,320	Bachelor's (various)
Plant supervising technical operator	$52,624	Bachelor's (Engineer)
Plant safety engineer	$90,620	Bachelor's (various)
Air quality control engineer	$92,000	Bachelor's (CE)
Field technician	$23,850	HSD/GED
Greenhouse gas emissions permitting consultant	$63,940	Bachelor's (Science)
Sequestration research manager	$73,876	Master's (Science)
GIS specialist	$47,380	Bachelor's (Geography)
Engineering geologist	$62,836	Bachelor's (Engineer)
Emissions accounting & reporting consultant	$64,400	Bachelor's (various)
Greenhouse gas emissions report verifier	$55,200	Bachelor's (Science)
Power marketing specialist	$63,480	Bachelor's (various)
CCS sampling technician	$35,144	HSD/GED
Energy trading specialist	$63,480	Bachelor's (various)
Carbon emission specialist	$63,480	Bachelor's (various)
Market & rate analyst	$72,680	Bachelor's (Business)
CCS power generation engineer	$105,800	Bachelor's (ME)
CCS technician	$42,780	Associate's
Emissions reduction credit marketer & market analyst	$72,680	Bachelor's (Business)
Emissions reduction credit portfolio manager	$46,460	Bachelor's (Business)
Emissions reduction project developer specialist	$63,480	Bachelor's (various)
Emissions reduction project manager	$78,200	Bachelor's (various)
Water resource engineer	$63,940	Bachelor's (Science)
Commercial energy field auditor	$24,012	Associate's
Power system operator	$50,784	HSD/GED
Air pollution specialist	$63,480	Bachelor's (Science)
Air resource engineer	$72,220	Bachelor's (Engineer)
CCS policy analyst	$41,400	Bachelor's (Science)
Power systems instructor	$50,784	HSD/GED
Air quality specialist & enforcement officer	$61,916	Bachelor's (Science)
Air emissions permitting engineer	$64,676	Bachelor's (Science)
CCS engineer/scientist intern	$6,440	HSD/GED

The third and final column lists the minimum recommended educational attainment to gain entry into that occupation, and a recommended degree is listed for the advanced educational requirements. Obviously, employers will not hold fast to these recommendations, but this

information can be useful to educational planners in providing an idea of the knowledge and skills that the employer is seeking in a candidate. Note that the education requirements listed include HSD/GED (high school degree or General Educational Development), and Apprenticeship/TS (trade school), and advanced degrees. With the more advanced (Bachelor's degree and higher) college requirements, some standard abbreviations were used to further define the recommended degree: CE, ME, EE – for chemical, mechanical, and electrical engineer degrees, etc. Also, note that many jobs can be filled by a candidate with one of several related science or engineering degrees and they are listed generically as such. Table 2.4 illustrates that in these new and emerging occupations:

- Salaries vary widely, from $20,000-$25,000 for field technicians and auditors to nearly $140,000 for a director of project development.
- Educational requirements span the gamut from apprenticeship/trade school and HSD/GED to advanced college degrees.
- However, there are a wide variety of jobs and education training requirements, and many of the jobs do not require college degrees.
- Similar jobs can have different salaries and education/training requirements. For example, a CCS technician may require an Associate Degree and earn a salary of about $43,000, whereas a field technician with apprenticeship training may earn a salary of more than $57,000.
- Similarly, an air quality control engineer with a Bachelor's Degree may earn $92,000, whereas a water resource engineer with a Bachelor's Degree may earn less than $64,000.
- Career paths exist that allow employees with apprenticeship/TS and HSD/GED to earn relatively high salaries, such as power system operator, field service technician, power systems instructor, CCS technician, and CCS sampling technician.

2.7.2 Potential Mismatch Between Skills Required and Skills Available

The jobs generated by the Aspirational Case will be disproportionately concentrated in fields related to the construction, energy, utilities, mining, industrial, technology, and related

sectors, reflecting the requirements of the initiatives and their supporting industries. An important issue that must be addressed is whether there will be an adequate skilled workforce available to meet the demands created by the initiatives, and, if not, what types of programs and policies may be required to address this problem.

There is currently a serious mismatch in the U.S. economy between unemployed workers, available jobs, and required skills. For example, despite current record high unemployment, many U.S. manufacturing, technical, and related jobs cannot be filled due to the lack of available workers with the requisite skills – including many jobs in the energy sector. Studies indicate that at present, in the manufacturing sector alone 600,000 positions cannot be filled because employers cannot find workers with the requisite skills, education, and training. The problem is especially acute with respect to skilled production jobs – machinists, operators, craft workers, distributors, technicians, and related positions, and the shortage is inhibiting manufacturers' ability to expand operations, drive innovation, and improve productivity.

Similarly, there is concern about the capacity of the U.S. EPC and construction infrastructure to mount large energy projects – retrofits, new energy facilities, and similar projects and even about the ability to hire adequate skilled labor for current projects. As large numbers of older and experienced employees retire, finding younger talent to replace them has become increasingly difficult, exacerbating the skills shortage. The anticipated retirement exodus over the coming decade could seriously impede industries in specific workforce segments. The Aspirational Case will greatly increase the demand for workers in these sectors and a shortage of such workers could be a major impediment to the initiatives' success.

There are some common attributes in the energy related industries upon which the Aspirational Case initiatives will place the greatest demands:

- The average age in is relatively high.
- Degree programs and enrollments are down significantly.
- A large wave of retirements over the coming decade is likely.
- Often, even replacing retiring workers may be a daunting challenge.
- Expanding the workforce significantly in the near future may be difficult.

- There may difficulty in recruiting appropriate new workers.
- There is often a lack of succession planning.
- Lack of workers is currently restraining industry expansion.
- There will be a significant increase in demand for output and workers in next two decades.
- Many applicants lack requisite skills and education.
- There are not nearly enough workers "in the pipeline."

The bottom line here is that the U.S. energy-related workforce infrastructure has seriously degraded over the past two decades, and it may take decades to remedy this. Unfortunately, we may not have decades to spare. There is no single solution that can address these growing skills gap concerns. Larger forces in addition to the Aspirational Case initiatives, such as globalization and technology, will continually change the landscape, and all industries will have to adjust accordingly. Some issues may need to be addressed through public policy, but there are some demonstrated methods that may be able to mitigate the problem.

Knowledge management plans and solutions can address the brain drain as older workers retire, taking with them valuable knowledge and experience. Capturing critical information through technology and passing it on to newer and younger workers can help reduce training time, can improve collaboration and communication, and even help companies by leveraging previous programs. Older workers can also gradually scale back their hours as they phase into retirement or work as a part-time pensioner while helping younger colleagues gain the required knowledge and skills. Many industries and skilled trades have historically used apprenticeship programs to pass on specialized skills from an experienced craftsman to a new worker. Through mentoring programs, whether informal or established by a company, experienced workers can provide coaching and advice to less experienced colleagues. Employers can also leverage their local community colleges or trade schools to supplement employee skills.

2.8 New Industry, Industries, and Industrial Rebirth

The Aspirational Case will create new industry, industries, and industrial rebirth, and will revitalize large sections of U.S. industry, manufacturing, and technology. It will create an

especially robust labor market and greatly enhance employment opportunities in many industries and in professional and skilled occupations. In particular, these initiatives will provide a critical stimulus to the U.S. manufacturing, industrial, technical, and related sectors. This is especially important because manufacturing is an essential component of a competitive and innovative economy:

- creates spillover benefits to local regions
- firms provide most U.S. innovation: 70% of private sector R&D and more than 90% of patents issued
- creates intersections of innovation and production and facilitates a virtuous cycle: The "industrial commons," – ecosystems of innovative know-how, process engineering, and workforce skills required for innovation in manufacturing industries
- manufacturing jobs are high skilled and well paying: the average U.S. manufacturing worker earns $77,000/year (pay and benefits), compared to the average U.S. worker's earnings of $56,000/year
- manufacturing has large economic and job multipliers throughout economy
- over the past two decades, manufacturing productivity has increased twice as fast as the U.S. average

The Obama Administration recognizes these benefits and just recently issued its "Blueprint for an Economy Built to Last." This blueprint:

- highlights importance of a competitive U.S. manufacturing sector
- provides a vision of U.S. economy that is innovative and competitive
- views manufacturing as a source of good jobs for American workers
- recognizes that the manufacturing sector "punches above its weight"

The Administration is thus focused on making manufacturing an economic priority, seeking a "renaissance" in American manufacturing and looking to "strengthen domestic

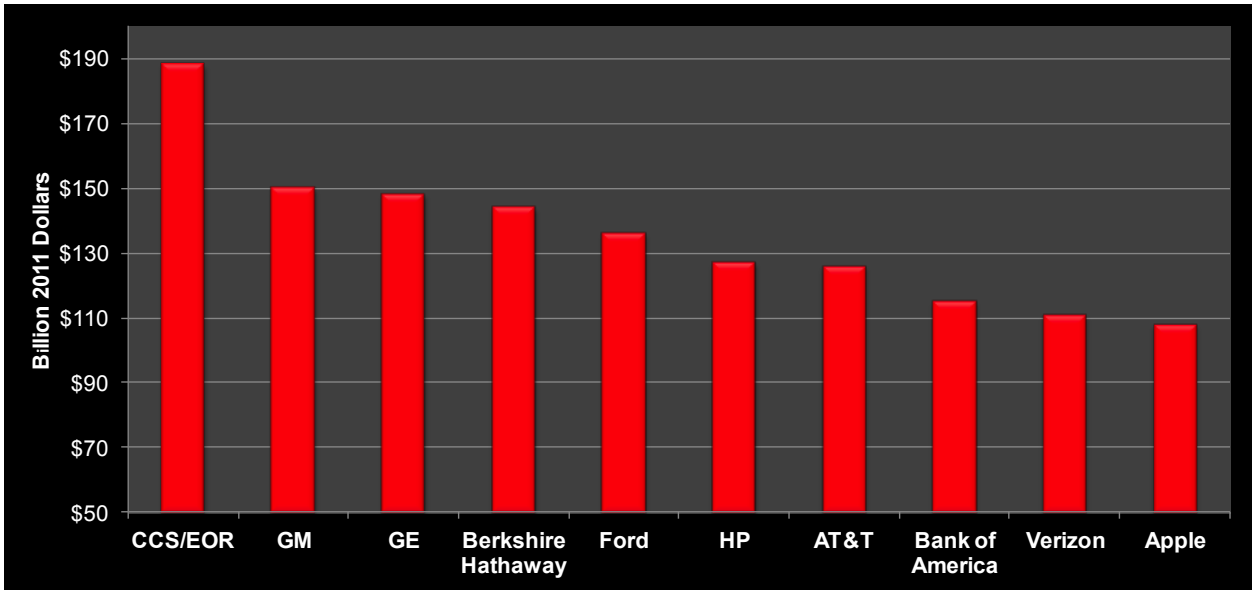
manufacturing to create jobs and meet the challenges of the 21st century." The initiatives, as articulated in the Aspirational Case, will facilitate achievement of these goals. Such initiatives are sorely needed because U.S. manufacturing and related industries are in serious trouble. For example:

- There has been a dramatic loss of U.S. manufacturing jobs over the past decade, and this was a break from the past and cannot be explained by productivity and technology gains.
- Since 2000, the manufacturing sector has lost a third of its jobs – 6 million jobs.
- Unlike preceding decades, manufacturing production actually declined from 2000-2010 by 5%.
- This decline was not just a result of the recession: From 2000-2007, manufacturing production increased only 1.3%/year – the worst performance since WWII.
- U.S. factories currently produce only 75% of what the nation consumes.

The sheer scale of the economic and employment benefits created by the Aspirational Case must be put into proper perspective to be fully appreciated. By 2030, the scenario is generating, on an annual basis, nearly $200 billion in industry sales and over 1 million jobs. To put this into context, during 2010, the entire U.S. economy created about 1.1 million new jobs. If "Clean Coal/CCS/EOR" were a company, it would rank 5th on the Fortune 500 and, as illustrated in Figure 2.5, would be significantly larger than such iconic American companies as General Motors, General Electric, Ford, Hewlett-Packard, AT&T, Verizon, and Apple.

Figure 2.5: Comparison of the Sales Generated in 2030 by the Aspirational Initiatives with the 2011 Sales of the Fortune 500 Companies

(*Fortune* magazine, Management Information Services, Inc., 2012)



The revenues of the "Clean Coal/CCS/EOR" company would be larger than the GDP of many nations. As illustrated in Figure 2.6, the company's revenues would be:

- Nearly as large as the GDP of such nations as the Czech Republic, Egypt, and the Philippines.
- About as large as the GDP of Romania.
- Significantly larger than the GDP of Hungary, Kuwait, New Zealand, Ukraine, and Vietnam.

Finally, in 2030, the Aspirational Case generates, in total, more than 1 million jobs. This level of employment ranks the "Clean Coal/CCS/EOR" sector among the largest in the United States. For example, as shown in Figure 2.7 this number of jobs is:

- Nearly as large the number of jobs in the Computer Manufacturing, Clothing Stores, and Legal Services sectors.

- About as large as the number of jobs in the Machinery Manufacturing and Automobile Dealers sectors.
- Significantly larger than the number of jobs in the Chemical manufacturing, Gasoline Stations, Telecommunications, Accounting Services, Dentists Offices, and Automobile Repair sectors.

Figure 2.6: Comparison of the Sales Generated in 2030 by the Aspirational Initiatives with the 2011 GDP of Selected Nations

(CIA World Factbook, Management Information Services, Inc., 2012)

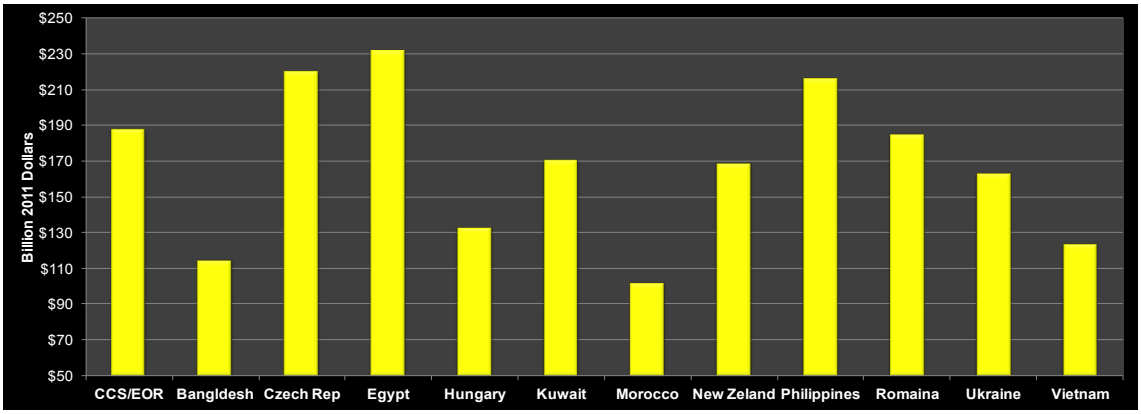
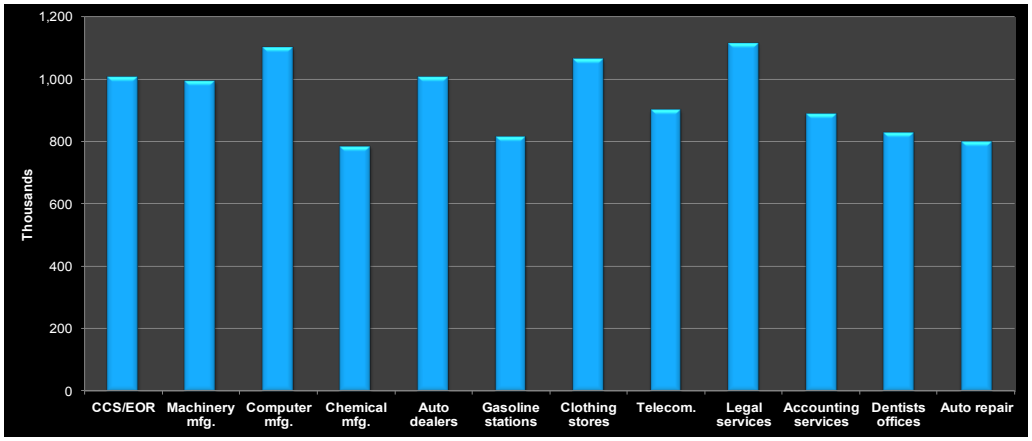


Figure 2.7: Comparison of the Jobs Generated in 2030 by the Aspirational Initiatives with 2011 Employment in Major U.S. Sectors

(U.S. Census Bureau, U.S. Bureau of Labor Statistics, Management Information Services, Inc., 2012)



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Chapter 3: Carbon Capture in Coal Power Generation and Coal-Based Alternative Fuels Production Systems

3.1 Key Findings

- There are several promising technology options for capturing coal-generated CO_2. These vary in technology readiness from laboratory experiments to being ready for commercial demonstration and/or deployment.
- Non-traditional opportunities for coal use such as "synfuels" (super clean synthetic gasoline, diesel, and jet fuel) or synfuels plus electricity (coproduction technologies) could have relatively low CO_2 capture costs based on commercially available technologies because CO_2 has to be removed from such systems as an inherent part of the process of synfuels manufacture. NOAK versions of such systems are likely to be economically attractive at current world oil prices, which will allow for an expanded use of coal in the domestic production of liquid fuels.
- Several CO_2 capture projects have been delayed or canceled, due in part to hurdles such as lack of PUC approval for rate-based reimbursement and uncertainty regarding regulatory and legal parameters for CCS.
- While coal-based power generation, synfuels production, and the coproduction of synfuels and electricity offer promising approaches for capturing a CO_2 stream suitable for EOR, all technologies have hurdles before widespread commercial acceptance and implementation can occur. Depending on the technology readiness, the hurdles can be technical, economic, institutional, or any combination thereof.
- Looking at several economic metrics (e.g., LCOE, capture cost, internal rate of return, minimum dispatch cost, etc.) leads to a comprehensive comparison of different CO_2 capture options. By using several economic metrics to evaluate the cost effectiveness of CO_2 from the existing fleet, it has been determined that there are circumstances under which retrofits can provide cost effective CO_2 for EOR after the technologies reach commercial maturity.
- The pathway to reduce the costs of CO_2 capture from coal utilization is through the pursuit of R&D and, more significantly, as a result of the cost reducing experience of demonstration and early mover capture projects ("learning by doing").

- For many CO_2 capture technologies, estimates FOAK capture costs are more than double or triple estimates for NOAK capture costs. Historically, for other air pollution control technologies, operating and construction experience has significantly reduced costs and CO_2 capture may also benefit from the same kind of learning experiences. There are a limited number of large-scale commercial demonstration projects under development, but these projects have yet to secure financing.
- The current method of government support for CCS RD&D is to provide funding through the annual appropriations process, which has been insufficient to adequately support commercial-scale demonstrations and early mover projects at the scale needed to accelerate near-term CO_2 capture technology development. The incrementally higher costs of early projects imply a need for additional financial resources for "cost buy down" through experience.
- Synfuels and coproduction technologies based on coal/biomass coprocessing with captured CO_2 used for EOR and eventually also stored in deep saline formations offer the opportunity for a greatly expanded role for coal in enhancing energy security even under a stringent carbon mitigation policy – with coal enabling, via such coprocessing systems, deep reductions in GHG emissions for transportation fuels.

3.2 Recommendations

- The Council recommends that the appropriate federal, state, and local regulatory agencies, with coordination and cooperation from industry, work with the Energy Secretary to develop a stable and consistent regulatory framework to promote CCUS/EOR technology applications.
- The Council recommends that the Energy Secretary encourage parallel tracks to pursue the pathway to reduce costs of CO_2 capture and purification processes (a) intensified R&D and (b) learning by doing through demonstration/early mover project experience.
- The Council recommends that the Energy Secretary meet and work with a wide range of stakeholders (including, but not limited to, coal, electricity generation, petroleum production, chemical manufacturers, and other stakeholders) to find new and innovative ways to develop financial support to create demonstration/early mover projects to reduce

deployment risks so that the CO_2 EOR industrial expansion envisioned in this report can be realized more quickly.

- The Council recommends that the Energy Secretary work with the Administration to explore and publicize the benefits of using our vast reserves of domestic coal.
- The Council recommends that the Energy Secretary and the DOE work with policymakers and business leaders to develop a methodology to compare different CO_2 capture options that is based on several economic metrics considered jointly (e.g., LCOE, IRRE, Capture Cost, MDC, etc.).
- For the near-term, the Council recommends that the Energy Secretary ask the DOE to lead an initiative to complete detailed engineering cost and design studies to better assess costs of implementing NOAK projects for each of the major capture options considered here for which the Technology Readiness Level (TRL) is at least 6.
- The Council recommends that the technologies selected for support for expedited demonstration or expedited first mover implementation be chosen based on their potential to become economically competitive in CO_2 EOR application in the near-term without further support and that technologies that are not making the needed progress against milestones be dropped from further expedited buy down support.
- To facilitate achieving the Aspirational Case goals and their beneficial consequences for the U.S. discussed in this report, the DOE should identify and document the key hurdles and roadblocks that have slowed current coal-based demonstration projects and early movers producing electricity and/or synfuels, and develop recommended approaches for dealing with them.

3.3 Introduction

Although various efforts continue to advance the development of CCUS processes, full-scale CCUS technology has yet to be demonstrated in practice or proven to be commercially acceptable for coal-based electric generating units due to significant technology, financial, and regulatory challenges. Numerous studies, including prior Council reports, have detailed these challenges and identified opportunities for accelerating the development of carbon capture systems for coal-based generation, including the integration of EOR or coproduction opportunities as a vehicle for capture technology advancement. The following chapter considers

the development status of potential carbon capture systems, potential for EOR and synfuel and coproduction opportunities to accelerate the development of these systems, and key issues that are and will continue to drive the decision making regarding the pursuit of such opportunities at a commercial level.

3.4 Metrics for Comparing CO_2 Capture Technologies

The following provides an overview of the metrics employed by this chapter to examine the development status and attributes of the carbon capture technologies discussed. These metrics are not the only ones that might be used, but the chosen set can be helpful in providing perspective both on the degree of additional RD&D needed before the technologies discussed can become commercially established, and how capture technologies compare to one another in terms of prospective economics and carbon intensities when captured CO_2 is stored underground via EOR.

3.4.1 Technology Readiness Level

Technologies to capture CO_2 from coal-fired power plants are in various stages of development. The DOE and others have utilized TRL to uniformly compare and evaluate potential capture technologies. The TRL approach was originally applied by NASA to provide a basis for decision making regarding the readiness of different technologies for deployment. Assigning TRLs to CO_2 capture technologies has recently been employed by the DOE, Electric Power Research Institute (EPRI), and others for similar purposes. In the following sections, the TRL of different CO_2 capture technologies is provided along with a discussion of the state of the respective technologies. The description of each TRL, as defined by the DOE, is provided in Table 3.1.

Table 3.1: TRL Descriptions

(Abbreviated from the DOE, 2009)

TRL	Description
1	Scientific research begins translation to applied R&D - Lowest level of technology readiness. Examples might include paper studies of a technology's basic properties.
2	Invention begins - Once basic principles are observed, practical applications can be invented.
3	Active R&D is initiated. Examples include components that are not yet integrated or representative.

4	Basic technological components are integrated.
5	The basic technological components are integrated with reasonably realistic supporting elements so it can be tested in a simulated environment.
6	Model/prototype is tested in relevant environment.
7	Prototype near or at planned operational system - Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in an operational environment.
8	Technology is proven to work - Actual technology completed and qualified through test and demonstration.
9	Actual application of technology is in its final form - Technology proven through successful operations.

3.4.2 Framework for Economic Analysis for CO_2 Capture Technologies

Many reports have been published that estimate the potential cost for CO_2 capture and related processes (CO_2 transport, geologic storage, and utilization) for coal-based power plants. The different assumptions and methods used in such studies make difficult arriving at meaningful comparisons of technologies described in different reports and comparisons of the findings of different reports for specific technologies. Moreover, no existing reports present absolute costs for CO_2 capture in which the reader can have a high degree of confidence. Meaningful estimates of absolute capture costs will not be feasible without the experience of early mover commercial-scale projects. But, it is feasible to understand relative costs for alternative technologies based on information in the literature if this information is analyzed in a self-consistent manner.

In this chapter, a self-consistent analytical framework, including specified exogenous energy prices, is used to present and compare capture costs for the major capture options considered in this chapter, based on information from the literature. This self-consistent cost analysis is an original work provided by Robert Williams (Princeton University's Energy Systems Analysis Group) for use in this Council study. Sense can be made of the ordering of the costs for different options estimated in this manner from consideration of the physical and chemical principles involved in the different technologies, as well as consideration of the costs for key components of the different capture technologies. Highlights of this analytical framework are mentioned here. Details are provided in Appendix 3A, which also includes an analysis showing that when NETL and EPRI analyses of capture costs are carried out for power generation systems in the same analytical framework, the estimated capture costs are essentially the same.

In all cases where systematic comparisons of technologies are made, costs are expressed in constant $2007 based on plant construction as of that year. The economic metrics presented in the main text of this chapter [capture cost, real IRRE, LCOE, and minimum dispatch cost] were chosen so as to facilitate self-consistent comparisons among the diverse systems considered here: systems that provide only electricity, systems that provide mainly synthetic fuels, and systems that provide synfuels and electricity as major coproducts. Other metrics relevant only to synfuel systems and systems that coproduce synfuels and electricity [levelized cost of fuel (LCOF) and breakeven crude oil price (BECOP)] are presented in Appendix 3A.

Also, to accommodate synfuels and coproduction, this study chose a more risk oriented framework for the financial analysis than that of EPRI (2011), which is focused on making only electricity. For this study, the assumed plant life is 20 years instead of EPRI's 40 years, the assumed debt/equity ratio is lower (45/55 vs. 50/50), the hoped for real rate of return on equity is higher (9.0%/year vs. 8.3%/year), and the discount rate is higher (6.4%/year real *before-tax* average cost of capital compared to 5.4%/year *after-tax* cost of capital). However, the specific framework chosen for making systematic comparisons among technologies is much less important than that the framework is reasonable and consistently applied.

One caution in comparing the relative economics of carbon capture alternatives is that the development level of the technology influences the confidence one can have in a cost estimate, i.e., one can have more confidence in an estimate the more advanced a technology in the development cycle. In addition, because no commercial-scale carbon capture and utilization/storage process has been demonstrated on a coal-based power plant, experience-based cost and development considerations from actual projects are not available to inform or validate such estimates.

3.4.3 Greenhouse Gas Emissions Index

Whether coal is used to generate power, synthetic fuels, or both via coproduction, the amount of GHGs added to the atmosphere can be reduced through CO_2 EOR if the purchased CO_2 is securely stored underground. Similarly, adding "closed loop" biomass to an energy system will reduce GHG emissions. Therefore, it is important to consider the relative greenhouse gas emissions as well as the costs for the alternative energy systems analyzed. Here, a greenhouse gas emissions index (GHGI), originally introduced in Liu et al. (2011), is utilized to characterize the carbon mitigation features of the technologies considered. The GHGI for an

energy conversion system is defined as the fuel-cycle-wide GHG emissions for energy production and consumption divided by the GHG emissions for the fossil energy displaced. The fossil energy displaced is assumed to be electricity from a new supercritical coal plant venting CO_2 and, in the case of synthetic transportation fuels, the equivalent crude oil-derived products.

The GHGI is particularly useful in describing the carbon mitigation features of a coproduction system, if equal percentage reductions are assumed for each of the coproducts. For example, a system coproducing electricity and liquid transportation fuels for which GHGI = 0.5 could be characterized as providing electricity with half the GHG emission rate of a new supercritical coal plant venting CO_2 (approximately the rate for a natural gas combined cycle venting CO_2) and providing liquid transportation fuels with half the GHG emission rate for the crude oil products displaced (equivalent to the maximum allowable GHG emission rate for "Advanced Biofuels" under the RFS2 Mandate of the Energy Independence and Security Act of 2007).

3.5 Technologies to Capture, Transport, and Use CO_2 from Coal-Based Generation

CO_2 capture from coal-based generating units can be divided into three general categories: post-combustion, oxy-combustion, and pre-combustion (note that synthetic fuels production and coproduction plants are discussed in subsections of pre-combustion capture). 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 differences among the three approaches are how the CO_2 is concentrated. Each process has its own advantages, disadvantages, applicability to various coal-based generation technologies, and opportunities for EOR or coproduction.

3.5.1 Post-Combustion CO_2 Capture

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). Post-combustion capture is necessary because the power plant flue gas is at atmospheric pressure and approximately 10-15% CO_2. Various post-combustion capture technologies have been successfully utilized in other industries that are being developed for transfer to coal-based power generation applications. Usually post-combustion CO_2 capture technologies are

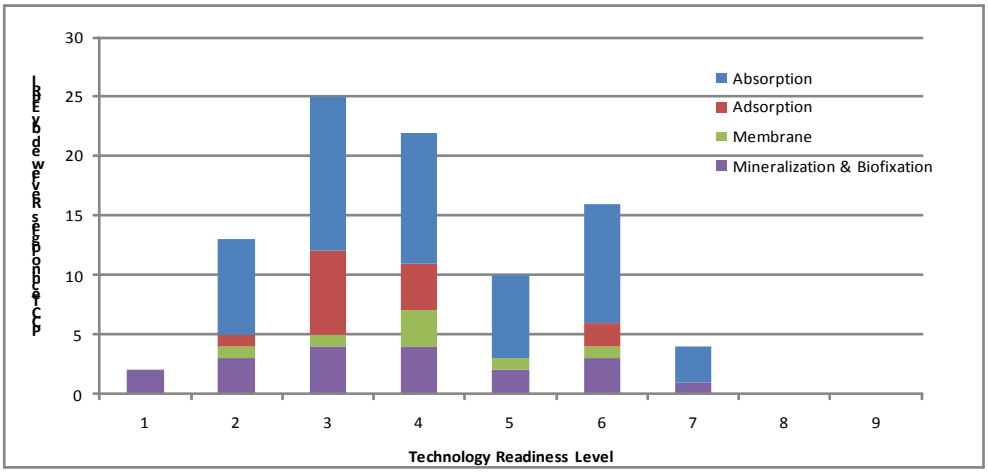
implemented upstream of the existing stack and downstream of other air pollution control technologies. One of the post-combustion CO_2 capture technologies with the highest TRL is an aqueous amine system that utilizes a temperature swing for regeneration. Post-combustion CO_2 capture is often considered the least disruptive option for power plant operation and could be applied to the existing fleet of coal-fired power plants as well as new units.

Although a number of projects have been proposed and are currently under development, commercial-scale post-combustion capture systems have yet to be demonstrated at a coal-based power plant. EPRI completed an assessment of the TRL for post-combustion CO_2 capture technologies, which is summarized below. A graph of the TRL for post-combustion CO_2 capture technologies is provided in

Figure **3.1**. In this column graph, the number of technologies at each TRL is indicated by the bar height (i.e., y-axis).

Figure 3.1: Technology Readiness Level for Post-Combustion Technologies

(Bhown, 2011)



As is shown in

Figure **3.1**, none of the post-combustion CO_2 capture technologies can be considered fully commercial. In fact, the most advanced post-combustion CO_2 capture technologies are characterized as having a TRL of 7, which means a prototype system is near in development, but

not yet demonstrated. Several processes using improved amine- and ammonia-based solvents are reaching the demonstration phase, at scales suitable for pre-commercial demonstrations at power plants. In fact, several slipstream plants, which could be considered pre-commercial are scheduled to begin startup in 2012. Table 3.2 includes a list of recent post-combustion CO_2 capture projects (EPRI, 2011). It is important to note that nearly all the projects moving forward at the pilot or demonstration-scale are receiving financial support from the DOR. Even with this assistance, several important projects have been cancelled due to their cost, experienced delays due to the process in determining regulatory and legal parameters for CCS, face difficulties in obtaining public utility commission approval of rate-based reimbursement of costs, and other factors (EPTI, 2012).

Table 3.2: Greater than 10 MW Post-Combustion CO_2 Capture Projects at Power Stations in the United States

Project	Location	MW_e Equivalent (plant net, type, coal)	Tons CO_2 per Year (1,000)	Technology	Notes
AEP, Mountaineer	New Haven, West Virginia	20	120	Alstom Chilled Ammonia	Startup September 2009; first saline formation injection from coal power in October 2009; Project completed in 2011. Follow up project was cancelled.
Basin Electric, Antelope Valley	Beulah, North Dakota	120	900	HTC Purenergy / Doosan Babcock amine; EOR	DOE award $100M; decision to proceed postponed in December 2010

NRG, W.A. Parish Generating Station Unit 7	Thompsons, Texas	240	500	Fluor Econamine FG+; EOR or geologic storage	DOE award $167M; startup 2014 (2-year test)
Searles Valley Minerals/Argus Cogeneration	Trona, California	54 (cogen)	270	ABB Lummus Global Process; brine carbonation for soda ash production; process upgrades by HTC Purenergy	In service starting 1978; considering capture upgrades to allow mineral sequestration of an additional 620,000 tons/year (560,000 metric tons/year)
Southern Company Services at Alabama Power's Plant Barry	Mobile, Alabama	25	150	MHI KM-CDR (KS-1 amine); saline	Startup in June 2011
Tenaska, Trailblazer	Sweetwater, Texas	600	600	Fluor Econamine FG Plus; EOR, dry cooling	Air permit received December 2010

In addition to the projects shown in Table 3.2, there are smaller CO_2 capture operations for food grade CO_2 as well as many different post-combustion CO_2 capture technologies at various TRLs. A significant portion of the post-combustion capture RD&D seeks to minimize drawbacks of the CO_2 capture processes that are closest to commercial maturity. Technology developers are attempting to reduce the overall costs and/or energy penalty for CO_2 capture using improved aqueous amines, non-aqueous solvents, adsorption using dry sorbents, membranes, etc.

3.5.2 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. While additional energy is required to produce the necessary oxygen, the result is a significantly increased CO_2 concentration in the flue gas (up to 85% or possibly 90% volume compared to 13% with conventional air combustion) in the flue gas stream because the nitrogen has been eliminated from the combustion oxidant. However, depending on the CO_2 specifications additional purification may be necessary, which could be in the form of

distillation; if distillation or additional CO_2 purification is necessary it may be less costly than post-combustion CO_2 capture due to its flexibility in the level of purity (although the cost of oxygen production must be considered). Commercial-scale demonstrations are needed to better quantify opportunities and challenges associated with oxy-combustion. However, the promise behind oxy-combustion was recognized by the Global CCS Institute when it reported that for the U.S. Gulf Coast region "oxy-combustion combustion has the lowest breakpoint" when compared to post-combustion, pre-combustion, and NGCC with CO_2 capture. For a detailed, technical description of oxy-combustion, please refer to previous Council studies (e.g., 2008).

There is a significant range in the TRL for different oxy-combustion projects. To date, no commercial-scale oxy-combustion system has been demonstrated at a coal-based power plant. However, under the DOE's FutureGen 2.0 program, a 170 MW commercial-scale oxy-combustion power plant has just completed Phase 1 and will likely move into Phase 2 (FEED) in July 2012. Most advanced demonstration projects are in the planning and engineering stage. If these projects are constructed and operated successfully, the respective technologies will be considered to be at a TRL of 8 (GCCSI Oxy-Combustion, 2012). There are several technology developers developing technologies at lower TRLs, which have the potential to reduce the overall costs or increase the efficiency of oxy-combustion. Most such projects can be characterized by having TRLs between 6-7.

In terms of development, several pilot plants (up to 30 MW_e) have been operated to test process variations and critical components. The largest membrane unit separating oxygen from air, which is to produce 100 tons/day, is scheduled to come online in the second half of 2012. In addition, a 170 MW_e coal-fired boiler is being retrofit to operate with high flame temperature oxy-combustion and the DOE NETL's Integrated Pollutant Removal (IPR™) system for CO_2 capture. The CO_2 from this project will be used for EOR. Pressurized oxy-combustion is still under development as a system, but many of the key unit operations and major components have been tested at gasification plants at large-scale (Crew, 2011; Weiss, 2011), although the DOE has stated that pressurized oxy-combustion will require significant RD&D (DOE NETL, 2012a). In addition, chemical looping is another potential means to carry out combustion in oxygen, but the DOE has found it will also require significant RD&D before being considered commercial (DOE NETL, 2012a).

As with any CCS technology, the primary challenges to implementation are: 1) the capital cost in the absence of sufficient offsetting CO_2 value for CCUS and 2) energy consumption for oxygen production as well as CO_2 purification and compression. However, even considering these challenges, several studies (DOE Oxy-combustion, 2007) including the Interagency report on CCS (2010) noted that new oxy-combustion for CO_2 capture may result in a lower LCOE than new pre-combustion or new facilities with post-combustion CO_2 capture.

An important consideration for EOR applications using CO_2 from oxy-combustion capture is that the O_2 must be limited in the capture CO_2 stream, as discussed in Section 3.5.4. One critical issue to determine the cost of oxy-combustion CO_2 for EOR is the range of CO_2 specifications for a) EOR, b) existing CO_2 pipelines, and c) pipelines which could be built to accommodate CO_2 transport of less pure CO_2 which still meets EOR requirements. A careful cost analysis to determine long- and short-term CO_2 EOR costs based on whether it is more economical to have more stringent or less stringent pipeline specifications, which may also depend on costs due to distance assumptions is required. This requires comparing a range of capital and operating costs for: 1) pipelines with different materials and 2) distillation or other processes to purify CO_2 beyond its capture status.

Comparisons of the results from techno-economic sources (studies) for different technologies such as oxy-combustion, integrated gasification combined cycle (IGCC), or post-combustion processes, unless generated by the same source using consistent assumptions and methodology, are historically unreliable. Even results from a common source must be taken in the context of the associated uncertainties of the designs, predicted performance, varied risk mitigation strategies, and cost estimates. Cost estimates are always subject to ranges resulting from the level of detail exercised during the cost estimating process (e.g., how much is based on current quotes versus historical estimating data etc.), typically these ranges are +/-30% or at best +/-20% accuracy. In addition, contingencies applied to capital costs to account for FOAK or NOAK scope uncertainties vary greatly between sources. Valid comparative LCOE or resulting CO_2 capture cost for different technologies derived from different sources is even more complex and adds considerable uncertainty. When comparing results from different sources, especially for retrofit studies, very careful scrutiny is required to be certain that the equipment design basis (coal properties, site conditions and elevation, steam cycle efficiency, CO_2 purity, and other critical factors including other upgrades assumed) and the financial analysis basis (discount rate,

debt-equity ratio, tax rate, etc.) leading to the capital cost factor and levelization factors are identical or at least fully understood so they can be adjusted to common basis.

Considering the caveats described previously, oxy-combustion retrofits' LCOE is about $65.4 MWh and capture cost is about $54.4/metric ton CO_2, +/-30% (B&W, 2011). Other studies fluctuate around these values but considering the uncertainty range, the appropriate conclusion is that oxy-combustion and post combustion retrofits take about the same space, have about the same equivalent power penalty, and cost about the same (Jupiter Oxygen, 2012). However, oxy-combustion has the advantage of not having a significant impact on the steam cycle where pulverized coal combustion (PCC) requires a major modification of the low pressure turbine or an additional steam source for solvent regeneration. PCC has the advantage of allowing treatment of a slip stream from a single unit where oxy-combustion requires conversion of an entire unit. However, partial capture can also be achieved with some oxy-combustion technologies by operating the plant with air firing when power prices are high (to maximize net output) and operating in oxy-combustion mode when electricity prices are low to capture CO_2. Moreover, if CO_2 is regulated at a plant level, one (or more) unit could be converted to achieve the composite emissions target.

3.5.3 Pre-Combustion CO_2 Capture

Pre-combustion CO_2 capture technologies have been used in oil, gas, and chemical industries for decades and similar to oxy-combustion, most pre-combustion technologies also require purified oxygen (albeit less oxygen is required per unit coal for gasification compared to oxy-combustion). There are also existing coal and petcoke gasification-based plants that are capturing CO_2. For example, the Coffeeville Resources plant – a gasification plant that uses petcoke – captures CO_2 for ammonia production. Also, the Dakota Gasification Company's Great Plains Synfuels Plant captures CO_2 emissions from a coal gasification process for EOR use. In fact, the Synfuels Plant captures more CO_2 from coal conversion than any other facility in the United States. As such, pre-combustion capture of CO_2 for chemical industry and coal gasification is commercially practiced with a TRL of 9. In addition, all major components of an IGCC plant with carbon capture, such as the air separation unit, gasification, gas cooling, shift reaction, sulfur control, and CO_2 capture can be described as having a TRL of 9 (fully commercial). Included under the category of pre-combustion CO_2 capture are IGCC power

plants, plants that gasify coal primarily to produce liquid fuels, and coproduction plants capable of generating significant amounts of electricity and liquid fuels.

IGCC Power Plants

Pre-combustion capture technologies are applicable to coal-based gasification processes, including coal-based 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. Because the partial pressure of CO_2 is greater for pre-combustion CO_2 capture, CO_2 separation is less costly than for post-combustion CO_2 capture. However, costs for IGCC power plants venting CO_2 are higher than that for pulverized coal units, so without a price on CO_2 emissions it is difficult for IGCC power plants to be competitive economically. 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. For a detailed technical description of pre-combustion technologies, please refer to previous Council (2011) and DOE (2010) studies. While there is no operating coal gasification-based power plant (i.e., IGCC) with CO_2 capture, several IGCC projects with CO_2 capture technology are at different stages of planning/operation. Table 3.2 presents a list of full-scale gasification-based with CO_2 capture demonstration projects that are under development.

Table 3.2: Large-Scale Gasification-Based Power Plant with CO_2 Capture Projects

(MIT, 2012)

Project Name	Organization	Feedstock	Size (MW)	Capture (%)	CO_2 Disposition	Start-up Date	Location
TCEP	Summit Power	Coal	400	90	EOR	2014	Texas
Kemper County	Southern Company	Coal	582	67	EOR	2014	Mississippi
HECA	SCS	Petcoke	390	90	EOR	2014	California
Belle Plaine	TransCanada	Petcoke	500	80-90	Undecided	Undecided	Saskatchewan, Canada

Don Valley Power Project	2Co	Coal	650	90	EOR	2015	South Yorkshire, UK
Magnum	Nuon	Various	1200	90	EOR/ EGR	2020	Eemshaven, Netherlands
GreenGen	GreenGen	Coal	250/400	Up to 80	Saline	2018	Tianjin City, China

Biomass Cofiring for Electric Generating Stations

If it is desired to reduce the GHGI, one option is to use biomass cofiring, which is possible for both pulverized coal power plants and gasification plants. Industrial practice shows that up to about 15% by thermal content biomass cofiring in a coal-based power plant does not have detrimental effect on efficiency or availability of the coal plant. If significantly more (e.g., 30-50%) biomass cofiring is desired, the biomass could be gasified in a separate, atmospheric pressure CFB gasifier; the gas so generated could be piped without cleanup to and cofired with coal in the pulverized coal boiler. Because of the lower operating temperature of the CFB gasifier, the biomass ash is generated in a form that makes it easily removed from the gasifier, where it does not cause shagging or fouling problems.

Synfuels and Coproduction Systems

Rather than being used only for power production, gasified coal can also be used to make synthetic fuels via the Fischer-Tropsch (FT) liquids or methanol-to-gasoline (MTG) processes (see Appendix 3B for additional details), which are fully commercial energy conversion options. Coal versions of these technologies will be referred to here as CTL and CTG, respectively. These synfuel systems can be designed to maximize liquid fuel production, which are referred to here as CTL_{max} and CTG_{max}. They can also be designed to provide electricity as a major coproduct, referred to here as CTL_{coprod} and CTG_{coprod}. Each of these approaches to synfuels production is discussed below, after describing the common features of both approaches.

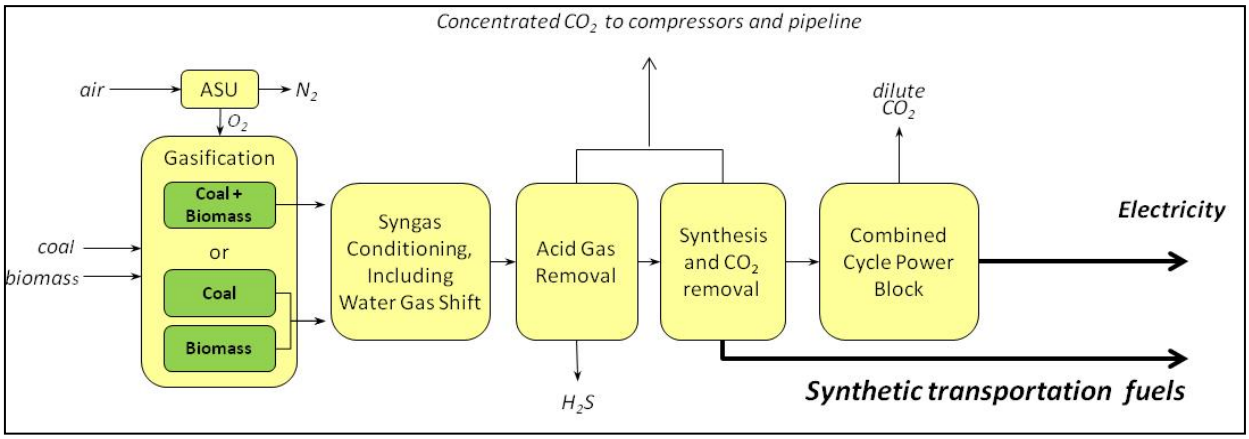
As in the IGCC case, the process of making a synthetic fuel begins with gasification to produce syngas, a gaseous mixture whose main constituents are hydrogen (H_2) and carbon monoxide (CO). After suitable cleanup and processing, the syngas is passed to a synthesis

reactor in which the H_2 and CO react in the presence of an appropriate catalyst to make synthetic fuels. From a capture perspective, a key aspect of synthetic fuels manufacture is that most CO_2 is removed from syngas before it enters the synthesis reactor as an essential feature of the process of making a synthetic fuel. In the absence of a carbon mitigation policy or a market opportunity such as EOR, this high purity CO_2 stream (Kohl, 1997) would be vented. The already separated CO_2 can, at low cost, be dried and compressed to make it ready for pipeline transport. Because it is available at high purity, the captured CO_2 would easily satisfy requirements for pipeline transport and EOR use.

Similar to plants that use coal to generate electricity, synfuels and coproduction systems also could use biomass to decrease the GHGI (discussed in further detail in subsequent sections).

Figure **3.2** is a general schematic of a coproduction plant designed to coprocess biomass with coal; biomass can be gasified either in the same gasifier (upper green box) or in separate gasifiers (lower green boxes).

Figure 3.2: Coproduction of Transportation Fuels and Electricity via Coprocessing Coal and Biomass



Synthetic Fuels Production

In CTL_{max} and CTG_{max} systems, unconverted synthesis gas after passing through the synthesis reactor is recycled back through the reactor to make more liquid fuel. In such systems, the net electricity available for export to the electric grid is modest, typically less than 10% of total net energy output. These system designs are likely to be chosen for making synfuels in regions remote from major electricity markets where coal prices are low (e.g., Wyoming,

Montana). Such systems (see, e.g., Figures 3A1 in Appendix 3A4[1]) might typically involve large plants [i.e., 50,000 bbl/d)] located near coal mines so as to exploit both economies of scale and the availability of low priced coal. For this system GHGI = 0.89, sharply down from GHGI = 1.7 for the corresponding system that vents CO_2; since capture for this system requires only CO_2 drying and compression, the capture cost is about $8/metric ton (see Table 3A7).

No U.S. CTL_{max} plants are currently planned, but plans are being made for a CTG_{max} project at Medicine Bow Wyoming (DKRW). The plan is that the first phase would be online by the middle of the decade producing 10,600 bbl/d of gasoline. DKRW has already secured contracts to sell 100% of its gasoline output and the CO_2 for EOR. DKRW has contracted to sell up to ~10,000 metric tons/day to a subsidiary of Denbury Resources for CO_2 EOR applications (Chapter 5). DKRW was able to negotiate a contract to sell CO_2 for EOR because both the synfuels technology and the CO_2 capture technology for these synfuel systems are commercial; TRL = 9 for this capture technology.

Coproduction of Synthetic Fuels and Electricity

A coal synfuels plant might alternatively be designed to provide electricity as a major coproduct. In a CTL_{coprod} plant, syngas not converted to liquid fuels in passing once through the synthesis reactor is burned in the gas turbine combustor of a combined cycle power plant. In such a plant configuration, typically 25-35% of energy output (electricity plus diesel and jet fuel plus gasoline or naptha) is electricity (see, for example, Figure 3A2). As in the CTL_{max} case, CO_2 has to be removed from syngas before it passes to the synthesis reactor, and this can be compressed at low cost for pipelining. Also, when an iron FT synthesis catalyst is used, additional CO_2 generated in synthesis can be captured at high partial pressure downstream of synthesis (see Figure 3A2). The relative profitability of CTL_{coprod} and CTL_{max} investments depends on electricity and oil prices, but for the assumed electricity price and plausible oil prices, the profitability is about the same for each approach (see Figures 3A3 and 3A4). Because modest scale coproduction systems with CO_2 capture evaluated as power generators offer attractive economic features in a world of high oil prices and low CO_2 selling prices (see Section 3.7), they might become the preferred approach to synfuels production in regions where new

[1] Figures 3A1 through 3A14 and Tables 3A1 through 3A10 in support of analysis in this chapter are available for interested readers in Appendix 2A. Henceforth, such figures and tables will be mentioned without explicitly referring to Appendix 3A.

electricity supplies are needed – if the institutional challenges posed by coproduction options (see Section 3.8) can be overcome. Evaluated as power generators, such coproduction plants could be built at Greenfield sites or considered as rebuild options for older coal power plant sites.

In order for coal to be used in large quantities to make synfuels under a possible eventual carbon mitigation policy, it may be necessary to pursue not only CCS but also the coprocessing of biomass with coal. For such systems that capture CO_2, storing photosynthetic CO_2 underground represents negative emissions that can be used to offset positive CO_2 emissions from coal. For example, a coproduction plant cogasifying coal with 5% biomass (energy basis) with CCS has a GHGI = 0.5 (see Figures 3A5 and 3A6). Because the 250 MW_e dry-feed gasifier-based IGCC at Buggenum has operated successfully with up to 20% biomass (energy basis) since 2006, such a plant would have a TRL of 6 or 7.

Coproduction in the Longer-Term

If, over the next decade or so, coproduction technologies coprocessing small biomass input percentages (<10%) were to be successfully demonstrated and launched in the market using captured CO_2 for EOR, over the longer-term the biomass percentage could be gradually increased. Coproduction systems coprocessing ~30% biomass with coal could provide simultaneously low carbon electricity and low carbon synthetic "drop-in" transportation fuels (GHGI < 0.1 – see Tables 3A3 and 3A8), prospectively with quite attractive economics under a carbon mitigation policy compared to many other low carbon electricity and transportation fuel options, even for the longer-term situation in which captured CO_2 might be stored in deep saline formations instead of used for EOR (see, e.g., Figures 3A10-3A12). Moreover GHGI values <0.1 can be realized for such coproduction systems using <40% as much lignocellulosic biomass to provide a gallon of gasoline equivalent transportation as with advanced biofuels (see Table 3A8).

One of the broader implications is that coproduction based on coal/biomass coprocessing with CCS offers a fast route for shifting from food biomass (e.g., corn for making ethanol) to lignocellulosic biomass (the production of which need not conflict with food production) in making low carbon transportation fuels. A more far reaching implication is that, for the United States at least, coal is key to realizing deep reductions in GHG emissions for transportation fuels at affordable cost. Moreover, in principle at least, addressing the climate and energy security

challenges for transportation and electricity simultaneously could turn out to be easier than addressing these challenges separately.

3.5.4 CO_2 Pipeline Requirements

While CO_2 capture technologies can provide a significantly purified CO_2 stream compared to the gas being treated, it is likely that there will be differences in the exact concentration of other constituents in the CO_2. Whether this CO_2 stream will need further purification to meet pipeline or injection specifications has yet to be fully determined, in cases where additional purification is necessary, it must be added into the overall CO_2 capture cost. Most CO_2 specifications are currently discussed only in private contracts and are not readily available to the public. However, a recent report provided a few examples of CO_2 specification compositions in different streams, which are provided in Table 3.3. Note that for the purposes of this study, the Kinder Morgan pipeline specifications will be the basis of any cost analysis. Determining CO_2 specifications for pipeline transport and EOR injection involves critical issues of pipeline configuration and oil field reservoir size, which can be classified into two cases:

- Case 1: Use of highly interconnected pipeline network including existing pipelines, with a CO_2 common carrier approach for transportation to many EOR sites, requiring a rigorously standardized CO_2 specification for reasons of near-term and future interconnect capability.
- Case 2: CO_2 is from one or a small group of specific coal-fired power plants and transported to single or a specific grouping of oil fields with sufficient reservoir size for a 20-30 year EOR project, with one or more dedicated pipelines. CO_2 specification can be broader with the pipeline constructed for the allowed CO_2 constituents depending on well geology, oil characteristics, and/or relaxed safety considerations.

If the captured CO_2 requires additional purification, especially to achieve O_2 and N_2 purity levels, the capital and operating purification costs must be compared to additional pipeline capital and maintenance costs required to handle those levels of O_2 and N_2 without the additional purification. In addition, another issue that must be highlighted is the mixing of CO_2 capture via

post-, oxy- and pre-combustion; which may generate different CO_2 purities. For example, H_2S from pre-combustion and SO_2 from post-combustion can be a concern due to sulfur precipitation.

Table 3.3: Examples of CO_2 Pipeline Specifications

Component	Kinder Morgan CO_2 Pipeline Specs (Bliss et al., 2010)	Potential Range of CO_2 Specs (Melzer, 2007)
CO_2	≥ 95 vol%	≥95 - 96 vol%
Water	≤ 30 lb/MMcf	≤ 25 – 30 lb/MMcf or 20 ppmv
H_2S	≤ 20 ppmw	≤ 10 - 10,000 ppmw
Total Sulfur	≤ 35 ppmw	≤ 30 – 35 ppm
N_2	≤ 4 vol%	≤ 3 – 4 vol%
Hydrocarbons	≤ 5 vol%	≤5 vol%
O_2	≤ 10 ppmw	≤ 5, 10, or 50 ppmw
Other	Glycol: ≤ 0.3 gal/MMcf	CH_4: ≤ 0.7 vol% C_2+: ≤ 2.3 vol% CO: ≤ 0.1 vol%

One of the main concerns regarding CO_2 purity is that it is high enough that other constituents, such as N_2, do not interfere with the CO_2 being compressed and transported in a dense phase. Sulfur compounds are often controlled based on concerns related to biological exposure, while high O_2 concentrations could lead to chemical reactions and aerobic bacterial growth during injection. Water is of concern due to the risk of corrosion (Bliss et al., 2010).

One important consideration is related to the operational flexibility of the different technologies. EOR requirements and load following are unlikely to go hand in hand. All the technologies could potentially vent CO_2 in the case of a lack of demand, but the cost effects should be considered. Also, demand for CO_2 will vary through the life of an EOR project with highest demand on initial operation and decreasing demand as increased CO_2 is produced with the oil and then recycled. This may be mitigated to some degree by a strategy of incremental addition of new fields to offset decreased demand, but it is correct to assume that capture plants will require flexibility to reduce production while not compromising electricity, chemical or fuel production.

3.6 Considerations for Retrofits with CO_2 Capture

The decision to deploy CCS technology as a retrofit to the existing coal-based generation fleet will be strongly influenced by the optimization and resolution of a variety of technical and non-technical challenges. Key areas of consideration include technical, financial, permitting, legal, and public engagement issues – all of which were discussed in depth in the 2011 NCC Report. The following list highlights some of the technical considerations that were identified for carbon capture retrofit projects. A more complete discussion of the all retrofit considerations can be found in the 2011 NCC report. Key technical considerations for retrofit projects include:

- For post-combustion capture, 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, the effect on steam turbine performance and plant load following, and space provisions in the plot plan.
- For oxy-combustion, a determination of the concentration of SO_2 and NO_x in the flue gas that is acceptable to the CPU inlet. 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.

When examining the viability of the existing coal-based generation fleet for CCS retrofit potential, several key questions 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? For utility generating units, space limitations are likely become more acute with the addition of emissions upgrades required by the EPA's new Mercury and Air Toxics (MATS) and Cross State Air Pollution Regulation (CSAPR) standards.

- 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 sufficiently near 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?

3.6.1 Retrofitting with CO_2 Capture

Post-Combustion

Because of the size of the U.S. coal fleet, retrofitting operating units for capture of CO_2 from the flue gas represents a major opportunity for reducing CO_2 emissions from coal-based power generation and for providing CO_2 for EOR. Limited published design studies of retrofitting exist because of the issues of making a generic estimate for a situation in which each existing plant is different and offers different retrofit design challenges and costs. Greenfield capture costs reported in the literature are ~$40/metric ton of CO_2 (MIT, 2007; Geisbrecht, 2009; Simbeck, 2009). For the current analysis, it is assumed that the capital cost for a post-combustion capture retrofit is approximately 30% higher than for a new Greenfield plant as estimated in EPRI (2011). When this done, and the capital cost is deflated to a 2007 $ costing basis (so that a self-consistent basis for comparing this technology to others can be made), the result is a $50/metric ton capture cost (see Table 3A3 in the Appendix 3A for details).

Oxy-Combustion

Retrofit with oxy-combustion is commercially ready, but it requires conversion of the entire unit. Studies have shown that this can be accomplished with approximately the same footprint and comparable (perhaps lower) levelized cost compared to retrofit of post-combustion (for the same CO_2 capture performance). This might be attractive for sites with multiple units where one or more are converted to achieve overall site CO_2 emissions limits. Further, the "swing plant" concept where the unit is designed to run air-fired (with air emissions) and store

oxygen when electricity prices are high to maximize net output and run oxy-combustion when electricity prices are low storing the CO_2 – thus, partial capture of a single unit.

Studies by B&W and Air Liquide for the DOE (DE-FC26-06NT42747) showed that oxy-firing is an economically viable retrofit technology for existing boilers. The incremental cost of oxy-firing for existing boilers varies between 5-7¢ a kilowatt-hour, (shown as $29/metric ton and ~$43/metric ton for a new supercritical and subcritical retrofit, respectively) which is competitive with other technologies (incremental cost assumes the plant is fully depreciated; no capital remaining and O&M costs for the pre-retrofit equipment are not included). The efficiency loss for retrofitting oxy-PC ranges between 8-9%, which is considered consistent whether the retrofit is applied to a subcritical or supercritical base plant.

This is a comparison from the referenced study showing the cost of CO_2 avoided and removed comparing oxy- and post-combustion retrofit cases. Case 1, a subcritical oxy-combustion retrofit, is lower than those derived from the DOE post-combustion study referenced and slightly higher than the DOE post-combustion study assuming half the solvent cost.

3.6.2 Repowering, Rebuilds, and New Build Plants

All of the options for concentrated CO_2 generation (i.e., post-combustion capture, oxy-combustion, pre-combustion capture) can be applied when repowering, rebuilds, and new plants are taken into consideration. Repowering and rebuilding older plants may be of particular interest. Out of the approximately 330 GW_e of pulverized coal capacity in the United States, about 30 GW_e are slated for closure. Many of the existing units are old, paid-off subcritical units; most are between 200-500 MW_e in size. Some of the units scheduled for closure and a number of the operating units have potential for repowering or rebuilds because of their age, current emissions levels, and current low efficiency.

3.6.3 Brownfield Plants and Repowering

Because each unit and site is different, generic economic evaluations are problematic. For the repowering options for Brownfield sites that involve conventional generating technology, the capital cost, CO_2 capture cost, LCOE increase, and the space available would all need to be taken into consideration. In addition to being integrated into the existing coal receiving and power export infrastructure that is already available at the site, the rebuilt plant must be integrated into a supercritical CO_2 pipeline infrastructure to deliver the captured CO_2 to EOR site

or sites. This latter infrastructure would not be available, but in certain areas of the United States a trunk CO_2 line might be or become available at a reasonable distance.

One example of an ongoing project that involves repowering is FutureGen 2.0, which will convert an existing oil-fired power plant into a 170 MW_e coal oxy-combustion unit with CO_2 capture for geologic storage. Following the two-year test period, the unit is intended to operate as a commercial CCS facility for several decades. Although not initially designed for EOR, the CO_2 has been purified and could be sent to a user should the opportunity arise once the objectives related to geologic storage have been addressed.

3.6.4 Greenfield Power Plants

New coal-fired power plants can be designed and built in such a way that the efficiency of the plant can be greater and the CO_2 capture process can be integrated into the plant steam cycle. In the face of CO_2 regulations and the requirement of CO_2 for EOR, the location of the new plants should be strategically located near existing or new CO_2 pipelines whenever possible. However, despite the many potential benefits offered by new, more efficient, strategically located coal-fired power plants, mounting regulations have made it prohibitively difficult for such plants to be built.

3.7 Exploring the Economic Feasibility of Various CO_2 Production Options

(Please note that the economic analysis provided in this section is an original work prepared by Robert Williams from Princeton University and provided to the Council.)

Considering prospective relative economic performances along with TRL and GHGI indices can be helpful to policymakers and industrial leaders in allocating scarce resources for both R&D and commercial demonstration projects and in guiding planning by these decision makers for eventual widespread deployment if R&D and demonstration efforts prove to be successful. However, it is necessary to compare options on a self-consistent basis. The economic analysis explored in this section has been carried out based on NOAK costs estimates. Depending on a technology's TRL, additional development, demonstrations, and/or early commercial projects must be completed to achieve NOAK costs. While significant investment may be necessary to achieve the NOAK costs compared to the FOAK costs, the purpose of this section to explore the potential for NOAK plants. While the economic analysis allows exploration of the roles different CO_2 capture technologies may play in the future, it must be

noted that because none of these technologies have achieved full commercial maturity the costs used as the basis of the economic analysis include uncertainty. Various metrics can be used to describe relative economics. In this section, four metrics are singled out for discussion: the CO_2 capture cost[5] (see Figure 3.3), IRRE (see Figure 3.4), LCOE (see Figure 3.5), and minimum dispatch cost (MDC – see Figure 3.6); the IRRE, LCOE, and MDC are presented as a function of the plant-gate selling price of CO_2 because a major focus of this study is on potential CO_2 EOR applications. Four metrics are presented because no one metric conveys an adequate description of particular technology's economic merits – as will become clear from the discussion below. The IRRE was chosen so as to enable a self-consistent comparison among electricity generating, fuel producing, and coproduction options. The MDC is an indicator of a technology's prospects for realizing the design capacity factors assumed for the analyses[6] presented in Figure 3.3, Figure 3.4, and Figure 3.5 as a result of economic dispatch competition (see Box 3.2). In what follows, the merits of each of the major classes of capture options is discussed based on the economics indicated by these figures, as well as considerations of TRL and GHGI indices.

When examining Figure 3.3 and Figure 3.4, it is important to keep in mind that the information used to develop the information shown is based on cost estimates for NOAK plants. While it is very promising that some coal-generated CO_2 streams could be competitive in an EOR market without additional CO_2 regulation or taxes, this will not be realized until demonstrations and early mover projects are completed.

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[5] The capture cost (CC, in $ per metric ton) for power only systems is defined as: CC ≡ ($LCOE_{cap}$ –$LCOE_{vent}$, in $/MWh_e$)/(CO_2 capture rate, in t/MWh_e), where LCOE values are for the Cap and Vent versions of the same technology. In Appendix 3A, capture costs for power only systems are also estimated relative to the LCOE for the least costly new coal power plant (a Sup PC-V plant). In this section the capture cost (CC) for synfuels and coproduction systems is defined as: CC ≡ [$LCOF_{cap}$ –$LCOF_{vent}$, in $/gallon of gasoline equivalent (gge)]/(CO_2 capture rate, in t/gge)

[6] The assumed design capacity factors are 80% for IGCC plants with capture, 85% pulverized coal plants with capture and 90% for synfuels and coproduction plants. For NGCC-V (and NGCC-Cap) plants a 40% average capacity factor is assumed because for the IRRE analysis it is assumed that LCOE for such plants determines the average selling price for electricity. Even if natural gas prices stay low, NGCC plants would have great difficulty defending their 85% design capacity factors in economic dispatch competition if there were significant coproduction capacity on the electric grid.

Box 3.1: Using Experience Curves to Estimate FOAK Capture Costs

All capture costs and other economic metrics presented in this chapter to characterize alternative CO_2 capture technologies are for NOAK plants, where N ~5 (see Figure 3B1). With a reasonable estimate of the capital cost in hand for an NOAK plant, one can estimate very roughly the cost of a FOAK plant using experience curves which show that costs for industrial products tend to decline at a relatively constant "learning rate" for each cumulative doubling of production (DOE NETL, 2012c). Learning for power systems might be expressed in terms of cumulative capacity deployed (e.g., in GW_e – see Figure 2B2) or as number of plants deployed. In either case, the cost $Y(x) = A*x^{-b}$ where x = cumulative production. The quantity $(1 - 2^{-b})$ is called "the learning rate" and 2^{-b} "the progress ratio," and both are usually expressed as percentages, as "b" and "A" are estimated by statistical analysis of experience data.

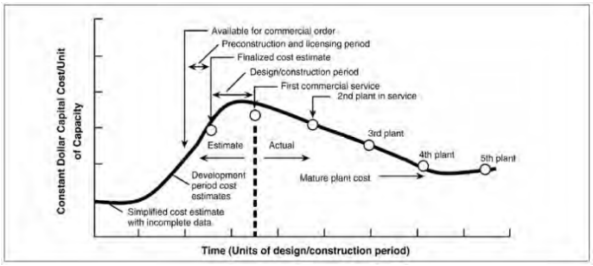

Fig. 3B1: History of Anticipated Cost Evolution for the First Few Commercial-Scale Plants of a New Energy Conversion Technology (EPRI, 2011)

Suppose for a CO_2 capture technology that cumulative production is measured as the number of plants built and that NOAK capture costs have been estimated to be $Y(N = 5) = A*5^{-b} = 1$, in arbitrary units. In this expression, A is the ratio of the FOAK cost to the cost of the 5th unit as estimated by the experience curve.

In Appendix 2A, it is shown that the estimated capture cost for IGCC plants built with construction costs as of 2007 is ~ $30/t expressed in constant dollars of that year. If the learning rate for these plants were the same as for FGD technology (11% learning rate, for which b = - 0.17 – see Figure 3B2) the capture cost for a FOAK plant would be almost $65/t. If instead the learning rate were 19% [average for 108 industrial products (see Figure 3B3), for which b = -0.30], the FOAK capture cost would instead be almost $100/t. But FOAK capture costs would decline rapidly toward NOAK levels with experience, as a result of learning by doing.

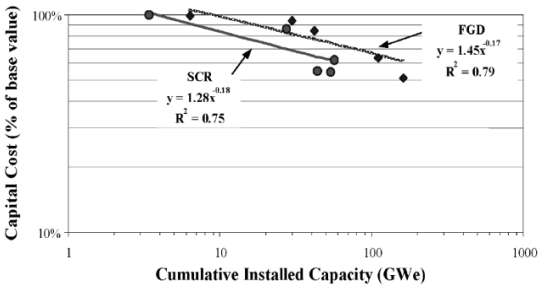

Figure 3B2: Experience curves for flue gas desulfurization (FGD) and selective catalytic reduction (SCR) environmental control technologies (Rubin et al., 2004). The corresponding progress ratios are 89% and 88% for FGD and SCR technologies, respectively.

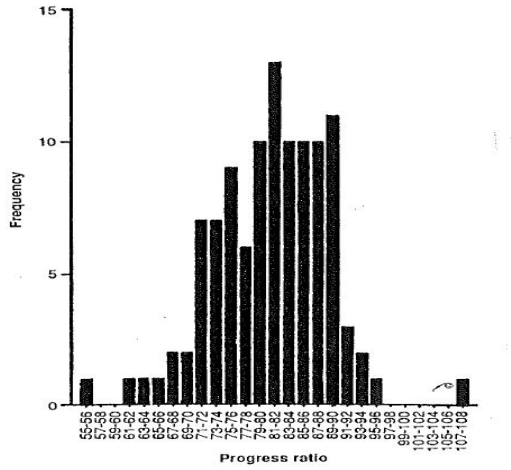

Figure 3B3: Progress ratios for 108 industrial products (Dutton and Thomas, 1984). For these technologies the average progress ratio was 81%.

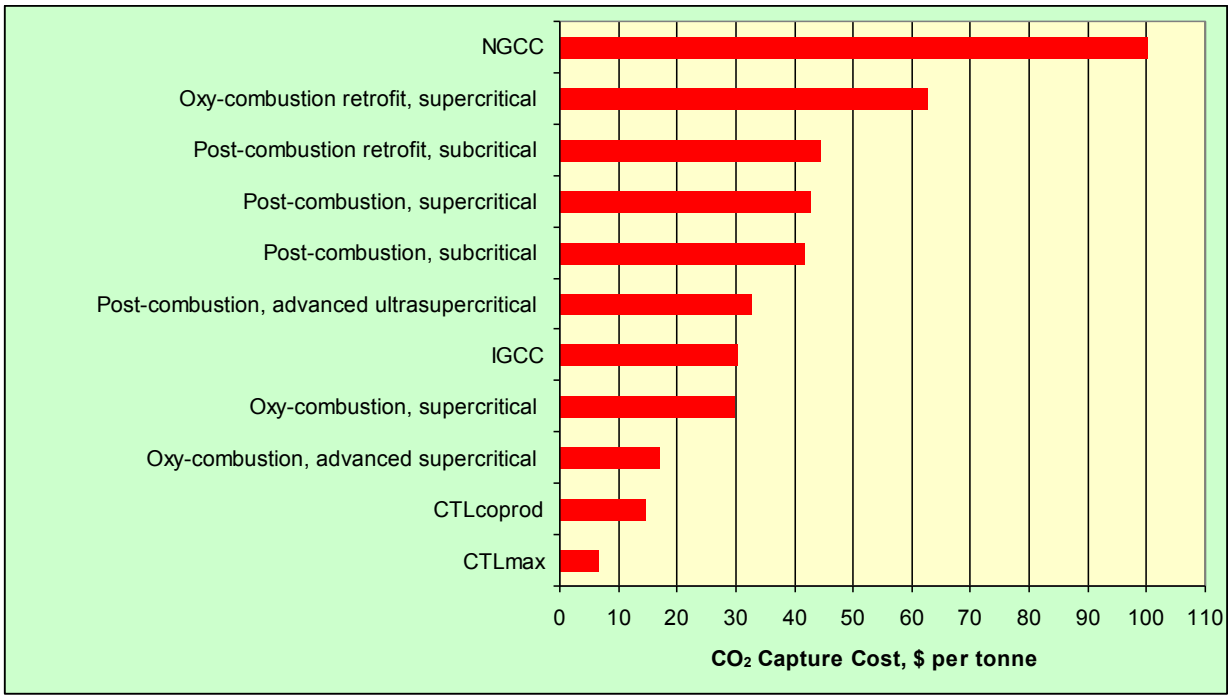

Figure 3.3: Capture Costs for NOAK Plants Costs are in 2007 $ for plant construction as of 2007. Capture cost estimates were carried out on a self-consistent basis, assuming the reference technology is the same technology venting CO_2. See Tables 3A1, 3A3, 3A5, 3A6, and 3A7 for details. All but NGCC (natural gas combined cycle) are coal options. CTL_{max} and CTL_{coprod} are FT liquids plants that maximize liquid fuels production and provide electricity as a major coproduct, respectively.

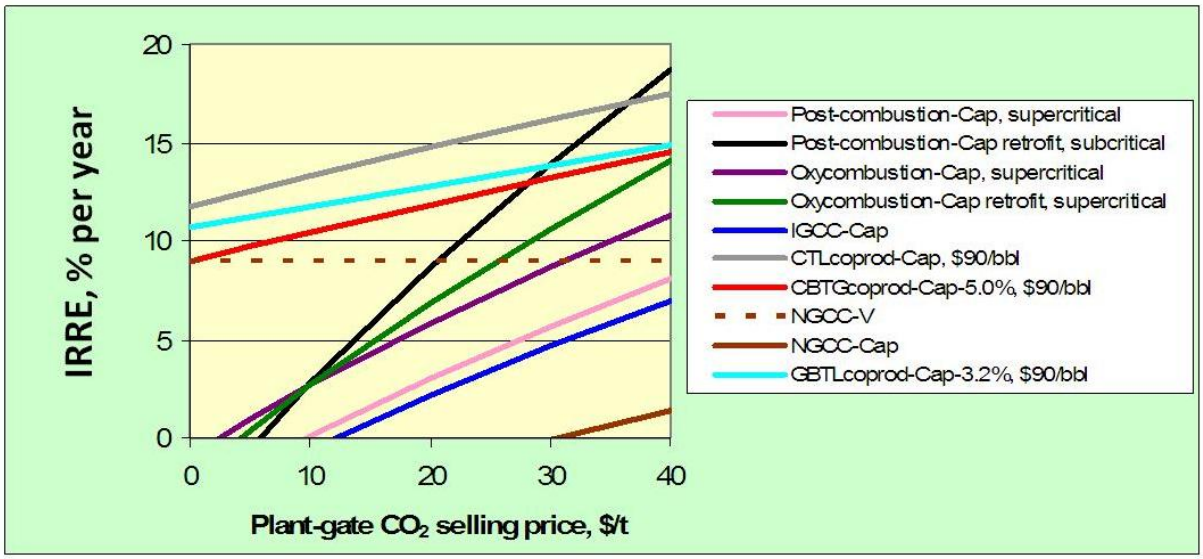

Figure 3.4: Real Internal Rate of Return on Equity (IRRE) for Alternative Technologies that Provide Pressurized CO_2 for EOR Applications. Here, -V and -Cap signify plants that vent and capture CO_2, respectively. CTL_{coprod} is a FT liquids coproduction plant based on coal. $CBTG_{coprod}$ is a gasoline coproduction plant coprocessing coal and biomass. $GBTL_{coprod}$ is a FT liquids coproduction plant coprocessing natural gas and biomass. The percentages attached to the latter two indicate the biomass energy percentage coprocessed. See Tables 3A1, 3A3, 3A5, and 3A6 in Appendix 3A for details.

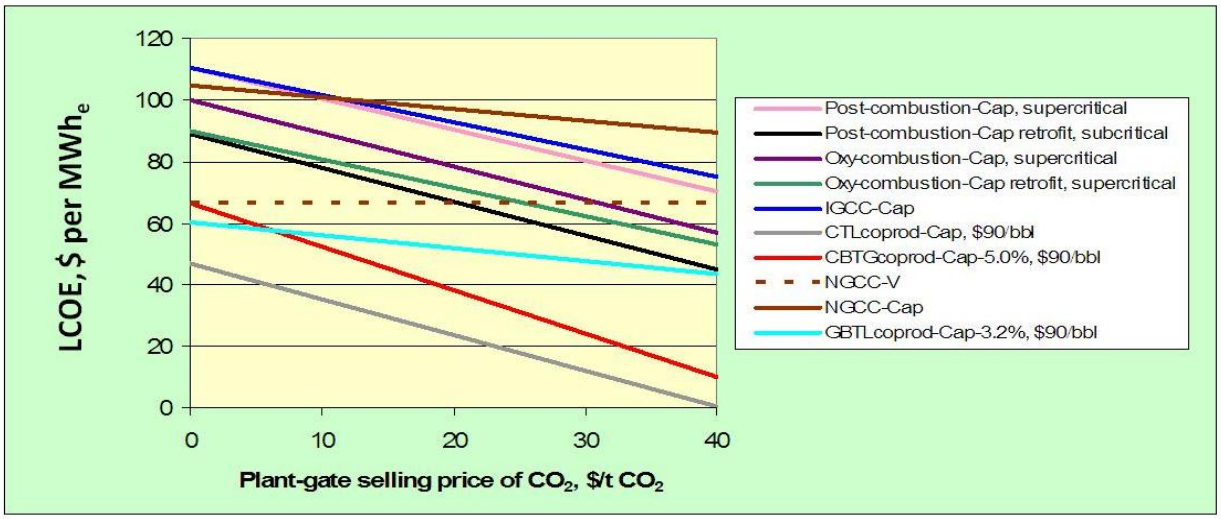

Figure 3.5: Levelized Cost of Electricity (LCOE). The LCOE is for the same set of technologies as in Figure 3.4. See Tables 3A1, 3A3, 3A5, and 3A6 for details.

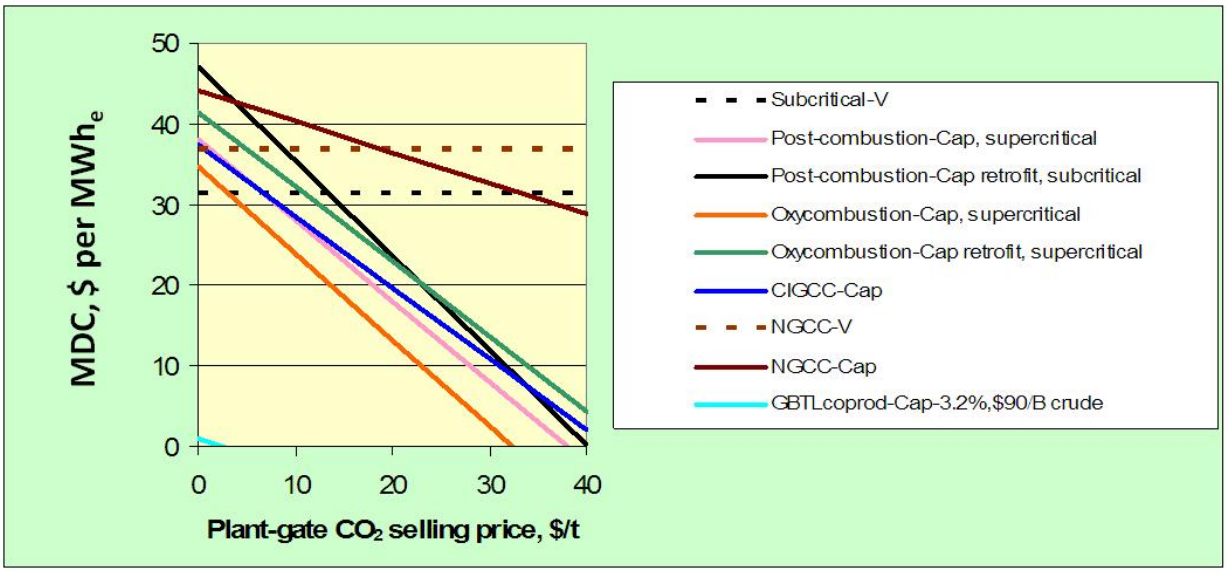

Figure 3.6: Minimum Dispatch Cost (MDC) vs. Plant-Gate CO_2 Selling Price No MDC curves are shown for coal-based coproduction options because at the assumed $90/barrel crude oil price their MDCs are <$0/MWh (see Tables 3A1, 3A3, 3A5, and 3A6 for details)

3.7.1 Post-Combustion Capture for Coal Plants

Figure 3.3 shows that for near-term technologies (amine scrubbers), NOAK capture costs for pulverized coal plants are >$40/metric ton, which is higher than for several alternative options – with retrofit capture costs being slightly higher than for new builds. Figure 3.4 can be used to help explain why only evaluating capture cost does not tell the entire story. For plant-gate CO_2 selling prices >$35/metric ton, the IRRE for a post-combustion retrofit is greater than for any of the other capture options considered here – which implies that this option is likely to be very competitive in nearby EOR markets.

Another important insight that can be gleaned from the information in Figures 3.3, 3.4, and 3.5 relates to the relative merits of a post-combustion retrofit for a subcritical plant and post-combustion capture for a new build supercritical plant. One might think that the latter would be the more profitable investment in light of the facts that: (a) the capture cost is higher for the retrofit than for the new build (see Figure 3.3), (b) the assumed capital cost of capture for the retrofit is 1.3x the incremental capital cost of capture for a new build (see Table 3A3), and (c) the new plant option requires 13% less coal per MWh_e (see Table. 3A1 and 3A3). But, as it turns out, this hunch is not the reality: instead, Figure 3.4 shows that in EOR applications the retrofit is always much more profitable than the new build, and Figure 3.5 shows that the LCOE is always lower. The reason for this surprising finding is simple: the total specific capital cost ($/$kW_e$) for the new build is about 70% higher than for the retrofit (see Tables 3A1 and 3A3).

Moreover, Figure 3.6 shows that for CO_2 selling prices >$20/metric ton, the post-combustion retrofit technology could defend its high design capacity factor in economic dispatch competition if the competition were only NGCC plants or subcritical coal plants that vent CO_2. However, the figure also demonstrates that several other coal power generating have lower MDC values and that dispatch competition would be especially fierce if there were significant amounts of coproduction technology on the electric grid, making difficult defense of the high design capacity factor for this retrofit technology. It is noteworthy that with advanced post-combustion technology the new build post-combustion capture cost could approach $30/metric ton (see

Figure 3.3) and the MDC for a new build would be considerably less than for a retrofit (see Figure 3.6), so that R&D investments in this area are warranted.

3.7.2 Oxy-Combustion for Coal Plants

Figure 3.3 shows that a NOAK version of a new build oxy-combustion plants is likely to have a capture cost comparable to that for an IGCC and advanced post-combustion capture technologies, and that with advanced oxy-combustion technology the capture cost could potentially be reduced by half. Moreover, Figure 3.4 shows that at all CO_2 selling prices current new build oxy-combustion technology would offer a higher rate of return than either post-combustion and IGCC capture technologies, and that the new build oxy-combustion technology would require about a $30/metric ton CO_2 selling price to realize typical power company rates of return on equity investment.

Another important finding is that, for CO_2 selling prices greater than ~$15/metric ton, the IRRE for the retrofit version of oxy-combustion technology is greater than that for the new build – for essentially the same reason as for post-combustion technology – the specific capital cost is higher for the new build than for the retrofit (compare Tables 3A5 and 3A6). Moreover, at all CO_2 selling prices the LCOE is lower for the retrofit than for the new build (see Figure 3.5). This figure also suggests that the oxy-combustion retrofit would be less profitable than the post-combustion retrofit. However, this finding should be approached cautiously because the oxy-combustion capture retrofit has been explored much less than the post-combustion capture retrofit. Finally, the analysis presented here suggests that from an economic perspective oxy-combustion is a strong candidate for continuing R&D support.

3.7.3 Pre-Combustion Capture for Coal Plants

Figure 3.3 shows that for IGCC-cap technology the capture cost (~$30/metric ton) is lower than for post-combustion capture. But, Figure 3.4 shows that the IRRE is less than for all the other options except NGCC-Cap, and Figure 3.5 indicates a high LCOE for the IGCC. These graphs show that IGCC-Cap is not an economically strong candidate option for a rebuild at an old coal power plant site or, more generally, for being launched in the market via the CO_2 EOR opportunity.

3.7.4 Post-Combustion Capture for Natural Gas Combined Cycle Plants

There is an ongoing rush to switch from coal to natural gas for electricity generation. However, GHGI = 0.56 for NGCC-V technology, so that eventually CCS will have to be pursued for NGCC as well as for coal power plants if there is an eventual carbon mitigation policy in the U.S. For its design capacity factor of 85%, the capture cost for NGCC-Cap is a relatively high at $57/metric ton. But, these plants are likely to fare poorly in economic dispatch competition (see Figure 3.6). If, as a result of dispatch competition, a typical capacity factor of NGCC-Cap plants turns out to be 40%, the capture cost would increase to $100/metric ton, as indicated in Figure 3.3. Moreover, these plants would offer very low IRRE values even at the highest CO_2 selling prices considered here for EOR applications (see Figure 3.4) and would have very high LCOE values at all CO_2 selling prices (see Figure 3.5).

3.7.5 Pre-Combustion Capture for Synfuel and Coproduction Plants

As shown in Figure 3.3, synfuel plants offer the lowest capture cost of all the technologies considered (<$10/metric ton), and coproduction plants come in second – with capture costs that are much lower than for any current electricity only technology. As noted earlier, CTL_{max} and CTL_{coprod} with CO_2 capture offer comparable IRRE values (see Figures 3A3 and 3A4 in Appendix 3A for details). For this reason, and because CTL_{max}-Cap technologies are commercially ready, the rest of this subsection is focused on coproduction options.

The first coproduction option considered here is CTL_{coprod}-Cap, a new build option for which electricity accounts for 32% of the plant's energy output (see Table 3A3 in Appendix 3A for details). Considered as a power plant, this technology might be deployed at either at a Greenfield site or at the site of an old coal power plant that will be or might be retired. For this technology, the capture cost is $15/metric ton (see Figure 3.3). Assuming that the crude oil price is $90/barrel, this option offers the highest rate of return of all the capture options considered, up to a CO_2 selling price of $35/metric ton – above which the post-combustion retrofit is the most profitable (see Figure 3.4). Also, this technology offers the lowest LCOE of all the options considered at this oil price (see Figure 3.5). Moreover, at this crude oil price, the minimum dispatch cost for this option is <$0/metric ton (see Figure 3.6), so this option would be able to defend its high (90%) design capacity factor in economic dispatch competition. The technology is ready to be deployed at commercial-scale, although such a plant has not yet been built. Despite

its attractive economics, this technology might not be widely deployed under a carbon mitigation policy because it's GHGI = 0.69. Over the longer-term, GHGI values <0.2 might be needed.

Such deep reductions in GHG emissions could be realized by coprocessing in coproduction plants up to ~30% biomass on an energy basis, as pointed out previously. Such large biomass coprocessing rates are not feasible in the near-term. However, coproduction plants coprocessing small percentages of biomass could be deployed in the post-2020 period if such technologies were to be demonstrated at commercial-scale during this decade. To illustrate the possibilities, Figure 3.4 shows the IRRE for $CBTG_{coprod}$-Cap-5%, a coproduction option coprocessing 5% biomass for which electricity accounts for 28% of the plant's energy output. As noted earlier, this amount of coprocessed biomass is just enough to realize GHGI = 0.5 for the system. *Inter alia*, this means that the fuel cycle wide GHG emission rate for the synthetic gasoline is the same as the maximum allowable emission rate for advanced biofuels under the RFS2 mandate of the Energy Independence and Security Act of 2007. For this technology, the IRRE is only modestly less than that for CTL_{coprod}-Cap (see Figure 3.4).

Also shown in Figure 3.4, is the IRRE for a coproduction plant making FT liquids and electricity from natural gas and 3.2% biomass ($GBTL_{coprod}$-Cap-3.2% – see Table 3A3 and Figure 3A7) – again just enough biomass to realize GHGI = 0.5. This option is presented because: (a) there is already considerable U.S. industrial interest in developing gas to liquids technology from shale gas (especially from the Marcellus and Utica plays) and (b) its IRRE is about the same as for $CBTG_{coprod}$-Cap-5.0% even though the latter is twice as capital intensive. Moreover, Figure 3.5 shows that for CO_2 selling prices >$8/metric ton, the $CBTG_{coprod}$-Cap-5.0% offers a lower LCOE than $GBTL_{coprod}$-Cap-3.2%. These figures show that coal-based coproduction options ought to be about as effective in attracting capital investment as natural gas-based coproduction options.

Box 3.2: Minimum Dispatch Cost

The average capacity factor for an electric generation technology is determined not by the design engineer but rather by market forces in economic dispatch competition. Once a power plant has been built, the power plant operator will bid to sell electricity into the grid in continual auctions as long as the selling price is not less than the short-run marginal cost for the plant – the so-called minimum dispatch cost (MDC).

An example of the influence of economic dispatch competition is that during 2003-2009 (when gas prices were relatively high) the U.S. average capacity factor (CF) for NGCC-V plants was 39% – much lower than the 85% design CF for this technology. This low capacity factor arose to large extent because coal power plants with which these NGCC-V plants were competing in this period had lower minimum dispatch costs.

Coproduction plants considered as power generators would have ultra-low MDCs in a world of high oil prices. For these technologies, MDC = (short run marginal cost) – (revenues from sale of transportation fuel coproducts). These coproduction technologies would be able to defend high design capacity factors in economic dispatch competition and force down capacity factors of competing power only options as their market penetration on the grid expands (see Figure 3.6).

The attractive prospective economics of these coproduction systems that coprocess modest amounts of biomass, their relatively low GHGI values, and their relatively high TRL values make them strong candidates for commercial-scale demonstration projects. Issues relating to such demonstration projects are discussed in Chapter 6.

Another important finding regarding these coproduction technologies is that they would still be quite profitable if the CO_2 selling price were as low as $10/metric ton or less. This implies that if they were deployed as rebuild options at old coal power plant sites that are going to be or might be retired, they could very likely be competitive in distant CO_2 EOR markets if an adequate CO_2 pipeline infrastructure were in place. Such sitings would bring substantial economic benefits (including a diversion of economic rents from foreign oil producers) to these communities, many of which are economically depressed. Finally, Figure 3.4 shows that, for $90/barrel crude oil, all coproduction options would be more profitable than NGCC-V plants operated at 40% capacity factor.

3.8 Institutional Challenges Relating to Energy Systems that Capture CO_2

All of the capture technologies discussed in this chapter face institutional as well as technological and/or economic challenges; the magnitude of these challenges varies significantly among the technologies. All capture options bring to the power industry novel technology

management needs. As a result of tightening air pollution control regulations, power companies, which have mainly mechanical and electrical engineering staffs, have already been forced to focus more on chemical process management, but adopting capture technologies will involve even more dependence on chemical processing.

Post-combustion capture involves the least change in power system operation and management because it can be implemented downstream of energy conversion and other air pollution control equipment and is already widely regarded as an acceptable approach to CO_2 capture in the power industry. Oxy-combustion capture is less familiar and potentially more complex, requiring oxygen generation. Although oxygen generation is a commercial technology, it is not usually carried out at pulverized coal power plants. However, under mutually agreeable and mutually beneficial commercial arrangements many industrial gas suppliers are willing to sell oxygen "over-the-fence" to power plants. In this contract structure scenario, operating an oxy-combustion plant is almost business as usual for a utility. Pre-combustion capture for IGCC is technically still more demanding from a chemical system management perspective, and coproduction adds an additional level of chemical complexity to system management. The intensification of chemical process management requirements will make early mover capture projects more challenging to manage and potentially more costly. However, with shifts in skill mix and experience, the power industry will be able to manage the required chemical process technologies.

An additional and more challenging institutional issue is posed by coproduction systems because the operating entity must simultaneously produce and manage three very different commodity products: electricity, synthetic liquid fuels, and CO_2. Where a CO_2 EOR market opportunity exists, and the CO_2 coproduct can be sold at plant-gate prices attractive to the CO_2 provider, managing this output should be relatively straightforward. Managing the other two products is the greater challenge.

Oil companies have the chemical process operating capability and fuel marketing network and know-how. And power companies certainly understand how to manage electricity production and marketing. However, oil company/power company investment partnerships would be difficult to bring about due to the very different cultures and approaches to financial and technical risk management in these two industries. The oil industry in the United States has not shown interest in synfuels production as a result of concerns about the capital intensity of this

approach to making transportation fuels relative to the crude oil-based approach and uncertainties regarding future oil prices and relating to regulatory issues and the permitting process for investments in synfuels. Utilities are not likely to get involved with coproduction technologies until they are comfortable with the process technology and can find satisfactory ways to manage the transportation fuel output. One way to accomplish the latter would be to secure a long-term purchase contract for the transportation fuel produced, as DKRW has done for the gasoline it expects to produce at its Medicine Bow synfuels plant in Wyoming.

Regulated electricity generators, to whom state regulators grant a fair rate of return on prudent investments in new electric generating supplies, face a major regulatory challenge because there is no unique way to separate investments for the synfuel and electricity parts of coproduction systems. Although this is a major challenge in theory, in practice it might eventually prove to be not so formidable, because regulators are, above all, interested in securing low electricity rates for consumers. Coproduction systems, in a world of high oil prices, offer a route to such low rates if the entire coproduction investment were to provide the basis for the "fair" rate of return for prudent investments in the social contract between the power company and its regulators. The issue warrants close attention on the parts of both regulated power generation companies interested in these technologies and their regulators.

There are also major institutional challenges associated with coprocessing biomass with coal. First, as a feedstock, biomass is different from coal and requires much different management skills and technologies, and second because the supply chain for providing biomass is in its initial stages of development, which makes supply management especially difficult at this point in time. At the same time, coprocessing coal and biomass could potentially enable a relatively low cost approach to carbon mitigation for both transportation fuels and electricity while enabling expanding roles for coal in enhancing energy supply security in a carbon constrained world. Such considerations suggest the merits of some level of involvement of the coal industry in advancing the concept of coprocessing biomass with coal in CCS systems that make synfuels or synfuels plus electricity (coproduction).

For all the CO_2 capture technologies, a final constraint relates to the need for substantial external financial support both for the very first commercial-scale plant and for the first few follow on plants (up to 4-5 total). This number of plants might be required to achieve a large fraction of the learning-by-doing cost reduction gains that would enable capture technologies to

compete in CO_2 EOR markets. Subsidies should be limited to early mover plants, and demonstrated technologies that are not rapidly evolving toward economic competitiveness should not be further subsidized.

There are one or more FOAK projects going forward in the United States for each of the categories of post-combustion capture, oxy-combustion capture, and pre-combustion capture for power production, but none are currently planned for pre-combustion capture systems coproducing transportation fuels and electricity with CCS. Such technology that involves coprocessing of <10% biomass with coal is characterized by TRL 6-7 and is thus technologically ready for a FOAK commercial-scale project. Moreover, the comparative economic analysis of this chapter strongly supports pursuing this technology through demonstration (see Chapter 6 for details).

Over time, a continuing R&D effort will likely generate additional promising technologies in several of the capture technology categories that will eventually reach a TRL of 6-7, warranting demonstration at commercial-scale. Ongoing technological evolution implies the need for continuing external financial support to "buy down" costs to NOAK levels as a result of accumulating experience for the first few plants. The justification for such support is the expectation that commercial success of these new technologies will contribute to establishing a dynamic and robust EOR industry linked to captured CO_2. In Section 3.9, a strategy is outlined for carrying out and supporting such commercial-scale early mover projects.

3.9 Enabling a Viable and Robust Enterprise for Demonstration and Early Movers

In the future, envisioned in this report, an evolving U.S. CO_2 capture industry enables a rapidly growing CO_2 EOR industry that can enhance the nation's energy security (see Chapter 1), promote job growth (see Chapter 2), and establish economically viable CO_2 capture technologies in the market even in the absence of a comprehensive federal carbon mitigation policy (shown in this chapter). Although several of the technologies considered here are "almost commercial," most are not advanced to the point where performance and cost can be estimated accurately. This requires the construction of commercial-scale demonstration and early mover plants and the associated learning-by-doing via projects that are implemented in a manner that enhances the likelihood of eventual commercial success. Also, in the current environment for the

industries involved, these demonstration and early mover plants will not be built without some level of external financial support.

While in the fossil energy area, R&D is a major strength of the DOE, its track record with regard to commercial-scale demonstrations, with some notable exceptions, has been mixed. The DOE's critical skills have generally been focused on energy R&D, not the development and management of commercial-scale projects – nor should they be.

3.9.1 Addressing the Development and Management of Commercial

Demonstration and Early Mover Projects

Over the years, there have been numerous suggestions for new institutional approaches for addressing the demonstration/early mover project challenge. Because such projects are so resource-intensive, suggestions have been made that they should managed more like business activities than like R&D projects. One study called for establishing a quasi-public entity that has been called an Energy Technology Corporation (ETC) dedicated to this purpose (Ogden et al., 2008). A recent report by the American Energy Innovation Council (AEIC, 2012), calls for a new Clean Energy Development Administration, which is a government-backed institution that would build off the successful elements of the DOE's loan guarantee program.

The suggested Clean Energy Development Administration would be structured around the principles and design features of: (a) independence (having sufficient autonomy to take calculated risks, without political interference), (b) private sector coinvestment (to help ensure that new technologies eventually meet the test of competing in real world markets), (c) strong expertise from both the public sector (to provide technical evaluation) and the private sector (concerning the commercial aspects of potential investments), (d) the flexibility to offer financing products based on market gaps, (e) governance and oversight via a diverse board of directors that would provide guidance on priorities and best practices, while ensuring that the institution adheres to its organizational mission, operating principles, and strategic objectives, (f) a goal of becoming self-funded after an initial public capitalization (i.e., eventually funded to the extent possible by financing fees and by returns on profitable investments), (g) a portfolio investment approach [i.e., the Office of Management and Budget (OMB) and the new institution would jointly develop a methodology to score investments at the portfolio level, rather than on a

project-by-project basis)], and (h) transparency (decision processes, selection criteria, and investment results would be published to provide feedback to the private sector and reduce the perception that projects are being selected on the basis of partisanship or favoritism).

The vision for evolving a dynamic capture industry set forth in the current chapter cannot be realized unless the demonstration/early mover challenge for capture can be addressed successfully. Thus, it is urgent to revisit the demonstration/early mover challenge with innovative thinking, taking full account of the lessons from the past. The Energy Secretary is ideally positioned to initiate and lead such an activity.

3.9.2 Addressing the Funding of Demonstration and Early Mover Projects

Not only is a new approach needed to manage demonstration projects to make them more commercially relevant, but a new approach to financing such activities is also needed. As illustrated by the FutureGen I experience, the external support required for a single capture demonstration project can run from several hundred million dollars to over $1 billion – equivalent to about half of the total DOE energy RD&D budget. Moreover, as this chapter has shown, a panoply of such projects aimed at advancing multiple approaches is needed – requiring perhaps a couple of billion dollars per year over a few decades.

Even in flush times, it is difficult for the federal government to use part of its budget for even one commercial demonstration/early mover project. With growing concerns about the rising federal debt, it will be virtually impossible to do so, at least in the near-term. An alternative approach would be to seek "off-budget" mechanisms for financing such projects. There are many possible off-budget approaches to help cover the extra costs of demonstration/early mover projects (AEIC, 2012). The Council would obviously welcome the opportunity to explore alternative innovative approaches with the Energy Secretary.

3.9.3 Getting Started with Demonstrations Before a Generic Solution Is in Place

Solving the generic demonstration/early mover support problem will not be accomplished overnight. In the interim, the Council would welcome the opportunity to work with the Energy Secretary to find a way to go forward with one or two urgently needed commercial-scale CO_2 capture demonstration projects coupled to CO_2 EOR opportunities with private sector resources and public policy instruments already in hand.

From the perspective of the private sector, the key to such early action stems from recognition that the learning-by-doing process for demonstration/early mover projects generates significant intellectual property and know-how, with substantial economic value. Preferential access to this IP should be an incentive for industrial firms to cooperate if they have the opportunity to capture this IP before their competitors. This could be a significant incentive for cooperative involvement. On the private sector side, the Council would like to encourage the Energy Secretary to bring together a group of companies with the objective of moving forward on the one or two most attractive technologies which appear most likely to be economically competitive with the prospect of continuing high oil prices. Of course, prospective industrial stakeholders need to preferentially receive IP and know-how gained from such demonstrations to justify their capital infusion into these projects.

On the public sector side, the Council encourages the Energy Secretary to determine to what extent the DOE might be able to contribute in supporting one or two high priority early mover projects with already available resources and policy instruments in hand.

In summary, the Council would like to work with the Energy Secretary to help develop both near- and long-term strategies for supporting demonstration/early mover projects for capture technologies to enable technology cost buy down and hence successful market launch of the most promising options in ways that would attract wide stakeholder and political support.

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Chapter 4: Enhanced Oil Recovery Technology

4.1 Key Findings

- A recognition/endorsement of the robust opportunity for CO_2 EOR for storage could initiate an expedient pathway towards the goal of GHG emission reductions.
- The original baseline of CCS directions aimed at injection into deep saline formations needs to be augmented to one of utilizing CO_2 EOR thereby reinvigorating power plant investment and accelerating U.S. oil production and capture, utilization, and storage of CO_2.
- Widely held, conventional views of CCS have believed that, in the absence of measures to limit CO_2 emissions, there are only small, niche opportunities for the deployment of CCS technologies (IPCC, 2005). Others have subscribed to the belief that oil and gas reservoirs have limited potential as storage reservoirs (e.g., Dooley et al., 2010).
- New findings and higher oil prices combine to dispute the above claims and CO_2 EOR has now emerged as a viable path forward for CCUS. CO_2 EOR can almost immediately assist with the two challenges of: 1) providing revenue for plants which capture carbon and 2) identifying candidate regions where CO_2 can be permanently stored.
- CO_2 EOR can accelerate emission reductions and sequestration in two ways. The first is by converting a waste stream into a valued product so that the injection process becomes a resource recovery task in lieu of a waste disposal exercise. Thus, the commoditization of CO_2, via capture and purification, sidesteps, at least to a degree, the NUMBY (not under my backyard) concerns that many of the planned sequestration projects have faced. Second, the established value of the CO_2 as a commodity in CO_2 EOR contributes to the funding of capture and can help balance the market solution equation. A third and ancillary benefit will be to enable the inclusion of the existing qualified injection companies in not only the field injection operations but also as part of the team to assist with accelerating solutions for national energy security along with safe and secure emission reductions.
- Both the Gulf Coast and the Permian Basin have enormous potential for CCUS and can immediately utilize considerably larger volumes of CO_2 than are being currently used.

- The Midwest region of the United States, given available and affordable CO_2, friendly regulatory policies, and time, can emerge to become a viable home for significant enhanced oil production and CO_2 storage activity.
- With what we now know about concurrent EOR and storage, accompanied by new policy initiatives, an American contribution to carbon sequestration could be occurring at a much faster pace, and provide insurance against an energy, economic, security, and/or climate crisis.

4.2 Recommendations

- Promote and enable the concept of concurrent CO_2 storage with CO_2 EOR when using anthropogenic CO_2 by:
    A. Encouraging the regulatory community in states familiar with EOR practices to work with industry to establish state-based rules for concurrent EOR and storage that are commercially viable while protecting the environment. The rules adopted by Texas can be used as a model, and the IOGCC is well positioned to assist in this role.
    B. Assisting states having less experience with in-state EOR operations to develop their set of rules for concurrent EOR and storage (the IOGCC is, again, in a good position to assist the DOE in this role).
    C. Encouraging technically and economically feasible state-based, site-by-site protocols for reservoir monitoring requirements for EOR projects for long-term storage that are tailored to the individual storage site attributes and risk profiles while discouraging a "one-size-fits-all" set of monitoring requirements. The DOE can aptly assist in this role with the critical support of the state Geological Surveys.
    D. Conducting studies of the economic potential, jobs, and value to the states of CO_2 capture projects, CO_2 pipelines, and additional enhanced oil production. The DOE can guide these studies.
    E. Encouraging the DOE and state involvement in educating industry and state agencies of the economic and environmental significance of facilitating the

formation of large mineral units for EOR and simultaneous CO_2 storage. The DOE, though the regional CCUS Partnerships, can assist in this task.

- Accelerate and incentivize regional, large-scale, and coal-based capture projects via a long distance pipeline to connect the CO_2 sources with established EOR markets for the CO_2.
- Charter regional studies and state-by-state surveys of the additional EOR potential of ROZ with the express purpose of augmenting the potential size of regional EOR and storage targets.
- Expand the DOE's Oil/Gas Research Program sponsored research to better understand the mechanics of CO_2 injectivity and retention in carbonate and clastic reservoirs in three- and four-phase reservoir systems.

4.3 CO_2 EOR Fundamentals

4.3.1 Primary, Secondary, Tertiary Phases of Oil Production

The oil and gas sector is most often portrayed as an industry dominated by drilling for new oil and gas fields. And, in fact, most companies that could be called exploration companies make their entire living doing exactly that. However, there is a growing sub-industry within the larger sector which concentrates on extending the lives of producing fields (i.e., getting more oil from a given discovery (field)). Tradition tends to brand these companies as production firms, in contrast to drilling focused, exploration companies. The production companies generally require a broader set of engineering skills and are challenged in trying to recover more and more oil (call it advanced recovery) from a "reluctant" reservoir. History shows that the advanced recovery approach is more costly per barrel produced than oil from newly discovered fields and monetary rewards for success come to these companies more slowly. In a fast paced world seeking immediate gratification, most companies opt for the exploration path to provide more immediate returns for their shareholders. Although the advanced recovery business plan leads to relatively large oil reserves and long lived production, fewer companies over time have chosen the route and have opted for an exploration focus. It is useful to examine oil and gas production in a framework the industry has come to call the phases of production.

4.3.1.1 Primary Production Phase

The first producing phase of a reservoir is known as the primary production phase where a new field discovery is found and initial well penetrations are drilled into the formation. Oil or gas is produced using the pent-up energy of the fluids in the reservoir rock (generally a sandstone or carbonate (limestone, dolomite) formation). As long as a company is proficient at finding new oil or gas and avoiding the "dry holes," the returns come quickly, while the reservoir fluid pressures are high. Eventually, however, the energy (usually thought of as reservoir pressure) is depleted and the wells cease to flow their fluids. This requires a stage called "artificial lift" wherein fluids are pushed or lifted to the surface and production can be prolonged. Over time, the pore pressures are so thoroughly depleted and the fluids move so slowly within the formation to the wellbore that the wells produce uneconomic volumes. At this point, as in the case of oil reservoirs, considerable amounts of the oil are left in place, with sometimes as much as 80-90% remains trapped in the pore spaces of the rock.

4.3.1.2 Secondary Phase of Production

The field may be abandoned after depleting the fluid pressures or it can be converted to what is called a secondary phase of production wherein a substance (usually water) is injected to re-pressure the formation. New injection wells are drilled or converted from producing wells and the injected fluid sweeps oil to the remaining producing wells. This secondary phase is often highly efficient and can produce an equal or greater volume of oil than was produced in the primary phase of production.

As mentioned, water is the common injectant in the secondary phase of production since water is relatively inexpensive. Normally, fresh water is not used during the waterflood, and this is especially true today. The water produced from the formation is recycled back into the ground again and again. Ultimately, in most reservoirs, 50-70% of the oil that was present in the field at discovery still remains in the reservoir after the waterflood since it was bypassed by the water that does not mix with the oil.

4.3.1.3 Tertiary Production Phase (aka Enhanced Oil Recovery Phase)

If a company desires to produce (access) more of the remaining oil in the reservoir, it can choose to enter a third phase (tertiary operations) of production. This will require the use of some

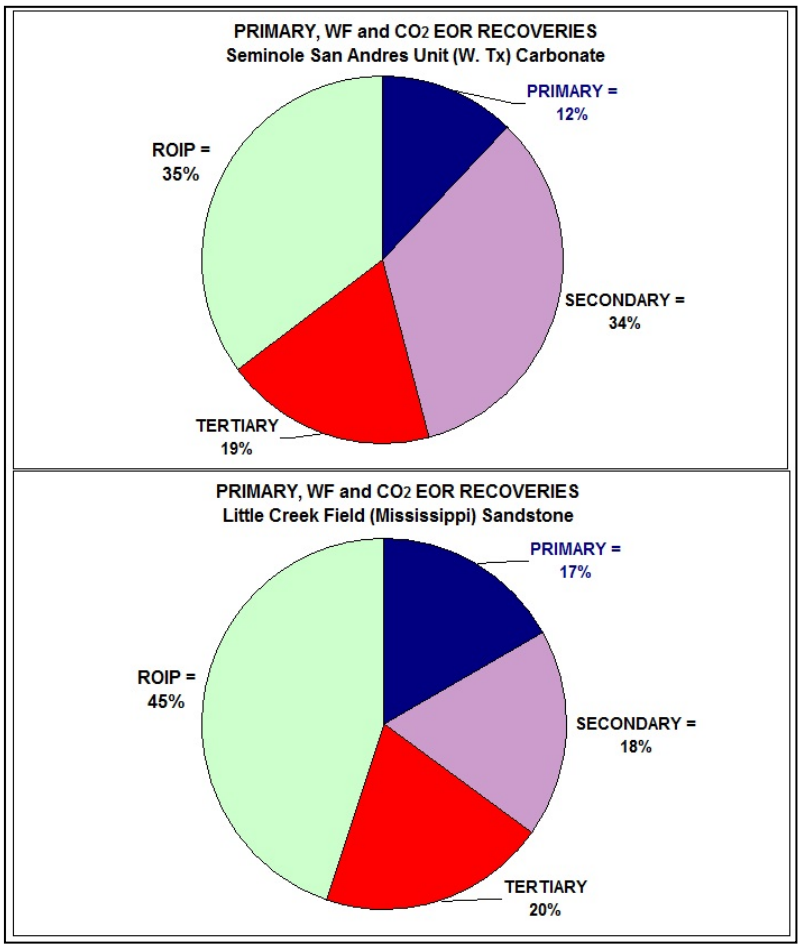
injectant that reacts with the oil to change its properties and allow it to flow more freely within the reservoir. Heat, hot water, and chemicals can accomplish this (see the next section). These techniques are commonly lumped into a category called *enhanced oil recovery*, or EOR.

One of the most proven of the EOR methods is CO_2 flooding. Almost pure CO_2 (>95% of the overall composition) has the property of mixing with the oil causing it to swell, making it lighter, detaching it from the rock surfaces, and causing the oil to flow more freely within the reservoir so that it can be swept-up in the flow from injector to producer well. Generally, the behavior of the CO_2 in oil reservoirs is described as "miscible" or "immiscible." The CO_2 will behave in one of these two manners based on the characteristics of the oil and the depth (pressure) of the oil reservoir. The difference is that above a minimum "miscibility," pressure (MMP), the mixed CO_2 and oil will sweep through the reservoir as a liquid, contacting more oil and using less CO_2 to produce the oil than if the CO_2 was injected below the MMP. Additionally, as the pressure in reservoirs most generally increases with depth, CO_2 becomes significantly denser. Therefore, more CO_2 can be stored in a reservoir at greater depths. Because CO_2 exists in this dense phase below depths of approximately 2,500 feet, and since the likelihood of miscible behavior occurs, both the EOR and sequestration processes are more efficient below that depth (i.e., more CO_2 can be stored in the pores of the reservoirs at these depths and more oil can be produced).

Two examples of the percentage of the original-oil-in-place (OOIP) in the reservoir produced after the three above phases of production are shown in Figure 4.1. Note that a sandstone (Mississippi) and a carbonate reservoir (Texas) are represented. CO_2 EOR is effective at "cleaning oil from the pores," but producers still leave more than a third of the OOIP in the reservoir due to an inability to contact all of the pore space with CO_2 (sweep efficiency).

4.3.2 The EOR Methods

Figure 4.1: Percentage of Original Oil in Place Produced after 3-Phases of Production (Two Examples)



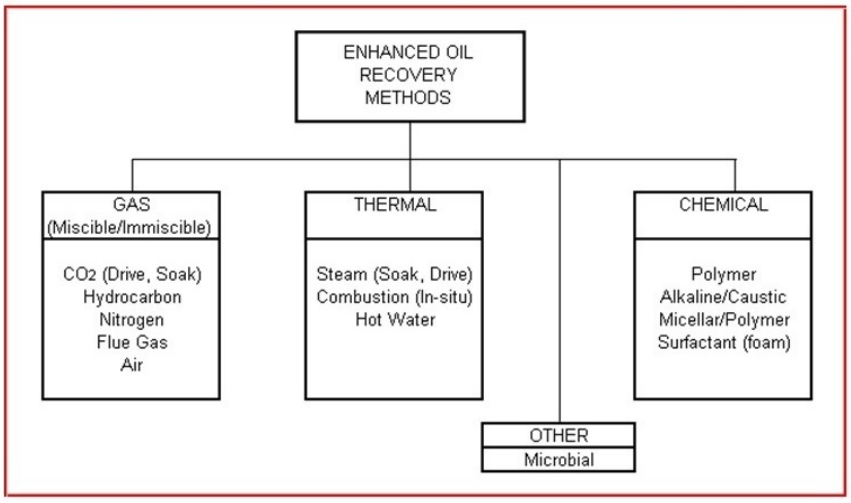
Although CO_2 EOR is the leading enhanced recovery technique for light oils, several other methods are commercially proven and, as such, can offer alternatives to the oil production using CO_2 EOR. Steam flooding (thermal EOR) for shallow, heavy oil reservoirs is the most commercial of the group. Nitrogen EOR has a niche application in light oil reservoirs deeper than 9,000-10,000 feet in depth. Hydrocarbon miscible gas recovery has also been very successfully applied, especially where a very limited or non-existent market exists for selling the associated gas. When the natural gas liquids are part of the injected stream, the results can be very similar to CO_2 flooding (Jarrell et al., 2002). In today's world, wherein methane prices are so low, this method along with chemical EOR (see below) offer the most competition to the use

of CO_2 for EOR.

In addition to these three techniques, there is chemical flooding. The types of chemical flooding (ChEOR) are generally grouped into three categories: surfactant, alkaline, or polymers. The first two attempt to change the interfacial tension between the oils and the rock while polymer flooding attempts to change oil movement in the reservoir so that it behaves more like the formation water. Currently, there is significant interest in ChEOR, especially in non-optimal CO_2 applications such as shallow reservoirs and locations where CO_2 infrastructure is not sufficient.

But, where pipeline infrastructure costs can be overcome, CO_2 EOR has emerged as the advanced recovery technique of choice for light oils with reservoir depths greater than 2000-3000 feet. When pressures are sufficient, and as outlined in the last section, CO_2 combines with the oil to form a mixture that not only acts as a solvent but also moves in a miscible state as a liquid through the reservoir pushing oil in front of it. Even in an immiscible behavior condition, CO_2 swells the oil, reducing viscosity and making it more able to flow through the pore spaces of the rock. There are other EOR methods beyond those mentioned here although their commercial significance is yet to be widely demonstrated. Figure 4.2 categorizes the various techniques.

Figure 4.2: Classification of the Various EOR Techniques



4.3.3 CO_2 EOR Metrics

The key to a successful EOR project directly relates to the exposure of significant volumes of oil with the injected CO_2. Since the process depends on the mobilizing of oil by

changing its properties, the more oil that is contacted, the more oil produced. The industry has adopted a term for this volumetric exposure or spreading of the injectant called sweep efficiency. The amount or percentage of the oil-bearing reservoir that is contacted by the CO_2 is termed the "volumetric sweep efficiency." Intuitively, some reservoirs are amendable to promoting this spreading while others are not. For example, highly fractured reservoirs can offer short circuit pathways for the CO_2 to move from injection to production wells without the spreading (sweeping). Other reservoirs are highly channelized and prohibit lateral spreading of the CO_2 and contain the movement of CO_2 to the confines of the channels. Some techniques have been developed to overcome some of the issues (called "conformance" control) in order to promote better recoveries. Volumetric sweep efficiencies in the range of 25-45% are typical for a successful CO_2 flood.

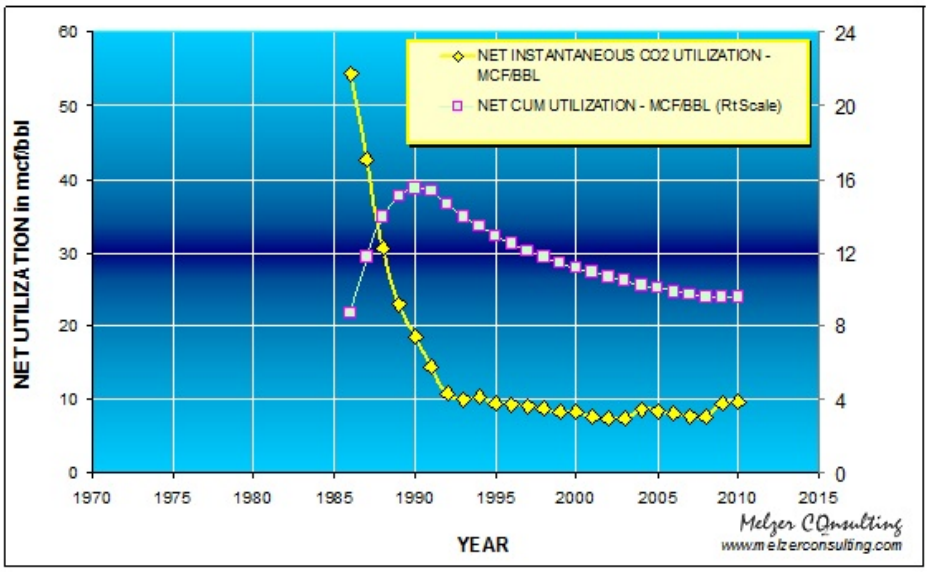
Another measure of efficiency of flooding is the utilization factor (UF). This is defined as the volume of CO_2 that is required to produce a barrel of oil and is often reported in units of thousand cubic feet (Mcf) per barrel. And, since the CO_2 that is used is purchased at a significant price, how much oil it will yield is critical to a flood's success. We also know that the produced CO_2 that comes with the oil must be captured and recycled so the numerator in the metric can either be only the purchased (or new) CO_2 or it can be the total CO_2 (new + recycled). Over time, the industry has determined that it is instructive to keep track of both and the terms "net" (new only) and "gross" (new + recycled) are used. The use of the terms net and gross has often been misused in the context of storage. The industry commonly defines retained (i.e., stored) CO_2 during EOR as a function of the total injected volumes, including the recycled volumes, and hence appears to be saying about half the CO_2 is ultimately vented which is untrue. In practice, at least 800 million tons of CO_2 have been successfully injected and stored into oil bearing formations since EOR operations began. If the industry had chosen to state retention as a function of the new CO_2, the stored percentage of CO_2 ultimately exceeds 90-95% (Melzer, 2012).

The cost of CO_2 and related equipment to recycle the produced volumes is a practical incentive for EOR operators to maximize the efficiency with which they utilize this commodity (CO_2). Effective use of CO_2 requires careful planning and intensive reservoir management efforts to ensure the CO_2 flood is efficiently executed to maximize the value of the asset. This means that EOR operators are very careful to utilize value added technology, and methods to

monitor and control the movement of the CO_2 through the formation and adjust when necessary to maximize oil recovery. This value driven incentive has the collateral benefit of ensuring that the EOR operator is in control of the CO_2 volumes, not only at the surface and in the wells, but also within the reservoir, minimizing the chance of release.

A project's UF is not a constant. During the early stages of a flood, CO_2 is being injected and no additional or "incremental" oil is being produced. In this case, both the new and gross utilization factors are infinite. But, as the flood matures, the oil responds to the contact with the CO_2 and the factor begins to drop, indicating more oil produced per volume of CO_2 injected. With this concept in mind, one can understand that it might be instructive to look at the UF in both a cumulative sense and in an instantaneous one. There is often some miscommunication within the industry as to this difference and one will occasionally see companies comparing apples (cumulative UF) to oranges (instantaneous UF). The most common factor chosen by the operationally oriented personnel is instantaneous gross UF. This gives them a measure of what is happening at the moment in their field (like in total CO_2 injection and today's barrels produced). Reservoir personnel back in the office and flood analysts will often migrate to using cumulative net UF and compare their project against the many other floods in that fashion. The Permian Basin's cumulative net utilization curve and net instantaneous curves are shown in Figure 4.3.

Figure 4.3: Permian Basin Net Instantaneous and Cumulative Net Utilization of CO_2 in EOR (Mcf/bbl)



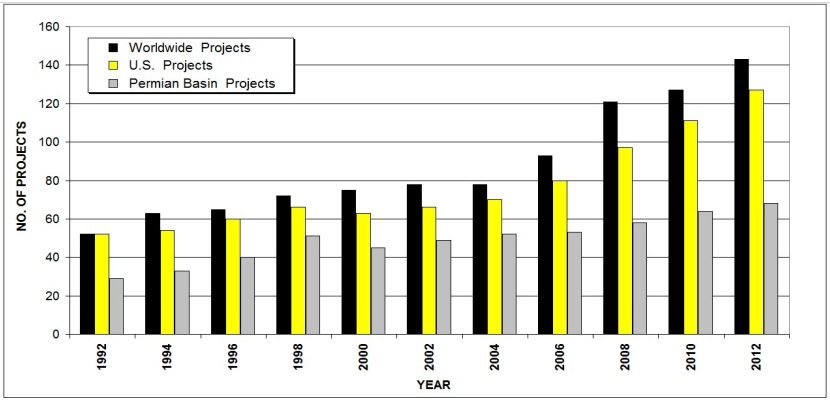
While the retention of CO_2 in an oil reservoir during the EOR project is a widely observed fact, the science of why the retention is occurring is not fully understood. Many suspect the wetting phase (water or oil) to be involved along with the relative permeability of the three [sometimes four] phases (water, oil [gas], and dense phase CO_2). Retention has been relegated to the status of a "necessary evil" with the oil industry due to the fact that the CO_2 remains stuck in the reservoir, does not recycle, and is unavailable to do more work in liberating additional oil. As the world of CO_2 EOR merges with CCS, a better understanding of the science of retention may provide large upsides in storage volumes.

4.4 History, Current Status and CO_2 EOR Project Planning

4.4.1 Historical Development

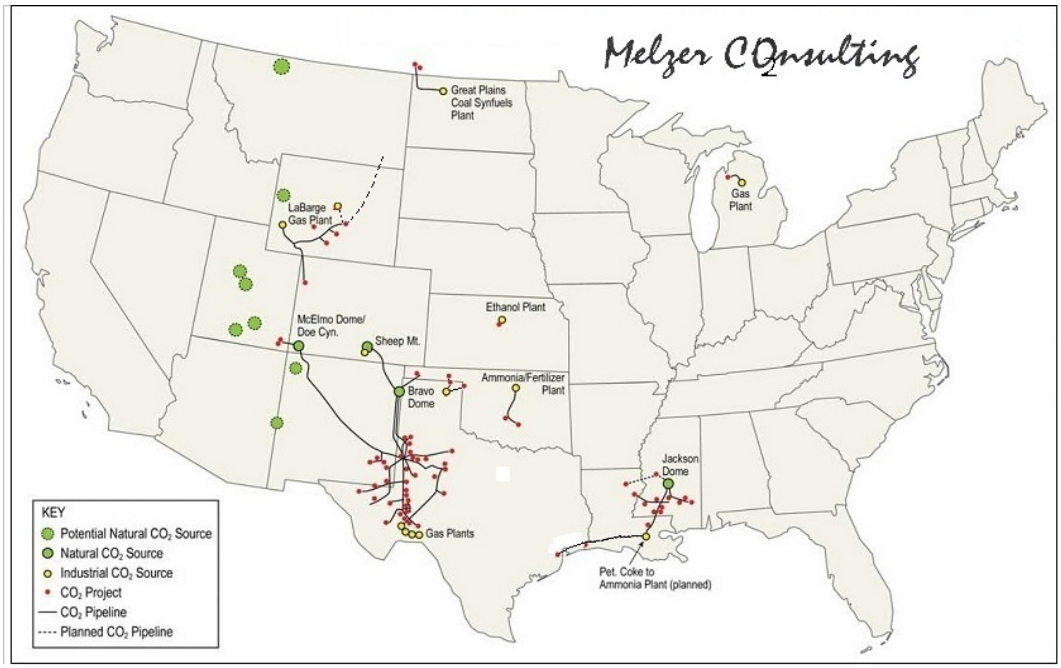
The CO_2 EOR technique was first tested at large-scale in the early-1970s in the Permian Basin of West Texas and southeastern New Mexico. The first two large-scale projects consisted of the SACROC flood in Scurry County, TX, implemented in January 1972, and the North Crossett flood in Crane and Upton Counties, TX, implemented in April 1972. Over the following five to ten years, the U.S. petroleum industry was able to conclude that incremental oil could be produced commercially by the injection of CO_2 into fields that had previously produced oil both in the primary and secondary phases, and therefore the number of CO_2 flood projects began to increase. Figure 4.4 illustrates the worldwide, United States, and Permian Basin growth of new projects and production from 1986 through the present day. As illustrated, the Permian Basin constitutes the bulk of U.S. CO_2 EOR output.

Figure 4.4: Growth of Worldwide, U.S., and Permian Basin CO_2 EOR Projects (1992-2012)



The CO_2 for the first projects came from CO_2 separated from produced natural gas processed and sold in the southern region of the Permian Basin (see Figure 4.5).

Figure 4.5: Active U.S. CO_2 Pipeline and Injection Site Infrastructure



Following the initial development, companies became aware that naturally occurring source fields with relatively pure CO_2 could offer large quantities of CO_2 and three relatively pure CO_2 source fields were developed – Sheep Mountain in southcentral Colorado, Bravo Dome in northeastern New Mexico, and McElmo Dome in southwestern Colorado. Wyoming and Mississippi burst onto the scene as well with natural gas byproduct CO_2 in southwestern Wyoming and a pure source field at the Jackson Dome in Mississippi. Pipelines were constructed in the early-1980s to connect the new CO_2 source fields with existing oil fields. The new supplies of CO_2 led to an invigorated growth of projects throughout the early-1980s.

The oil price crash of 1986 resulted in a drop of oil prices per barrel into single digits in many regions. The economics of flooding for incremental oil were crippled; capital for new projects was nonexistent. But, due to the long-term nature of the advanced recovery sub-industry (see text block and as demonstrated in Figure 4.4), the EOR projects survived the crash with fairly minor long-term effects and the growth curve resumed until the next price crash in 1998.

4.4.2 Current Flooding

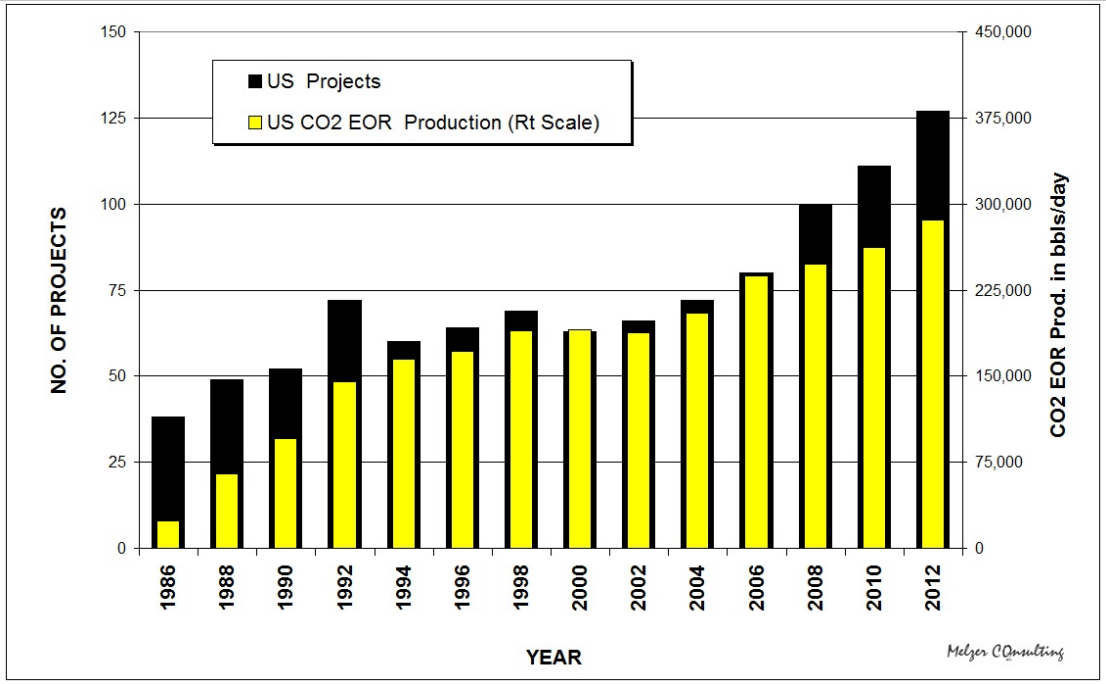
Long-Term Nature of the Industry

CO_2 EOR is composed of long-lived projects. While fluctuations of oil prices have an effect of temporarily decreasing the pace of project starts, the steady baseline growth represents a refreshing exception to the otherwise frustrating cyclicity of gas and oil drilling/exploration. To prove the point, both of the first two floods (SACROC and Crossett) are still in operation today and are producing nearly one million barrels per year. After almost 40 years of operation under CO_2 injection, these floods are still purchasing approximately 300 million cubic feet per day (over six million tons per year) of CO_2. The long-term nature of the floods continues to generate enormous economic benefits, providing local, state and federal taxes as well as long-term employment and energy production for the area and nation. These barrels will be produced from reservoirs already developed, most with established surface footprints and should represent another 15% of the original oil in place within the reservoirs. This can occur with CO_2 molecules from captured emissions or from naturally pure underground CO_2 traps. Without the advent of CO_2 flooding, the barrels would have been lost, i.e. left in the reservoir upon abandonment of the waterfloods.

The most recent decade has once again seen a flourish of new CO_2 floods. Today, 127 floods are underway in the United States. All but nine of these are miscible floods. The numbers have doubled since the year 2000 (as noted in the impact of flood numbers in the years following 1998 in Figure 4.6). New CO_2 pipelines are being constructed in the Gulf Coast, Mid-continental regions and in the Rockies, promising to grow the flooding activity in all three of those regions dramatically. The Permian Basin is effectively sold out of its required daily CO_2 volumes and, as a result, growth there has slowed to a crawl. CO_2 prices have climbed to record highs, now exceeding half the value of natural gas. Algorithms relating the price of CO_2 to the value of oil at mature and successful EOR project sites are shown IOGCC (2011), GCCSI (2011). In the Permian Basin, where oil has recently been valued at roughly $90/barrel, CO_2 is in acutely short supply, and prices have been rising to exceed $35/metric ton.

The aggregate production from CO_2 EOR has grown to ~6% of the total U.S. oil production (Figure 4.6) or roughly 350,000 out of the 6,000,000 barrels of U.S. crude oil produced every day. Where the infrastructure is most mature, as in the Permian Basin, the share of CO_2 EOR to total state production is approaching 20%.

Figure 4.6: Historical U.S. CO_2 EOR Project and Production (1986-2012)



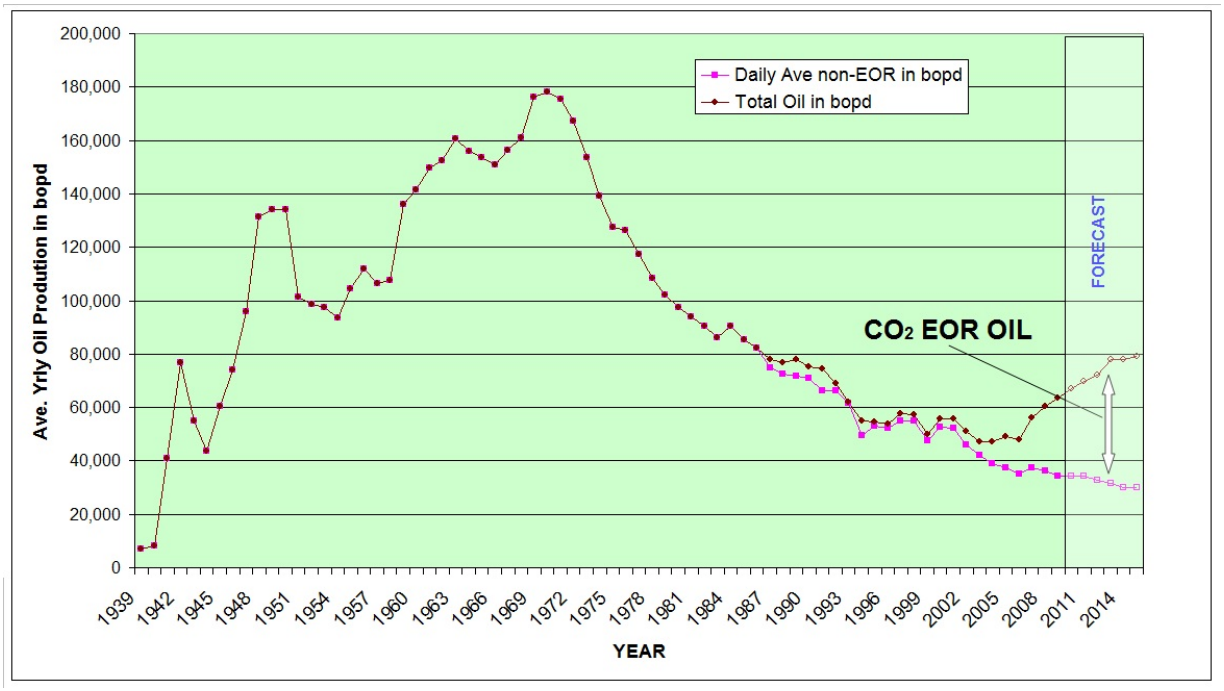
A perspective that emphasizes the critical importance of CO_2 EOR to the U.S. reserve picture relates to the fact that the discovery of a new billion barrel oil field is very rare today. The oil industry rightfully touts new significant oil discoveries. It is interesting to note that the billionth CO_2 EOR barrel in the United States was produced in 2003, and forecasts would suggest the second billionth barrel will be produced by 2015. The CO_2 bought and sold in the country every day now totals 3.1 billion cubic feet (Bcf) or about 65 million tons a year (DiPietro et al., 2011). For a reference point, this equates to the CO_2 capture volumes from 20 Texas Clean Energy Projects (each being 400 MW in size) (TX Clean Energy Project, 2012). In order to grow CO_2 EOR in the dramatic fashion as suggested herein (Aspirational Case), it will take enormous volumes of anthropogenic CO_2 (DiPietro et al., 2011).

4.4.3 U.S. Project Planning

Historically, the development of CO_2 EOR flooding has clearly favored the Permian Basin with its mature and extensive resource and pipeline infrastructure. In addition, it has a large number of large and mature oil fields which have been shown to be amenable to CO_2

injection. As the EOR industry has matured and more companies become involved, the newer trend is showing considerable growth occurring in the Gulf Coast, the Rockies, Oklahoma, and Michigan. Figure 4.7 illustrates the growth and oil projections occurring in Mississippi.

Figure 4.7: Mississippi Oil Production History and Short-Term Projections ("Violating the Hubbert Curve")



If the CO_2 source volumes are able to keep pace with demand, as it has been there, the EOR companies continue planning new CO_2 EOR projects in each of the mentioned regions. Where CO_2 is not available, new or expansions of existing EOR projects quietly get shelved. In Mississippi, Denbury Resources has averaged two new project startups per year in the Gulf Coast region for the last decade. Because CO_2 is available, Wyoming and Oklahoma are two other areas with intense CO_2 activity. And, it is probably reasonable to infer, when oil prices are in excess of $70/barrel, and, with the advent of new sources of CO_2 and the infrastructure build-out which would come with the new sources, other regions of the United States will develop as well. Where CO_2 demand outpaces supply, pent-up projects abound. An informal survey by the authors of this chapter would suggest the backlog of projects in planning is easily estimated at more than 20, with most of those being located in the Permian Basin region where a broader-based expertise for CO_2 EOR exists.

Much of the impetus for the planning of new CO_2 floods results from the modern and more widely held recognition of the technical success and economic viability of the CO_2 EOR process. The current oil price is a significant factor as well. The additional key factor relates to the maturity of many of North American's oilfields and the fact that most (secondary) waterfloods are very mature and approaching their economic limit. Many of those waterfloods are over 50 years old.

Technological advancements are another major reason for the continued growth and development of CO_2 flooding. Three-D seismic, geomodeling, and subsurface surveillance techniques have had a measurable impact on delineating heretofore uncharacterized features of many reservoirs. The ability to characterize and model the reservoir and to simulate the effects of CO_2 injection have clearly reduced the risk of a flood (economic) failure and improved the efficiencies in flooding.

4.4.4 Case Histories of Infrastructure Buildout

Rapidly expanding CO_2 capture into commercial storage sinks is not entirely without its existing models. Admittedly, the capture was not anthropogenic and the motives were purely driven by the demand for CO_2 in EOR. Nonetheless, the models are useful to understand as they may be used at least in part to extend to CCUS. Three relatively robust U.S. examples are notable, the Permian Basin, with its world class and unequaled CO_2 pipeline and EOR infrastructure, the Rockies, and the Gulf Coast.

Permian Basin

The Starting Place: An initial build-out of CO_2 infrastructure in the southern reaches of Texas. The original motive for CO_2 capture and pipeline build-out dates back to a Texas incentive. The incentives were twofold: 1) relief from the daily production allowables in force at the time was offered by the oil and gas regulator in Texas, the Texas Railroad Commission (TRCC) and 2) a special tax treatment of oil income from experimental procedures. The motivation for incentive stemmed from widespread concerns from Texas officials that unnecessary volumes of oil in the Kelly Snyder field (later to become the SACROC unit) would be left in the ground unless better reservoir management procedures were adopted by the disparate operators in the field. If the field were unitized and "experimental" recovery techniques

employed, the TRRC would allow the operators to produce the field without the widespread production ("daily allowable") restrictions of the day.[7] A consequence of the incentive was to precipitate actions by the disparate owners of the leases in the field to unitize (i.e., consolidate their tract-by-tract ownership into a single, large geographical unit). Additionally, the cooperating companies sought to find a source of CO_2 for an experimental procedure to gain the allowable relief and found byproduct CO_2 from natural gas production that was being separated from several gas plants nearly two hundred miles away. They then formed a company to capture the "waste" CO_2, compress it, transport it to the field, and implement, in 1972, the first commercial-scale CO_2 EOR project in the world.

Through the next five to ten years, the petroleum industry was able to conclude that incremental oil could indeed be produced by the injection of CO_2 into the reservoir, and the numbers of CO_2 flood projects begin to mount. As noted, the CO_2 for those first projects came from a waste product, (i.e., CO_2 separated from processed natural gas, see Figure 4.5). The separation was necessary to purify the methane for sale and thus costs of processing (excepting compression) were borne by the sale of the natural gas. So, in many ways, the original capture, transportation, and CO_2 deliveries were much like the new world order expected in CCUS. It was only later, as the process was better understood, that companies became aware that naturally occurring source fields with relatively pure CO_2 could offer large quantities of CO_2 and three source fields were developed – Sheep Mountain in southcentral Colorado, Bravo Dome in northeastern New Mexico, and McElmo Dome in southwestern Colorado. Pipelines were constructed in the early- 1980s to connect the CO_2 source fields with the Permian Basin oil fields. The new supply of CO_2 led to a growth of projects through the early-1980s and expansion to other regions of the nation.

Those first byproduct natural gas sources had a compositional specification of the CO_2 with a high H_2S composition (>100 ppm). It required extra operational safety precautions due to the toxicity of H_2S and some extra steel specifications for sulfur service that the new underground sources could avoid. The result of this was an inability for the first sources to be interconnected with the subsequent underground sources and led to declining use of the natural gas byproduct CO_2 over time. Though the capital deployment for capture, pipeline, and EOR

[7] The common practice of the time was to limit production from a well to one day per month. This authority was based upon the charter of the Texas Railroad Commission to provide oversight to the oil and gas industry and conserve the hydrocarbon resources of the state.

infrastructure, an expansion of CO_2 EOR in the Permian Basin was in full swing during the 1980s and, with short-term interruptions due to the oil price collapses in 1986 and 1998, has continued through to today.

Rockies

The model for the initial capture and pipelines in the Permian Basin was utilized by Exxon in the early-1980s at the firm's LaBarge field in western Wyoming and a new nearby plant (Shute Creek) to separate natural gas, CO_2, H_2S, and helium. Opportunities for CO_2 EOR were exploited in western Colorado at Chevron's Rangely field and Amoco at its Lost Soldier field (central Wyoming). Pipelines were built to interconnect the sources and sinks and done with a foresight to design the pipeline capacities to handle growing volumes. These forward thinking planners have facilitated the recent expansions of source capture and EOR deployment so that Wyoming's oil production has resumed a growth curve analogous to the one shown in Figure 4.7 for Mississippi.

Gulf Coast

As with the Permian Basin and the Rocky Mountain region, Gulf Coast CO_2 EOR has been driven by large, "anchor" source(s) of CO_2. The Jackson Dome field (see Figure 4.5), near Jackson Mississippi, was discovered in the 1960s while oil and gas was being explored. Jackson Dome is one of the deepest commercial CO_2 resources in the world producing from formations below 15,000 feet. CO_2 EOR was piloted in Mississippi in the 1970s with good technical results and using CO_2 delivered via tanker truck; however, oil prices and the cost of emplacing the needed infrastructure did not support large-scale development until the mid-1980's when Shell developed three fields in southcentral Mississippi. Denbury purchased one of those, the Little Creek field, in 1999 and expanded the CO_2 flood there. In 2001, Denbury purchased the Jackson Dome CO_2 supply field and related pipeline infrastructure. Since then, the CO_2 activity in Mississippi has accelerated significantly with ten active floods in the state. Infrastructure has recently been augmented to support additional CO_2 EOR in Louisiana and South Texas. The 323-mile Green Pipeline was completed in 2010 expanding the network to serve as a catalyst and backbone to support new CO_2 capture plants and as a connector to CO_2 EOR in South Louisiana and South Texas.

4.5 Challenges to Overcome in Order to Fully Enable the Application

Large infrastructure programs, such as an EOR project, are exceedingly difficult to justify in public markets driven by next quarter earnings. And, in addition to the longer-term returns, many barriers have to be overcome to accomplish an EOR project. The following discussions, although written specifically with the Midwest Region of the United States in mind, apply to many other parts of the country and indeed the world as well.

4.5.1 Initiating CO_2 EOR in the Midwest

A perceived long-term demand for a particular commercial product is considered essential when commercial interests are evaluating large capital outlays for long-term investments. CO_2 capture and EOR projects both have their challenges in this regard. Although power and transportation fuels are fundamental to a functioning society, the long-term viability of coal and oil as the predominate source of power and fuels is not necessarily fundamental. These perceptions are further reinforced by the long-term nature of the investments. In the modern and fast changing world, quick returns on investment are critical. Thus, the obstacles for starting capture and EOR in the Midwest are met with challenges. And, on which end do you start? Do you attempt to establish a demand for CO_2 from oilfield owners and operators, or do you start with CO_2 capture projects and assume the EOR demand will come? This is your classic "chicken or egg" scenario with large, long-term investment on either side waiting on the other to move first. This chapter deals with CO_2 EOR and thus the focus is demand for CO_2 for use in commercial-scale CO_2 EOR. The next chapter will address how to work both EOR and capture simultaneously.

What is occurring today is simply insufficient. Almost no CO_2 EOR progress has been made in the Midwest. In its simplest form, there are two ways forward: 1) to attempt to develop interest of current Midwest oilfield owners/operators to initiate commercial-scale CO_2 and/or 2) to introduce Midwest oilfields and CO_2 EOR opportunities there to active companies owning and operating current CO_2 EOR fields outside of the Midwest. With either course of action, the challenges can be grouped into five areas: oilfield owner resources, perceived risks, technical challenges, operational challenges, and regulatory.

4.5.2 Oilfield Owner Resource Challenge

In most instances, there are effectively no major oil companies and very large independent oil companies operating. Nearly the entire group of active oil companies has extremely limited capital resources, are small entities with predominantly field employees, has few to no geoscientists and engineers, and have too few bankable assets to collaterize a large-scale CO_2 EOR project and long-term commitment for the purchase of CO_2.

To overcome these challenges, the apparent and perceived risk relative to companies of this size must be addressed and reduced so that it becomes manageable for a company to seriously consider undertaking a commercial-scale CO_2 EOR project.

CO_2 EOR Experienced Staff. Because of the size and the experience of their staff, in-house CO_2 experience within these companies is highly unlikely. Cursory knowledge, or even practical experience, of injection project concepts and basics may be known, but it is unlikely that any degree of specifics of implementing a CO_2 field operation is possessed. While company owners and their staff are knowledgeable and perhaps skilled in traditional oilfield activities, very few have the resources for a small-scale pilot study or even EOR simulation studies. Companies of this size look to successful project analogs to their producing properties; this could be in completion type, waterflood operations, or infill drilling. A successful, commercial-scale demonstration project with data and field operations available and accessible to these operators would provide direct information and analog to determine the feasibility of success for a CO_2 flood at their own properties.

CO_2 EOR Experienced Service Providers and Consultants. Owners of companies with access to staff or consultants with expertise in surface equipment, CO_2 EOR design criteria, related economics, scoping/screening criteria, EOR projections, and CO_2 injection projections have a better perspective of the feasibility and perceived risk associated with CO_2 EOR. Providing workshops and short courses in technical and operational areas that included these types of professionals would improve Midwest oilfield owners and operators' working knowledge of CO_2 EOR. Additionally, the opportunity to build relationships with consultants and service companies with CO_2 EOR-related expertise in other basins would start the necessary steps towards privately funded pilots, and advance interest in long-term commitments to a CO_2 supply requiring a CO_2 pipeline.

Overcoming the Owner Resource Challenges. A successful, commercial-scale

demonstration project with data and field operations available and accessible to these operators would provide direct information and analog to determine the feasibility of success for a CO_2 flood at their own properties. Providing Midwest oilfield owners and operators the opportunity to build relationships with professionals with CO_2 EOR experience and company representatives that offer oilfield services in CO_2 EOR areas at workshops and short courses in technical and operational areas could make CO_2 EOR seem more achievable for smaller companies. This could include a new session at existing conferences such as the annual CO_2 EOR Flooding Conference in Midland, Texas, for instance, to emphasize networking opportunities between Midwest operators and professions working actively in CO_2 EOR.

Specific business portfolios of oil companies operating in the Midwest is beyond the scope of this report. However, a general assertion is that seminars on the business aspects of finding capital or means of funding commercial-scale EOR projects would be necessary for many operators. This could include government loans. Direct experience from existing CO_2 EOR as an analog would be invaluable.

4.5.3 Perception Challenge

Through the course of learning more about CO_2 EOR, there are some aspects of EOR in the Midwest that may be perceived differently compared to the more mature areas of CO_2 EOR, such as the Permian Basin of West Texas. Those are: 1) corrosion will destroy existing wellbores, 2) shallow reservoirs cannot sustain miscible floods, 3) immiscible floods are not economic, and 4) the drilling of new injection wells and production wells is impractical.

Corrosion. The injection of CO_2 into an oil reservoir that has brine saturated the pore space, leads to an acidic fluid, carbonic acid. Without a preventive, corrosion plan, in relatively short time into a CO_2 EOR project, various degrees of corrosion can occur in wellbore tubulars, downhole equipment, surface production facilities, and related piping. Staff operating oilfields with historical CO_2 EOR has addressed the issue of corrosion by identifying replacing key components with non-reactive materials and chemical corrosion inhibitors (Jarrell, et al., 2002). In the DOE sponsored EOR pilots of the Midwest Geologic Sequestration Consortium (MGSC), commercially available corrosion inhibitors were applied to control CO_2 related corrosion. Additionally, to controlling corrosion, the operator reported fewer wells' downhole tubulars and equipment failures during the CO_2 EOR pilot compared to previous years (Frailey et al., 2012).

Shallower reservoirs. Compared to deeper formations, shallower reservoirs have relatively lower temperature. CO_2 density is higher at lower temperatures, compared to higher temperatures. Some of the shallower oilfields operated as waterfloods in the Midwest can have higher injection pressures due to higher fracture pressure (and subsequent regulated pressure). For example, in the Illinois Basin a 1.0 psi/feet fracture gradient is a common value to use (Frailey, et al., 2004). Consequently, a waterflood operated at 1,800 feet may have an average reservoir pressure exceeding 1,500 psi. Reservoir temperature and pressures combinations can lead to the opportunity for CO_2 in a liquid phase, which is expected to be miscible with crude oil.

Immiscible floods. In the mature CO_2 EOR areas of the United States, the use of the term "immiscible" is generally associated with an expectation of a low performing CO_2 EOR project and one that is challenged to be economically successful. The challenges come as a result of early and/or large volumes of CO_2 production with limited oil production. A miscible project, on the other hand, would be at higher pressures and temperatures, requiring large volumes of CO_2 and high injection pressures. For a planned low pressure, immiscible flood in a relatively shallow reservoir, less pressure and CO_2 would be expected. Illinois Basin oilfield modeling results showed that compared to miscible CO_2 EOR, an immiscible flood would have about 50% less oil production – however, it would take 70-80% less CO_2 volume (MGSC, 2005). A single immiscible reservoir relatively far from of source, may never result in a CO_2 EOR project. However, for those fields with multiple oil productive reservoirs of which some would be miscible and others may be immiscible, these immiscible targets could provide low cost incremental oil production once the CO_2 transportation infrastructure is in place for the miscible oil reservoir targets.

Replacing existing wells. There may be a misperception that new wells need to be drilled, and if so, then CO_2 EOR could not be economical. In many of the Permian Basin CO_2 EOR floods, infill drilling of injection wells occurred simultaneously to the initiating CO_2 injection. This was to reduce spacing and increase oil production, by decreasing the distance between injection and production wells. It was not a necessity from a technical perspective but an economic perspective. Consequently, there is field evidence of the practicality of drilling new CO_2 injection well and using existing oil production wells. The Salt Creek CO_2 flood in Wyoming is an example of economic successful CO_2 flood that required all new injection and

production wells in some areas of the field, including locating and properly plugging many of the previously abandoned wells. Historically, CO_2 EOR floods have proven that the costs associated with drilling and completing numerous new wells is economically feasible. Screening of CO_2 floods candidates should not exclude those fields that require new wells without considering the economics.

Overcoming the Perception Challenges. Workshops and seminars addressing these issues are likely necessary to increase awareness of pre-existing perception of these aspects of CO_2 EOR historical activities.

4.5.4 Technical Challenges

Once operators in the Midwest area are more interested in CO_2 EOR, some of the technical and operation questions will arise. The technical questions are some of the differences between pre- CO_2 EOR reservoir conditions between the Midwest and the Permian Basin.

Pre-CO_2 flood oil recovery. A significant difference between many Midwest and Permian Basin oil reservoirs is the oil recovery prior to CO_2 injection. For example, in the Illinois Basin, the sum of primary and waterflood recovery can be up to 50%. Permian Basin estimates are generally between 10-20%. The impact of much lower oil in place prior to injecting CO_2 is not known but definitely leaves less oil as a CO_2 EOR resource.

Subcritical temperature: gas and liquid CO_2 floods. From numerical modeling and small-scale pilots, there are strong indications of CO_2 EOR potential of immiscible and liquid miscible in shallow reservoirs. However, operationally, there is much less experience and practical knowledge of these types of floods. Immiscible CO_2 is likely to have low viscosity CO_2 and unfavorable mobility, such that CO_2 velocity is much greater than the *in situ* crude oil. This leads to early breakthrough of CO_2, initially bypassed oil, and need to capture and recycle CO_2 much earlier than a traditional miscible flood. There are methods of managing CO_2 mobility in miscible floods such as injecting CO_2 in alternate volumes with water. However, low pressure CO_2 will result in lower volumes at the surface and need for compression of CO_2 to lower pressures. As such, these types of problems in miscible floods may be manageable in low pressure, immiscible floods.

For liquid miscible CO_2 floods, there is little to no documentation in the literature. Very few to no fields are reported to operate at reservoir temperatures and pressures to be a liquid CO_2

flood. Solubility of CO_2 in crude oil will be higher at lower temperature. Crude oil viscosity will higher due to lower temperature. There is less associated gas in crude oils at lower pressures. The affect, if any, that lower temperature and pressure have on oil recovery is not well documented. This may not be a technical challenge, but it is presently technically uncertain.

Lithology: Sandstone vs. Carbonate: Historically, CO_2 floods have been predominantly in carbonates. The Midwest has more sandstone than carbonate oil reservoirs. Sandstones have different wettability characteristics than carbonates and may have different technical considerations. There is much less literature for CO_2 flooding sandstones compared to carbonates. For example, the literature suggests continuous CO_2 may yield higher oil recovery than WAG in strongly water wet sandstones (Tiffin and Yellig, 1985). There is general disagreement in the literature if there is any difference when rocks are water wet but not strongly water wet. The three- and four-phase behavior is complex but the phenomenon of water blocking is generally thought to be controlling. This is a function of wettability and the pore structure and has become an increasingly important process when adding the concepts of permanency of storage in addition to retention.

Overcoming the Perception Challenges. Fundamental research in basic fluid characterization and coreflood studies using crude oil and cores from oilfields in the Midwest could further EOR estimates for immiscible and liquid miscible CO_2 floods. Characterization of crude oil and CO_2 for gas and liquid CO_2 at subcritical pressure temperature could compliment the more extensive literature covering similar characterization at supercritical temperature.

4.5.5 Operational Challenges

Once oil company resource and technical challenges are addressed, there are operational challenges directly related to field activities. These include presence of well service providers with CO_2 EOR experience, the integrity of casing and cement of older wells, pre-law well completion types and locations, and maintaining reservoir pressure in a liquid miscible CO_2 flood.

Field well work support. In general, well work related to wells producing and injecting in CO_2 EOR floods are identical. The only difference is the fluid being injected and produced is highly energized compared to water injection or associated gas production. Well work may be routine, but working with and around CO_2 is not. Local service companies will not have CO_2

EOR experience or CO_2 compatible equipment available until a market is present and adequate demand for services and equipment is made. Service providers include pulling units, workover rigs, stimulation trucks and pumps, and cased hole logging tools. Most all tools and downhole equipment used in the subsurface will need to CO_2 compatible or deemed safe to run in the downhole environment encountered in a CO_2 EOR oilfield. Equipment may include specific type of CO_2 compatible equipment and parts on production and injection wellheads and surface separation equipment.

Casing and cement integrity of early wellbores. Age of existing wells is a consideration in most all oilfield activities and is of particular importance for CO_2 EOR. While re-drilling wells may be an acceptable solution, for those wells remaining, it is important to ensure integrity of the wellbores. Casing integrity for most operators is likely relatively routine and potentially need to account for increased surface pressure requirements for CO_2 injection and fluid production wells.

Pre-law well completion types and locations. In general, pre-law wells refer to wells drilled, completed, and/or abandoned prior to regulations within a given state. Pre-law wells had no requirement in the use of cement or steel casing, no plugging requirements on abandonment, and zero notification or record filing requirements with regard to location or depth of the well. Uncertainty of location and completion records of pre-law well is an operational challenge only if the wells are known to exist or they are found subsequent to CO_2 EOR and from a surface or subsurface release of reservoir fluids above the caprock of the oil reservoir. Depending on the volume of fluids flowing from a previously unknown well can be dealt with on a case by case basis similar to how they would currently from a waterflood. If CO_2 reaches a well like this, it may be necessary to have professional outside of the area to work on the problem well. Operators would need to have a risk management plan to deal with events like this. Fortunately, most pre-law wells are very shallow (<1000 feet) and will not penetrate shallow reservoirs considered for CO_2 EOR.

Maintaining reservoir pressure in a liquid-miscible CO_2 flood. Pure CO_2 within reservoirs with temperatures that are below the critical temperature of CO_2 (subcritical) must maintain a specific pressure or a phase change between liquid and gas will occur. Sustaining miscibility in shallow reservoirs is more difficult due to this possible phase change ($T_{res}<T_c$). Consequently, during periods that injection wells are shut-in, a portion of the reservoir is at risk of losing miscibility. In general, this leads to reduced oil recovery rates. Operators will likely

want to adapt practices of monitoring well pressure closely and consider temporarily shutting-in producing wells in the area of the injection well. Because liquid miscible CO_2 floods are not prevalent historically, maintaining pressure may be an operational uncertainty and could prove to be less of a challenge in practice.

Overcoming the Operational Challenges. Awareness of operational challenges can be addressed in properly designed workshops and seminars. However, most solutions to operational challenges can only be addressed in real time field practices. A large-scale demonstration pilot would likely encounter all of these challenges, and documented solutions would be an outcome of this pilot.

4.5.6 Regulatory Challenges

Existing regulations and laws regarding oil and gas production have been documented for the oil producing states in the Midwest. The primary regulatory challenges for CO_2 EOR flooding are: UIC injection well permitting, unitization, taxation, and severed mineral estate.

Permitting: UIC Class II. Applying for brine injection permits is routine for most oilfield operators. Areas without previous CO_2 injection may not have a regulatory pathway of permitting a CO_2 injection well or have very little practice in completing the necessary application. Injection permits typically have a maximum surface injection pressure and daily injection rate. So that downhole pressure gauges are not required, permits often include the surface injection pressure. For brine injection, this is a relatively direct calculation using the density of the brine. For CO_2, a similar calculation can be made, but the density of CO_2 is highly variable with the geothermal gradient and injection pressures encountered in most oil reservoirs. The primary difference is that higher surface CO_2 injection pressure is required to achieve the bottomhole pressure via brine.

CO_2 injection permits for the MGSC included both surface and subsurface injection pressure stated (Frailey et al., 2012). The challenge will be to have permits that have stated surface pressures that achieve the desired bottomhole pressure. It is possible that the only solution is for an operator to include bottomhole pressure gauges which would be atypical for most all operators in this Midwest.

Unitization. When a water or CO_2 flood is planned, one of the initial steps is to organize the operators in a specific field or geologic subset of the field (area or reservoir) into an

agreement to share operating expenses and revenue – a process called unitization. Because it is a tedious process and can be difficult to get all parties in agreement, most states provide a unitization procedure requiring a supermajority of owners to agree to the unit bringing in the remaining minority owners. There has to be some type of hearing so that the minority interest owners and the royalty owners are treated fairly and equitably by the majority. Because CO_2 EOR would be relatively new, require significant capital expense and long-term CO_2 contracts, unitization may be a challenge compared to water injection only in the Midwest.

Mineral estate severed from real estate. In the mature oilfields of the Midwest, oil producing wells are plugged and abandoned as a result of uneconomic production rates. If all wells on a lease or unit are plugged, the lease or leases expire. The mineral estate is now free to be sold or leased again by the mineral owner, for example, to an oil production company considering CO_2 EOR on this acreage. In the older oilfields, it is likely that the real estate owner and the mineral estate owner are not the same people, referred to as a severed mineral estate. When the estates are severed, the mineral owner may be heirs to the original owner. Consequently, there are several more owners that must agree to the terms of a new lease or sale of the mineral estate.

County records of the most recent contact information for these owners may be incomplete or unavailable. In order to facilitate an operator to continue to develop CO_2 EOR in areas like this, mechanisms need to be known and accessible such that after recognized due diligence, the oil company owners can set aside (e.g., escrow) the royalty owed to the unknown mineral estate owners. Regulatory or assessing bodies need to exist at the county or state level to document the due diligence search and proper record and accounting that unknown mineral estate owners interest is protected.

Overcoming the Regulatory Challenges. The states of Texas, New Mexico, Wyoming, and Mississippi have existing statutes and regulations that have been adopted to be applicable for CO_2 EOR. These rules have seen several decades of service and can serve as models to develop state-based regulations that are conducive to both CO_2 EOR and concurrent storage. For those states that do not have regulations that offer solutions to these challenges, an organized effort should be made by the DOE or an industry initiative to offer assistance to states with primacy so that water related UIC Class II permits are adaptable to CO_2 EOR. The models/examples that are available from other states (e.g., Texas) should be utilized.

4.5.7 Developing Outside Interests in the Midwest CO_2 EOR Opportunity

The current owners and operators of CO_2 EOR projects in the United States have developed an understanding of the technical and operational challenges, risks, regulations, and resource requirements for this type of oilfield activity. In order to bring their expertise to the Midwest, they will need to become familiar with the current and historical oilfield activity there, geology, remaining oil resources in-place, previous CO_2 EOR related pilot activity, and location of potential anthropogenic CO_2 sources. Workshops and seminars that were developed for Midwest operators could easily be adapted to the CO_2 EOR goals in the Midwest. The new workshops could be offered in key locations where current EOR operators have offices, such as Midland, Casper, and Houston. Meetings could include sessions with the management staffs at these companies, designed in such a fashion to allow them to make an informed assessment of the CO_2 EOR opportunities in the Midwest that may have gone overlooked.

4.6 Current Status

4.6.1 Rate of Growth and Factors Affecting Growth

As noted, CO_2 EOR has its origins with the first large-scale floods in the Permian Basin in the early-1970s. After a period of observation to demonstrate the commercial success, the growth phase kicked off in the 1980s. Figure 4.6 chronicles the growth through the decades in spite of some difficult times caused by oil price crashes in 1986 and 1998. Recent years have witnessed accelerated growth, especially in the Gulf Coast areas. Growth in the Rockies and, in particular, the vital Permian Basin is now being limited by the availability of new CO_2 sources.

4.6.2 The Existing CO_2 EOR Players

The vast U.S. oil and gas industry is primarily comprised of exploration companies intent on drilling new prospects and not especially dedicated to maximizing production from newly discovered fields. The flooding sub-industry, dedicated to advancing fields into secondary and tertiary phases of production, numbers some 30 companies. One of the challenges discussed in the last section relates to increasing the amount of CO_2 EOR producers, which would require a heavy emphasis on engineering skills and reservoir engineering. The list of current CO_2 flooding companies is provided in Figure 4.8 below.

Figure 4.8: List of Active U.S. CO_2 Flood Operators

Anadarko Petroleum Corporation	Hess
Apache Corporation	Kinder Morgan
Chaparral Energy	Legado Resources
Chevron	Merit Energy
ConocoPhillips	Orla Petco
Core Energy	Occidental
Denbury Resources	Resolute Natural Resources
Devon Energy	SandRidge Tertiary
Energen Resources	Stanberry Oil
Fasken Oil & Ranch Interests	Tellus Operating Group
Great Western Drilling	Whiting Petroleum
George R. Brown	XTO Energy Inc.

4.6.3 Supply and Demand Status of CO_2 in EOR

For the first 25 years of the history of CO_2 EOR industry, pure underground natural CO_2 source fields and pure byproduct natural gas plants were of ample size to provide the CO_2 needed for what growth CO_2 EOR would require. Pipelines had also been built of sufficient throughput capacity to transport the contracted quantities needed for EOR projects. Today, the situation has changed. Depletion of the source fields and/or size limitations of the pipelines are now constricting EOR growth. While it is true where demand exceeds supply, market forces generally work to provide the new supplies. But, new, pure underground sources are not readily available.

The costs of new CO_2 supplies are also a factor. Large point source industrial plants have been viewed as the coming EOR growth catalyst but with some notable exceptions, like natural gas byproduct CO_2, the Dakota Gasification Project in North Dakota, the Coffeyville (petroleum coke) Gasification project in southern Kansas, and the coming Mississippi Power IGCC in Kemper County, the new age of anthropogenic supplies of CO_2 has just not advanced to meet the growing demand and abate the supply shortages. The CO_2 cost gap between industrial CO_2 and the pure, natural CO_2 remains a barrier. Increasing values of CO_2 due to the growing demand and constricted or declining natural sources is helping change the landscape but the gap persists.

As mentioned earlier, the Permian Basin has dominated the CO_2 EOR development picture of the past. The ample pure underground sources and robust infrastructure were a

significant part. Growth continued until new project demands ran up against the supply barriers. Two other regions, the Gulf Coast and Wyoming, are now booming with new oil development growth through EOR. As a case in point, the Mississippi growth is a classic example of production growth where CO_2 supply was not a limiting factor. The Jackson Dome natural source field near Jackson, Mississippi has been developed in very rapid fashion to provide the necessary new CO_2 to fuel the expansion of EOR. Wyoming (i.e., ExxonMobil) has a similar story with its LaBarge field and very recent expansion of capture capacity of the Shute Creek plant north of Green River. New announcements of the DKRW coal gasification plant near Medicine Bow and the aforementioned Coffeyville plant in Kansas will further accelerate activity in those regions.

4.7 Promise of the Future

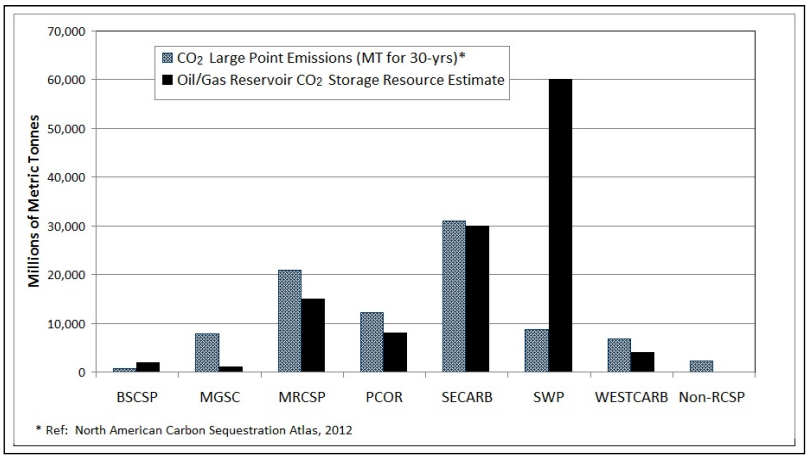
4.7.1 Size of Conventional Targets

Today, the total U.S. oil production from projects under CO_2 EOR accounts for over 350,000 bbl/d and uses mainly natural CO_2 but with some anthropogenic sources. NETL, in its recent report on EOR potential (DOE/NETL, 2011) concluded that using today's state-of-the-art practices, EOR has the potential to deliver 26-61 billion barrels of additional oil – significantly expanding domestic oil production using existing oil fields. NETL also estimated that next-generation EOR technology could provide 137 billion barrels of additional technically recoverable domestic oil, with about half (67 billion barrels) economically recoverable at an oil price of $85/barrel and could reduce imports by a third. Technical CO_2 storage capacity offered by CO_2 EOR could equal 45 billion metric tons.

NETL also noted that this additional supply from EOR development is constrained by insufficient supplies of CO_2. NETL estimated that to recover the 67 billion barrels of economically recoverable oil, nearly 20 billion metric tons of CO_2 are necessary. Natural sources of CO_2 have the capacity to supply only 2 billion metric tons – anthropogenic sources would be needed to supply the remaining 18 billion tons to increase oil production to the cited levels. By NETL estimates, the market for captured CO_2 emissions from power plants for economically feasible CO_2 EOR projects would be sufficient to permanently store the CO_2 emissions of 93 large one GW size coal-fired power plants operated for 30 years. The geographical distribution of the EOR resource base is a key factor in realizing the CO_2 capture and EOR potential. Figure

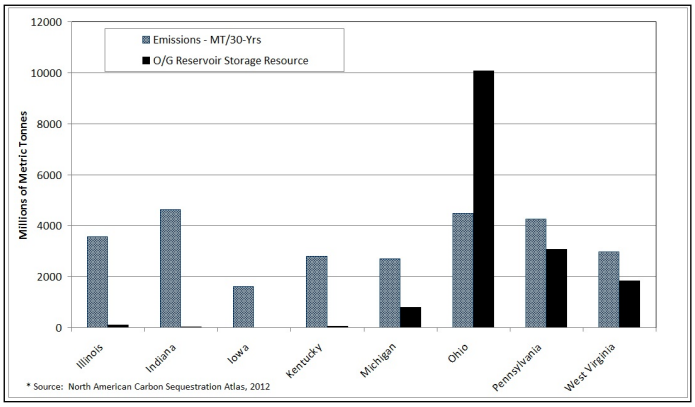
4.9 breaks down the Oil and Gas reservoir (EOR) potential and the magnitude of the capture potential CO_2 sources within the Sequestration Partnership Regions according to the DOE/NETL North American Carbon Sequestration Atlas (2012).

Figure 4.9: Large CO_2 Point Sources and Oil/Gas Reservoir Capacity in the United States (Regional Carbon Sequestration Partnerships)



Of particular interest in this report is the Midwest region of the United States with its large and high volume point sources of CO_2 and untapped CO_2 EOR potential. Figure 4.10 breaks out the source and EOR sink capacities for the Midwest region. Additional information on Midwest EOR potential has been posted by the Midwestern Governors Association (2012).

Figure 4.10: Breakout of CO_2 Sources and EOR Capacity in the Midwest



4.7.2 Upside Storage and EOR Capacity – the "Less Conventional"

Recent pioneering EOR projects are dramatically expanding the view of commercial oil reservoir targets. Eleven projects are now recovering oil beneath the oil/water contacts in the Permian Basin region. Recent studies have demonstrated that the origins of these zones are due to a natural waterflooding process and can be extraordinarily large in extent and as successfully flooded using EOR as man's waterfloods (Melzer, 2006). The work in the Permian Basin to identify the origins and distribution of these intervals ROZs has been extended to the BigHorn Basin in the Rockies (Mohrbacher et al., 2011) and is likely to be common in many parts of the United States and around world.

4.7.3 Options for Facilitating the Infrastructure Buildout

In a world driven by short-term investment strategies and rates of return methodology, infrastructure projects are difficult to finance. It is difficult enough to fund one capital intensive project today, but the new industry we are discussing in this report requires a convergence of not one but three exceedingly large financial endeavors: the CO_2 capture, pipeline, and EOR industries. Challenges abound and will be discussed in the following chapters of this report.

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Chapter 5: Coupling EOR with Plant Operations

5.1 Key Findings

- Current sources of CO_2 do not cover the EOR demand. If capture projects are developed that can provide the needed CO_2, it could have a major impact on developing the U.S. EOR potential over the next 20 plus years.
- The source potential in the Midwest is almost double the Gulf Coast and is equal to the Gulf Coast and Texas combined and is essentially undeveloped. It is also important for the states involved to proactively help to remove barriers and help align surface and subsurface resources.
- It is imperative that, as CO_2 capture technology evolves as discussed in Chapter 3, that the necessary transportation and EOR related infrastructure move forward in lockstep.
- The current DOE RD&D program for geologic carbon sequestration (including CCUS) continues to be the most robust in the world and has played a critical role in gathering data to support the use of CO_2 in EOR applications. We also have far more active CO_2 EOR and sequestration projects than any other country in the world.
- In the United States, multi-plant pipeline systems connecting multiple sources to multiple fields offers significant flexibility and provides a better overall strategy to linking sources and EOR sinks than close coupled systems.

5.2 Recommendations

- The Council recommends that the Energy Secretary focus on removing barriers for systems that will lead to multi-plant pipeline systems.
- The Council recommends that the Energy Secretary finish demonstrations that are currently underway or in development at the Regional Partnerships which provide support for perceived regulatory, financial, and environmental barriers.
- The Council recommends that the Energy Secretary selectively develop a demonstration project focused on EOR applications that will help to build regional support for perceived risks with both CO_2 capture and EOR use as well as work on the demonstration goals provided above for EOR. Based on the large amount of stationary sources and the relatively undeveloped nature of the Midwest from both a CO_2 removal and EOR

perspective, this is a desirable region of the United States to focus on for this demonstration.

- The Council recommends that the Energy Secretary help, as appropriate, to ensure that state level support, which is needed to remove barriers, is secured and helps with alignment of both subsurface and surface interests.
- The Council recommends that the Energy Secretary ensure that the proposed Midwest demonstration also takes advantage of the use of a multi-plant pipeline as much as possible.

5.3 Introduction

Continuing to expand CCUS deployment through EOR is dependent on the successful capture of CO_2 from coal-based power plants and large industrial sources. Based on this study, the 2011 NCC CCS report, and data provided in Chapter 4, an area of focus from a source perspective is the Midwest (Illinois, Indiana, Kentucky, Pennsylvania, Ohio, and Michigan) which contains large sources of CO_2 (Figure 5.1). The Midwest also provides significant opportunities for EOR as do other parts of the country (see Chapter 4). To date, the encouragement to capture CO_2 has not had a demand driver from CO_2 EOR. Several key actions are needed and, to maximize chances of success, both sides (capture and EOR) need attention.

The capture process should begin in the Midwest as its sources potential is great (see Figures 4.8, 4.9, 5.1, and Reference 4). To catalyze EOR in the Midwest, a near-term step could be the construction of a pipeline linking the Midwest to the existing pipeline networks near on-going EOR operations, such as in the Gulf (see Figure 6.5). This should be coupled with promoting a demonstration in the Midwest to access and incentivize mature Midwest oil fields (see Figure 5.3). Current understanding of EOR potential suggests that EOR near-term demand for CO_2 in the Gulf Coast is over four times as great as the Midwest due to the existence and success of ongoing EOR projects, but this must be balanced with the large number of stationary CO_2 sources in the Midwest (see Figure 5.1, DOE, 2010). Not much is known about the EOR upside in the Midwest which drives a need for pilot projects to establish the demand.

The 2011 NCC CCS focused report and Chapter 4 both state a need to develop transportation infrastructure as well as take advantage of the evolving large EOR opportunities across the U.S. (including the upside potentially created by ROZs). Current sources of CO_2 do

not cover the EOR demand. If anthropogenic capture projects are developed, they can provide the needed CO_2, and could have a major impact on developing the EOR potential over the next 20 plus years. As pointed out in the last two NCC reports, without proper planning and development, the infrastructure for transporting and managing the large volumes of CO_2 that could be recovered from power plants and others sources will not be possible. It is imperative that, as CO_2 capture technology evolves as discussed in Chapter 3, the necessary transportation and EOR related infrastructure move forward in lockstep. The current DOE RD&D program for geologic carbon sequestration (including CCUS) continues to be the most robust in the world and has played a critical role in gathering data to support the use of CO_2 in EOR applications. Much value is to be gained on both the energy resource and environmental fronts. It is also worth noting that the platform for success in the United States is second to none. We have far more active CO_2 EOR and sequestration projects than any other country in the world.

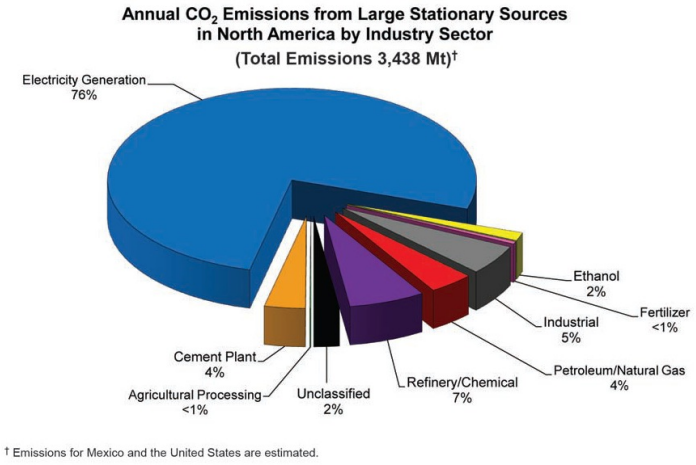
5.4 Power Plants and Other CO2 Stationary Sources

5.4.1 Overview

According to the EPA, total U.S. GHG emissions are estimated at 6,960 million metric tons CO_2 equivalent. Of this total, 5,570 million metric tons are from fossil fuel combustion and 3,438 million metric tons were from stationary sources. Power plants represented 76% of this total with the rest distributed across eight other categories (see Figure 5.1).

Figure 5.1: CO_2 Stationary Source Emissions by Category

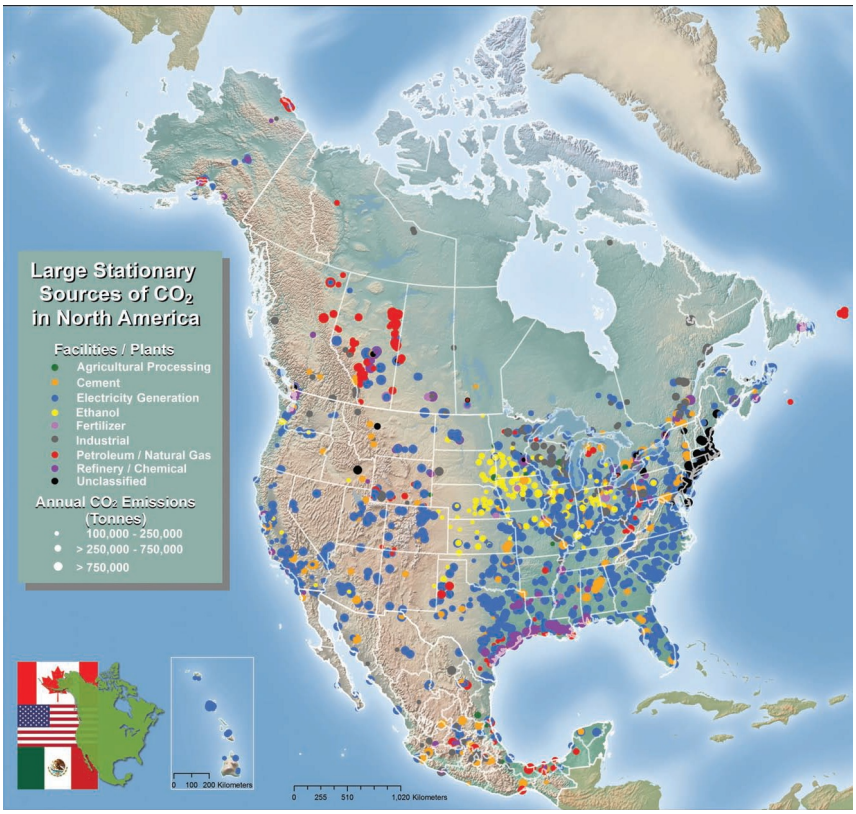
(DOE, 2012)



An overview of United States, Canadian, and Mexican CO_2 stationary sources is provided below (see Figure 5.2). Sources are primarily concentrated along coastlines and major river valleys. In addition, many sources are clustered in areas of petroleum and gas processing like the U.S. Gulf Coast and the Canadian Alberta Providence. As shown, there are a wide range and large number of stationary CO_2 sources. However, few sources provide pure CO_2 streams. Sources with relatively pure CO_2 streams include gas processing facilities that strip CO_2 from natural gas and ethanol plants. CO_2 from coal-fired power plants require capture and compression facilities as discussed in Chapter 2 but represent the bulk of the CO_2 available from stationary sources and thus should be the area of prime focus.

Figure 5.2: U.S., Canadian and Mexican CO_2 Stationary Sources

(DOE, 2012)



CO_2 emissions from power plants can be separated from stack emissions either post-combustion or pre-combustion. Capture technologies are discussed in detail in Chapter 3 of this report. Because stationary sources and specifically power plants represent such a large portion of

the available CO_2 emissions in the United States it is important to focus on developing technically and commercially practical CO_2 separation and compression solutions that will accelerate CO_2 capture from power plants and will allow the rapid development of infrastructure necessary to expand the use of CO_2 in EOR applications.

Oil and gas reservoirs that can use CO_2 from an EOR (CCUS) perspective are discussed in detail in Chapter 4. A source and sink model that compares CO_2 stationary sources and EOR indicates that Texas, the U.S. Gulf Coast, the Midcontinent and Midwest, and selective locations in the West offer the best opportunities for expanding EOR use through recovery of CO_2 from stationary sources. If commercial and technical barriers can be overcome, the opportunity to recover anthropogenic CO_2 and to use that CO_2 in EOR applications is significant.

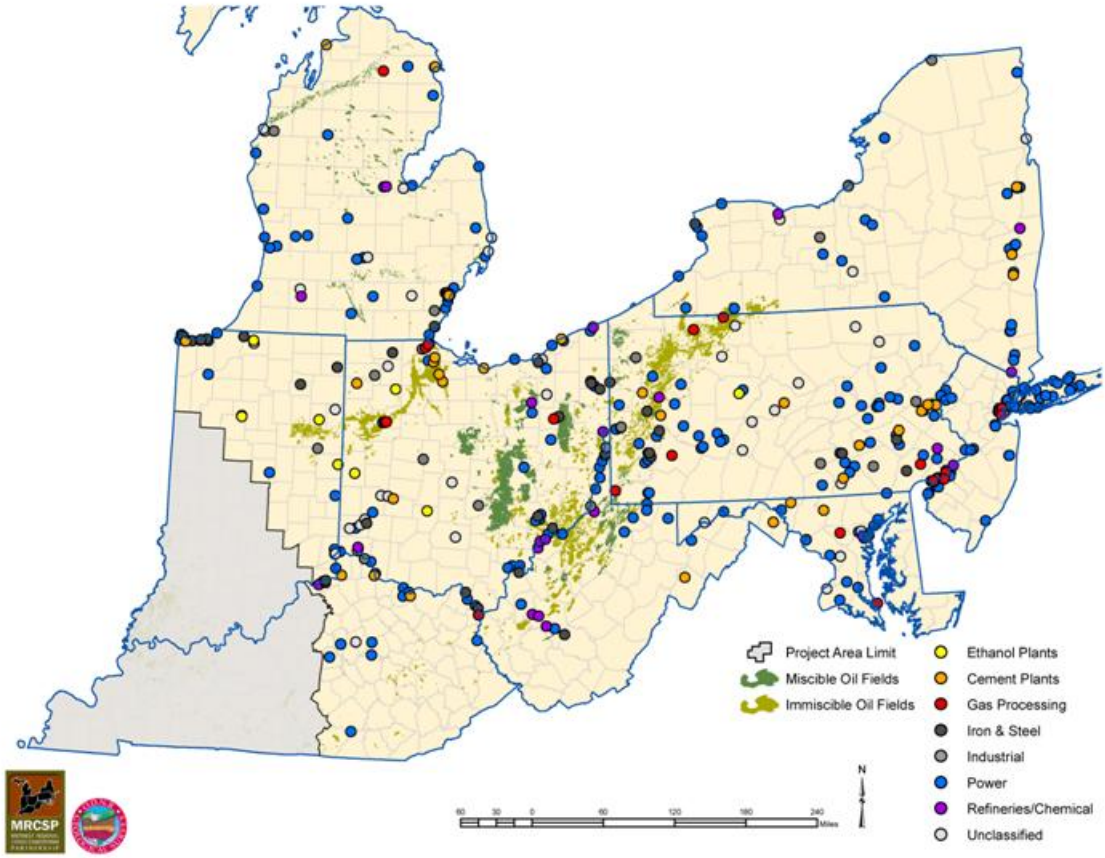
The wealth of EOR experience in both the Permian Basin of Texas and along the Gulf Coast demonstrates economically attractive EOR deployment and viable state level regulatory environments that are conducive to expanded CO_2 use in EOR as long as anthropogenic CO_2 can be made available in a manner that is economically viable and reliable as a source. In a recent study done by SECARB and ARI, the Eastern Gulf Coast oil reservoirs (Alabama, Florida, Mississippi, and Louisiana) offer 5.6 billion barrels of oil recovery using 2.6 billion metric tons of CO_2 (ARI, 2012). This area has a significant start on the necessary pipeline infrastructure. This infrastructure can be utilized as anthropogenic CO_2 becomes available in the Midwest and elsewhere in the U.S. if additional pipelines are built to connect to the Gulf Coast trunk lines or if other networked systems are developed. The Midwest (Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and Michigan) provides a significant, undeveloped market for CO_2 related EOR applications and has one of the largest concentrations of stationary sources of CO_2 in the United States. To provide perspective, a more in-depth look at the Midwest and Gulf Coast are provided below.

5.4.1.1 Midwest

Although covered in depth in Chapter 4, it is worth noting that based on work done by the Midwest Regional Carbon Sequestration Partnership (MRCSP, 2010), there is an estimated 1.2 billion barrels of potential oil recovery by CO_2 EOR based on available data for 265 fields. Of this, there is an estimated 705 million barrels of oil that could be potentially recovered

through CO_2 EOR from the top 10 fields. By looking at the source Atlas and Figure 5.2 above, many of the fields are located near or adjacent to large stationery sources of CO_2.

Figure 5.3: Miscible and Immiscible Oil Fields in the MRCSP Region and CO_2 Source Locations



5.4.1.2 Gulf Coast

Based on study work that has been done by ARI for the SECARB Region, the eastern Gulf Coast reservoirs in Alabama, Florida, Mississippi, and Louisiana offer considerable potential for utilizing CO_2 for miscible EOR. With currently available state-of-the-art technology, the technically feasible potential is provided in Table 5.1 below:

Table 5.1: Eastern Gulf Coast Oil Reservoirs favorable for EOR (2011 NETL/ARI Study)

State	Number of large Oil Fields Favorable for Miscible CO2-EOR	Technically Recoverable Oil for CO2-EOR		Technical Storage Capacity from CO2-EOR	
		Data Base	Extrapolated	Data Base	Extrapolated
Alabama	9	175	292	66	109
Florida	6	210	350	100	167
Mississippi	24	284	423	120	199
Louisiana	63	2,594	4,373	1,267	2,111
Total	**102**	**3,263**	**5,438**	**1,553**	**2,586**

5.4.2 Summary

Based on the above, there are two primary ways to couple CO_2 sources with EOR applications. Both require the use of pipelines. The first is close coupling a stationary source (or sources) with an EOR opportunity which may involve a very short pipeline system or a single pipeline between the source and the application. The second is to provide a means of moving the CO_2 into a network that allows for the CO_2 produced to be used in EOR locations that may not be contiguous with the CO_2 source. Both of these approaches were discussed in-depth in the 2011 NCC report, but this report will go into more detail on barriers and issues that need be solved to expand the use. The two primary ways of coupling CO_2 sources and EOR applications are provided in sections 5.3 and 5.4 below.

5.5 Close Coupling – Power Plants (CO_2 Generation Sources) with EOR opportunities

5.5.1 Overview

If a source of CO_2 is close to a potential EOR application, then it may be close coupled, which provides both potential benefits and issues. However, it is worth noting that the benefits, at least currently, do not outweigh the more obvious issues. Possible business arrangements exist for close coupling include: 1) a joint venture between a CO_2 source and an EOR asset or 2) a firm that owns both a CO_2 source and a nearby EOR asset. A key is to ensure

that contractual relationships are sufficiently aligned to address inherently different cultures and possible business drivers.

The potential benefits include but are not limited to potentially overall lower capital and operating costs, potentially more streamlined permitting requirements, synergistic operating costs that allow for the use of the same team (e.g., management, maintenance, operators) for the large CO_2 generator (e.g., industrial plant, refinery, cogenerator, power plant) and the EOR application, potentially better quality control with the simple linkage created by close coupling, and a possibly overall business relationship if both assets are owned by the same entity. The rest of this section will deal with considerations and issues that need to be addressed with this approach.

5.5.2 Operating Considerations

There are several considerations, primary of which is aligning differing commercial and technical timelines. Investment timelines related to EOR development and development of CO_2 capture need to be aligned. CO_2 quality is a concern (discussed below), but this will be known and agreed in the development of the purchase contracts for the CO_2. Reliability of supply and reliability of the EOR field and life expectancy of both projects need to be considered. The EOR operation is generally reliable and can accommodate occasional upsets. Operational communication related to "turnarounds" is critical to ensuring efficient operations between the parties.

5.5.3 Quality

In order to properly manage the EOR use of the generated CO_2, the quality must be reasonably consistent, and should be at least 95% CO_2, although there are opportunities for optimization allowing for higher H_2S concentrations as long as the pipeline and downhole metallurgy and overall EOR applications allows for it. Examples include: increased H_2S concentration in the CO_2 stream as is used at Weyburn or from the NG plants in West Texas.

CO_2 quality for EOR is driven by three key considerations: 1) metallurgy of the pipeline, process piping, and well equipment, 2) the ability of the CO_2 injectant to be miscible or near-miscible with the reservoir condition oil, and 3) safety. These have direct bearing on expenses to insure safety and corrosion control in the tubulars, recovery factor, and ultimate success of the EOR operations.

Plant upsets resulting in off-specification CO_2 will typically be rejected by the transmission pipeline and be vented or otherwise recycled into a recycle process. In order to ensure a reasonably consistent quality stream of CO_2, the CO_2 recovery plant needs to be able to provide means to control upsets or to manage quality of the CO_2 within agreed to downstream use parameters.

5.5.4 Supply reliability

Currently, EOR users have and still do require a stable, long-term supply at a consistent quality (as discussed above) and pressure. In a close coupled situation, it may be harder to maintain a consistent pressure and throughput when the power plant is incorporating new technology or demonstrating technology for CO_2 recovery causing the plant to cycle versus operating continuously. This needs to be taken into account in the implementation of recovery technologies discussed in Chapter 3. Further, EOR operations, in some areas, reduce CO_2 needs during the summer due to heat impacts on the CO_2 density at the wellhead. Similarly, if an EOR site utilizes a Water Alternating Gas (WAG), CO_2 supply may alternate during a specified interval, albeit on a projected regular basis. In both of these cases, EOR project design and operational practices can provide the flexibility needed. However, upsets with the recycle of CO_2 in an EOR project can have an adverse effect potentially causing a need for more redundancy in a recovery plant to assure consistent CO_2 supply, as much as practical.

In addition, it is important that the CO_2 supplier works with the CO_2 user. In order to remove unnecessary communication barriers the following may be considered; (a) turnaround and maintenance dialogue/coordination, (b) establishment of joint supply coordinating committee that builds a strong communication linkage, (c) senior level plant and EOR field managers being familiarized with each other and their respective operations, and (e) establishment of strong operating supply agreement(s) and protocols. Many of these considerations/issues can be mitigated to a large degree by multiple suppliers and users and a robust pipeline network.

5.5.5 Economic/Economics Considerations

As indicated above, there needs to be a purchase and sale agreement between the CO_2 supplier and the EOR end-users that discusses quality and reliability issues and also deals with the pricing of the CO_2, even if the close coupled operation is put together through a joint venture or other business approach. A pricing model is needed that will allow recovery of the cost of CO_2 capture, compression, and treatment and will also allow the EOR end-users to want the CO_2 no matter if the CO_2 source is close coupled or not. The cost structure for recovery in the close coupled application will have a should have a low pipeline cost which will be offset by the need to include redundancy to lower risks/issues as discussed above.

5.5.6 Possible Incentives

There may be more appropriate needs for incentives to commercialize the best technical solutions and help to overcome typical "first mover" risks. In many deployment scenarios, the EOR can be the lower risk technology, and the incentives, if any, should be focused on the capture (production) of CO_2 versus the use of CO_2. Several initiatives are underway or being considered to incentivize capture to assist in closing the pricing gap between the cost to capture and the EOR pricing of CO_2.

5.6 Multi-Plant Pipeline and CO_2 Delivery Systems

5.6.1 Overview

As discussed, multi-plant systems connecting multiple sources to multiple fields offers flexibility relative to the close coupled system discussed above. The investment requirements increase as do the strategic planning needs to create effective networked multi-plant systems. Once a commitment is made by a CO_2 supplier to provide CO_2 to a networked system, having an EOR site in mind could be of value but is not necessary depending on the robustness and maturity of the pipeline system.

5.6.2 Operating Considerations

Operating considerations that exist with a close coupled system (quality, pressure, quantity, reliability) exist with multi-plant networked systems but are mitigated by the flexibility

created by the pipeline system itself as well as both storage and mixing inherent with the system. Quality is managed based on contractual terms with CO_2 suppliers. If any one supplier goes down, CO_2 can still be supplied to the EOR operations, possibly at a lower rate, and if any one EOR operation goes offline, supply volumes can be redirected to other EOR fields.

As in the close coupled case, communication is a key to managing operational needs and variables. Similarly, several communication improvement options are suggested: (a) turnaround and maintenance dialogue/coordination, (b) establishment of joint supply coordinating committee that builds a strong communication linkage, (c) senior level plant and EOR field managers being familiarized with each other and their respective operations, and (d) establishment of strong operating supply agreement(s) and protocols.

5.6.3 Interstate/Intrastate Considerations

Pipelines (or other means to connect multiple CO_2 generating plants as is being demonstrated in Europe with the HUB barge system) are the drivers of the entire multi-plant CO_2 management system. A pipeline, once built, is much more difficult to move but is the lowest risk part of the system with the plant that is generating the CO_2 having the shortest relative life and the EOR field the next shortest life. In all cases, the anticipated life of the system is in excess of 20 years.

NETL has created a complex multi-plant and multi-site model which can serve as a basic tool for analysis. The growth and development of the CO_2 pipeline networks in the Permian Basin, the Gulf Coast, and in Wyoming provide a model for how a nationwide system might develop.

5.6.4 Economic Considerations

A pricing model is needed that will allow recovery of the cost of CO_2 capture, compression, and treatment and will also allow the EOR end-users to want the CO_2. The cost structure must take into account the pipeline system costs as well as both source and end-user needs for the economic model to be effective.

5.6.5 Possible Incentives

There may be more appropriate needs for incentives to commercialize the best technical solutions and help to overcome typical first mover risks. In many deployment scenarios, the EOR

can be the lower risk technology, and the incentives, if any, should be focused on the production of CO_2 versus the use of CO_2. Several initiatives are underway or being considered to incentivize capture to assist in closing the pricing gap between the cost to capture and the EOR pricing of CO_2.

5.7 Demonstration Projects

The current DOE RD&D program for geologic carbon sequestration (including CCUS) continues to be the most robust in the world and has played a critical role in gathering data to support the use of CO_2 in EOR applications. When this broad effort is combined with the following three points:

(1) Capture – (discussed in Chapter 3) additional sources of CO_2 are needed and can be easily utilized in EOR applications if they can be made available to the market in an economically attractive manner which could drive selective capture related demonstration opportunities and is the charter of the National Carbon Capture Center in Wilsonville, Alabama.

(2) CO_2 pipelines – there is 40+ years of history safe operation of CO_2 pipelines in the U.S. covering both intra and interstate applications. There is a need to continue to expand and develop the U.S. CO_2 pipeline system, but there is no need for demonstration of the technology employed. But, there is, however, a need to educate the public in the safe and effective manner that the existing system enjoys.

(3) EOR has been effectively deployed in the United States for over 40 years in a wide range of formation types and depths. Monitoring has been accomplished for the purpose of reservoir management and surveillance and generally applies for the purpose of assuring storage permanence. Removing barriers to wider EOR use, with a focus on the Midwest, will be important going forward as well as the continued demonstration of technology.

Focusing on the ongoing DOE driven regional partnership demonstration programs as discussed recommendations specific to this chapter and summarized above include:

- Finish demonstrations that are currently underway or in development at the Regional Partnerships, which provide support for perceived regulatory, financial, and environmental barriers.
- Selectively develop a demonstration project focused on EOR applications that will help to build regional support (specifically in the Midwest) for perceived issues with both CO_2 capture and EOR use as well as work on the demonstration goals provided above for EOR. In addition to other barriers that need to be moved, state level support is needed to remove barriers and must include alignment of both subsurface and surface interests.

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Chapter 6: Linking CO_2 from Synfuel and Coproduction Plants to CO_2 EOR Opportunities

6.1 Key Findings

- Synfuel and coproduction plants that capture CO_2 for EOR markets and coprocess modest quantities of biomass with coal would be able to provide liquid transportation fuels with near-zero levels of sulfur and other contaminants.
- Synfuel plants are likely to be built in regions near low cost coal supplies that are remote from major electricity markets.
- Coproduction plants are likely to be the preferred route for providing synfuels in regions where new electricity supplies are needed and would provide a strong basis for economic revitalization of regions such as the Ohio River Valley where many coal power plant retirements have been announced.
- At current oil prices, NOAK synfuel and coproduction plants, where N is less than five, are likely to be very competitive in CO_2 EOR markets, as they would represent profitable investments in liquid fuels and electricity production, even at low plant-gate CO_2 selling prices.
- In an analysis comparing as competitors in CO_2 EOR markets post-combustion capture retrofits and coproduction plants considered as rebuilds at existing coal power plant sites, it was found that:
    - Retrofits are likely to be the more profitable investments when the plant-gate CO_2 selling price is high (which often means the CO_2 EOR site is nearby), but
    - Coproduction plants are likely to be the more profitable investments when the plant-gate CO_2 selling price is low (which often means that EOR opportunities are remote from these plant sites).

  This suggests that CO_2 captured at sites of most existing U.S. coal power plants could, using the appropriate capture technologies, compete in CO_2 EOR markets when an adequate CO_2 pipeline infrastructure is in place, if the needed commercial-scale demonstration and early mover capture projects are successful.
- The prospect that coproduction plants can be built with ultra-low emissions of criteria pollutants and air toxics (even mercury) at relatively modest incremental costs suggests that the permitting process for such plants ought to be relatively smooth, especially for

rebuilds at Brownfield sites. Thus, there is a strategic opportunity to increase linked coproduction and CO_2 EOR activities relatively quickly when the required CO_2 pipeline infrastructure is in place if these activities are adequately coordinated.

- Coproduction systems that coprocess a modest amount of biomass (<10% on an energy basis) are ready to be demonstrated at commercial-scale.
- Demonstrating such systems in the near-term would provide a solid technology base that would facilitate increasing the biomass input percentage later. Such a technological evolution could enable large roles for coal in providing synfuels as well as electricity.
- Liquid transportation fuels for which fuel-cycle-wide GHG emissions are <10% of the emissions for crude oil products displaced can be provided by coprocessing less than 30% non-food biomass in coproduction systems at lower cost than advanced biofuels such as cellulosic ethanol. Also, for such systems the non-food biomass required to produce a gallon of gasoline equivalent fuel would be <40% as much as is required for advanced biofuels such as cellulosic ethanol.

6.2 Recommendations

- The Energy Secretary should work with the Council, interested parties in the private sector, and the seven Regional Carbon Sequestration Partnerships to find ways whereby a commercial-scale coproduction plant coprocessing a modest amount of biomass and using the captured CO_2 for EOR could be built.
- The Energy Secretary, the Council, private sector companies, and Regional Partnerships should also find ways whereby a small number (<5) of follow-on plants can be built if the commercial demonstration project is a success and suggests a clear path to the technologies becoming economically competitive as a result of experience with these follow-on plants. Key foci for these activities should be on reducing investment costs and improving operational effectiveness and robustness (as a consequence of learning by doing), so that the technology will be cost competitive in CO_2 EOR markets without subsidy.
- The Energy Secretary, the Council, private sector companies, and Regional Partnerships should also work together to ensure that capture activities, CO_2 pipeline construction, and

CO_2 EOR activities advance in a coordinated manner to enhance prospects for rapid buildup of the associated industries and the ensuing benefits to the United States.

- The DOE should pursue R&D aimed at both helping ensure the success of the demonstration project and advancing technologies that could enable larger biomass percentages to be used in synfuel and coproduction plants in the longer-term.

6.3 Introduction

Chapter 6 explores some implications of the attractive environmental features and prospective favorable economics for CO_2 EOR-linked synfuel and coproduction systems described in Chapter 3.

6.4 Implications of Meeting the NCC Aspirational EOR goal via Two Alternative Thought Experiments Involving CO_2 Captured at Existing Coal Power Plant Sites

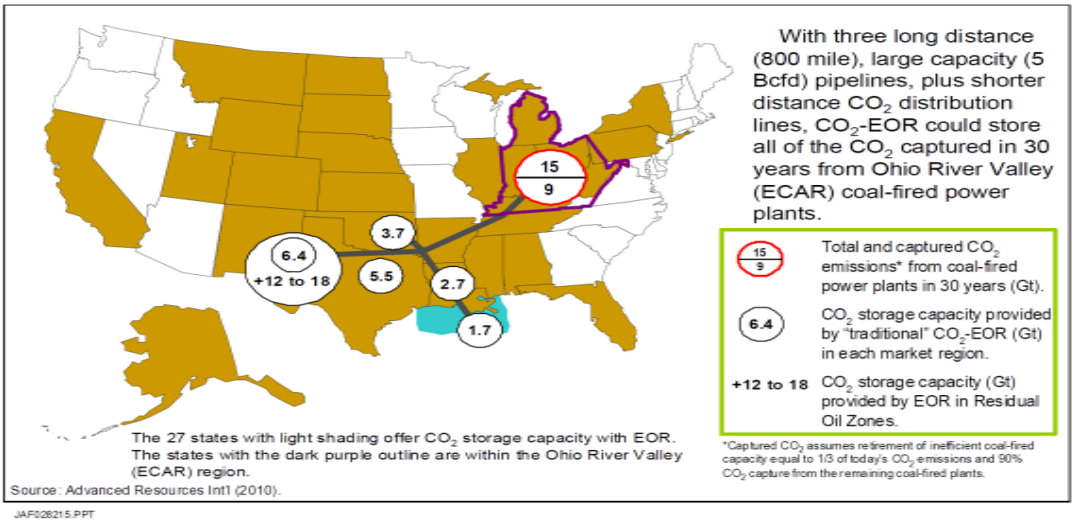
The Aspirational Case for CO_2 EOR in this NCC study (Chapter 2) is to increase crude oil production from 350,000 bbl/d in 2012 to 4 million bbl/d by 2030 (adapted from ARI, 2010; see also DOE NETL, 2011). Of this total, 600,000 bbl/d would involve using available CO_2 supplies from natural sources and gas processing plants and the remaining 3.4 million bbl/d would involve using CO_2 captured at energy conversion facilities.

In this section, two "thought experiments" are described to explore the implications (challenges and prospective benefits) of meeting this NCC Aspirational Case using only CO_2 captured at existing coal power plant sites. Meeting the Aspirational goal would certainly involve using other CO_2 supplies as well. But, this simplified approach to meeting the goal is likely to represent a large percentage of the total opportunity because of: (a) prospective coal power plant retirements (discussed below) and (b) the prospect that such CO_2 provided either by capture retrofits of existing coal plants or rebuilds via coproduction plants that capture CO_2 are leading candidates for providing CO_2 for EOR, as shown by the economic analysis in Figures 3.4 and 3.5 of Chapter 3.

For both thought experiments it is assumed that the CO_2 purchase rate for EOR is 0.3 metric ton CO_2/incremental barrel of crude (the estimated average for next-generation CO_2 EOR

technology[8]) so that the anthropogenic CO_2 needed for EOR by 2030 in either thought experiment is ~370 million metric tons/year.

Figure 6.1: Kuuskraa (2010) proposed the above pipeline infrastructure linking prospective anthropogenic CO_2 supplies in the Ohio River Valley to EOR opportunities in Texas, Louisiana, and Oklahoma.



In Thought Experiment #1 (TE #1) 100% of this amount of captured CO_2 would be provided by post-combustion capture retrofits. In TE #2, 100% would instead be provided by CO_2 captured from rebuild plants coproducing electricity and gasoline (via coal-to-methanol-to-gasoline process) and coprocessing 5% biomass (the $CBTG_{coprod}$-Cap-5.0% system discussed in Chapter 3), as well as from some plants coproducing electricity and FT liquids from shale gas and 3.2% biomass (the $GBTL_{coprod}$-Cap-3.2% system discussed in Chapter 3) – both of which are characterized by GHGI = 0.5.[9]

It is assumed for TE #2 that all the natural gas projected for export as LNG in 2030[10] in the EIA's *Annual Energy Outlook* (AEO) *2012* is instead used to provide FT liquids via coproduction plants. In Chapter 3, it was shown that the $CBTG_{coprod}$-Cap-5.0% and $GBTL_{coprod}$-Cap-3.2% options are likely to be comparably profitable even though the former are likely to be

[8] The average CO_2 purchase requirement per incremental barrel of crude oil is 7.9 Mscf (0.42 metric tons) with "state-of-the-art technology" and 5.7 Mscf (0.30 metric tons) with next-generation technology in the Permian Basin – see Table IV-5 in US DOE NETL (2011).

[9] The greenhouse gas emissions index (GHGI) is defined in Section 3.4c of Chapter 3.

[10] In *AEO 2012 Early Release*, it is projected that 0.72 Quads/year of natural gas is exported as LNG in 2030.

about twice as capital intensive as the latter. Shale gas-based coproduction systems are included in TE #2 for two reasons: (a) there is already shale gas community interest in building gas-to-liquids plants; coproduction variants of such plants could provide significant quantities of CO_2 for EOR applications and (b) a major focus of Section 6.7 below is to consider linking coal-based coproduction plants in the Ohio River Valley to CO_2 EOR opportunities in the Gulf region; gas-based coproduction plants based on use of Marcellus and Utica shale gas might end up sharing CO_2 pipeline capacity with coal-based coproduction plants in the same region, thereby improving the CO_2 transport economics for both via scale economy gains.

Other common assumptions for the two TEs are that: (a) the total amount of electricity provided annually is the same as for the existing coal power plants displaced and (b) all makeup electricity is provided by NGCC plants that vent CO_2. The results of the two thought experiments are summarized in Tables 6A1 and 6A2 of Appendix 6A, and highlights for 2030 are sketched out here:

- In TE #1, 58 GW_e of existing coal electric capacity is retrofitted with post-combustion capture equipment, as a result of which capacity is reduced to 43 GW_e; NGCC makeup electricity is <7% of total electricity generation for the TE.[11]
- In TE #2, 47 GW_e of existing coal electric capacity is replaced by 25 GW_e of $CBTG_{coprod}$-Cap-5.0% + 6 GW_e of $GBTL_{coprod}$-Cap-3.2%; NGCC makeup electricity is <11% of total electricity generation for the TE.
- The total amount of displaced coal capacity by 2030 in the TEs (47 to 58 GW_e) is comparable to the range of total potential coal capacity retirements expected by 2020 (see Section 6.7).
- In either case, the total amount of natural gas needed for makeup power is much less than the amount projected in EIA *AEO 2012* to be available in the Reference Scenario for new natural gas-based electricity generation in 2030.[12]
- Coal use in 2030 for the coal capacity involved would be:

[11] Makeup requirements are modest because it is assumed that the existing coal plants displaced operate at 67% capacity factor (the average for all coal power in 2010), while the capacity factors for the post-combustion capture retrofits and coproduction plants are 85% and 90%, respectively.

[12] In the *AEO 2012* Reference Scenario, the net incremental gas available for domestic consumption, 2010-2030, is 1.74 Quads/year, of which 1.04 Quads is for new power generation. For comparison, the amount of gas needed for makeup power in 2030 is 0.15 Quads/year for TE #1 and 0.22 Quads/year for TE #2 (see Table 6A1).

- 4.4 Quads/year, up from 3.4 Quads/year for existing coal plants retrofitted in TE #1
- 5.3 Quads/year, up from 2.8 Quads/year for existing coal plants displaced in TE #2

- By design, the CO_2 captured in each TE supports 3.4 x 10^6 bbl/d of incremental petroleum, but TE #2 provides in addition ~1.2 x 10^6 bbl/d of gasoline equivalent synfuels for which the GHG emission rate is half that for the crude oil products displaced.
- Total GHG emissions avoided are about the same for TE #1 & TE #2 (see Table 6A2), even though GHGI = 0.20 for the post-combustion retrofit technology in TE #1 while it is a much higher 0.50 for each of the coproduction technologies in TE #2. This surprising result arises because emissions are reduced according to the GHGI value for two outputs (liquid fuels + electricity) in TE #2 but for only one output (electricity) in TE #1.
- The required capital investment[13] for the energy conversion plants is much greater for TE #2 ($245 billion) than for TE #1 ($88 billion) – see Table 6A2. Although capital requirements for TE #2 are high by power industry norms, the systems involved would be quite profitable for investors (see Chapter 3), and electricity regulators should be attracted to the prospective low LCOE values that would arise for the these coproduction systems (see Figure 3.5). Besides, investment capital would not be scarce if the United States were able to find a way to shift to capital formation some of the $330 billion it spends annually on crude oil imports, which would be dramatically reduced as a result of pursuing either of these thought experiments.

6.5 Plausibility of Meeting the NCC Aspirational goal for EOR Using CO_2 Generated at Old Coal Power Plant Sites

Neither scenario described in Section 6.4 is realistic when considered alone. As shown in Chapter 3, it is unlikely that post-combustion retrofit plants remote from EOR sites will be competitive in selling captured CO_2 for EOR, but coproduction plants might well be operated profitably in selling CO_2 at prices low enough to enable them to compete in distant CO_2 EOR markets when an adequate CO_2 pipeline infrastructure is in place (see Figure 6.1). In contrast, as

[13] Total overnight cost [total plant cost (TPC) + owner's cost (OC)], which excludes interest charges during construction.

demonstrated in Chapter 3, coproduction plants located near EOR sites might be less competitive than post-combustion retrofits. But, a linear combination of the two thought experiments (a small fraction of TE #1 + a large fraction of TE #2) could plausibly provide profitably without subsidy for NOAK plants the CO_2 needed to meet the aspirational goal that framed this exercise. Furthermore, it is feasible to build up quickly CO_2 EOR-linked coproduction capacity in power short regions such as the Ohio River Valley where there have already been substantial coal power plant retirements with more likely coming. This judgment is based on:

- The attractive environmental features of these systems (see Box 6.1) that are likely to facilitate the new plant permitting process.
- The existing coal supply infrastructures in such regions – especially when coproduction systems are deployed as rebuild options at sites of coal plants for which retirement has already been announced or is likely in the future.

The prospect that with an adequate CO_2 pipeline infrastructure in place, NOAK versions of coproduction plants built in power-short regions could plausibly compete in distant CO_2 EOR markets (this assertion is discussed quantitatively in Section 6.7). But, there cannot be a high degree of confidence in this judgment until coproduction technologies are established in the market – a process that begins with commercial-scale demonstration. Section 6.8 below discusses ways to address this challenge. Even if NOAK economics for the energy conversion systems in the thought experiments turn out to be near the estimates presented in Chapter 3, the Aspirational goal could not be realized unless oil production via CO_2 EOR can grow fast enough to keep up with the anthropogenic CO_2 supply availability and the pipeline infrastructure can be created as needed to link CO_2 supplies with CO_2 EOR opportunities.

Box 6.1: Environmental Benefits of Coproduction

Coproduction systems for which captured CO_2 is stored underground via CO_2 EOR offer not only attractive economics (e.g., see Figure 3.4), but also significant carbon mitigation benefits. If 100% of the CO_2 emissions from a CTL_{coprod}-Cap plant (see Chapter 3) were allocated to net electricity output and all remaining fuel-cycle-wide GHG emissions were allocated to synfuels,

the electricity emission rate would be 952 lb of CO_2 per MWh_e, and the synfuels GHG emission rate would be 10% less than for the crude oil products displaced. With this allocation scheme for $CBTG_{coprod}$-Cap-5.0% (see Chapter 3), the electricity emission rate would be 462 lb of CO_2 per MWh_e, and the synfuels GHG emission rate would be 31% less than for the crude oil products displaced.

Moreover, coproduction systems with CCS that coprocess about 30% biomass could be able to provide both synfuels and electricity with near-zero fuel-cycle-wide GHG emissions (see Box 6.2).

The synthetic fuels provided have near-zero levels of sulfur and other contaminants. SO_2 emissions from coproduction plants would also be near-zero because sulfur must be removed to extremely low levels from the synthesis gas to protect synthesis catalysts. Moreover, particulates, mercury, and other toxics can be removed at relatively low costs from syngas streams in which these pollutants are undiluted by nitrogen from combustion air that would make their removal from flue gases more challenging.

To illustrate, the mercury control cost is estimated for coproduction plants[14] that use Illinois #6 coal, under the assumption that the eventual EPA standard turns out to be the same as for new IGCC plants, for which the New Source Performance Standard is 0.003 lb per gross GWh_e (U.S. EPA, 2012). According to NETL (2010), 34 different samples of such coals had an average mercury concentration of 90 ppb (dry basis), with almost all samples containing <250 ppb of mercury. The Parsons Infrastructure and Technology Group has developed a conceptual design and cost estimates for a carbon-bed mercury adsorption system for gasification energy systems (that Eastman Chemical Company developed and has had extensive experience with), considering both 90% and 99% capture rates – the latter being realized by deploying two beds in series (Klett et al., 2002). Per lb of mercury removed, costs (updated to 2007 $) were estimated to be $4,550 for 90% removal (1 bed) and $6,380 for 99% removal (2 beds). Assuming a coal with 250 ppb mercury and that all the mercury enters the gas phase and none leaves with gasifier slag, two beds would be required to meet the standard – for which the cost would be ~$2/$MWh_e$ (gross) or ~$3/$MWh_e$ (net).

[14] The EPA has not yet promulgated MACT emissions standards for coproduction plants.

Box 6.2: Coproduction Systems Coprocessing Biomass in the Longer-Term

Conventional wisdom is that a carbon mitigation policy would be a constraint on coal use as a feed-stock for making synthetic transportation fuels, because even with CO_2 capture and storage, the fuel-cycle-wide GHG emission rate for coal synfuels is only modestly less than that for crude oil products displaced (see, for example, Table 3A7 in Appendix 3A of Chapter 3[15]), and such a policy would aim, *inter alia*, to realize deep reductions in GHG emissions for transportation fuels.

Actually, a strong carbon mitigation policy would enable a huge coal role in providing cost-competitive low carbon fuels as well as low carbon electricity, even when CO_2 is stored in deep saline formations instead of sold for EOR. This possibility arises when coal is used in coproduction systems that coprocess substantial biomass quantities. For example, consider the $CBTL_{copod}$-Cap-29% system that coprocesses 29% biomass (energy basis) that is described in Table 3A3 and Figure 3A9. For such systems, both the LCOF and the LCOE decline rapidly with GHG emissions price for the reasons shown in Tables 3A9 and 3A10. Figures 3A12 shows that: (a) for all GHG emissions prices up to \$100/metric ton CO_{2eq} this coproduction system would be able to provide synthetic transportation fuels for which the fuel-cycle-wide GHG emission rate is <10% of the rate for the crude oil products displaced at lower LCOF than either advanced biofuels or synfuels plants coprocessing with coal enough biomass to reduce GHG emissions more than 90% and (b) the transportation fuels provided would be competitive with crude oil-derived products for GHG emissions prices >\$50/metric ton, at which price the LCOF would be ~\$2.7/gallon of gasoline equivalent when the crude oil price is \$90/barrel. Moreover, Figure 3A10 shows that at this same GHG emissions price such coproduction systems considered as power generators would provide electricity at a lower LCOE than all the other electricity generating options shown when the crude oil price is \$90/barrel, including a natural gas combined cycle that vents CO_2. Furthermore, Figure 1A11 shows that at high GHG emissions prices investors in these technologies would be well protected against the financial risk that oil prices might eventually be much lower than now.

The potential role for coal in providing low carbon transportation fuels depends on how much biomass is available. Although the DOE (2011) has estimated that more than 1 billion tons of

[15] In this chapter reference will be made to several figures and tables in Appendix 3A of Chapter 3. Henceforth these will be referred to only by the figure and table numbers (e.g, Table 3AX or Figure 3AY).

biomass might be available annually, the potential might turn out to be much less if there are constraints on the use of good agricultural land for growing biomass energy crops. The NRC's *America's Energy Future* study points out that if growing biomass as an energy crop on good agricultural land is not allowed because of conflicts with food production and indirect land use impacts (Tilman et al., 2009), the U.S. sustainable biomass potential would instead be 0.5 billion tons per year (PALTF, 2009).

If, hypothetically, all this 0.5 billion tons per year of non-food biomass were used in $CBTL_{coprod}$-Cap-29% systems, the result would be the production of 5.4 million bbl/d of gasoline equivalent transportation fuels[16] plus 1,150 million MWh_e of electricity, each provided with <10% of the GHG emissions of the fossil energy displaced. The amount of low carbon liquid fuels produced is large because the amount of biomass required to produce a gallon of gasoline-equivalent fuel with this technology is <40% as much as is required for advanced biofuels such as cellulosic ethanol (see Table 3A8). The annual coal use by such systems would be ~10 Quads/year more than the amount of coal used to produce this same amount of electricity in 2010. The CO_2 storage rate for this thought experiment would be ~1,900 million metric tons/year. Such an energy future for 2050 in the United States is described in more detail in the Fossil Energy chapter of the forthcoming *Global Energy Assessment* (Larson and Li, 2012).

Table 6.1: Potential Demand for Anthropogenic CO_2 for EOR Using Next-Generation EOR Technology[a]

Region of EOR Demand	Technical Demand[b]	Economic Demand[b,c]	
	10^6 metric Tons	10^6 metric tons	30-year average, 10^6 metric tons/year
Appalachia (NY, OH, PA, WV)	1160	290	10
California	2320	1760	59
East and Central Texas	5640	3220	107
Michigan/Illinois Basin (MI, IL, IN, KY)	1050	570	19
Mid-Continent (OK, KS, NE, AR)	6530	3270	109
Permian Basin	7080	3210	107
Rockies (CO, UT, WY)	2560	1040	35
Southeast Gulf Coast (LA, MS, Al, FL)	3260	1310	44

[16] For comparison, U.S. crude oil production is now roughly 6 million bbl/d.

Williston Basin (ND, SD, MT)	1150	360	12
Alaska	4110	2330	78
Offshore Gulf of Mexico (LA, TX, Federal)	1770	260	9
Total	43,130	17,630	587

[a] For next-generation CO_2 EOR technology the CO_2 purchase rate is 0.3 metric tons per incremental barrel of crude oil (US DOE NETL, 2011).

[b] Source: US DOE NETL (2011).

[c] The estimates of economic demand are for a crude oil price of $85/barrel and a CO_2 selling price of $40/metric ton, under which conditions the pre-tax rate of return for CO_2 EOR would be 20% a year (US DOE NETL, 2011).

Table 6.1 shows the technical and economic demands for CO_2 in EOR markets by U.S. region. The best prospects for evolving oil production via CO_2 EOR fast enough to keep up with CO_2 supply availability are for the economic demand case shown in this table. In the final column of this table, the economic potential is averaged over a 30-year period. The resulting annual CO_2 demand for EOR might be considered to be a crude estimate of the economic market demand for CO_2 in the year 2030. This table suggests that the Aspirational goal based on next-generation EOR technology (~370 million metric tons a year by 2030) could be met by using less than two thirds of the total potential economic market demand according to this metric.

Table 6.1 also shows that Aspirational goal for 2030 probably cannot be met based only on the economic demand unless a large fraction of the CO_2 supply is delivered to CO_2 EOR sites in the Permian Basin, East and Central Texas, and the Midcontinent. This implies the need for large trunk pipelines (e.g., see Figure 6.1) linking prospective CO_2 in the Ohio River Valley and other Eastern regions where CO_2 supplies will be concentrated to these large western EOR markets.

Can the CO_2 pipeline infrastructure be built fast enough to keep up with the need for linking growing CO_2 supplies and demand? In short, the answer is "probably yes." There are no technical constraints on building long, large capacity CO_2 pipelines. The 500-mile pipeline carrying 15 million metric tons annually from the McElmo Dome in western Colorado to the Permian Basin has been in operation for many years. And the U.S. pipeline construction industry is well established and very dynamic – for example, on average, 2,200 miles of natural gas pipelines were added annually during 1998-2011. Moreover, as shown by the discussion in Sections 6.6 and 6.7, business plans are already being developed to link anthropogenic sources of CO_2 to distant CO_2 EOR markets.

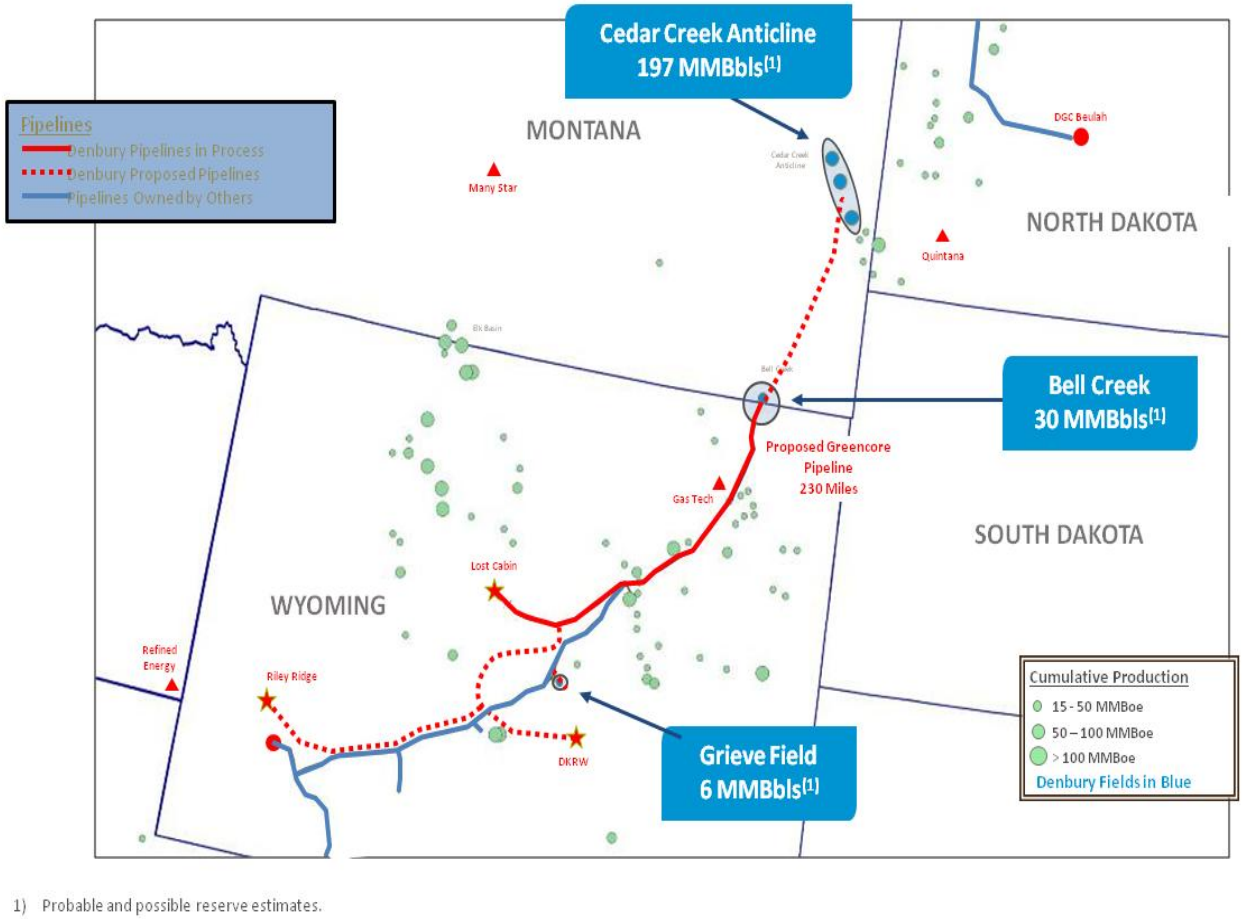
6.6 Synfuels Production in the West

Synfuels plants might be built in the West (especially in Montana and Wyoming) at minemouth sites where coal is available at low prices. Plants built in this region would tend to be remote from major electricity demand centers so that most synfuels plants would probably generate little if any electricity for extramural sale. Their very low CO_2 capture cost (<$10/metric ton of CO_2 – see Figure 3.3) makes these plants strong competitors in selling CO_2 into EOR markets. The 10,600 bbl/d coal-to-methanol-to-gasoline plant being planned for Medicine Bow, Wyoming (see Chapter 3) would capture CO_2 and sell it into the EOR market via a contract with Denbury, as shown in Figure 6-2.

Synfuel plants using only coal as a feedstock that capture CO_2 and store it underground either via EOR or, over the longer-term, in deep saline formations (the CTL_{max}-Cap or CTG_{max}-Cap systems discussed in Chapter 3), would be able to provide transportation fuels at a GHG emission rate that is slightly less than that for the crude oil products displaced (see, for example, Table 3A7). If coal synfuel plants are to produce substantial amounts of fuel it could be necessary to augment the carbon mitigation benefits offered by CCS with the coprocessing of biomass with the coal (PALTF, 2009; Tarka et al., 2009; Liu et al., 2011).

Although biomass supplies are scarce in western states such as Wyoming and Montana, states where synfuel plants are most likely to be built, biomass grown in biomass-rich regions might eventually be hauled to such coal-exporting states by coal unit trains that would otherwise return empty. In the case of Powder River Basin (PRB) coal, the biomass might be brought in via trains that could pick up biomass supplies on the way back to the PRB from biomass-rich southeastern and midwestern states.

Figure 6.2: CO_2 EOR Linkage for Wyoming Coal-To-Gasoline Project



1) Probable and possible reserve estimates.

Likewise trains hauling coal to the West Coast from Wyoming and eastern Montana could pick up biomass supplies in Washington, Oregon, Idaho, and western Montana before returning. Establishing such biomass supply logistics infrastructure is likely to be challenging. Studies should be conducted to scope out the conditions under which this strategy makes strategic and economic sense, and what policies might be needed to facilitate the development of such an infrastructure. In the meantime, a small number of plants might be built in Wyoming and Montana using woody biomass from pine bark beetle tree kills in Wyoming (Thompson, 2010) and crop residues in Montana (Williams, 2009).

6.7 Synfuels + Electricity Coproduction in the Ohio River Valley

Implementing CSAPR, MATS, and Section 316 (b) EPA environmental regulations as well as competition resulting from low natural gas prices (Burtraw et al., 2012) might lead to

substantial retirements of coal generating capacity. One projection is that 50-66 GW_e of coal capacity is threatened by retirement in the period to 2020 (Celebi et al., 2010). Already announcements of U.S.-wide coal power plant retirements for the period through 2020 total 32.5 GW_e (Ventyx's Energy Velocity, 2012). Of this, 13.9 GW (42% of the total) represents 83 plants in the five states bordering the Ohio River (Pennsylvania, West Virginia, Ohio, Indiana, Kentucky). In the absence of a new effective course of action, the Ohio River Valley will be the most severely impacted region as a result of these retirements.

The economic hardship created by these retirements might be converted into a strategic opportunity for economic revitalization of the region if some of the larger Brownfield sites were to be used for siting coproduction rebuilds equipped with CO_2 capture equipment that would sell CO_2 into EOR markets. Of course, there has to be adequate space for the coproduction equipment at such Brownfield sites; however, the economic analysis of coproduction developed in Chapter 3 does not allow for any economic benefit from use of existing coal power plant sites, so that that only potential benefit of the availability of such sites is the pace at which new plants are built – which might be faster for Brownfield sites than for Greenfield sites.

Would it be practical to gather the CO_2 from coproduction plants located at some such sites in the Ohio River Valley via a network of pipelines linking such sites to the large CO_2 EOR opportunities in the Gulf and compete in those markets. Suppose, hypothetically, that five $CBTG_{coprod}$-Cap-5.0%[17] plants were located at some mix of Brownfield and Greenfield sites in Ohio and linked to CO_2 EOR opportunities in the Gulf region via a Midwest pipeline system, for which the CO_2 transport distance is 1,000 miles. The calculation presented in Table 6-2 suggests that if an Ohio River Valley $CBTG_{coprod}$-Cap-5.0% plant were to sell its CO_2 at a plant-gate price of $20/metric ton, which would be a profitable selling price for an NOAK version of such a plant (see Figure 3-4), the cost of CO_2 delivered to an EOR site 1000 miles away in the Gulf region would be $40 to $42/metric ton (see Table 6-2). Would this represent a competitive price at the EOR site?

Average CO_2 prices at EOR sites in the Gulf region are low because of low cost natural CO_2 supplies from Jackson Dome. The market CO_2 price will be the cost of the marginal supply, which will be higher. CO_2 market prices are negotiated on a case-by-case basis and are not

[17] These five plants would have aggregate electric, gasoline, and CO_2 output capacities of 1.7 GW_e, 76,000 bbl/d, and 23 million metric tons per year, respectively.

disclosed or posted (at least not at this time). But, some CO_2 price correlations for EOR markets have been published. According to Wehner (2010), during 2008-2011, the market CO_2 price (in \$/Mscf (thousand standard cubic feet)) for EOR at the Denver City, TX "hub" varied between 1.4% and 3.3% of the West Texas Intermediate crude oil price (in \$/bbl). This correlation can be restated as a price in \$ per metric ton as 27% to 63% of the crude oil price[18] or \$24/metric ton to \$57/metric ton for the \$90/barrel reference crude oil price assumed for this NCC study. Also, the CO_2 EOR economic analysis in DOE NETL (2011) considers the market CO_2 EOR price (in \$/Mscf) to be in the range 2-3% of the crude oil price and assumes a base case price in \$/Mscf of 2.5% of the crude oil price (\$43/metric ton for \$90/bbl crude oil). Such considerations suggest that $CBTG_{coprod}$-Cap-5.0% plants in the Ohio River Valley might end up being competitive in Gulf Region CO_2 EOR markets.

Table 6.2: Delivered CO_2 Cost in Gulf Region from 5 Ohio-Based CBTL-PB-CCS-5.0% Plants

	Distance, miles	CO_2 cost[a], \$/t
Assumed plant-gate CO_2 selling price		20.0
Transport for single plant to hypothetical Ohio trunk line[b]	100	3.8
Transport for 5 plants via Ohio trunk line to planned Denbury trunk line[c]	300	4.6
Transport for 5 plants via Denbury trunk line from Rockport, IN, to Tinsley, MS)[c]	441	6.7
Transport for single plant via distribution line from Tinsley to EOR site[b]	159	6.1
Totals	1000	41.2

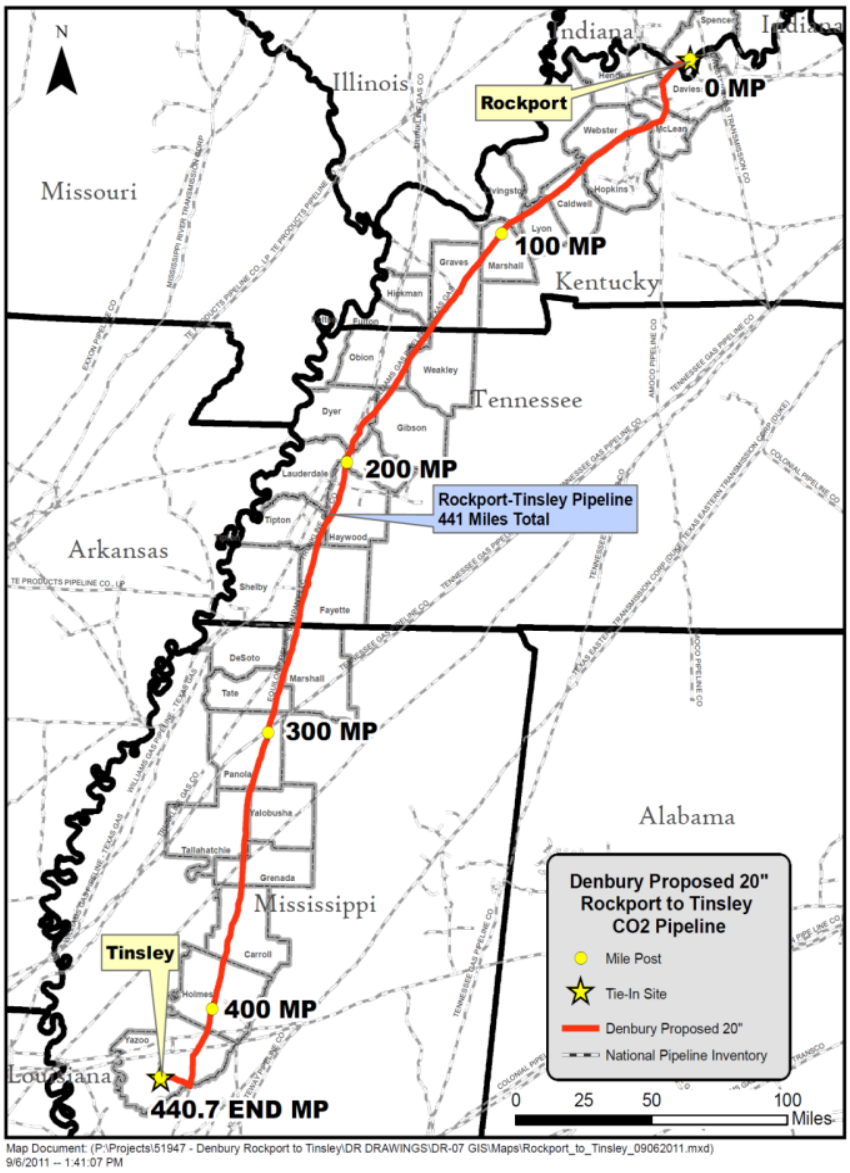
[a] The indicated CO_2 transportation costs (in 2011\$) were carried out by Vello Kuuskraa using a pipeline cost model developed by Advanced Resources International [see, for example, Kuuskraa (2012)] that takes into account pipe and CO_2 recompression costs (for compressors and electricity). The calculations are for: a CO_2 pressure of 2000 psi (138 bar) at the pipeline inlet; a pipeline operating capacity factor of 90%; 100% equity financing with an annual capital recovery factor of 12%; and an electricity purchase price of \$66 per MWh_e. The above CO_2 pipeline costs have not been fully optimized for pipeline diameter and number of pressure booster stations.

[b] Assumed to transport 4.5 million metric tons of CO_2 annually

[c] Assumed to transport 22.7 million metric tons of CO_2 annually

[18] The conversion is for one metric ton of CO_2 occupying 18.9 Mscf.

Figure 6.3: Denbury's Proposed 20-inch, 441-mile Rockport-to-Tinsley CO_2 Pipeline



The proposed pipeline from Rockport in south Indiana to Tinsley, Mississippi, near the Jackson Dome natural CO_2 source and local CO_2 distribution pipelines would facilitate linking anthropogenic CO_2 sources in the Ohio River Valley or other upper Midwest regions to EOR opportunities in the Gulf Region.

6.8 RD&D Needs and Recommendations

Toward FOAK commercial-scale demonstrations for CO_2 EOR-Linked coproduction technologies. In Chapter 3, it was shown that coproduction systems coprocessing small amounts of biomass are the leading candidates discussed there for commercial-scale demonstration projects that are not already going forward in FOAK projects:

- The technologies have a technology readiness index of TRL = 6 to 7, which indicates that they are sufficiently advanced technologically to be demonstrated at commercial-scale.
- The technologies offer prospectively attractive IRRE and LCOE values for NOAK plants deployed in CO_2 EOR applications, even at low CO_2 selling prices (see Figures 3.4 and 3.5).
- The technologies have attractive carbon mitigation features (e.g., GHGI = 0.5 for the $CBTG_{coprod}$-Cap-5-5.0% system given focused attention in Chapters 3 and 6).
- The technologies will not be commercialized without FOAK commercial-scale demonstration, which is the first step in the learning-by-doing process that is essential for any new technology to become commercially robust.
- Success with a FOAK commercial-scale demonstration project could be the first step along a path to future technologies coprocessing larger biomass percentages that offer lower GHGI values under a possible carbon mitigation policy while enabling substantial new roles for coal in providing both cost competitive low carbon fuels and decarbonized electricity under such a policy (see Box 6.2).

The DOE should focus on defining the best process components and the limits of operation for demonstration and early mover projects for CO_2 EOR-linked systems coprocessing coal and biomass to make liquid transportation fuels + electricity. The DOE should also work with industry to identify the best candidate locations for such projects. No attempt is made here to address these important issues definitively but rather the focus is on principles to guide the process – although suggested answers are given that seem to be in accord with these principles. Appendix 6B addresses in some detail two issues associated with planning a FOAK commercial-scale demonstration project:

- Choosing technological components for the demonstration project
- Choosing a site for the demonstration project

Only the key ideas in each of these areas are summarized here.

Choosing technological components for the demonstration project

The most important principle that should guide technology demonstration choice is that *the planning goals should be to maximize prospects for success and to speed the technology on*

to commercial robustness. The demonstration should not be thought of as R&D or a technology development project. This principle might be satisfied by designing a coproduction system made up entirely of components that are either commercial or near-commercial. The analysis in Appendix 6B suggests that an attractive combination of system components might be cogasification of coal and torrefied biomass[19] in a dry-feed entrained-flow gasifier coupled to a system making synthetic gasoline via the methanol to gasoline process. It is further suggested that strong consideration be given to using a mix of poultry litter and woody biomass in a FOAK plant as a strategy to minimize biomass supply logistics challenges.

Choosing a site for the demonstration project

The guiding principle for site selection for a commercial-scale demonstration is should be *to find a site for which total system costs would be as low as possible*. The analysis in Appendix 6B suggests that a Gulf coast site (e.g., Mississippi) would be a strong candidate, because of relatively low construction costs in the Gulf region, near access to CO_2 EOR opportunities, and opportunities for acquiring biomass supplies at lower cost and with less difficulty than for many other regions.

R&D Priorities for advancing coproduction and coal/biomass coprocessing: The DOE should pursue R&D aimed at (a) helping ensure the success of the demonstration and early mover CO_2 EOR-linked coproduction projects that coprocess coal and small amounts of biomass and (b) advancing the technologies that could enable larger biomass percentages to be used in such systems in the longer-term. Specific suggestions along these lines are discussed in Appendix 6C.

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[19] Torrefied biomass is biomass that is "cooked" prior to gasification to destroy the fibrous nature of biomass so that it can easily be milled, like coal is milled.

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Chapter 7: Other Uses for Coal and CO_2

7.1 Key Findings

- Converting coal to SNG is currently economically viable in global markets and may be a technology option for the future use of coal in U.S. markets.
- Beyond EOR, other current and potential alternative applications of CO_2 for industrial, commercial, and biological uses also offer economic advantages.
- The potential storage of CO_2 in coals and gas shales offers promise, with the added benefit of producing incremental hydrocarbons in association with storing CO_2. In addition, CO_2 storage in coal and shale formations can offer a significant capacity storage option in regions of major CO_2 emission sources in cases where finding other suitable geologic sites for CO_2 storage becomes a challenge.
- Specifications for capturing CO_2 in power plants and coproduction plants also need to consider the CO_2 composition and pipeline requirements for enhanced coal bed methane (ECBM) and shale gas recovery applications.
- Several companies are developing processes to use CO_2 to manufacture cement. Cement manufacture is a potentially important pathway to CCUS. The production of cement is on the rise across the globe and CO_2 emissions from such production are projected to increase significantly.
- Algae ponds offer a potential for CO_2 utilization in large quantities to produce biofuels and dry biomass for animal feed. For example, one ton of algae produced in a pond consumes approximately 1.9 tons of CO_2. Locating these ponds near major coal-fired power plants can offer an economic advantage for a viable approach to utilization of captured CO_2.
- Supercritical CO_2 (S-CO_2) power generation cycles have been analyzed by Sandia Laboratories for potential applications for closed cycle, high efficiency, coal-fired, and nuclear power plants to generate electric power in size ranges up to 200 MW_{th}. Such an application could offer an economic advantage for the use of CO_2.
- Given the projected availability of natural gas from shale reserves, converting coal to synthetic natural gas might not be economically competitive.

7.2 Recommendations

- A number of alternative uses for coal and CO_2 have been identified as noted in the Key Findings section above. The DOE should work with key stakeholders in these technology areas to explore further development of these alternatives into commercially viable technologies. Deployment of economical alternatives will be positive steps toward effective management of carbon emissions.

7.3 Background

In 2011, CO_2 emissions from U.S. coal-fired power plants were 1,789 million metric tons, approximately 81% of the total CO_2 emissions from the U.S. power generation fleet[1] (EIA, 2012 Annual Report Summary). The United States will continue to benefit from reliable and affordable electricity from coal. New markets are emerging for the production of liquids and chemicals, and synthetic natural gas. Other current and potential alternative applications of CO_2 for industrial, commercial, and biological uses also offer economic advantages. The following sections describe other uses for coal and CO_2 aside from the focal area of CCUS EOR and liquid fuels production described in earlier chapters.

7.4 Converting Coal to SNG

The Council has dealt extensively (2006, 2008, 2009) with the opportunities and benefits of converting coal to SNG, including an online report, *Turning Coal into Pipeline Quality Natural Gas (http://www.nationalcoalcouncil.org)*. In an earlier report, *Coal: America's Energy Future* (2006), the Council found that 340 million tons of coal/year could be utilized to produce about 4,000 Bcf of SNG at affordable prices. This activity would provide a reliable fuel supply for a wide range of applications including power generation, manufacturing, space heating, and possible export markets. An SNG industry would also create thousands of jobs in the mining and gas production sectors. In short, creating SNG from abundant, domestically produced coal provides a clean, competitive and secure alternative that enhances U.S. energy security and promotes economic growth. Further, SNG with CCUS has significantly lower GHG emissions than liquefied natural gas (LNG) production.

In the current gas markets in the United States, the interest in producing SNG from coal has waned because of the belief that shale gas has permanently institutionalized the expectation of increased natural gas supplies at low prices. But, the unknowns relating to shale gas abound. Regarding supply, long-term questions on environmental impacts, deliverability, cost, and price stability remain unanswered. Paralleling these unknowns, factors increasing the demand for gas further cloud the future – LNG export facilities are being built, the chemical industry is rejuvenating, gas vehicles are entering the market, and gas-based generation capacity is growing. Simply put, the gas market of today is not the gas market of tomorrow and predictions of future supply and price of natural gas have a high level of uncertainty. Longer-term, the probability is that LNG at the global level will be tied to the price of oil, similar to the current situation in Asia where LNG prices have exceeded $17/mmbtu during the first half of 2012. As the United States enters this emerging global market, LNG prices will gain increasing significance in policy decisions relating to cost and energy security.

Meanwhile, promising new SNG technologies have migrated to other countries, particularly China where hundreds of millions of tons of coal are being converted into SNG and related products GreatPoint Energy (GPE), for instance, is planning to construct a $1.25 billion facility near Turpan, Xinjiang province. Utilizing Greatpoint's Bluegas hydromethanation technology, this facility will have a capacity of 30 Bcf/year. As other units are added, production will expand to over 115 Bcf of SNG from coal within two years. Eventually, upon completion of all planned units, the natural gas production complex would manufacture 1 trillion cubic feet (Tcf) of pipeline quality SNG/year from the very large and low cost coal resource base in the western regions of the country. Paralleling the development of the Bluegas plant in Xinjiang, GPE plans to expand to other significant natural gas markets inside and outside of China, including Japan, South Korea, India, and Europe.

These SNG projects are at the cutting edge of emerging technology to meet the world's energy requirements. The EIA has projected that global demand for natural gas will increase 50% by 2035 – i.e., about 55 Tcf, or more than twice the current gas production of North America. The need for SNG from coal will thus be great. As the rising tide of global gas demand waxes over coming decades, the future of SNG from America's vast coal reserves is full of promise for our own economic benefit.

7.5 CO_2 for Enhanced Coal Bed Methane and Shale Gas Recovery

CCUS is an important focus because it provides revenue from the use of CO_2 to offset the costs of storage. In addition to EOR, ECBM and enhanced shale gas recovery are the subject of further research. If successful, these technologies would warrant additional emphasis on the development and consideration for CCUS.

ECBM also can use nitrogen with the CO_2 while still trapping CO_2 in the reservoir. Further developmental work is needed to clarify when to use nitrogen and, if so, how to optimize the mixture of CO_2 and N_2 to enhance production and/or storage for different coals (and possibly shales). Oxy-combustion may be advantageous for ECBM in some settings, since conventional oxygen production plants can produce both oxygen and nitrogen.

Providing the deep, un-mineable coal seams are never disturbed, CO_2 can be stored underground in place within deep coal seams. Estimates of CO_2 storage potential in un-mineable coal areas in the United States and one Canadian province range from 65 billion to 128 billion tons. This estimate may be high due to economic and technical constraints for ECBM methane recovery. Furthermore, coal swelling appears to be the most significant constraint on CO_2 injection into coal seams. Coal swells in volume as it adsorbs CO_2, resulting in decreased porosity and permeability, restricting the flow of CO_2 into the formation, and impeding the displaced methane recovery. This is reduced if nitrogen is used with CO_2.

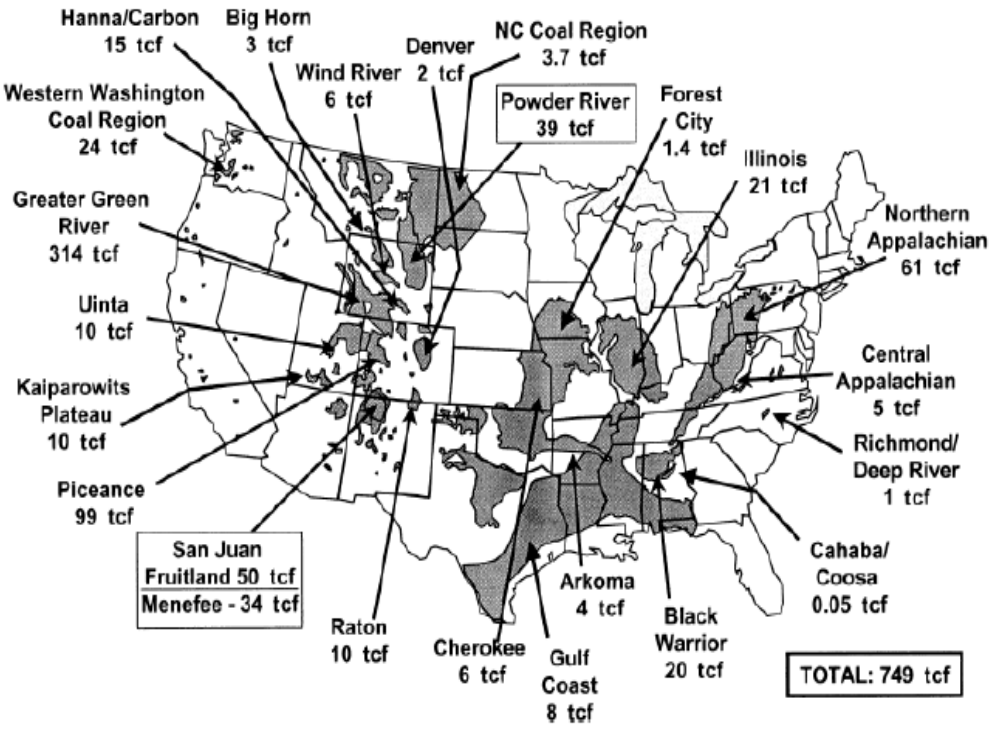
It has been estimated, based on current costs and performance, that CO_2 ECBM may be profitable in the United States at wellhead natural gas prices of U.S. $1.75 to $2.00/Mcf with capture, transport, and sequestration costs in the range of under $50/metric ton CO_2. In addition, the potential for enhanced shale gas recovery through CO_2 injection should be considered for CCUS. Simulation work indicates that shales can store CO_2 based on trapping through adsorption on organic material (similar to coals), as well as with the natural fractures within the shales. However, this has not been demonstrated on a field-scale.

Unconventional production of natural gas has been increasing over the years. It is estimated that unconventional natural gas production represents some 45% of total U.S. natural gas production. Unconventional production techniques for natural gas production offer a major potential. According to the EIA *AEO 2007*, the potential for unconventional natural gas production in the United States is projected to be over 6 Tcf by 2030.

Organic-rich shale formations constitute the most common, low permeability cap rocks that could prevent migration of buoyant CO_2 from underlying storage units, particularly deep saline aquifers. These shales may also form potential storage units for CO_2 based on trapping through adsorption on organic material (similar to coals), as well as with the natural fractures within the shales. The most critical factors in determining shale storage capacity and injectivity of CO_2 appear to be the extent of natural fracturing within the shale formation, volume of gas contained within the natural fracture network, volume and rate that methane can be desorbed and then produced from the shales, volume and rate that the CO_2 can be injected and stored within the fracture matrix, and volume and rate that CO_2 can be adsorbed and permanently stored on the shales.

The Illinois Basin offers a major potential for the production of CBM (Mastalerz, M. Potential for Coal Bed Methane and Enhanced Coal Bed Methane in Indiana. April 5, 2012). This potential is demonstrated in Figure 7.1 along with the total CBM basins in the United States.

Figure 7.1 Existing CBM Basins in the United States

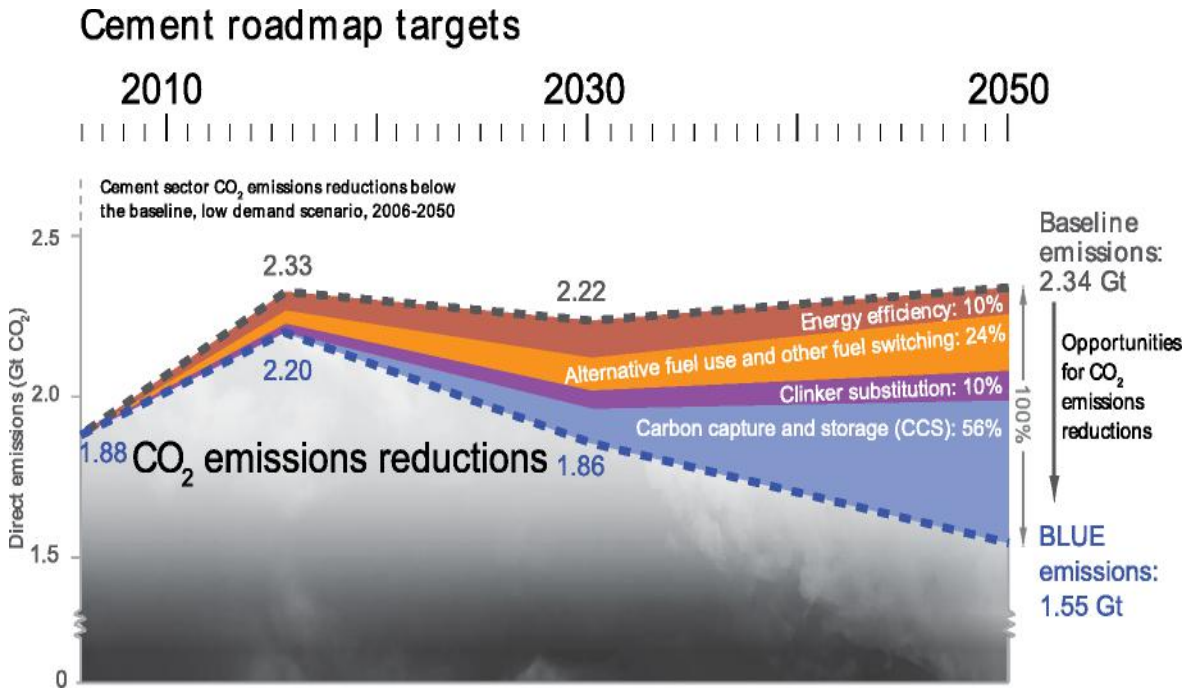


7.6 CO_2 Uses in Construction Materials

7.6.1 Cement and Concrete Production

According to the "Cement Technology Roadmap" published by the IEA, cement production (and consumption) will increase from 2.6 billion tons/year in 2006 to 3.6 billion to 4.4 billion tons/year in 2050. CO_2 emissions from cement production would increase in the base scenario (business as usual) from 1.88 billion tons/year in 2006 to 2.34 billion tons/year in 2050 (see Figure 7.2).

Figure 7.2: The International Energy Agency Cement Targets Roadmap
(IEA, WBCSD, 2009)



One manufacturing process utilizes cement with CO_2, resulting in concrete, without addition of heat, which is required in normal concrete manufacturing processes. During the manufacture of conventional cement a chemical reaction takes place in the material, converting limestone (calcite or $CaCO_3$) to calcium oxide (CaO) and releasing CO_2. This is referred to as calcination. In the Calera process, however, CO_2 is mixed with briny, brackish seawater, oil field wastewater, or other salty waters. This causes minerals in the water to bond with CO_2, and then precipitate as particles of synthetic limestone. The briny water then can be more easily treated to produce potable water.

Conventional cement is most commonly composed of calcium silicates, and requires heating limestone and other ingredients to 2,640 degrees F (1,450 degrees C) by burning fossil fuels. Producing one ton of cement results in the emission of approximately one ton of CO_2, and in some cases much more.

In contrast, another proposed process of cement making would not eliminate all CO_2 emissions, but it would reduce significantly the emissions of CO_2 compared to conventional cement making process. This process essentially mimics marine cement, which is produced by coral when making their shells and reefs, taking the calcium and magnesium in seawater and using it to form carbonates at normal temperatures and pressures. The manufacturer claims to convert the CO_2 into carbonic acid and then into carbonate. All the process needs is water and CO_2. The process is based on using spray dryers that utilize the heat in the flue gas to dry the slurry that results from mixing the water and stack gas. Once dried, the cement can be used as a replacement for the Portland cement that is typically blended with rock and other material to make the concrete used in roads and buildings.

The dissolution of carbonate minerals in the ocean causes CO_2 to be transferred from the atmosphere to the ocean through a process characterized by the net reaction:

(1) $CO_2 + H_2O + CaCO_3 \text{ --> } Ca_2+ + 2HCO_3$

CCS has been reviewed by many people including prominent marine chemists. Equation 1 above represents a well-established net reaction involving dissolution of carbonate minerals in the ocean. It is also well known that the formation of carbonate minerals from seawater, such as in the formation of coral skeletons, drives a flux of CO_2 from the ocean to the atmosphere, essentially driving this reaction in reverse:

(2) $Ca^{2+} + 2HCO_3- \text{ --> } CO_2 + H_2O + CaCO_3$

Precipitating carbonates from seawater tends to lower ocean pH and thus exacerbate the ocean acidification problem. While this process of making calcium carbonate cement would not eliminate all CO_2 emissions, it would reverse that equation. The color of the resulting cement: snow white. Once dried, the cement can be used as a replacement for the Portland cement that is typically blended with rock and other material to make the concrete in everything from roads to buildings. In addition to these activities, Carbon Sciences in Santa Barbara, California, plans to

use flue gas and the water leftover after mining operations, so-called “mine slime,” which is often rich in magnesium and calcium, to create similar cements.

Halifax, Nova Scotia-based Carbon Sense Solutions plans to accelerate the natural process of cement absorbing CO_2 by exposing a fresh batch to flue gas. And a number of companies are working on reducing the energy needs of making Portland cement. The key will be ensuring that such specialty cements have the same properties and the same or lower cost than Portland cement. But, the companies may also find it challenging to get their cements approved by regulators and, more importantly, accepted by the building trade.

At a pilot plant located on the Pacific Ocean at Moss Landing California, third-party certification by the engineering firm R.W. Beck (2010) documented that, with sodium hydroxide, the process has been able to capture up to 90% of CO_2 from the stack gases of a 10 MW-equivalent power plant with a net energy penalty of about 5-10%. This penalty applies only to the absorption process that produces aqueous calcareous material. It is noteworthy that a similar chemical process is hypothesized by others for gaseous storage of CO_2 in saline aquifers where slow mineralization is thought to take place.

7.6.2 Summary and Conclusions

The CO_2 to cement conversion technology offers potentially significant advantages along with major challenges:

- CO_2 capture efficiency; energy efficient electrochemistry process
- Potentially low energy penalty compared to other carbon capture processes
- Competes with available solutions to reduce cement and concrete carbon footprints
- Needs suitable quantity and quality of brines and alkalinity sources; produces more calcareous material and more HCl than current markets can accept
- Requires environmental acceptability of pumping brines from and into geologic formations
- Technical demonstration of concrete mix design and long-term performance

7.7 Uses of CO_2 in Algal Ponds for Photosynthesis

Algae can capture CO_2 to produce large amounts of algal biomass. This biomass contains oils which can be converted into biodiesel. The residue remaining after oil extraction is valuable and its use as feed for poultry, cattle, and fish can make the overall process more economically competitive. Advantages of algae over other crops as energy source include:

- For every ton of biomass produced from algae, 1.9 tons of CO_2 is consumed
- Algae can be raised outdoors in lined or unlined ponds
- Algae are an order of magnitude more productive than terrestrial crops
- Algae can grow in salt, brackish, or waste water
- Algae can be harvested every day instead of once a year as terrestrial crops
- Residual algal bio-solids are claimed to be a source of new food products and drugs
- Low capital cost, easy to scale up to large areas

In the United States, the algal farms locations include: Gila Bend Arizona; HR Algae Farm in Hawaii; Imperial Valley, California; and Spring Grove, Virginia. The algae harvested from these ponds are used to produce biodiesel, and the remaining solids are used for animal feed. Dow Chemical and Algenol Biofuels have a plant in Texas, which uses CO_2 as a byproduct of several different chemical processes. At this plant, algae would be exposed to sunlight, in water mixed with CO_2 and would give off ethanol and oxygen. Dow plans to use ethanol as a feedstock for plastics, replacing natural gas.

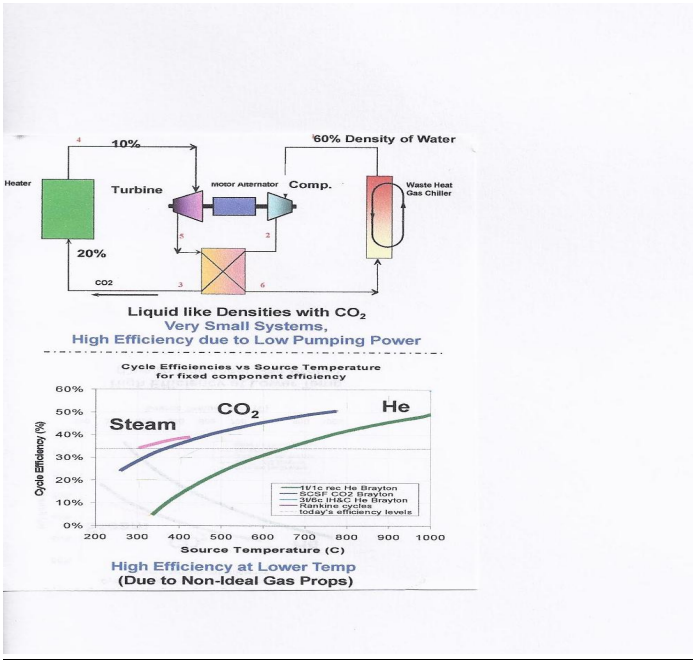
7.8 CO_2 in Chemical and Beverage Industries

CO_2 could offer other applications in the beverage industry for carbonated products, in wine making, for brewing beer, and in pharmaceutical industry. Liquid CO_2 is used as a non-toxic professional dry cleaning alternative. CO_2 dry cleaners use the same process as standard dry cleaning, except liquid CO_2 is used as the solvent, which eliminates the need for toxic cleaning chemicals. The amount of coal based CO_2 that could be utilized is open to some question but additional research is needed in this area. While beneficial to producing commercial products, however, the CO_2 eventually escapes to the atmosphere.

7.9 Supercritical CO_2 Brayton Cycle Application

The DOE NETL prototype development work at Sandia National Laboratories is based on utilizing S-CO_2 as the working fluid in a Brayton Cycle engine. This application identifies yet another potential, but perhaps limited, avenue for the beneficial use of CO_2 to produce electric power on a small-scale. Based on the preliminary development results from Sandia, application of S-CO_2 in a Brayton Cycle offers at least some potential of improved economics and environmental performance in power generation systems. A simplified diagram of the S-CO_2 Brayton Cycle is presented in Figure 7.4 below.

Figure 7.4: S-CO_2 Brayton Cycle Presentation



7.9.1 Key features

According to the Sandia National Laboratory, the key features of an S-CO_2 Brayton Cycle are:

- Peak gas turbine exhaust temperatures are well matched to a variety of heat sources, including natural gas, coal, syngas, and nuclear fuel
- Offers up to 50% efficiency in power plant sizes from 10-300 MWe
- Standard materials such as high nickel alloys and stainless steels can be used

- Offers high power density and modular capability at 10-20 MWe

The DOE has invested five years and up to $11 million on Proof-of-Principle development for S-CO_2 Power Systems. The potential economic and environmental benefits of S-CO_2 Power Systems are significant:

- Useful with all heat sources
- Dry cooling, Oxy-Combustion with CCS, and EOR
- Smaller, simpler, improved efficiency

Development is still needed:

- To date, only small-scale proof-of-concept development loops are operating – heat source and power cycle are linked (cycle/design research)
- Heat exchanger development is needed
- Micro-Channel design costs, transient cycling, packaging, failure modes, cost reductions, nuclear certification
- Commercial engineering and demonstration is needed using Industrial Hardware (~10 MW_e)
- The industry/government/industry partnership role started by Sandia makes sense for further exploration of this development

7.9.2 Potential

The potential benefits of the S-CO_2 power generation systems to improve economics and environmental issues on a large-scale are:

- Dry Cooling
- Oxy-Combustion, with CCS and EOR
- Smaller and simpler (than steam)
- Improved efficiency
- Combined heating, cooling, and power cycles

- Applicable to all types of heat sources

7.10 Summary

The demand for energy is on the rise throughout the world, including the United States. Fossil fuels are estimated to account for the great bulk of that demand growth through 2035 and likely beyond. This fossil fuel utilization will result in increased CO_2 emissions. Beneficially using these emissions is a "win-win-win" (energy, economy, environment) strategy that deserves vigorous pursuit. This report has demonstrated CO_2 emissions can be used in EOR, but additional pathways will be needed as emissions rise in a constantly growing world. Several promising technologies have been briefly discussed here. Other technologies are emerging and will continue to emerge. CCUS will give CO_2 value, stimulating the economy and enhancing energy security, while reducing GHG emissions.

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[iii] The Obama Administration supports CO_2-EOR. To that end, the DOE now refers to CCUS as "Carbon Capture, Utilization and Storage," with "Utilization and Storage" largely understood to mean CO_2-EOR. *See also* "*Report of the President's Interagency Task Force on CCUS*" (2010).

[iv] Many of EPA's actions remain subject to judicial review, including the so-called Tailoring Rule that EPA published on June 3, 2010. *75 Fed. Reg. 31514.* Under that regulation, EPA "tailored" the

applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHG emissions under the Prevention of Significant Deterioration and title V programs of the CAA. Without the Tailoring Rule, PSD and title V requirements would have applied, as of January 2, 2011, to the 100 or 250 tons per year levels provided under the CAA, greatly increasing the number of required permits, imposing undue costs on small sources, overwhelming the resources of permitting authorities, and severely impairing the functioning of the programs. On March 8, 2012, EPA proposed to maintain GHG permitting thresholds at current thresholds. *77 Fed. Reg. 14226.*

[v] SDWA § 1425(a). In contrast, to obtain primacy over well classes other than UIC Class II, state programs must demonstrate to EPA that their regulations provide effective minimum requirements. Id. § 1422.

[vi] "Geologic sequestration" means the "long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations." 40 C.F.R. § 144.3.

[vii] 76 Fed. Reg. 56982 (Sept. 15, 2011).

[viii] 40 C.F.R. § 146.93(b)(1).

[ix] See http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm.

[x] 40 C.F.R. § 144.19(a).

[xi] 40 C.F.R. § 144.19(b).

[xii] The nine factors are: (1) increase in reservoir pressure within the injection zone(s); (2) increase in CO_2 injection rates; (3) decrease in reservoir production rates; (4) distance between the injection zones and USDWs; (5) suitability of the Class II area of review delineation; (6) quality of abandoned well plugs within the area of review; (7) the owner's or operator's plan for recovery of CO_2 at the cessation of injection; (8) the source and properties of the injected CO2; and (9) any additional site-specific factors as determined by the regulator. 40 C.F.R. § 144.19(b).

[xiii] 74 Fed. Reg. 56260 (2009).

[xiv] 74 Fed. Reg. at 56349.

[xv] *Id.* at 56350 (emphasis added).

[xvi] *Id.* at 75060.

[xvii] *PSD and Title V Permitting Guidance for Greenhouse Gases*, at p. 43, EPA-457/B-11-001 (Mar. 2011).

[xviii] "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage," Advanced Resources International (March 10, 2010).

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