THE INTEGRATED CARBON SOLUTIONS INDEX LIBRARY AND TECHNOLOGY MARKET ASSESSMENT REPORT

Key Contributors:

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DOCUMENT PURPOSE

As part of a strategic plan to move the City of San Antonio towards a more sustainable future, CPS Energy commissioned research at the Texas Sustainable Energy Research Institute (the Institute) to explore methods that economically reduce and manage carbon dioxide (CO₂) emissions from coal and natural gas power plants.

Specifically, the Institute was asked to complete a literature review of peer-reviewed journal articles and reports pertaining to carbon mitigation technologies, analyze the various technologies and processes in this market, and create profiles of companies and products available in the market for future reference.

Consequently, this document includes an analysis of the current carbon mitigation technology market and profiles of companies with technologies in the market. It also includes appendices with a list of worldwide carbon capture and sequestration (CCS) projects, instructive cost and efficiency reports, a list of literature reviewed, and some selected article abstracts.

It is not a document that explains “why” CPS Energy should be interested in carbon mitigation, but rather a document that provides some insights into “how” CPS Energy could employ technologies to reduce and manage CO₂ from their coal and natural gas power plants.

As this market is rapidly evolving, the Institute does not expect the report to remain accurate for a protracted period, given the nature of the changing industry landscape and the likelihood for market disruption by companies currently in the development or demonstration phase; however, this report represents a fairly comprehensive analysis of the market at this time.

Potential next steps for CPS Energy and the Institute could be to focus on particular carbon mitigation technologies, assess their applicability to CPS Energy’s generation assets, and quantify their impacts for implementation by CPS Energy.
EXECUTIVE SUMMARY

Introduction
From the Institute’s review of peer-reviewed literature and other related documents, it is apparent that: 1) cost-effective carbon mitigation technologies are still in the research and development stage, 2) the industry is diverse, 3) the industry is evolving rapidly, and 4) San Antonio entities can play a key role in the industry’s development.

Certain CO₂ capture technologies have been commercially available and successfully used for many years, albeit on a much smaller scale, in various industrial applications (examples: natural gas processing, fertilizer production). Some technologies have shown promise in limited demonstration and pilot projects. However, significant research, development, and demonstration efforts are still required before cost-effective solutions that economically reduce and manage CO₂ emissions from coal and natural gas power plants become widely commercially available.

Some analysts question whether carbon capture and storage technologies will ever be cost-effective, and even if the technology’s costs can be reduced, some question whether the increased power, fuel, and water requirements of CCS plants will actually help mitigate the effects of carbon globally.

However, given the prevalence of coal and natural gas in the world’s power generation fleet and future projections of their continued use, the U.S. Department of Energy (DOE) and other government entities, both domestically and internationally, have been investing heavily in carbon mitigation technologies and projects in an attempt to find solutions and lower their costs. These efforts have attracted an impressive list of corporate partners and start-up companies, but have not yet resulted in the breakthroughs to commercially produce widespread, cost-effective solutions.

Major companies such as Air Products, Alstom Power, BASF, Dow, Fluor, Hitachi, Linde Group, Mitsubishi, and Siemens have been actively researching and developing solutions in this industry and could be natural partners for CPS Energy and UTSA on future efforts. There are also many smaller companies with limited focus, such as Skyonic, Calera, Novomer, and MTR, with promising products and processes that could be key drivers of the next generation of carbon mitigation technologies.

Much of the peer-reviewed literature addressed the technical feasibility of specific technologies and/or the technical performance of demonstrated solutions, rather than assessments of the cost-effectiveness of the solutions at scale. Given the lack of large-scale demonstrations, this lack of reliable, peer-reviewed cost data is understandable. Some instructive analyses from DOE and others have been included in the appendices for reference. Additional analysis will be required to determine the financial implications and feasibility of deploying particular carbon mitigation solutions at CPS Energy facilities.

CPS Energy is playing a key role in the continued development of pre-combustion carbon capture technology with its involvement in Summit Power’s Texas Clean Energy Project (TCEP) Integrated...
Gasification Combined Cycle (IGCC) plant and should be commended for its leadership in this area. The data gathered and lessons learned from that plant will provide information on the cutting edge of pre-combustion capture research and could help usher in an era of new clean coal plants. However, since IGCC pre-combustion technologies are not typically suitable for retrofit to existing plants, the industry will continue to search for carbon mitigation technologies that can be applied to the world’s existing fleet of coal and natural gas plants. There are opportunities for CPS Energy and other San Antonio entities to help lead in this area as well.

Specifically, energy producers and utilities like Vattenfall in Europe, SaskPower in Canada, as well as Chinese and Japanese power companies have been working with a variety of carbon capture industry leaders to develop and test advanced chemical solvents, solid sorbents, membranes, and other technologies for post-combustion capture. CPS Energy, with the help of other partners, could play a similar role in testing and advancing post-combustion technologies that would result in increased efficacy, less parasitic energy loss, and/or less water usage.

CPS Energy could also determine if its facilities are suitable for promising oxy-combustion technologies, or if there is a role for the utility to help advance emerging “chemical looping” technologies that act in a similar fashion.

In addition to opportunities to help advance specific carbon capture technologies, San Antonio could also be a leader in process improvements for carbon capture, such as designs for “flexible operation” of plant facilities in which utilities can store quantities of solvents for regeneration at off-peak times, where the parasitic energy loss of carbon capture operation would be less noticeable.

In addition to carbon capture innovation, Texas has also been on the forefront of carbon storage and sequestration research and development, with impressive activities involving storage of CO₂ in the Gulf of Mexico, shale formations, aquifers, and other applicable sites. Given the proximity of San Antonio to the vast Eagle Ford shale and abandoned wells, specific opportunities for storage should be investigated.

In addition to opportunities to help advance specific carbon capture technologies, San Antonio could also be a leader in carbon capture process improvements, such as “flexible operation” of plants, as well as in carbon reutilization in related local industries.

Texas has also helped demonstrate the potential of carbon reutilization techniques by showing the value of carbon reuse in enhanced oil recovery (EOR), cement/aggregate production, fertilizer production, conversion to plastics, conversion to other solids, and carbonation in the beverage industry. It is important to note that CO₂ does not need to be captured in gaseous form, then stored or sequestered, to be successfully and economically mitigated.

One such example is a major demonstration project of Skyonic’s carbon “mineralization” technology, which is active in San Antonio at a Capitol Aggregates facility. Skyonic’s “SkyMine” combines salt water with carbon dioxide to produce crystalline baking soda, hydrogen gas, and chlorine gas. San Antonio could be a leader in successfully reutilizing CO₂ in green building materials, plastics, and other solids.

In all, there appears to be a lot of opportunity in a market that is not yet well-defined. A summary of the mitigation strategies analyzed as well as additional major conclusions follows.
Mitigation Strategies Summary

Throughout the literature reviewed, strategies and methods for reducing CO₂ emissions were interchangeably named and categorized. For the purpose of this report, carbon mitigation strategies and technologies have been grouped and analyzed in the following categories:

- **Carbon Capture**: The process of separating and capturing carbon dioxide at a power plant before it enters the atmosphere.
  - These technologies were further categorized into pre-combustion, post-combustion, and oxy-combustion technologies based on accepted industry nomenclature.
  - Some carbon “mineralization” technologies have been included as capture technologies, even though they do not result in a useable gaseous stream of CO₂.

- **Carbon Storage**: The process of trapping captured CO₂ in a geological formation, aquatic feature, or other appropriate abiotic (non-living) storage site to prevent release into the atmosphere (examples include: salt domes, depleted oil and gas fields, oceans, aquifers).

- **Carbon Sequestration**: The process of trapping captured carbon dioxide in a biotic (living) organism, such as algae, trees, and vegetation.

- **Carbon Reutilization**: The re-use of captured CO₂ as a raw material or critical component of another product or process (examples: enhanced oil recovery for the oil & gas industry, urea for the fertilizer/agricultural industry, carbonation for the beverage industry, carbonate/cement products for the concrete industry).

- **Carbon Management**: The combination of technical solutions with socio-economic factors such as policy, regulatory framework, social structure, cultural values, education levels and economic implications to develop a comprehensive solution for a technical and scientific challenge.

A schematic diagram depicting common carbon mitigation processes is presented below.

![FIGURE ES-1. Representation of Common Carbon Capture and Storage/Sequestration Processes](image)

*SOURCE: Intergovernmental Panel on Climate Change, 2005*
A summary of our technology analyses follows. Detailed analyses can be found in Section 1 and overviews of specific companies can be found in Section 2.

**Technology Overview: Carbon Capture**

Three general categories of carbon capture technologies applicable to coal and natural gas power plants are pre-combustion, post-combustion, and oxy-combustion technologies (DOE/NELT, 2010; David and Thrombeau, 2001). Pre-combustion refers to the separation of CO₂ from a fuel source prior to igniting it, while post-combustion refers to CO₂ separation after the burning of fuel, typically from flue gas. Oxy-combustion refers to burning a fuel source in oxygen (and possibly re-circulated flue gases), rather than in air, making it much easier and economical to recover CO₂.

**Pre-combustion capture is mainly applicable to integrated gasification combined cycle (IGCC) power plants, while post-combustion and oxy-combustion technologies could be applied, or retrofitted, to conventional power plants.**

Captured CO₂ can be transported via pipeline or tanker truck for storage and/or sequestration after compression and dehydration (DOE/NELT, 2010).

A summary of these processes in a coal plant is depicted in the diagram from EPRI below.

CO₂ capture technologies have been commercially available and successfully used for many years, albeit on a much smaller scale, in various industrial applications. Examples include natural gas processing as well as in the fertilizer and beverage industries. However, cost-effective, carbon capture technologies are still not commercially available for large-scale implementation on power plants. Three primary reasons are often cited for the lack of available technologies:

1) They have not been successfully demonstrated at the scale necessary for power plants;
2) The parasitic loads (both steam and power) required to support CO₂ capture significantly decrease power generating capacity and require more fuel input to produce the same power output; and
3) They are not cost-effective (DOE/NELT, 2010).

Demonstration projects under the DOE’s Clean Coal Power Initiative (CCPI) have been successful, but literature reviewed indicated that current electricity markets do not support CCS project costs and risks, even where climate policies and carbon pricing are already enacted (Global CCS Institute, 2011). Heavy
Subsidies and incentives are making particular demonstration projects economical. However, significant research, development, and demonstration efforts are still required before cost-effective solutions that economically reduce and manage CO₂ emissions from power plants become widely available. Based on the Institute’s research and analysis, the technology readiness of the various methods of carbon capture has been summarized below.

**TABLE ES-1. Technology Readiness of Carbon Capture Technologies**

<table>
<thead>
<tr>
<th>Priority</th>
<th>Technology</th>
<th>Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>“Tier 1” Technologies (&quot;Proven&quot; Technologies)</td>
<td>Pre-Combustion: Physical solvents in IGCC plants with water-gas shift systems</td>
<td>Examples: Linde Rectisol, Dow Selexol</td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Amine-based chemical solvents</td>
<td>Examples: Fluor Econamine FG Plus, Hitachi H3, Mitsubishi Heavy Industries KS-1</td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Ammonia-based chemical solvents</td>
<td>Example: Alstom’s Chilled Ammonia Process, Powerspan ECO₂</td>
</tr>
<tr>
<td></td>
<td>Oxy-Combustion</td>
<td>Examples: Air Products, Alstom</td>
</tr>
<tr>
<td></td>
<td>Carbon Mineralization</td>
<td>Examples: Skyonic, Calera</td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Other/advanced amine solvents</td>
<td>Examples: Aker Clean Carbon, Cansolv, Dow/Alstom UCARSOL, Siemens PostCap</td>
</tr>
<tr>
<td></td>
<td>Pre- and Post-Combustion: Solid sorbents</td>
<td>Examples: RTI International’s Dry Carbonate, ADA-ES</td>
</tr>
<tr>
<td></td>
<td>Pre- and Post-Combustion: Membranes</td>
<td>Example: MTR Polaris</td>
</tr>
<tr>
<td></td>
<td>Pre-Combustion: IGCC with pressure swing adsorption systems</td>
<td>Example: Air Products H₂PSA from Sour Syngas Technology</td>
</tr>
<tr>
<td></td>
<td>Chemical Looping</td>
<td>Examples: Alstom Limestone, Ohio State Metal Oxide</td>
</tr>
<tr>
<td>“Tier 2” Technologies (&quot;Promising Unproven&quot; Technologies)</td>
<td>Advanced Oxy-Combustion</td>
<td>Examples: Air Products, Alstom</td>
</tr>
<tr>
<td></td>
<td>Pre- and Post-Combustion: Advanced membranes</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Advanced Chemical Looping</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Metal Organic Frameworks</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Ionic liquids</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Post-Combustion: Enzymes</td>
<td>Example: Codexis</td>
</tr>
<tr>
<td>“Tier 3” Technologies (&quot;Conceptual&quot; Technologies with Significant RD&amp;D Needed)</td>
<td>Post-Combustion: Other biological processes</td>
<td></td>
</tr>
</tbody>
</table>

The Institute presented these tiers in terms of technology readiness, rather than in terms of cost-effectiveness or applicability to specific CPS Energy sites, because information for implementation of a given technology at a specific power plant is highly dependent on the design and unique characteristics of the power plant. Consequently, it is very difficult to provide meaningful cost information (construction, capital, and annual operation and maintenance) or feasibility estimates for any technology without design specifications of individual plants.
Additionally, electric utilities may have different views on the effects of the loss of steam and/or energy output at a power plant as a result of the CCS processes (i.e., it is not just simply increased capital costs), which affects cost-effectiveness. Some representative cost information is presented in the appendices, but specific cost figures for CPS Energy will have to be determined based on the characteristics of individual plants, current energy prices, and the items CPS Energy would like to include in the cost model. Specific examples of deployment and demonstration of carbon capture technologies follow.

Specific Examples: Carbon Capture Technology Deployments

<table>
<thead>
<tr>
<th>Technology</th>
<th>Pre-Combustion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical Solvent: Linde Rectisol</td>
<td>Proposed at Summit Power’s IGCC Texas Clean Energy Project (TCEP)</td>
</tr>
<tr>
<td>Physical Solvent: Selexol</td>
<td>Proposed at SCS Energy’s Hydrogen Energy California (HECA) project</td>
</tr>
<tr>
<td>Physical Solvent:</td>
<td>Demonstrated at Wabash River</td>
</tr>
<tr>
<td>Physical Solvent:</td>
<td>Proposed at Southern Company’s Kemper County IGCC</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Technology</th>
<th>Post-Combustion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amine-based:</td>
<td>Licensed at commercial scale in 26 industrial plants worldwide, including three</td>
</tr>
<tr>
<td>Fluor Econamine FG+</td>
<td>in the United States</td>
</tr>
<tr>
<td></td>
<td>Demonstrated at NRG’s Washington Parish Plant</td>
</tr>
<tr>
<td></td>
<td>Proposed at Tenaska’s Trailblazer Energy Center in TX</td>
</tr>
<tr>
<td>Amine-based:</td>
<td>Deployed at Southern Energy’s Plant Barry Power Station and a plant in Nagasaki,</td>
</tr>
<tr>
<td>Mitsubishi Heavy Industries KS-1</td>
<td>Japan</td>
</tr>
<tr>
<td>Amine-based: CanSolv</td>
<td>Proposed at SaskPower’s Boundary Dam project</td>
</tr>
<tr>
<td>Amine-based: Aker Clean Carbon</td>
<td>Being tested at Technology Centre Mongstad in Norway</td>
</tr>
<tr>
<td>Amine-Based: Hitachi</td>
<td>Will be the first technology tested at the testing facility at SaskPower’s</td>
</tr>
<tr>
<td></td>
<td>Shand Power Station</td>
</tr>
<tr>
<td>Chilled Ammonia Process:</td>
<td>Demonstrated at AEP’s Mountaineer Project</td>
</tr>
<tr>
<td>Alstom</td>
<td>Demonstrated at We Energies Pleasant Prairie Plant</td>
</tr>
<tr>
<td></td>
<td>Being tested at Technology Centre Mongstad in Norway</td>
</tr>
<tr>
<td>Mineralization: Skynomine</td>
<td>Demonstrated at Luminant’s Big Brown Steam Electric Station</td>
</tr>
<tr>
<td></td>
<td>Demonstrated at Capitol Aggregates cement plant in San Antonio</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Technology</th>
<th>Oxy-Combustion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxy-Combustion:</td>
<td>Demonstrated at Vattenfall’s Schwarze Pumpe plant in Germany</td>
</tr>
<tr>
<td>Air Products</td>
<td>Demonstrated at Doosan Babcock’s Clean Combustion Test Facility in Scotland</td>
</tr>
<tr>
<td></td>
<td>Piloted at a boiler simulation facility in Windsor, CT</td>
</tr>
</tbody>
</table>

Additional Summary Analysis: Carbon Capture Technologies

Most pre-combustion carbon capture technologies demonstrated to date have used gasifiers and other systems to produce a CO₂ stream, then employed physical solvents (examples: Linde Rectisol, Selexol) to treat the gas before igniting it. Research and development efforts for pre-combustion technologies include the use of advanced physical solvents and membranes as well as the use of chemical looping and pressure swing adsorption (PSA) systems in IGCC designs to reduce costs and improve efficiency.

CPS Energy is playing a key role in the continued development of pre-combustion capture technologies with its involvement in Summit Power’s Texas Clean Energy Project (TCEP) IGCC plant. The data gathered and lessons learned from that plant will provide information on the cutting edge of pre-combustion capture development. However while IGCC with capture is a technically viable and proven method, it can only be retrofitted to plants in limited circumstances (Gutierrez, 2006), therefore
additional methods of capture that can be applied to the world’s existing coal and natural gas fleets continue to garner significant interest as well.

Research on post-combustion carbon capture is attracting much attention due to the fact that it can be retrofitted on existing coal power plants (Darde et al., 2012). Post-combustion carbon capture technologies successfully demonstrated to treat flue gases include amine-based chemical solvents (examples: Fluor Econamine FG Plus, Mitsubishi Heavy Industries’ KS-1), ammonia-based chemical solvents (examples: Alstom CAP, Powerspan ECO2), and carbon mineralization technologies (examples: Skyonic, Calera).

Existing amine-based systems can be commercially utilized; however, they have a number of major disadvantages, including high parasitic steam loss due to the needs of the solvent regeneration process, sensitivity to other gases/pollutants (e.g., SOx and O2), solvent loss due to vaporization, and higher capital and operating costs than common physical solvents (Nelson, 2008). Current post-combustion amine processes are more expensive, from an electrical utility’s perspective, than current physical solvent pre-combustion options (Southern Energy presentation, 2011).

Research and development for post-combustion technologies include the use of advanced amine solvents, other chemical solvents, solid sorbents, membrane systems, metal organic frameworks, ionic liquids, enzymes, and other biological processes. Research is also being conducted into “flexible” operation of coal fired power plants with post-combustion capture technologies, including the use of solvent storage as a method to increase plant efficiency at times of peak need (Chalmers et al., 2009).

By storing used solvent, rather than immediately subjecting it to the regeneration process, parasitic power losses can be reduced. Plant operators could also choose to selectively bypass the capture technologies at times of peak need, assuming plant design accommodates it, which could be environmentally preferable to running inefficient gas peaking plants or other generation sources (Chalmers et al., 2009).

Research on post-combustion carbon capture is attracting much attention due to the fact that it can be retrofitted on existing coal power plants.

Much attention is also given to oxy-combustion technologies since they could be particularly cost-effective and efficient retrofit technologies.

Much research and development attention is also given to oxy-combustion technologies since they could be particularly cost-effective and efficient retrofit technologies. Oxy-combustion has a lower relative cost on both levelized cost of electricity as well as avoided CO2 costs when compared with other CCS technologies (Global CCS Institute, 2011).

Other benefits of oxy-combustion are that it can utilize a wide variety of coals including lignite, sub-bituminous and bituminous fuels and that retrofitting/repowering requires less complex integration into the existing plant energy balance than post-combustion carbon capture (Vitalis, 2007). Additionally, no new chemicals or waste streams are introduced into the plant process. The bottom ash, fly ash, and flue gas desulfurization waste streams remain unchanged, and there is no major change to the plant water balance. In fact, for low rank fuels, there may be a positive water balance from condensation of water from the flue gas stream (Vitalis, 2007).

At the same time, these technologies are the least mature technologies and have a higher level of uncertainty (Global CCS Institute, 2011). They also have some increased capital costs. To drastically reduce the cost of oxy-combustion, systems and process improvements will need to be developed to
reduce the cost of oxygen production. Current oxy-combustion technologies, such as systems from Air Products, typically use expensive cryogenic oxygen systems to provide the oxygen. New technologies or processes to produce oxygen, such as chemical looping, could reduce costs significantly. A summary of potential R&D paths as a function of both cost reduction benefits and time to commercialization is shown below (Figueroa, 2007).

![Diagram showing potential research and development paths for carbon capture technologies.](https://example.com/diagram)

**FIGURE ES-3. Potential Research and Development Paths for Carbon Capture Technologies**  
*SOURCE: Figueroa, 2007*

Additional details and analysis on the relative advantages and disadvantages of the carbon capture technologies can be found in Section 1 (Technology Analysis). Company profiles can be found in Section 2 (Company Profiles).

**Technology Overview: Carbon Storage and Sequestration**

The terms “storage” and “sequestration” are used synonymously throughout industry literature; however, for the purposes of this document, storage and sequestration have been divided into two distinct groups based on whether the carbon is stored in a biotic location (i.e., a living organism) or an abiotic environment.

> “Carbon storage” will refer to the process of trapping captured carbon dioxide in a geological formation, aquatic feature or other appropriate abiotic storage site to prevent release into the atmosphere (examples: depleted oil and gas fields, salt domes, oceans, aquifers), while “carbon sequestration” will refer to the process of trapping captured carbon dioxide in living organisms, such as algae, trees, and vegetation.

Internationally, there have been demonstrations of carbon storage, reuse, and sequestration in multiple locations, including in geologic formations, aquifers, and oil fields. In Texas there has been a pilot carbon storage project in the Frio Formation, and there have been additional activities in the Permian...
Basin for enhanced oil recovery and for storage in the Tuscaloosa-Woodbine formation (Doughty et al, 2008).

Because of economic, geologic, and geographic conditions, Texas could be a prime location for wide scale implementation of geological CO₂ storage and enhanced oil recovery. With large geological formations such as those in the Permian Basin and the Gulf Coast, paired with myriad abandoned oil wells, Texas is in a better position than other states to exploit geologic CO₂ storage as part of its emissions management portfolio (Gromatzky et al., 2010). CO₂ storage in saline aquifers may also be a viable option in Texas due to the state’s abundant brackish groundwater resources. However, since San Antonio is located about 140 miles from the coast, CPS Energy’s ability to incorporate oceanic storage as part of its carbon management strategies is limited.

Carbon storage in the state has not been utilized to its fullest extent to date due to financial implications, technical limitations, and lack of clear regulatory framework. However, research continues to provide answers to questions posed in those areas (Gromatzky et al., 2010). It should also be noted that transporting CO₂ increases the overall costs, carbon footprint, and energy requirements associated with implementation, so even if storage is technically feasible, the transportation/infrastructure costs could make storage/sequestration uneconomic.

Technology Overview: Carbon Reutilization

Carbon reutilization is the use of waste CO₂ as a raw material or critical component of a new beneficial product or process. In an ideal sustainability scenario, the waste products of one industry serve as raw materials for another.

Several products and processes have the potential to use CO₂ captured from local power plants, including the fertilizer industry and the oil & gas industry. Some companies have also been investigating the use of captured carbon into green building materials, plastics, and other household products. More research will be necessary to demonstrate the viability and safety of products that use captured CO₂ and to ensure they meet federal standards, but they appear to hold much potential. Potential uses for captured CO₂ in other processes are shown in the following figure.
CO₂ reutilization is a technology that would benefit CPS Energy as well as the San Antonio economy.

**Policy Overview: Carbon Management**

Carbon management is the combination of technology and innovation with socio-economic factors such as policy, regulatory frameworks, social aspects, cultural values, knowledge management, capacity building, geography, and economic implications to develop a set of comprehensive solutions that allow for the reduction of carbon emissions while remaining competitive in the marketplace for a technical and scientific challenge.

Clean energy policies, as well as sound economic principles, are needed on a global scale to transition away from fossil fuels (Cleetus, 2011). Policies are currently being executed in the United States at the state level, but a cohesive federal policy has yet to be implemented.

Carbon markets are designed to facilitate the buying and selling of emissions credits. There are two sub-markets of the global carbon market: compliance (regulatory) and voluntary (Bayon, 2003).

**Policy makers have discussed the topic of climate change and reducing global CO₂ emissions for over 20 years, with increasing attention since the 1997 Kyoto Protocol (Pielke, 2009).**

**Two market-based instruments for carbon reduction have been widely considered since 2003: emissions-trading and carbon taxes (Helm, 2003).**
Compliance markets are tied to the Kyoto Protocol, or other regulatory frameworks, using regulation mechanisms such as emissions trading, joint implementation, or clean development mechanisms. Voluntary markets, also referred to as “green power markets,” allow consumers to choose cleaner electricity sources for their own consumption in order to support the development of renewable energy sources (Bird, 2008).

Cap-and-trade programs are different from carbon trading in that there is an overall cap to the amount of emissions allowed. Due to the emissions cap and associated tax, the cost of electricity generation from traditional fossil fuels would increase, thus benefiting renewable and cleaner energy generation alternatives (Bird, 2008). The United Nations Framework Convention on Climate Change has attempted to negotiate commitments to cut greenhouse gas emissions from nations with large outputs; however a debate has ensued over whether a flat tax on carbon emissions or a cap-and-trade policy will be more beneficial (Cleetus, 2011).

Regardless of the carbon management strategy selected, for an energy policy to be effective and be an integral part of our carbon mitigation portfolio, it must “reduce our dependence on fossil fuels, protect the environment, and take meaningful steps to solve global warming while creating jobs and saving money” (Cragg, 2009).

Conclusions: Summary of Major Barriers
As analyzed in this document, there are many methods and technologies that could be employed to reduce and manage CO₂ emissions from coal and natural gas power plants, but there are some major obstacles and challenges that will need to be overcome before they become widely commercially available, especially in Texas. Some of those major barriers include:

- Cost-Effectiveness
- Technology Risk
- Parasitic Power Loss / Energy Penalty
- Water Usage
- Policy/Regulatory Uncertainty
- Identification and Availability of Appropriate Storage/Sequestration/Reutilization Sites

Cost-Effectiveness
As stated in the Tenaska Front-End Engineering Design Study for their Trailblazer Project:

“One of the well-known challenges with CCS is the cost – primarily in terms of the capital cost and energy consumption. Under current market conditions, power plants with CCS cannot compete with those without CCS” (Fluor, 2012).

Increased Capital Costs
Part of these increased costs of carbon mitigation technologies are related to additional capital expenditures for additional requisite equipment. For example, when the proposed Good Spring IGCC was announced to be changed to a NGCC on May 17, 2012, the press release touted a reduction in capital costs of at least 60% (Canada NewsWire, 2012).

DOE/NETL analyses indicate that for a nominal 550-MW net output power plant, the addition of CO₂ capture technology increases the capital cost of a new IGCC facility by $400 million. For post-
combustion and oxy-combustion capture, the increase in capital costs is $900 million and $700 million respectively. For an NGCC plant, the capital cost would increase by $340 million (DOE, 2010).

**Increased Fuel Costs and Decreased Revenues**

A plant with carbon mitigation technologies will operate at a lower efficiency due to parasitic power and steam losses, therefore a greater amount of fuel will be needed to produce the same net output, which will increase fuel use and, therefore, fuel costs. Also, any reductions in potential net output of a plant represent forgone revenues.

**Cost of Energy Challenges**

The increased costs of these plants leads to increased electric prices for generated power, which in the current power markets, may be prohibitive. For example, the reported Levelized Cost of Electricity (LCOE) reported in recent DOE/NETL analyses ranged from $116/MWh to $151/MWh, depending upon the type of facility and whether the application was for a new plant or retrofit of an existing plant. This compared to an LCOE of $85/MWh for a new supercritical pulverized coal plant and a $27/MWh LCOE for the existing fleet of power plants.

A study released in June 2011 by Alstom Power, based on experience from their 13 pilot and demonstration CCS projects and validated by independent experts, concluded that the cost of generating electricity at commercial scale in 2015 will be below 10.6 cents/kWh when burning coal and below 8.1 cents/kWh when burning gas (at today’s euro-USD exchange rates).

A compilation of multiple costs of energy figures compiled in the 2011 Global CCS Status Report can be found in Appendix F.

**Effects of Natural Gas Prices**

Another major challenge for carbon mitigation projects in Texas is the low price of natural gas. Over 50% of ERCOT’s generation capacity is natural gas, and therefore the cost of natural gas sets the marginal price of power. For a utility looking to purchase low-cost baseload power, natural gas plants are currently much more competitive than coal plants with carbon capture (and natural gas plants with the additional cost of carbon capture).

A sensitivity study performed by DOE on natural gas price reveals that the COE for IGCC is equal to that of NGCC at $7.73/MMBtu, and for pulverized coal, the COE is equivalent to NGCC at a gas price of $8.87/MMBtu (DOE NETL, 2008). With natural gas prices predicted to stay under $5/MMBtu levels for at least the next 5 years, per UT’s Bureau of Economic Geology, it will be hard to have a competitive bid from an IGCC or other CCS project.

**Effects of Additional Revenue Streams**

Additional revenue produced by carbon reutilization markets help project economics, but merely offset some costs and contain variability adversely impact economics. As stated in the Tenaska Front-End Engineering Design Study for their Trailblazer Project:

“The strategic location of the Project provides the ability to sell CO₂ into the mature Permian Basin EOR market. This defrays some of the costs of CCS. However, the current CO₂ market prices are insufficient to cover the entire costs of CO₂ capture. In addition, the CO₂ prices vary as a function of oil prices, which introduces uncertainty in this revenue stream over the life of the Project.”
Technology Risk
Carbon capture and storage projects have significant additional costs and risks from scale-up and the first-of-a-kind nature of incorporating capture technology (Global CCS Status Report, 2011). Electricity markets do not currently support these costs and risks, even where climate policies and carbon pricing are already enacted (Global CCS Status Report, 2011).

Parasitic Power Loss / Energy Penalty
Another major challenge for carbon mitigation technologies can be the energy penalty or ‘parasitic load’ involved in applying the technologies (Global CCS Status Report, 2011). Both CO₂ capture technologies and CO₂ compression technologies require auxiliary power to operate and often require steam as well. In the published project documents, Southern Power stated that operating costs for an amine technology were too high, due to elevated steam usage for regeneration; therefore, a physical solvent was selected.

DOE/NETL analyses indicate that for a nominal 550-MW net output power plant, the addition of CO₂ capture technology results in an energy penalty of 20%. For post-combustion and oxy-combustion capture, the energy penalties would be 30% and 25%. For an NGCC plant, the energy penalty would be 15% (DOE, 2010).

Additionally, since the plant is operating at a lower efficiency, a greater amount of fuel is needed to produce the same net output. This increased fuel use increases cost.

Policy/Regulatory Uncertainty
The lack of stable regulatory and policy environments is also a key barrier to the development of this industry. The presence of a price on carbon emissions would directly affect project economics, but the framework for such a financial mechanism is not imminent. Future tax credits and other incentives are also not guaranteed.

We have also observed that obtaining regulatory approval to recoup the additional costs of projects with carbon mitigation technologies has been problematic. Southern Company ran into some issues with the Kemper County IGCC and the Illinois Legislature voted against certain project incentives, for example.

Identification and Availability of Storage/Sequestration/Reutilization Sites
Another challenge will be finding and securing suitable sites to store or sequester captured carbon. Texas has been experimenting with storage and sequestration in shale formations, oceans, and aquifers, but there is not an unlimited supply of storage/sequestration sites. Even when sites can be identified, transport from San Antonio generation assets to those locations could prove problematic, given the lack of CO₂ pipeline infrastructure from Central Texas to the Gulf Coast.

There are also concerns expressed about the duration of sequestration, especially with seismic events. The long-term effects on nearby life forms are also under debate in literature reviewed.
Conclusions: Additional San Antonio Considerations

With the largest municipally-owned, vertically-integrated, electric and natural gas utility in the nation, San Antonio is uniquely positioned to be a leader in the demonstration of carbon mitigation strategies and technologies. Investor-owned utilities may face stronger opposition from their shareholders and local regulators to embark on carbon mitigation projects that could incur additional costs, even if there are increased social benefits. For example, AEP successfully demonstrated Alstom’s chilled ammonia process at their Mountaineer Plant and was preparing to undertake a larger demonstration project, but cancelled the project given regulatory uncertainty. Southern Power’s Kemper IGCC project and the FutureGen project in Illinois both ran into regulatory hurdles that could likely be avoided in San Antonio.

With strong community support of—and commitments to—both competitive electric rates and environmental protection, CPS Energy finds itself in a great position to pursue a diversified generation fleet that includes next generation clean coal technology in favorable state and local regulatory environments. CPS Energy has a Board of Directors made up of local stakeholders (not investors), who have vested interests not just in financial returns, but also in long-term environmental benefits for the surrounding community. As a state, Texas is very supportive of energy development, and clean coal in particular.

As previously mentioned, CPS Energy is playing a key role in the continued development of pre-combustion carbon capture technology with its involvement in Summit Power’s Texas Clean Energy Project IGCC plant and should be commended for its leadership in this area. However, since IGCC pre-combustion technologies are not typically suitable for retrofit to existing plants, the industry will continue to search for technologies that can be applied to the world’s existing fleet of coal and natural gas plants. There are opportunities for CPS Energy and other San Antonio entities to help lead in this area as well.

Energy producers and utilities like Vattenfall in Europe, SaskPower in Canada, as well as Chinese and Japanese power companies have been working with a variety of carbon capture industry leaders to develop and test advanced chemical solvents, solid sorbents, membranes, and other technologies for post-combustion capture. CPS Energy, with the help of UTSA and other partners, could play a similar role in testing and advancing post-combustion technologies that would result in increased efficacy, less parasitic energy loss, and/or less water usage. CPS Energy could also determine if its facilities are suitable for promising oxy-combustion technologies, or if there is a role for the utility to help advance emerging “chemical looping” technologies that act in a similar fashion.

In addition to opportunities to help advance specific carbon capture technologies, San Antonio could also be a leader in process improvements for carbon capture, such as designs for “flexible operation” of plant facilities in which utilities store solvents for regeneration at off-peak times, where the parasitic energy loss of carbon capture operation would be less noticeable.

Given the proximity of San Antonio to the vast Eagle Ford shale and abandoned wells, specific opportunities for storage and sequestration should be investigated.

However, it is important to note that CO₂ does not need to be captured in gaseous form, then stored or sequestered, to be successfully and economically mitigated. Texas has also helped demonstrate the potential of carbon reutilization techniques by showing the value of carbon reuse in enhanced oil recovery (EOR), cement/aggregate production, fertilizer production, conversion to plastics, conversion
to other solids, and carbonation in the beverage industry. One specific example is the major demonstration project of Austin-based Skyonic’s carbon mineralization technology in San Antonio at a Capitol Aggregates facility. San Antonio could be a leader in successfully reutilizing CO₂ to produce end use products, such as green chemicals, green building materials, plastics, and other solids.

Our analysis of carbon mitigation strategies and technologies follows in Section 1. Overviews of specific companies can be found in Section 2 (Company Profiles). Appendices containing a list of literature reviewed, some selected article abstracts, a list of worldwide CCS projects, CCS project descriptions, as well as some instructive cost and efficiency reports have also been included for reference.
SECTION 1:
ANALYSIS OF MITIGATION STRATEGIES
OVERVIEW

Throughout the literature reviewed, strategies for reducing carbon dioxide emissions were interchangeably named and categorized. For the purpose of this report, the carbon mitigation strategies and technologies have been grouped and analyzed in the following categories:

- **Carbon Capture**: The process of separating and capturing carbon dioxide at a power plant before it enters the atmosphere.
  - These technologies were further categorized into pre-combustion, post-combustion, and oxy-combustion technologies based on accepted industry nomenclature.
  - Some carbon “mineralization” technologies have been included as capture technologies, even though they do not result in a useable gaseous stream of CO₂.

- **Carbon Storage**: The process of trapping captured carbon dioxide in a geological formation, aquatic feature, or other appropriate abiotic (non-living) storage site to prevent release into the atmosphere (examples: salt domes, depleted oil and gas fields, oceans, aquifers).

- **Carbon Sequestration**: The process of trapping captured carbon dioxide in a biotic (living) organism, such as algae, trees, and vegetation.

- **Carbon Reutilization**: The re-use of captured CO₂ as a raw material or critical component of another product or process (examples: enhanced oil recovery for the oil & gas industry, urea for the fertilizer industry, carbonation for the beverage industry, concrete industry use).

- **Carbon Management**: The combination of technical solutions with socio-economic factors such as policy, regulatory framework, social structure, cultural values, education levels, and economic implications to develop a comprehensive solution for a technical and scientific challenge.

A schematic diagram depicting common carbon mitigation processes is presented below.
ANALYSIS OF CARBON CAPTURE TECHNOLOGIES

Three general categories of carbon capture technologies applicable to coal and natural gas power plants are pre-combustion, post-combustion, and oxy-combustion technologies (DOE, 2010; David and Thrombeau, 2001). Pre-combustion refers to the separation of CO₂ from a fuel source prior to igniting it, while post-combustion refers to CO₂ separation after the burning of a fuel source, typically from flue gas. Oxy-combustion refers to burning a fuel source in oxygen or a mixture of oxygen and re-circulated flue gases, rather than in air, which eliminates nitrogen content (typically 65-75% of flue gas volume since it is so prevalent in air) thereby making it much easier and economical to recover CO₂. These processes are depicted in the diagram below.

Pre-combustion capture mainly refers to processes at integrated gasification combined cycle (IGCC) power plants, while post-combustion and oxy-combustion technologies could be applied, or retrofitted, to conventional power plants. Captured CO₂ can be transported via pipeline or tanker truck for storage and/or sequestration after compression and dehydration (DOE/NELT, 2010).

There are CO₂ capture technologies commercially available that have been successfully used for many years in various industrial applications. Examples include natural gas processing as well as the fertilizer and beverage industries. In their current state of development these technologies are not commercially available for large-scale implementation on power plants for three primary reasons:

1) They have not been successfully demonstrated at the scale necessary for most power plants;

2) The parasitic loads (steam and power) required to support CO₂ capture processes would significantly decrease power generating capacity and require more fuel input to produce the same power output; and

3) They are generally not cost effective (DOE/NELT, 2010).
**Detailed Analysis of Pre-Combustion Carbon Capture Technology**

Pre-combustion carbon capture refers to the separation of CO$_2$ from a fuel source prior to igniting it. Today, pre-combustion capture is mainly applicable to IGCC power plants, in which a fuel source like coal is converted into gaseous components in a “gasifier” then combusted to produce electricity. An acid gas removal system is used to separate the CO$_2$ prior to combustion using physical solvents, chemical solvents, solid sorbents, or membranes.

One great advantage of an IGCC power plant is that it can utilize different fuel sources such as coal, natural gas or biomass (Rhodes and Keith, 2005). Its greatest disadvantages are cost and the fact that the technology is not suitable for retrofitting applications.

**Additional Process Details**

A schematic representation of the pre-combustion carbon capture process is shown below.

![Block Diagram Illustrating Power Plant with Pre-Combustion CO$_2$ Capture](source: DOE NETL, 2010)

By applying heat under pressure in the presence of controlled amounts of steam and oxygen in a gasifier, a fuel source like coal is converted into a synthesis gas, or "syngas", which can be treated and then combusted to produce electricity. An air separation unit (ASU) is typically used to remove nitrogen from air and produce oxygen for the gasifier.

To capture CO$_2$ and prevent its release into the atmosphere, the syngas is typically "shifted" in a chemical process called a water-gas shift (WGS) reaction. The reaction converts carbon monoxide (CO) into CO$_2$ in the presence of a catalyst and steam and produces additional hydrogen (H$_2$) for combustion. A large amount of steam ensures maximum conversion of carbon monoxide and inhibits side reactions, but it also reduces the overall efficiency of the IGCC plant. An acid gas removal system can then be used to separate the CO$_2$ from the hydrogen.

Such systems could employ physical solvents, chemical solvents, solid sorbents, or membranes. Physical solvents are currently viewed as an efficient approach for processing high-pressure, CO$_2$-rich streams, such as those encountered in IGCC systems that employ an upstream WGS reactor. Both Dow’s Selexol and Linde’s Rectisol are examples of physical solvents being utilized. However, these solvent-based processes have several disadvantages, including loss of pressure during regeneration and requirement of a low operating temperature, which requires cooling of the syngas prior to CO$_2$ absorption, followed by reheating to gas turbine inlet temperature.

After CO$_2$ removal, the hydrogen-rich syngas is used as a fuel in a combustion turbine to generate electricity. The CO$_2$ is compressed and available for storage, sequestration or other transport.
Relative Advantages/Challenges: Pre-Combustion CO₂ Capture Technologies

The following table summarizes major advantages and challenges of pre-combustion carbon capture technologies. As previously mentioned, one great advantage of an IGCC power plant is that it can utilize different fuel sources such as coal, natural gas or biomass. A major disadvantage of pre-combustion technologies is that they are typically not retrofit technologies.

<table>
<thead>
<tr>
<th>CO₂ Capture Technology</th>
<th>Advantages</th>
<th>Challenges</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Combustion: Physical Solvents and Solid Sorbents</td>
<td>CO₂ recovery does not require heat to reverse a chemical reaction</td>
<td>Must cool down syngas for CO₂ capture, then heat it back up and re-humidify for firing to turbine</td>
</tr>
<tr>
<td></td>
<td>Common for same solvent/sorbent to have high hydrogen sulfide (H₂S) solubility, allowing for combined CO₂ /H₂S removal</td>
<td>CO₂ pressure is lost during flash recovery</td>
</tr>
<tr>
<td></td>
<td>System concepts in which CO₂ is recovered with some steam stripping rather than flashed and delivered at a higher pressure may optimize processes for power systems</td>
<td>Some H₂ may be lost with the CO₂</td>
</tr>
<tr>
<td>Pre-Combustion: H₂/CO₂ Membranes</td>
<td>No steam load or chemical attrition</td>
<td>Membrane separation of H₂ and CO₂ is more challenging than the difference in molecular weights implies</td>
</tr>
<tr>
<td></td>
<td>H₂ Permeable Membrane Only: H₂ permeation can drive the carbon monoxide (CO) shift reaction towards completion, potentially achieving the shift at lower cost/higher temperatures</td>
<td>Due to decreasing partial pressure differentials, some H₂ will be lost with the CO₂</td>
</tr>
<tr>
<td></td>
<td>H₂ Permeable Membrane Only: Can deliver CO₂ at high-pressure, greatly reducing compression costs</td>
<td>H₂ Permeable Membrane Only: H₂ compression is often required and offsets the gains of delivering CO₂ at pressure</td>
</tr>
</tbody>
</table>

**SOURCE:** DOE/NETL, 2010

Demonstration Projects

IGCC power plants have been able to capture high proportions of CO₂ at the demonstration level, but there are very few plants running at scale. Four IGCC demonstration projects were included in the DOE’s 1986-1993 Clean Coal Technology Program: (1) the Pinon Pine IGCC Power Project, (2) the Wabash River Coal Gasification Repowering Project, (3) the Tampa Electric Integrated Gasification Combined-Cycle Project, and (4) the Kentucky Pioneer Energy Project.

The Wabash River IGCC (262 MW output) in West Terre Haute, Indiana and the Polk Power Station IGCC (250 MW) in Tampa, Florida have both been operational since the late 1990s. Each started as a demonstration level power plant through the DOE’s Clean Coal Energy Program and was later purchased and operated by a private company. The Wabash River plant uses ConocoPhillips E-Gas gasification technology and a two-stage Selexol physical solvent process. The Polk Power Station demonstrated Texaco’s oxygen-blown, entrained-flow gasifier and an amine-based capture process.
The Pinon Pine plant (107 MW) in Reno, Nevada was completed in 2003 and the Kentucky Pioneer Plant (580 MW) project was completed in 2005, though neither was maintained afterwards (DOE, 2000; DOE, 2006). The largest obstacle for these plants was the reduced power efficiency due to parasitic loads associated with the CO₂ capture process. This loss of power efficiency varied from 8 – 13% of the total energy output (Damen et al., 2005; Chen et al., 2009) and resulted in higher overall capital costs for the projects ($2,175/kW versus around $1,740/kW without carbon capture) (Wagman, 2006).

CPS Energy has committed to participate in the newest DOE-sponsored IGCC plant to be built by Summit Power in Penwell, Texas: the Texas Clean Energy Project (TCEP). The TCEP and additional examples of IGCC plants that employ pre-combustion carbon capture technologies can be found in the appendices.

It is worth noting that Tenaska recently investigated the possibility of building an IGCC plant in Texas at their “Trailblazer” site in Sweetwater, but instead decided to go with a conventional pulverized coal plant with post-combustion CO₂ capture. Tenaska’s official explanation for the choice was that IGCC technology works best with low moisture, high energy content (BTU) coal like the bituminous coals found in the eastern US and therefore Tenaska believed that pulverized coal technology was more appropriate for the high moisture, lower BTU coal from the Powder River Basin (Montana and Wyoming) that will be the fuel for their Texas site. Additionally, they noted that pulverized coal technology is more appropriate for the elevation near Sweetwater, Texas (2,100 – 2,300 feet above sea level) since IGCC technology works best at elevations closer to sea level.

**Additional Cost Analysis**

Recent DOE/NETL analyses indicate that for a nominal 550-MW net output power plant, the addition of CO₂ capture technology increases the capital cost of a new IGCC facility by $400 million and results in an “energy penalty” (i.e., parasitic loss) of 20 percent (NETL, 2010). For a natural gas combined cycle (NGCC) power plant, NETL concludes that the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO₂ capture. The levelized cost of electricity (LCOE) ranged from $116/MWh to $151/MWh in their analyses, depending upon the type of facility and whether the application is for a new plant or a retrofit of an existing plant. This compared to an LCOE of about $85/MWh for a new supercritical pulverized coal plant and a $27/MWh LCOE for the existing fleet of power plants. In terms of costs per metric ton (tonne) of CO₂ avoided, values range from $60/tonne to $114/tonne.

Even with significant incentives, the increased capital costs and parasitic energy losses of IGCC plants can be hard to justify. With natural gas prices hovering at extremely low rates in 2012, the increased costs compared to NGCC plants became even more pronounced. In May 2012, for example, it was announced that the developers of the Good Spring IGCC were changing the design to a NGCC plant and the press release touted a reduction in capital costs of at least 60% (Digital Journal, 2012).

Major corporations within the power industry continue to invest in research targeting improvements in the IGCC process as well as reduction of costs (Zheng et al., 2005). DOE/NETL and others are currently funding the development of several advanced pre-combustion CO₂ capture technologies that have the potential to provide significant improvements in both cost and performance as compared to the physical solvents Selexol and Rectisol that are mainly used today.
Detailed Analysis of Post-Combustion Carbon Capture Technology

Post-combustion refers to CO₂ separation after the burning of a fuel source, typically from flue gas. It is primarily applicable to conventional coal-fired, oil-fired or gas-fired power plants. Due to the large number of coal and gas-fired power plants and the importance of finding technologies that can be retrofitted onto them, many research efforts have concentrated on capturing CO₂ after combustion.

Technology for the removal of carbon dioxide from flue gas streams has been around for quite some time and has been in commercial operation in other industries for many years, albeit on a smaller scale. The technology was developed not to address the greenhouse gas effect but to provide an economic source of CO₂ for use in enhanced oil recovery (EOR) as well as industrial purposes, such as in the beverage industry (Johnson et al., 2009). Common methods for post-combustion carbon capture processes include the use of amine-based solutions, chilled ammonia processes, and other carbonates. Emerging methods include the use of membranes, metal organic frameworks (MOFs), solid sorbents, and biological processes.

Post-combustion capture of CO₂ can be difficult for many reasons, including the relatively low concentration of CO₂ in traditional flue gases, presence of other components in flue gases, high temperatures, and relatively high cost of implementation. These issues constitute barriers to commercial deployment of carbon capture technologies (Gibbins et al., 2008). Reducing the energy requirements for solvent regeneration is also one of the main challenges in post-combustion CO₂ capture from power plant flue gases.

Additional Process Details
A schematic representation of the post-combustion carbon capture process is shown below.

![Diagram](Image)

Post-combustion capture essentially involves adding a scrubber to extract CO₂ from exhaust gas (Alstom, 2012). The CO₂ capture process would be located downstream of the conventional pollutant controls for nitrogen oxides (NOx), particulate matter (PM), and sulfur dioxide (SO₂) (NETL, 2010). Traditionally, the preferred method of post-combustion carbon capture has been an amine-based solvent to trap CO₂. The CO₂ would be captured by “washing” the flue gas with the solvent, resulting in only nitrogen (N₂) and water vapor being released into the atmosphere (Alstom, 2012). The mixture of CO₂ and solvent would then be heated in a separate tank to regenerate the solvent and produce a stream of CO₂. The captured CO₂ would then be compressed and available for storage, sequestration, and reutilization.
The biggest challenge in this process is bringing the flue gas in contact with the solvent (Wall, 2007). The use of mono-ethanol amine (MEA) and methyldiethanolamine (MDEA) as carbon-capturing solvents has reached industrial scale (Idem et al., 2006), but analysis of cost/benefit efficiencies reveals the increased cost related to carbon capture is only manageable if power plants are operated at the highest possible efficiencies, i.e., >95% (Rao et al., 2005).

Research efforts and studies have focused on using different types of solvents and modifying the conditions under which capture takes place. Kim et al. (2010) found that MEA is superior to other traditional solvents such as methanol for carbon capture, while a study by Lee et al. (2009) concluded 2-amino-2 methyl-1-propanol (AMP) works better than MDEA. Merel’s group (2008) used different types of zeolites, with varying pore sizes as CO₂ adsorbent material and found CO₂ capture efficiency to be pore-size specific. Yang et al. (2008) summarized the different materials that can be used as adsorbents, but found it difficult to perform an objective evaluation of their performance since material performance was highly dependent on testing conditions. The research on post-combustion carbon capture emphasizes the relative inefficiency of the overall process and highlights the gaps to be filled for widespread use of these technologies. Chalmers et al. (2009) also attempted to analyze the efficiency of a power plant run with flexible operation parameters and found that fixed-point operation is the least likely to provide high efficiency when paired with carbon capture. There is strong support for the use of amine solvents and other materials for CO₂ capture. Efforts are required to improve efficiencies and reduce costs to achieve desired levels of implementation.

D’Alessandro et al. (2010) reviewed the various means for capturing CO₂ and highlighted those that had more promise in the energy sector. One of the more promising techniques is the use of a solid, such as calcium (Ca), sodium (Na), or potassium (K), to capture CO₂ gas. Various research teams have conducted experiments using such materials under varying conditions. Each of these materials has shown the ability to capture up to 90% of CO₂ from flue gas (Liang et al., 2003; Salvador et al., 2003; Oexmann et al., 2008; Lu et al., 2006). There are still questions to be answered, but demonstration projects have been set up to further evaluate the applicability of the technology. In a few cases, industrial scale carbon capture in a solid form has been achieved (St. Angelo et al., 2008).

Another promising technology is the use of membranes that selectively separate CO₂ from the flue gas (Merkel et al., 2010). A similar technology has been used in the water industry for some time to remove dissolved oxygen and other gases from waters being injected into aquifers for augmenting water supplies or as part of aquifer storage and recovery operations. Through a mixture of membrane types, membrane selectivity and solvent type, carbon dioxide can be captured and used in other areas such as the horticulture industry, where increased CO₂ concentrations contribute to better growth rates and productivity (Feron and Jansen, 1995).

Similar to the membrane method, metal organic frameworks actively trap CO₂ molecules by separating their particular size and shape from flue gas (Simmons et al., 2011; Li et al., 2011). Each of these technologies presents their own opportunities and challenges.

Post-combustion carbon capture is not a new technique nor is it a refined one. There is some concern that the emphasis on post-combustion CO₂ capture (currently unregulated) could lead to a decline in sulfur oxides and nitrogen oxides capture. A study by Tzimas et al. (2007) predicted that the decrease in capture efficiency could range from 5% to 24% for nitrogen oxides and 1% to 3% for sulfur oxides. Reduced SOx and NOx removal from flue gases could have significant impacts on a region’s ability to comply with air quality regulations, if not properly monitored.
**Relative Advantages/Challenges: Post-Combustion CO\textsubscript{2} Capture Technologies**

The following table summarizes major advantages and challenges of post-combustion carbon capture technologies. As previously mentioned, a major advantage of post-combustion technologies is that they are suitable for retrofitting applications.

<table>
<thead>
<tr>
<th>TABLE 1-2. Advantages and Challenges of Post-Combustion Capture Technologies</th>
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<tbody>
<tr>
<td><strong>CO\textsubscript{2} Capture Technology</strong></td>
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<tr>
<td>Solvents</td>
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<tr>
<td>Solid Sorbents</td>
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<td>Membranes</td>
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*SOURCE: DOE/NETL, 2010*

**Detailed Analysis of Oxy-Combustion Carbon Capture Technology**

Another method for capturing CO\textsubscript{2} is through oxyfuel combustion, also called oxy-combustion. Oxy-combustion refers to burning a fuel source in a mixture of oxygen and re-circulated flue gases, rather than in air (about 21% oxygen), which eliminates nitrogen content (typically 65-75% of flue gas volume since it is so prevalent in air, about 79%) thereby making it much easier and economical to recover CO\textsubscript{2}.

**Additional Process Details**

Typical coal and natural gas fired power plants use air as part of the combustion process. Air contains roughly 21% oxygen. Oxyfuel combustion burns fuel sources in an environment that is roughly 95% oxygen. Increased oxygen content reduces emissions that escape in the flue gas, making carbon capture easier and more efficient (Hadjpaschalis et al., 2009).
A schematic representation of the oxy-combustion process is shown below.

![Diagram](image)

**FIGURE 1-5. Block Diagram Illustrating Power Plant with Oxy-Combustion CO₂ Capture**  
*SOURCE: DOE NETL, 2010*

Retrofitting coal power plants for oxy-combustion has been accomplished in the past; however, researchers have identified various obstacles for wide scale implementation of this technology (Farley, 2006). One of the most critical challenges is the resultant higher boiler temperatures within the system. Materials of construction utilized in boilers used in today’s power plants are not capable of handling these higher temperatures, and retrofitting boilers for oxyfuel combustion tends to shorten their life span. More appropriate construction materials are required, which translates into higher capital costs. Additionally, high flame temperatures cause ashes to melt, thus enhancing the formation of nitrogen oxides (Jourdal et al., 2004). The high capital cost of current air separation units is also a disadvantage.

The future of oxy-combustion technology is promising, but will require technological improvements. Kakaras et al. (2007) developed an exclusive boiler design for oxyfuel combustion. The upgraded boiler was able to capture 90% of the CO₂ produced but resulted in higher boiler costs ($78/kWh) suggesting room for improvement.

Much like the IGCC power plants, oxyfuel combustion could utilize a wide range of fuel sources. Previous studies have looked at the impact of oxyfuel combustion with coal alone (Kakaras et al., 2007) and methane combined with various capture methods (Kutne et al., 2011; Tan et al., 2008). Although large-scale oxyfuel studies are limited, an optimization software platform, Independent Power Producer, has been used to conduct cost-benefit analyses and the results are promising (Hadjipaschalis, 2009). This technology may become part of a management strategy upon development and refinement of the process and reduction in costs.
Relative Advantages/Challenges: Oxy-Combustion Capture Technologies

The following table summarizes major advantages and challenges of oxy-combustion carbon capture technologies (DOE/NELT, 2010).

<table>
<thead>
<tr>
<th>CO₂ Capture Technology</th>
<th>Advantages</th>
<th>Challenges</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxy-Combustion</td>
<td>Combustion products are CO₂ and water</td>
<td>Cryogenic air separation units to produce O₂ are expensive and energy intensive</td>
</tr>
<tr>
<td></td>
<td>Relatively pure CO₂ is easily separated, making sequestration less expensive</td>
<td>Higher temperatures can degrade boiler materials or require new materials in new construction</td>
</tr>
<tr>
<td></td>
<td>Boiler and process air leakage</td>
<td>Additional contaminants from flue gas could enter sequestration stream</td>
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As previously mentioned, other benefits of oxy-combustion are that it can utilize a wide variety of coals including lignite, sub-bituminous, and bituminous fuels and that retrofitting/repowering requires less complex integration into the existing plant energy balance than post-combustion CO₂ capture. Additionally, no new chemicals or waste streams are introduced into the power plant process. The bottom ash, fly ash, and flue gas desulfurization waste streams remain unchanged, and there is no major change to the plant water balance. In fact, for low rank fuels, there may be a positive water balance from condensation of water from the flue gas stream (Vitalis, 2007).

Research and Development Trends for Carbon Capture Technologies

Research and development efforts for pre-combustion technologies include the use of advanced physical solvents and membranes as well as the use of “chemical looping” and pressure swing adsorption (PSA) systems in IGCC designs to reduce costs and improve efficiency. However while IGCC with capture is a technically viable and proven method, it can only be retrofitted to plants in limited circumstances (Gutierrez, 2006) therefore additional methods of capture that can be applied to the world’s existing coal and natural gas fleets continue to garner significant interest as well.

Research and development for post-combustion technologies include the use of advanced amine solvents, chemical solvents, membrane systems, solid sorbents, metal organic frameworks, ionic liquids, enzymes, and other biological processes. Research is also being conducted into “flexible” operation of coal fired power plants with post-combustion capture technologies, including the use of solvent storage as a method to increase plant efficiency at times of peak demand (Chalmers et al., 2009). Parasitic power losses can be reduced by storing used solvent, rather than immediately subjecting it to the regeneration process. Plant operators could also choose to selectively bypass the capture technologies at times of highest energy demand, assuming plant design accommodates it, which could be environmentally preferable to running inefficient gas peaking plants or other generation sources (Chalmers et al., 2009).

Much research and development attention is being given to oxy-combustion technologies since they could be particularly cost-effective and efficient retrofit technologies. Oxy-combustion has a lower relative cost on both levelized cost of electricity as well as avoided CO₂ costs when compared with other CCS technologies (Global Status CCS, 2011). To drastically reduce the cost of oxy-combustion, the cost of oxygen production can be reduced through systems and process improvements. Current oxy-
combustion technologies, such as systems from Air Products, typically use expensive cryogenic oxygen systems to provide the oxygen.

The use of “chemical looping” to reduce the cost of oxygen production is also particularly promising.

A summary of potential R&D paths as a function of both cost reduction benefits and time to commercialization is shown below (Figueroa, 2007).

![Diagram showing potential research and development paths for carbon capture technologies.](source: Figueroa, 2007)
ANALYSIS OF CARBON STORAGE TECHNOLOGIES

The term storage has also been used as a synonym for sequestration (Lal, 2008 and 2009; Anderson and Newell, 2003); however, for the purposes of this document, storage and sequestration have been divided into two distinct groups based on whether the carbon is stored in a biotic location (i.e., a living organism) or an abiotic environment.

In the context of this paper, “carbon storage” refers to the process of trapping captured carbon dioxide in a geological formation, aquatic feature or other appropriate abiotic storage site to prevent release into the atmosphere. Examples of carbon storage include depleted oil and gas fields, salt domes, oceans, and aquifers. “Carbon sequestration” refers to the process of trapping captured carbon dioxide in a biotic organism, such as algae, trees, and other vegetation.

Carbon Storage: Geological

The most commonly utilized type of carbon storage is geological storage. In geological storage, CO₂ is pumped into large underground formations. Studies looking into the possibility of geological storage of CO₂ in the state of Texas have found the state has large areas that might serve as long-term CO₂ sinks, especially along the Gulf Coast (Hovorka et al., 2003; Doughty et al, 2008).

Unresolved questions related to carbon storage technologies include dissolution and precipitation kinetics under varying operational conditions (pH, pressure, temperature). The impact of operational conditions as well as geological variables on stored CO₂ is not well understood, nor is the effect of stored CO₂ on groundwater and wells (Friedmann, 2007). Carbon is stored thousands of feet below these water sources, but understanding every aspect of this technique will reduce the risks of contamination.

To better understand the activity of carbon that is geologically stored, investigators have tested the dispersal of supercritical CO₂ plumes in different strata (Hesse et al, 2010) and have attempted to model the fate and transport reactions of the gases over geological time through computer simulation environments. Xu et al. (2006) were able to model CO₂ injection in bedded sandstone-shale with no negative consequences. Neufeld et al. (2009) and Celia et al. (2009) attempted similar models in different geological formations, but were unable to account for all of the environmental factors that are likely to affect dispersion rates.

Enhanced oil recovery (EOR) is a type of geological storage that has emerged as a viable option for CO₂ mitigation based on the availability of abandoned oil wells (Alvarado et al., 2010; NETL, 2009; Williams, 1996). During enhanced oil recovery, critical state CO₂ is pumped into an abandoned oil or gas well where the increased pressure and heat drive large amounts of oil and natural gas away from the pumping site, which can then be recovered at another location. Critical state CO₂ refers to the point, in terms of pressure, where there is no clear distinction between liquid and gas phases. In other words, CO₂ is pressurized to the point where it forms a light fog. Enhanced oil recovery using critical state CO₂ allows for increased extraction of gas and hydrocarbons, even from wells considered depleted. EOR is often favored among the storage types due to its relative simplicity, ability to utilize existing wells, and its ability to produce marketable products that can offset the cost of the entire process (Han et al., 2007). Transportation and implementation costs associated with enhanced oil recovery vary widely depending on local conditions and its applicability should be evaluated on a case-by-case basis (Dooley et al., 2010).
The DOE regulates the process of enhanced oil recovery to minimize air, water, and soil pollution through permitting and inspections of injection sites (Madden et al., 1991). This compliance process does increase the overall cost of EOR, but no more than other environmental compliance procedures.

Because of economic, geologic, and geographic conditions, Texas is a prime location for wide scale implementation of enhanced oil recovery and geological CO₂ storage. With large geological formations such as those in the Permian Basin and the Gulf Coast, paired with myriad abandoned oil wells, Texas is in a better position than other states to exploit CO₂ storage as part of its emissions management portfolio (Gromatzky et al., 2010). The DOE’s National Energy Technology Laboratory (NETL) has estimated the state of Texas has a sink capacity of 661 million to 2.4 billion tons of CO₂. Carbon storage in the state has not been utilized to its fullest extent to date due to financial implications, technical limitations, and lack of clear regulatory framework. However, research continues to provide answers to questions posed in those areas (Gromatzky et al., 2010).

**Carbon Storage: Aquifer**

The second type of CO₂ storage is the use of a saline aquifer for long-term trapping. During this process, critical CO₂ is pumped 1,650 feet to 10,000 feet (500 to 3,000 meters) below the Earth’s surface into an aquifer that is considered too salty for human consumption (>10,000 mg/L). Once in place, the CO₂ will theoretically undergo a mineralization process and become trapped long term (Zerai et al., 2011). Eccles et al. (2009) performed a study to determine the optimum depth and pressure for saline aquifer storage and determined it worked best at 5,250 feet (1,600 m) plus or minus 45 to 66% below the surface under a pressure of 2,880 to 5,000 pounds of CO₂ per square foot (1.36 to 2.36 Atm).

While this information would likely vary for the state of Texas, the ability to test these parameters and run other simulations (Basburg et al., 2009) shows the technology is on track to become commercially available. Texas does have deep saline aquifers that would suit this type of storage. There are some drawbacks associated with the disposal of CO₂ into underground saline aquifers. The first issue is that the dispersion of CO₂ within the aquifer is not well understood. Studies have tried to predict how the carbon will move but the diversity in geological features, varying salinities and heterogeneous temperatures make it difficult to model on a large scale. Each of the studies that attempted to model CO₂ dispersion in a saline aquifer was unable to account for these factors in their computer modeling due to the increased complexity resulting from trying to incorporate the variables (Ghesmat et al., 2011; Xu, 2006; Juanes, et al., 2010).

This uncertainty leads to a series of questions regarding the long-term safety of this practice under conditions that cannot be controlled. There are potential risks for blowback of pumped CO₂ (Bruant et al., 2002) as well as concerns over the possible contamination of groundwater resources. A study by Lemieux (2010) predicted CO₂ could have long lasting effects on the local environment. In addition to possible leaks from CO₂ seeping between geological layers and making its way back to the surface, the decreased pH caused from CO₂ injection could promote mobilization of lead, arsenic, and other elements/compounds into current and future sources of drinking water. As was the case with geological storage, long-term studies are lacking but their availability would greatly improve understanding of this issue and the technology’s viability as a long-term CO₂ solution.

In Texas, CO₂ storage in saline aquifers may be a viable option due to the state’s abundant brackish groundwater resources. The Texas Water Development Board (TWDB) estimated the State of Texas has greater than 2.7 billion acre-feet (equivalent to 880 trillion gallons) of brackish groundwater suitable for CO₂ storage (shown in the following figure). Suitable aquifers are geographically dispersed throughout...
the state. In particular, the Gulf Coast, Ogallala, Seymour, and Carrizo aquifers each have large pockets of brackish water that are considered too saline for human consumption (TWDB, 2003). Other aquifers, such as the Edwards and Trinity aquifers have greater portions of clean, potable water, but still have some layers that may be suitable for CO₂ storage.

![Map of Texas showing water quality](image)

**FIGURE 1-7. Distribution of brackish groundwater resources in Texas**


**Carbon Storage: Oceanic**

Another type of carbon storage is oceanic storage. Storage of CO₂ in the ocean is a practice that has been utilized for some time, though retention rates and long-term effects are still poorly understood (Adams et al., 2008). Oceanic carbon storage is performed in two major ways: dissolution and lake deposition. The former method, dissolution, is used to directly pump carbon below the ocean surface to the greatest depth possible in its critical state. As the CO₂ bubbles upward, it dissolves into the water. The primary means through which this is accomplished is using pipelines that are constructed for the deposition. These pipelines already exist in some areas but their availability and durability will likely play a role in utilizing this particular method. Pumping the CO₂ off moving ships can create the same result, though this practice has its own drawbacks. Ships traveling far enough from the shore to find the required depths may be required to burn large amounts of fuel, negating the positive effects associated with CO₂ storage (Ozaki et al., 2001).

The second method of oceanic storage, lake deposition, uses the unique pressures of the deep ocean to store carbon dioxide. During this process, CO₂ can be pumped into the abyssal zone of the ocean to create a “lake” of liquid CO₂. If the critical state CO₂ is pumped 9,800 feet (about 3,000 m) below the surface or more, the pressure is great enough (>72.9 Atm) that the pumped CO₂ will remain in a semi-liquid form. Semi-liquid CO₂ is denser than seawater and as a result, will then sink to the ocean floor.
This “lake” will eventually be dissolved into the water or trapped in the oceanic sediment (Goldberg et al., 2008; House et al., 2005). Previous research has generated positive reports on this process, but little is known about the wide scale and long-term impacts of oceanic carbon storage (Harvey, 2003).

A major concern for oceanic carbon storage is the effect the concentrated CO₂ will have on water quality and overall chemistry. Changes in these parameters have the potential to affect organisms in a variety of ways or disrupt important metabolic processes. These, in turn, can result in consequences for entire oceanic ecosystems. In particular, the generation of carbonic acid (H₂CO₃) during the normal assimilation of CO₂ into the ocean environment may create changes in pH that can be detrimental to oceanic life (Kita et al., 2003). CO₂ that mixes with saltwater will form carbonic acid in a “plume.”

Within the plume, increased levels of CO₂ have been shown to cause lower pH levels which, in turn, have decrease the survivability and growth of marine organisms such as shrimp (Bechman et al., 2011) and phytoplankton (Orr, et al., 2005). In addition to direct effects on survivability, an increased acidification of the ocean might result in the decreased ability of calcifying organisms such as corals, calcifying algae, and mollusks to utilize calcite and aragonite in their shells (Kroeker et al., 2010). Oceanic storage of CO₂ is a technology that is still immature and will require more understanding of the long-term implications should it be included in a carbon management portfolio.

Access to the ocean is a key factor for evaluating the applicability of these technologies. Since San Antonio is located about 140 miles from the coast, CPS Energy’s ability to incorporate oceanic storage as part of its carbon management strategies is limited, since CO₂ generated at the power plants will have to be transported to the coast for injection and disposal. Transporting CO₂ increases the overall costs, carbon footprint, and energy requirements associated with implementation of oceanic storage.
ANALYSIS OF CARBON SEQUESTRATION TECHNOLOGIES

In carbon sequestration, captured CO₂ is stored in various biotic (living) media such as microalgae, soil, trees, and other photosynthetic organisms and vegetation.

Because CO₂ is a major reactant in photosynthesis, excess carbon dioxide released to the atmosphere can be utilized to promote plant growth under controlled environments. Greenhouse enrichment is a process by which the concentration of CO₂ is increased artificially with captured CO₂. As early as the 1960s, Wittwer et al. (1964) demonstrated the increased productivity of plants grown in CO₂-rich atmospheres. Greenhouses maintained at 1,000 mg/L (ppm) of CO₂ showed an increased productivity of over 50%.

Subsequent studies and projects attempted to design novel CO₂ delivery methodologies, such as underground pipes or pores (Erickson, 2001). It should be noted that the CO₂ reutilization rate for greenhouses is reliant upon the source of carbon. CO₂ from fuel combustion produces heat that can be used to maintain optimal greenhouse temperatures but may also include impurities that can have detrimental impacts on plants if not removed correctly. The Ontario Ministry of Agriculture, Food, and Rural Affairs maintains demonstration scale greenhouses to test the viability of long-term greenhouse production using CO₂ supplementation (Blom et al., 2012).

A modified version of greenhouse enrichment has also been demonstrated using bioreactors that culture algae. By introducing a pure stream of carbon dioxide, bioreactors can increase the productivity of algae populations and increase the nutritional value as a feed for livestock (Zeiler et al., 1995; Chae et al., 2006; Rosa et al., 2011). The algae cultures may also be utilized to produce other fuel sources, such as methane. Studies have indicated that certain species may release methane as a byproduct when in the presence of carbon dioxide and oxidizable molecules (Barker, 1940). This process also produces water molecules, which may aid in the reduction of water consumed in order to generate the carbon dioxide, though only if this method is utilized in a large-scale application.
ANALYSIS OF CARBON REUTILIZATION

Carbon reutilization is the use of waste CO₂ as a raw material or critical component of a new beneficial product or process. In an ideal sustainability scenario, the waste products of one industry would serve as raw materials for another.

Several products and processes have the potential to use CO₂ captured from local power plants, including the fertilizer industry (urea), the oil & gas industry (EOR), and the beverage industry (carbonation). Some companies have also been investigating the use of captured carbon into green building materials, plastics, and other household products. More research will be necessary to demonstrate the viability and safety of products that use captured CO₂ and to ensure they meet federal standards, but they appear to hold much potential.

Potential uses for captured CO₂ in other processes are shown in the following figure.

![FIGURE 1-8. Schematic Illustrating the Many Uses of CO₂. SOURCE: DOE NETL, 2012](image)

CO₂ reutilization is a technology that would benefit CPS Energy as well as the San Antonio economy. Several products and processes have the potential to use CO₂ captured from local power plants, including the local concrete/aggregates industry, oil & gas industry (EOR), fertilizer industry, and construction companies. Reutilization will play a large role in the move towards sustainability for the city and the state in conjunction with some of the other technologies discussed. Additional analysis follows.
Conversion to Solids

One of the newer methods for CO₂ mitigation that has gained attention in recent years is the conversion of carbon gas into marketable solid products such as aggregates or substrates. This method not only removes CO₂ but also immediately provides a product that can be sold in the open market. Solids that are produced using carbon dioxide are not only environmentally friendly; they have an economic value and provide additional benefits to society.

Specifically, one of the more readily available uses of CO₂ in solids is the utilization of CO₂ in cement and concrete production. Cement production is the second largest source of carbon emissions (1st being power production) and an increase in the sustainability of that industry would have significant global impact. Flower et al. (2007) estimated that 1.1 tons of carbon dioxide are produced per ton of marketable cement. To offset the production of carbon dioxide in the process, studies have investigated the possibility of using common aggregate materials as adsorbents. During production of the concrete, carbon dioxide addition results in a reaction with calcium hydroxide that holds the carbon dioxide. This process is referred to as carbonation. Carbonation can be used to create an additional CO₂ sink using a material that is high in demand (Silaban et al., 1995; Lackner et al., 1997; Fernandez-Bertos et al., 2004; O’Connor et al., 2001; Monkman, 2010; Karceski, 2010; Bradley, 2010;). Frank Collins (2010) found that this process works for the primary production of cement but works better when recycled concrete is exposed to CO₂. Recycled concrete utilizes crushed cured concrete as an aggregate. Aggregates that are recycled tend to have a higher surface area to volume ratio and therefore have more sites for carbon dioxide to bind. The recycled concrete was found to be of lesser quality than the primary concrete but still has various uses such as non-aggressive service environments.

In a similar study, Shao et al. (2006) demonstrated that the introduction of carbon dioxide in the cement production processes could remove 9% – 16% of the cement’s weight in carbon dioxide. Using this model, each masonry block produced could remove around 0.3 pounds (0.136 Kg) of carbon dioxide emissions. The addition of carbon dioxide to cement does have some unique advantages that may serve the construction industry well. Aggregates made with the reutilization of CO₂ are lighter than typical cement and 30% to 90% stronger than the lightweight expanded clay aggregates that are utilized today (Gunning et al., 2009). In addition, carbonated concrete has shown porosity that is nearly 21% less than typical concrete, making it a good candidate for areas that are used for storing potentially hazardous chemicals (Cheng-Feng et al., 2005; Huertas et al., 2009). Carbonated concrete is not as strong as non-carbonated but the strength increases with the amount of carbon dioxide included up to a critical point. One downside of this approach is that carbonated concrete has a limited number of activation sites and thus CO₂ is only able to bond within a certain distance of the surface (Chang, 2006; Sang-Hwa et al., 2011). Sean Monkman (2008) found that the amount of carbon dioxide that can be added to cement is actually greater than previous models predicted (25% by weight versus 20% by weight) and is dependent on the form of concrete to which it is added (pre cured versus cured).

In a similar technique, aggregates can be directly produced from critical phase carbon dioxide. Steel slag and concrete waste are submerged in water then mixed with CO₂ in ambient air to simulate the same chemical process that is used in geological storage. The reaction results in a solid, calcium or magnesium carbonate that can be used as a component for further cement production (Stolaroff et al., 2005). The process of “green” cement production requires the addition of saltwater or possibly brackish groundwater to cooled carbon dioxide that is separated from the flue of a power plant. By providing an abundance of solutes to which the carbon dioxide can bind, large concentrations of calcium carbonate are produced at temperatures much lower than typical cement production. This not only removes carbon dioxide from flue gas but it also reduces the amount of fuel burned to produce the concrete.
further mitigating CO₂ emissions. The solid compounds produced in the saltwater reactor are later removed and dried. From there, they are ready for use as an aggregate in cement production. Testing has shown the capture of CO₂ for aggregates used in cement generally surpasses 50% efficiency and can reach 90% under the right conditions (Calera, 2009). The production of aggregates using carbon dioxide may require larger inputs of energy in the form of pressure for crushing and increasing reaction rates or the transport of salt/brackish water but an increase in the understanding and efficiency of the process will reduce these costs.

In some areas aggregate production using captured carbon dioxide has already reached demonstration scale and is being refined in preparation of wide scale distribution. Pilot scale plants using this “green” cement are being utilized in the United States and in Canada. Currently advertised processes are offered regionally, located adjacent to power plants and can capture high percentages (> 95%) of sulfur oxides and trace metals (chromium, cadmium and selenium) present in the flue gases. Current research is still attempting to identify the short and long-term costs of this process.

**Conversion to Plastics**
Donald Darenbourg (2006) has conducted extensive research looking into the possibility of using CO₂ to produce plastics. This process is still a novel approach to reducing emissions, but has the potential to play a significant role in future markets. During the process of plastic production, CO₂ is coupled to epoxides using a metal catalyst producing polycarbonates or cyclic carbonates. These compounds then act as building blocks for larger plastic polymers that can be used for a wide range of purposes. Due to the heavy use of plastics in the economy today, much of the work creating plastics from CO₂ focuses on developing more efficient catalysts and processes to streamline the waste to product timeline. Several types of monomers and polymers can be produced using this process, so extensive research will be required to understand potential application, costs, demand on resources and regulatory constraints associated with each product.

Another process that has shown some promise for the reutilization of CO₂ is for recycling polyethylene terephthalate (PET) beverage bottles. In this process, rather than melting the bottles down and remolding them, the container surface is broken down and reformed by mixing with CO₂. This process not only cleans the bottle, it refinishes the surface for a like-new bottle (Al-Ghatta, 1991). The safety of this process is still undergoing the approval process before wide scale use can begin. A similar process is performed by a dry cleaning system designed to use liquid CO₂ to adhere to a primary cleaner and remove an unwanted substrate (Dewees et al., 1993). Each of these processes has drawbacks but could prove to be a useful way to slow the flow of CO₂ into the atmosphere in an economically friendly way.
ANALYSIS OF CARBON MANAGEMENT

Carbon management is the combination of technology and innovation with socio-economic factors such as policy, regulatory frameworks, social aspects, cultural values, knowledge management, capacity building, geography, and economic implications to develop a set of comprehensive solutions that allow for the reduction of carbon emissions while remaining competitive in the marketplace for a technical and scientific challenge. Policy makers have discussed the topic of climate change and reducing global CO₂ emissions for over 20 years, with increasing attention since the 1997 Kyoto Protocol (Pielke, 2009). The largest contributor to the anthropogenic greenhouse effect is carbon dioxide and recent observations point to an increase in the airborne fraction of anthropogenic CO₂ (Houghton, 2007).

Clean energy policies, as well as sound economic principles, are needed on a global scale to transition away from fossil fuels (Cleetus, 2011), which is a current topic at the federal level in the United States. Policies have already been implemented in many US states, with California being the leader (Bird, 2008). Soon after Congress passed the National Energy Act, progressive regulators in California helped to create commercial renewable energy technology markets (Mallon, 2006). In 2006, California Governor, Arnold Schwarzenegger, created a plan to reduce CO₂ emissions to 1990 levels, statewide, by 2020 using a progressive cap-and-trade plan (Phillips, 2008).

In 2003, two market-based instruments for carbon reduction were actively being considered: emissions-trading and carbon taxes (Helm, 2003). Currently, the same two market-based policies are being discussed: a quantity-based cap and trade method that promotes long-term investments, and a price-based method of taxation that promotes short-term investment (Neuhoff, 2011). “Economic theory shows that there are two basic options for implementing a carbon price: we can set a cap on the quantity of emissions and allow the market to determine the resulting price; or, we can set a price and allow the market to determine the corresponding quantity of emissions” (Cleetus, 2011).

Policy Background
The United Nations Framework Convention on Climate Change adopted the Kyoto Protocol in 1997 as an international environmental agreement to stabilize greenhouse gas levels in the atmosphere (UNFCCC, 1997). While it has not been ratified by the United States, and the federal government does not currently regulate climate change pollutants such as CO₂ (Bayon, 2007), the international agreement encourages participating nations to reduce their emission levels over a given amount of time. The Protocol, signed by 37 industrialized nations, set a binding target of reducing emissions to 1990 levels over a period of time from 2008-2012 (UNFCCC, 1997), but was not ratified by major polluters including the United States and China (Kyoto Protocol: Status of Ratification, 2006).

In talks after the Kyoto Protocol’s establishment, leaders of the G8 (Group of 8) nations and Brazil, China, India, Mexico, and South Africa formed a nonbinding declaration of “Responsible Leadership for a Sustainable Future” in July of 2009. The declaration covers global issues, stating that challenges of climate change and sustainable uses of natural resources are important to ensure global sustainability (G8 Summit, 2009).

In an effort to improve upon the Kyoto Protocol, the Copenhagen Accord (2009) uses low emissions development strategies and provides incentives for developed countries to reduce emissions through ambitious mitigation strategies. Through the Copenhagen Accord, developing countries, not considered in the Kyoto discussions, are encouraged to work with developed countries to improve low carbon alternative technologies and mitigation strategies (Neuhoff, 2011).
Overview of Carbon Markets

Carbon markets are the regulation and action of buying and selling emissions credits. These markets often work in terms of carbon credits, which are defined amounts of carbon that are either emitted or contained (Bayon, 2007). Carbon emissions credits can be bought by nations that exceed their emissions limit and sold by nations that either do not have an emissions limit (developing nations) or those meeting their limits, thus allowing supply and demand to control the price of such credits (Laurance, 2008). The creation of a global carbon market has the potential to provide incentives for technological and economic innovation as well as diffusion of low-carbon infrastructure and technologies (Neuhoff, 2011).

There are two sub-markets of the global carbon market: compliance (regulatory) and voluntary (Bayon, 2007). Voluntary markets, referred to as “green power markets,” allow consumers to choose cleaner electricity sources for their own consumption in order to support the development of renewable energy sources (Bird, 2008). In San Antonio, Texas, CPS Energy has created a “Windtricity” program, allowing customers to voluntarily participate in support of investments made by the utility in clean energy and renewable sources of energy. Customers agree to pay a slightly increased rate ($0.03/kWh) on their electricity bill to cover the higher cost of producing wind energy (CPS Energy, 2012). Customers can choose to enroll based on a set rate (i.e. $20/month) or based on percentage (i.e. 20% of their total electricity consumption). Pacific Power, operating in the Northwestern United States, has a similar program, the Blue Sky Renewable Energy Program. The program allows customers to pay at least $1.95 per month in order to help bring new renewable energy sources online (Pacific Power, 2012).

Compliance markets are tied to the Kyoto Protocol, using regulation mechanisms such as emissions trading, joint implementation, and clean development mechanisms. The most developed of the three, emissions trading, is a transaction system that allows countries to purchase and sell credits. Joint implementation and clean development mechanisms are project-based transaction systems where reductions projects occur in other countries. In joint implementation, credits are purchased by developed countries from developed countries or countries in transition. Clean development mechanisms occur when developed countries fund reduction in developing countries (Bayon, 2007).

Carbon trading, or carbon offsets, is an integral portion of the carbon market. It requires defined carbon assets, such as the Carbon Financial Instrument, defined by the Chicago Climate Exchange as 1 metric ton of CO2 (Bayon, 2007; Bigsby, 2009). A reduction in carbon emissions or increase in sequestration by one entity will be traded to another entity, which produces an excess of emissions (Galik, 2009). According to Marland et al., (2001) “if sequestered carbon becomes a commodity that can be saved or sold, there would presumably be a system of both credits and debits.” Essentially, when carbon is sequestered, credits would be granted, however if carbon emissions were released to the atmosphere, debits would occur. The Kyoto Protocol (Article 3.4) implies that these credits and debits will occur continuously, but be evaluated at set times as compared to a baseline (Bottcher, 2008).

Cap-and-trade programs are different from carbon trading in that there is an overall cap to the amount of emissions allowed. Due to the emissions cap and associated tax, the cost of electricity generation from traditional fossil fuels would increase, thus benefiting renewable and cleaner energy generation alternatives (Bird, 2008). The United Nations Framework Convention on Climate Change (UNFCCC) has attempted to negotiate commitments to cut greenhouse gas emissions from nations with large outputs; however a debate has ensued over whether a flat tax on carbon emissions or a cap-and-trade policy will be more beneficial (Cleetus, 2011). Policy makers in the United States, European Union, and China are pressured to create national policies due to their respective contributions to global demands for energy.
and resulting emissions, as shown by the figure below. However, at UNFCCC negotiations, “there has been a disappointing lack of commitment from major emitting nations to curtail their greenhouse gas emissions and help developing nations cope with unavoidable climate change” (Cleetus, 2011). As Cragg points out in an article on Carbon Geography, both carbon pricing and non-price policies will likely be needed in order to meet goals for cutting carbon emissions (Cragg, 2009). However, it will not be sufficient, nor will it be possible, for one country to tackle the problem on its own due to globalization, free trade and other complicating factors. If one country attempts sustainable development at a higher degree, products made in that country will become more expensive, leading to greater imports from less sustainable countries, driving local companies in the first country out of business (Daly, 2008).

![Graph showing regional energy use and CO2 emissions.](image)

**FIGURE 1-9.** Regional Energy Use and CO2 Emissions. SOURCES: IEA, CDIAC for UN, World Bank, 2011.

**Future of Carbon Policy**

Rachel Cleetus establishes that a hybrid solution of the carbon tax and carbon cap-and-trade system may be preferred, as shown by prior US House and Senate bills that set an emissions cap, price floor, and price ceiling (Cleetus, 2011). For an energy policy to be effective, it must “reduce our dependence on fossil fuels, protect the environment, and take meaningful steps to solve global warming while creating jobs and saving money” (Cragg, 2009). While efforts are made to reduce dependence on fossil fuels, other efforts focus on reducing imports of foreign oil by expanding local production of oil through enhanced oil recovery (EOR) and development of shale resources.

According to a report from Massachusetts Institute of Technology (MIT) and University of Texas, Austin, using CO2 for enhanced oil recovery could not only cut CO2 emissions but also increase domestic oil production (MIT EI, 2010). The United States is focused on using clean sources of electricity such as wind, solar, nuclear, clean coal, and natural gas, in an effort to have a diversified portfolio of energy sources while reducing overall CO2 emissions (United States, 2011). Although carbon policies have been discussed for years, any serious policy proposed would face serious opposition on the political scene (Cleetus, 2011). Economist Herman Daly ascertains that “politically unpopular removal of subsidies and addition of taxes” are necessary for prices to be adjusted to support sustainable development (Daly, 2008).

California adopted a greenhouse gas cap-and-trade program in October of 2011 as part of the Global Warming Solutions Act (AB 32), which regulates major greenhouse gas emitters within the state. An
enforceable cap on emissions has been set and will decline over time, with emissions being granted through tradable permits. The permits will allow for a given quantity of certain emissions to be released, and permits will have specific restrictions as to how they can be traded or sold. This plan, as defined by California, fits into the Western Climate Initiative, a collaboration of eleven US states and Canadian provinces that have agreed to reduce climate-changing emissions (Adams, 2009).

The European Union (EU) has become a leader in climate change policies, with regional policies as well as countries adopting their own policies. In 2007, the EU made a commitment to cut emissions by at least 20% of 1990 levels, far exceeding the requirements of the Kyoto Protocol. More recently, the EU proposed an agreement that would begin in early 2013 to reduce its emissions to 30% by 2020 if other major emitters in the developed and developing world will do their part as well (Europa, 2011). The United States has been focused on energy independence for years, with President Obama stating, “the United States of America cannot afford to bet our long-term prosperity and security on a resource that will eventually run out” (United States, 2011).
SECTION SUMMARY

This section is comprised of profiles of the following companies with technologies in the carbon mitigation market:

- Air Products and Chemicals
- Alstom Power
- Aker Clean Carbon
- BASF
- Calera
- Cansolv Technologies, Inc.
- Codexis
- ConocoPhillips
- Dakota Gasification Company
- Dow Oil & Gas
- Fluor
- Hitachi
- Linde
- Mitsubishi Heavy Industries (MHI)
- Membrane Technology & Research (MTR)
- Novomer
- Powerspan
- Siemens
- Skyonic
- Southern Company
- UOP
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Hamilton, Pennsylvania 18195

Research & Technology Summary
From origins in cryogenic air separation technology, Air Products has grown to become a global supplier of industrial gases (e.g., merchant hydrogen) and of equipment based on cryogenic, adsorption, and membrane technologies. Air Products is a recognized leader in oxy-combustion carbon capture technology and has additional product offerings in carbon capture from gasification, membrane separation technologies, cogeneration technologies, and energy storage, just to name a few. They have over 18,000 employees, operations in more than 40 countries, 2010 revenues in excess of $9B, and were founded in 1940. They are currently working on several CCS projects around the world for power markets and industrial markets. Specific technologies include:

Oxy-Combustion Technologies:
Their oxy-combustion system coupled with their compression/purification technologies can reportedly provide a CCS system with the potential to remove up to 99% SOx, about 90% NOx, deliver a CO2 stream with purities in the 95-98% range, and capture up to one million tons of CO2 per year. It is retrofit or new-build technology and has been demonstrated/piloted in Germany, Scotland, and the United States. They are also working with Shanxi International Energy Group Co., Ltd (SIEG) to perform a feasibility study and reference plant design for potential installation at SIEG’s 350 MW Oxyfuel Electrical Generation Demonstration Project.

H2PSA from Sour Syngas Pre-Combustion Technology:
Air Products also has a proprietary low-cost option for pre-combustion capture that capitalizes on their years of experience in the design and operation of H2 pressure swing adsorption (PSA) systems associated with steam reformers. The “H2PSA from Sour Syngas” technology is an alternative to traditional physical solvent absorption processes like Rectisol.

Demonstrated? Yes or No

Demonstrations/pilots include:
• Demonstration at Doosan Power Systems’ facility in Renfrew, Scotland
• Pilot at Vattenfall’s Schwarze Pumpe plant in Germany
• Pilot at boiler simulation facility in Windsor, CT
• Working with SIEG to perform a feasibility study and reference plant design for potential installation at SIEG’s 350 MW Oxyfuel Electrical Generation Demonstration Project
Process Flow Diagrams

**Oxy-Combustion:**

Air Products’ CO₂ Compression and Purification Process
Integrated into a Coal-Fired Power Plant

![Air Products’ Oxy-Combustion Technology Process](image)

**FIGURE 2-1: Air Products’ Oxy-Combustion Technology Process**

*SOURCE: Air Products, 2012*

**Pre-Combustion:**

**CO₂ Capture from Gasification**

Air Products’ novel PSA technology in development processes sour syngas, potentially removing the need for additional acid-gas removal units. This simplified process has the potential to offer faster throughput and lower capital expense.

![Air Products’ Pre-Combustion Technology Process](image)

**FIGURE 2-2: Air Products’ Pre-Combustion Technology Process**

*SOURCE: Air Products, 2012*

**Additional Links / Information**

- Air Products Website: Air Products and Chemicals, Inc Carbon purification technologies
- Air Products Website: Carbon Capture using OxyFuel Technology
- Air Products Website: Carbon Capture from Gasification
- May 5, 2011 Article: Air Products’ Proprietary Technology Onstream at World’s Premier Demonstration of Oxyfuel CO₂ Capture and Storage at Vattenfall
- Vattenfall Website: Vattenfall’s Carbon Capture Technology
Research & Technology Summary

Alstom is a recognized leader in both post-combustion and oxy-combustion carbon capture technologies. Their strategy has been developed through their belief that these technologies are not only the most economically viable and sustainable solutions for customers, but also because they can be retrofitted to an existing installed base. Specifically, they have post-combustion chilled ammonia solutions, post-combustion amine solutions, and oxy-combustion systems that have been demonstrated worldwide and are currently testing chemical looping technologies as well.

Alstom’s list of global CCS partners includes AEP, Dow Chemical, EPRI, E.ON, Polska Grupa Energetyczna, Schlumberger, SRI International, StatoilHydro, Total, TransAlta, VattenFall, and We Energies. They are continuing their significant R&D efforts in CCS and are validating the technologies at a number of pilot and demonstration projects around the world (13 demonstrations in all). They are working closely with partners towards full-scale commercialization that hopes to be available on the market around 2015. Specific technologies include:

Chilled Ammonia Technology:
Alstom’s proprietary, proven chilled ammonia process (CAP) uses ammonium carbonate to absorb CO₂ from flue gas. Ammonia is an inexpensive and widely available commodity. There is no degradation of the solvent in the process; however there is some designed ammonia loss, and it requires high regeneration temperature and pressure. The process generates ammonium sulphate as by-product that could be sold as fertilizer.

Oxy-Combustion Technology:
Alstom’s process consists of burning fuel in a mixture of oxygen and recirculated flue gas, eliminating the high volume of nitrogen that comes from air during conventional combustion. The process then facilitates the second phase of the concentration and purification of the CO₂, separating up to 90% of the CO₂ created during combustion.

Advanced Amine Technology:
Dow Oil & Gas and Alstom are working on developing advanced amine process technology that utilizes UCARSOL FGC 3000, an advanced amine solvent from Dow, in combination with advanced flow schemes to provide cost effective post-combustion carbon capture. This process is reportedly more degradation-resistant and efficient when capturing CO₂ compared to traditional methods.

Demonstrated?  Yes  or  No

13 different pilot/demonstration projects, including:
• **Brandenburg, Germany:** Using an Alstom-engineered and built oxy-combustion steam generator system, the Vattenfall pilot plant operates on air-firing as well as oxy-firing modes. The pilot plant, with its complete oxy-combustion process chain, is intended to validate and support the technical concept and serve as the main step towards the construction of a 200-300 MW plant, generating “near-zero CO₂” electricity by 2015.

• **Pleasant Prairie, USA:** We Energies’ chilled ammonia CO₂ capture pilot in Wisconsin went into operation in 2008. The pilot, designed to capture 15,000 metric tons of CO₂ per year, has already logged more than 7,000 operating hours and been subjected to 24 x 7 operations to prove reliability – it succeeded and captured 90% of all CO₂ in continuous operation at full load.

• **Mongstad, Norway:** The carbon capture facility built by Alstom at Testing Centre Mongstad is also based on Alstom’s proprietary chilled ammonia process. CO₂ will be captured from flue gas from a combined heat and power plant with an annual capacity of 22,000 metric tons. The facility allows for testing of CO₂ concentrations in the range between 3% and 9% by recirculation of captured CO₂. This will be used to simulate a number of power and industrial sources of CO₂ such as gas turbines with flue gas recirculation.


**Process Flow Diagrams**

![Chilled Ammonia CO₂ capture](image)

**FIGURE 2-3:** Alstom Power’s Post-Combustion Chilled Ammonia Process  
*SOURCE: Alstom Power, 2012*
FIGURE 2-4: Alstom Power’s Oxy-Combustion Technology Process

SOURCE: Alstom Power, 2012

Additional Links / Information
- Company CCS Brochure, including Factsheets: Alstom CO₂ Solutions – Balanced Portfolio
Aker Clean Carbon AS
1324 Lysaker
Norway
http://www.akercleancarbon.com

Research & Technology Summary
Aker Solutions, the parent company of Aker Clean Carbon, is one of the world’s leading providers of oilfield products, systems, and services. The company’s knowledge and technologies span from reservoir to production and through the life of a field with approximately 18,500 people in more than 30 countries. Aker Clean Carbon was established in 2007 to commercialize carbon capture technology developed by a group of in-house expert engineers. They have subsequently been investigating additional solvents and processes as well as a unique concept involving bio energy plants.

Post-Combustion Amine Technology:
Aker Clean Carbon has developed a post-combustion technology for carbon capture based on the chemical reaction between an amine-based liquid absorbent and CO₂. They are currently experimenting with different solvents and processes in an effort to reduce costs.

Aker Clean Carbon’s research and development program, SOLVit, was initiated with the Scandinavian research organization SINTEF and the Norwegian University of Science and Technology (NTNU) in 2008. It is an 8-year program with a budget of approximately $60M. E.ON has been an active partner in SOLVit from the start and has now entered into stage 2 along with Energie Bade-Württemberg AG (EnBW). Their current research efforts are focused on selecting a “green and energy efficient” solvent, gathering emission and degradation measurements in pilots, and developing emission control systems. More than 80 solvent systems have been screened so far in the SINTEF and NTNU laboratories, and the best candidates have been selected for long term testing in the pilots.

Carbon Capture with Bio Energy:
Aker Clean Carbon has also developed a concept to combine CO₂ capture with a bio energy plant, providing steam and electricity to the capture facility. This concept takes any dependency on fossil fuel fired power plants for the capture facility and increases the total CO₂ capture by catching the emitted CO₂ from the bio fuel burner as well.

Demonstrated? Yes or No

Proposed pilots/demonstrations include:
• Tests at Technology Centre Mongstad in Norway
• EnBW’s carbon capture pilot in Heilbronn, Germany will be integrated as part of the on-going SOLVit program
• Tests at Longannet Power Station in Scotland
**Process Flow Diagram**

![Diagram of the CO₂ capture process.](image)

**FIGURE 2-5: Aker Clean Carbon’s Post-Combustion Technology Process**

*SOURCE: Aker Solutions, 2012*

**Additional Links / Information**

- Company Website: [http://www.akercleancarbon.com/section.cfm?path=418,456](http://www.akercleancarbon.com/section.cfm?path=418,456)
- Information on Aker’s Mobile Test Capture Facility: mobile test capture facility
Research & Technology Summary
BASF is one of the world’s leading chemical companies with a portfolio of solutions ranging from chemicals, plastics, and performance products to agricultural products, fine chemicals as well as oil and gas solutions. BASF has significant experience in capturing CO$_2$ from gas flows in industrial uses. The company markets its amine-based gas treatment technology under the brand name aMDEA (short for activated Methyldiethanolamine). For many years this BASF process has been used successfully around the world in more than 220 gas scrubbing facilities, mainly in natural gas and syngas facilities.

BASF also has a series of catalyst systems that can destroy carbon monoxide (CO) and volatile organic compounds (VOCs) produced by power generation equipment. In addition, BASF and its partners JGC Corporation and INPEX Corporation have successfully completed a test of removing carbon dioxide from natural gas under high pressure. The new gas treatment technology reportedly enables a reduction of 25-35% in the cost of CO$_2$ recovery and compression. Their “High Pressure Acid gas Capture Technology” (HiPACT) was developed by JGC and BASF and tested at an INPEX natural gas plant in Koshijihara.

BASF has been working on other CO$_2$ projects in partnership with RTI International, Linde Group, and others. BASF and RTI have been working to develop a new, cost-effective CO$_2$ carbon capture technology, while BASF’s partnership with Linde aims to market licenses and plants for the capture of carbon dioxide from flue gases.

Demonstrated? Yes or No

Demonstrations/pilots include:
- High pressure acid gas capture technology tested at an INPEX natural gas plant in Koshijihara, Japan
- Pilot facility for CO$_2$ scrubbing with the Linde Group and RWE at a lignite power plant in Niederaubem, Germany
Process Flow Diagram

FIGURE 2-6: BASF/JGC HI-PACT Process
SOURCE: JGC Corporation, 2012

Additional Links / Information

- Company Website on Solutions for Power Generators:
  http://www.catalysts.basf.com/p02/USWeb-
  Internet/catalysts/e/content/microsites/catalysts/prods-inds/stationary-emissions/sol-pow-gen
- Press Release on Partnership with Linde: http://www.basf.com/group/pressrelease/P-10-118
- Press Release on Partnership with RTI: http://www.basf.com/group/pressrelease/P-10-328
Calera’s mineralization technology captures carbon and converts it to solid materials that can be used as green building materials, such as cement. It was founded in 2007 and is backed by Khosla Ventures. Other partners include Peabody Energy, Bechtel, Dynegy, Grupo de Nora, and China Huaneng Group.

**Research & Technology Summary**

Calera’s technology captures carbon and converts it to solid minerals that can be used as building materials. They refer to this new process as Mineralization via Aqueous Precipitation, or MAP for short. In its simplest form, MAP involves contacting gas from a power plant or industrial source with alkaline water to form soluble carbonates. These carbonates can be used to make cement and aggregates, for example.

Calera is also developing a proprietary suite of electrochemical technologies called Alkalinity Based on Low Energy (ABLE). Once fully developed this could allow low energy and high efficiency production of chemicals, both for use as inputs to the MAP process as well as in green chemical applications.

Calera’s technology may be suitable for a variety of facilities, including both power plant retrofits and new plants (coal and natural gas). The Calera process has been proven to be robust and is not very sensitive to flue gas carbon dioxide composition. Other carbon capture technologies require pre-scrubbing of sulfur dioxide to very low levels prior to capture of carbon dioxide. In contrast, MAP actually removes sulfur dioxide compounds and other air pollutants using the same basic absorption and conversion techniques used for carbon dioxide.

Founded in 2007, Calera Corporation is a privately owned company backed by Khosla Ventures. It raised an additional $10.6M in December 2011. In January 2011, China Huaneng Group, Peabody Energy, and Calera announced the development of a green coal energy campus in the Xilinguole Region of Inner Mongolia that would use Calera technology to capture part of the carbon dioxide.

**Demonstrated?** Yes or No

**Demonstrations/pilots include:**

- A gas plant in Moss Landing, California
- Additional plans for demonstration in China
Process Flow Diagrams

**FIGURE 2-7:** Calera’s Mineralization via Aqueous Precipitation (MAP) Process

*SOURCE:* Calera, 2012

**FIGURE 2-8:** Calera’s Alkalinity Based on Low Energy (ABLE) Process

*SOURCE:* Calera, 2012

**Additional Links / Information**

- Company Website: Calera – Carbon Dioxide Technology
Proposed demonstrations/ have been successfully demonstrated.

Demonstrated
Cansolv has a proven SO₂ capture system and is developing CO₂ capture solutions. They have a post-combustion amine CO₂ capture technology that will be demonstrated by SaskPower at the Boundary Dam Power Station in Canada.

Research & Technology Summary
Cansolv provides advanced air pollution control and capture solutions for SO₂ and CO₂ emissions. Their research and development program is focused on continuously improving the Cansolv SO₂ process, developing a CO₂ capture process, and integrating advanced amine purification systems. At this time, fifteen commercial Cansolv SO₂ scrubbing systems are in operation and many more are in the detailed engineering or procurement phase. A number of Cansolv CO₂ capture demonstration and commercial units are currently being engineered or built, including a project with SaskPower at the Boundary Dam Power Station. Cansolv was acquired by ShellGlobal Solutions International BV, a member of the Royal Dutch Shell group, in November 2008.

The Cansolv CO₂ capture system is a regenerable CO₂ scrubbing process that uses an aqueous amine solution to capture CO₂ and SO₂. The process can be used in a multitude of applications, including treatment of power plant flue gases. The scrubbing by-product is a pure, water saturated CO₂ gas recovered from steam stripping. This system enables CO₂ to be absorbed from feed gas by having contact with the absorbent in the absorption tower. The absorbent reacts reversibly with the CO₂, therefore a multi-stage counter current contacting is used to achieve maximum loading of CO₂ into the absorbent. The solvent is then fed into the top of the tower and as it flows down it selectively reacts with the CO₂. At the bottom of the tower the amine is pumped into a regeneration tower where it is heated in order to reverse the absorption reaction. As the absorbent moves down the tower, the CO₂ is gradually stripped, and at the bottom the heat from the “lean” amine (the CO₂ stripped absorbent) is used to heat incoming rich amine to maximize the heat recovery. The amount of heat added at this point will determine the extent to which the absorbent will be stripped of CO₂. The Cansolv CO₂ capture system is typically designed to remove approximately 90% of the CO₂ in the absorption tower. The CO₂ that is removed is then cooled and available at a positive pressure for utilization/storage/sequestration.

Proposed demonstrations/pilots include:
- Its first commercial scale project is proposed at the Boundary Dam Power Station in the province of Saskatchewan, Canada. Partners include SaskPower and Hitachi. This project is projected to be operational in 2014.
Process Flow Diagram

FIGURE 2-9: Cansolv's Post-Combustion Technology Process

SOURCE: Cansolv Technologies, Inc., 2012

Additional Links / Information
• Publications by Cansolv: Cansolv Publications
• Technology Brochure: Cansolv Technologies Brochure
• News Release on Boundary Dam Project: Saskatchewan Committed to Proceeding with Carbon-Capture Project
Research & Technology Summary

Codexis, Inc. is a developer of industrial enzymes to enable the cost-advantaged production of biofuels, bio-based chemicals, and pharmaceutical intermediates. Partners and customers include global leaders such as Shell, Alcoa, Merck, and Pfizer.

The Codexis “CodeEvolver” technology platform combines sophisticated DNA shuffling and proprietary bioinformatics with advanced systems biology and nearly a decade of research experience to create powerful new biocatalysts. Biocatalysts are enzymes or microbes that initiate or accelerate chemical reactions. The CodeEvolver platform enables evolution of biocatalysts designed “fit for purpose” to perform specific functions at industrial scale. This technology can transform industrial applications of biocatalysts, by improving commercially relevant characteristics such as stability, activity, product yield and tolerance to industrial conditions.

They have been working with Alcoa and the U.S. Department of Energy under the ARPA-E program to develop enzymes to increase the amount of carbon dioxide captured by power plants with less parasitic energy loss and to convert carbon dioxide into useful end products such as nutrient rich fertilizer. Recent data from the DOE program show Codexis technology has improved carbon capture performance by about two-million-fold over natural forms of the enzyme. Based on initial models, Codexis believes that their biocatalysts may reduce parasitic energy loss by up to 35%. In the laboratory, these biocatalysts have also exhibited increased tolerance for flue stack-type operating conditions, though not yet at target commercial levels.

Over the past few months, the company has experienced some management turmoil. Their CFO resigned in January 2012, their CEO resigned in February 2012, and their Chief Business Officer will be resigning in August 2012. Their new CEO was announced in June 2012.

**Demonstrated?** Yes or No

**Proposed demonstrations/pilots include:**
- A project with Alcoa and the U.S. Department of Energy under the ARPA-E program
Process Flow Diagram

FIGURE 2-10: Codexis Technology Process  
SOURCE: Codexis, 2012

Additional Links / Information  
- Company Website: www.codexis.com/code_evolver_code_xporter
ConocoPhillips has been involved with CO₂ capture and storage technologies for over 20 years. They are also active in beneficial reutilization options. Their E-Gas technology has been demonstrated at the Wabash River Plant and was proposed at a cancelled project near their refinery in Sweeny, TX.

Research & Technology Summary
ConocoPhillips is actively pursuing advances in the technology components of CO₂ capture and storage and is making detailed studies of specific opportunities to demonstrate the process on a large scale. Their “E-Gas” gasification technology has over 20 years of commercial experience, including a DOE demonstration site at Wabash River. ConocoPhillips had been investigating building an IGCC plant near their refinery in Sweeny, Texas, but it was cancelled due to uncertain financial, regulatory, and market conditions.

The E-Gas technology converts petroleum coke, coal or other low-value hydrocarbon feedstocks into high-value synthesis gas used for a slate of products, including power, substitute natural gas, hydrogen, and chemicals. This clean, efficient technology facilitates carbon capture and storage, minimizes criteria pollutant emissions, and reduces water consumption. E-Gas Technology has been utilized in commercial applications since 1987, first at the Louisiana Gasification Technology facility in Plaquemine, Louisiana, and since 1995 at SG Solutions’ Wabash River Plant near Terre Haute, Indiana.

The company is also working to advance beneficial carbon reuse options. For example:

• The company is leveraging its more than 30 years of operational experience in miscible gas injection at its North Slope assets in Alaska and 25 years of CO₂ EOR experience in West Texas to evaluate new EOR opportunities to facilitate production growth.
• ConocoPhillips was selected by the DOE to conduct the first field trial using CO₂ to produce methane from gas hydrates on Alaska’s North Slope.
• The company is investing in CO₂ EOR research in Norway as part of the Ekofisk EOR program.
• ConocoPhillips has contracted to sell CO₂ captured from the ConocoPhillips’ Lost Cabin Gas Plant in Wyoming for use in EOR.

The company also collaborates with universities on other technologies with “game-changing” potential. ConocoPhillips provides financial support and participates in external CCS research, development, and policy programs that are funded by industry and government.

Demonstrated? Yes or No

Demonstrations/pilots include:
• Wabash River Plant near Terre Haute, Indiana
• Louisiana Gasification Technology facility in Plaquemine, Louisiana
• Proposed at a project near their refinery in Sweeny, Texas, but cancelled
Process Flow Diagram

FIGURE 2-11: ConocoPhillips’ IGCC Plant Process Flow
SOURCE: DOE/NETL, 2007

Additional Links / Information
The Dakota Gasification Company, a subsidiary of Basin Electric Power Cooperative, owns and operates the Great Plains Synfuels Plant, which is the only commercial-scale coal gasification plant in the United States that manufactures natural gas.

Dakota Gasification Company
1600 E. Interstate Ave
Bismarck, ND 58506
http://www.dakotagas.com/

Research & Technology Summary
Dakota Gasification Company (Dakota Gas) is a for-profit subsidiary of Basin Electric Power Cooperative. Dakota Gas owns and operates the $2-billion Great Plains Synfuels Plant, which began operations in 1984. The Great Plains Synfuels Plant is the only commercial-scale coal gasification plant in the United States that manufactures natural gas. The plant currently consumes more than 6 million tons of coal to produce 54 billion standard cubic feet of synthetic natural gas annually. It also produces fertilizers, solvents, phenol, carbon dioxide, and other chemical products for sale.

The Great Plains Synfuels Plant is adjacent to Basin Electric's Antelope Valley Station, a 900-megawatt coal plant, and a lignite coal mine. The Great Plains Synfuels Plant and Antelope Valley Station share certain facilities and coal and water supplies. Specifically, the Antelope Valley Station supplies the Synfuels Plant with electricity, and the Synfuels Plant supplies several of Basin Electric's gas peaking facilities with synthetic natural gas.

The plant has been an international leader in technologies that capture, compress, and transport CO₂ emissions from a coal gasification process. The Synfuels Plant currently captures more CO₂ from coal conversion than any other plant in the world and is participating in the world's largest CO₂ sequestration project. Dakota Gas captures approximately 3 million tons of CO₂ a year and 50% of CO₂ emissions are captured every day the plant is in operation. Since the end of 2008, Dakota Gas has captured more than 17 million metric tons of CO₂.

Some of the gas is transported through a 205-mile pipeline to oil companies in Saskatchewan, Canada that use it for enhanced oil recovery operations that result in permanent CO₂ geologic sequestration.

Demonstrated? Yes or No

Demonstrations/pilots include:
  • Great Plains Synfuels Plant in operation since 1984
FIGURE 2-12: Simplified Plant Process at the Great Plains Synfuels Plant

SOURCE: DOE/NETL, 2012

Additional Links / Information
- Company Website: The Dakota Gasification Company CO₂ Story
- Company Website: The Greatest CO₂ Story Ever Told – Dakota Gasification Company
- DOE/NETL Website: www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/6-apps/6-4-4-1_great-plains.html
Research & Technology Summary
Dow, through the Gas Treating Products & Services division of its Oil & Gas division, has proven technologies for economical bulk CO₂ removal and selective absorption of H₂S, COS, mercaptans, and BTEX from a variety of natural and synthesis gas streams. Specific technologies include UCARSOL and SELEXOL solvents, specialty amines, the UCARSEP amine reclamation system, UCARKLEAN solutions, gas treating chelants, and others. Dow offers solutions for both pre-combustion and post-combustion applications. To aid in both plant design and operation, Dow also offers a variety of support services, including advanced simulation capabilities, state-of-the-art laboratories, field testing equipment, analytical procedures, and an on-going optimization program.

Pre-Combustion Technology:
UCARSOL and SELEXOL solvents have been the first choice for many world-scale gasification projects in operation today. The SELEXOL line of physical solvents was created together with UOP to perform in the high pressure requirements of large-scale gasification operations. The treatment technology from Dow was coupled with UOP's process and technology know-how. SELEXOL is particularly effective in high-pressure, low-temperature, high-acid gas systems.

Post-Combustion Technology:
Dow Oil & Gas and Alstom Power are also working on developing advanced amine process technology that utilizes UCARSOL FGC 3000, an advanced amine solvent from Dow, in combination with advanced flow schemes to provide cost effective post-combustion carbon capture technology. This process is reportedly more degradation-resistant and energy efficient when capturing CO₂. Dow and Alstom are working together under a Joint Development Agreement to develop the Advanced Amine Process (AAP) by designing, constructing, and operating a carbon capture pilot plant on a coal-fired boiler.

Demonstrated? Yes or No

Demonstrations/deployments include:
• SELEXOL has been demonstrated at the Wabash River Power Plant and is the proposed capture technology for Mississippi Power’s Kemper County IGCC Plant; it has been used in many other industrial facilities as well
• Dow and Alstom are partnering in South Charleston, West Virginia on an industrial boiler combusting hard West Virginia coal using advanced amine post-combustion technology to capture approximately 1,800 metric tons of CO₂ per year
Process Flow Diagrams

**Selexol:**

![Selexol Flow Diagram](image)

**FIGURE 2-13: Simplified Selexol Flow Diagram**

*SOURCE: DOE/NETL, 2012*

**Post-Combustion Advanced Amine:**

![Post-Combustion Advanced Amine Diagram](image)

**FIGURE 2-14: Dow/Alstom’s Post-Combustion Advanced Amine Design in South Charleston, WV**

*SOURCE: Alstom/Dow, 2010*
**Additional Links / Information**

- Company Website: www.dow.com/gastreating/solution/ngp_cor.htm
- Company Website on EOR: Enhanced Oil Recovery
- Operational Comparison of DEA Versus Selective Amine Technology: msdssearch.dow.com/PublishedLiteratureDOWCOM/dh_0039/0901b803800391e2.pdf?filepath=gastreating/pdfs/noreg/170-01388.pdf&fromPage=GetDoc
- Details on Dow/Alstom Efforts in West Virginia: www.mcilvainecompany.com/Decision_Tree/subscriber/CO2DescriptionTextLinks/AlstomDow2010.pdf
- DOE/NEL Information on Gasification Technologies: http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/5-support/5-6_agr.html
**Research & Technology Summary**

Fluor designs, builds, and maintains power plants using a variety of fuel sources, including coal, gas, oil, nuclear, and wind. Fluor also has developed the proprietary Econamine FG Plus post-combustion carbon capture process, which uses different novel amine solvents. It was specially designed to capture CO\textsubscript{2} from low pressure, oxygen-containing streams.

Fluor’s solvent formulation and advanced reclaiming techniques allow the technology to work in an environment where most other processes would fail, such as on boiler and reformer stack gas and gas turbine flue gas streams. Fluor’s Econamine FG Plus is licensed in over 26 plants worldwide with flue gas derived from a variety of feed stocks such as bunker sea oil, heavy fuel oil mixed with coal, light fuel oil, heavy fuel oil, gas-fired reformer furnace, steam reformer, heavy fuel oil and refinery gas mixture, LPG, natural gas, and gas turbine exhaust. It is used at NRG’s Washington Parish Plant and proposed at Tenaska’s Trailblazer plant.

For more than two decades, Fluor has designed, constructed, and commissioned more gas-fueled power generating plants than any other EPC&M company. During the last decade alone, Fluor was the EPC and commissioning contractor for more than 30 percent of the gas-fired generation installed in the U.S., representing more than 60 power plants in operation today.

**Demonstrated?** Yes or No

**Demonstrations/pilots include:**

- Licensed at commercial scale in 26 industrial plants worldwide, including three in the US
- Used at NRG’s Washington Parish Plant
- Proposed at Tenaska’s Trailblazer plant
Process Flow Diagrams

**Figure 2-15:** Fluor Econamine FG Plus Process Flow
*SOURCE: DOE/NETL, 2010*

**Figure 2-16:** Typical Fluor Econamine FG Plus Process
*SOURCE: Fluor, 2012*

Additional Links / Information
- Company Website: [www.fluor.com/econamine/Pages/default.aspx](http://www.fluor.com/econamine/Pages/default.aspx)
- News Article: Secretary Chu Announces Up To $154 Million for NRG Energy’s Carbon Capture and Storage Project in Texas
Hitachi has been actively involved in the testing of post-combustion and oxy-combustion technologies for over two decades. They have developed proprietary solvent blends and advanced amine technologies. They also hope to be a supplier of turbines and other components to CCS projects. Partners include SaskPower, TEPCO, Vattenfall, Cansolv, Electrabel, and E.On.

Research & Technology Summary
Hitachi started their research, development, and deployment of post-combustion CO₂ capture for coal-fired applications in the early 1990’s. Hitachi’s first CO₂ capture pilot plant was built at Yokosuka Thermal Power Unit 2 in collaboration with Tokyo Electric Power Corporation in Japan. During the 2-year demonstration period, they tested five solvents, including a commercial MEA. The test for Hitachi’s proprietary solvent formulation, H3, was the best out of the five tested. The H3 solvent consistently achieved greater than 80% CO₂ removal with the average rate well above 90%. Since these tests, Hitachi has continued to refine their proprietary solvent blends in their laboratories.

Hitachi Power Europe is involved as a technology partner in the "Schwarze Pumpe" oxy-combustion pilot of energy supplier Vattenfall and is carrying out combustion tests there. Hitachi hopes to supply components for future oxyfuel process equipped power plants.

Hitachi and SaskPower are partnering to construct a $60 million carbon capture test facility (CCTF) at SaskPower’s Shand Power Station in southeastern Saskatchewan. SaskPower will act as owner/operator, but both companies will contribute approximately $30 million to the facility, with construction beginning in late 2012/early 2013 and scheduled completion in summer 2014. Hitachi’s proprietary amine technology is scheduled to be the first technology tested at the CCTF. SaskPower and Hitachi plan on evaluating a number of current and emerging carbon capture technologies.

In addition to the CCTF, Hitachi, SaskPower, and Cansolv Technologies, Inc. have joined along with other collaborators to be among the first to operate a commercial-scale power plant with a fully integrated carbon capture and storage operating system. Hitachi will provide the steam turbine designed to integrate a coal-fired power plant with CO₂ capture technology. Cansolv will provide the CO₂ capture technology process. This is the $1.24 billion project to rebuild a coal-fired unit at the Boundary Dam Power Station and equip it with a fully integrated carbon capture system.

Hitachi, working with utility partners Electrabel /GDF Suez and E.ON, is also currently building a large mobile pilot plant for the separation of CO₂ from coal-fired power plant flue gas. This plant will be used to generate the data needed to develop and design concept for both the new power plant integrated with CCS or the retrofit plant.

Demonstrated? Yes or No

Demonstrations/pilots include:
• Pilot at Yokosuka Thermal Power Unit 2 in Japan
• Pilot post-combustion capture facility with E.ON and GDF Suez in the Netherlands
• Pilot mobile plant for testing CO2 scrubbing agents in Duisburg, Germany
• Constructing a $60M test facility with SaskPower at the Shand Power Station
• Technology partner in the Boundary Dam Power Station project
• Technology partner in Vattenfall’s Schwarze Pumpe oxy-combustion pilot
• Additional project details can be found at:

Process Flow Diagram

![Process Diagram of the Hitachi CO₂ Capture System](image)

**SOURCE:** Hitachi, 2010

Additional Links/ Information
• Company Website: http://www.hitachi-power.com/en/co2-capture.html
• Coal-Gen 2010 Technical Paper:
  http://www.hitachipowersystems.us/supportingdocs/forbus/hpsa/technical_papers/Advanced
  %20Amine-based%20CO2%20Capture%20for%20Coal-fired%20Power%20Plants.pdf
The Linde Group
Bodenbacher Strasse 80
01277 Dresden, Germany

Research & Technology Summary
The Linde Group is a leading supplier of industrial, process, and specialty gases and is one of the most profitable engineering companies in the world. Linde has many solutions for CO₂ capture varying from the removal from industrial processes to carbon capture at power plants. They have proven post-combustion, pre-combustion and oxy-fuel combustion technology systems, as described below.

Pre-Combustion Technology:
Linde provides air separation units, gasification systems as well as synthesis gas separation and purification systems, including shift and RECTISOL selective CO₂ recovery systems. RECTISOL is a physical acid gas removal process that uses an organic solvent (typically methanol) at subzero temperatures. Due to the physical nature of the RECTISOL process, high pressure and high sour gas concentrations are particularly favorable. RECTISOL is therefore frequently used to purify shifted, partially shifted or unshifted gas downstream residue oil-, coal- or lignite gasification. Due to the low operation temperature, RECTISOL is also favorable for cryogenic downstream processes, like liquid nitrogen wash and cryogenic recovery of carbon monoxide.

Post-Combustion Technology:
In the post-combustion pathway, Linde provides an amine-based solvent system and CO₂ compression, drying, and purification systems. As of January 2010, they have entered into an agreement with BASF to jointly market licenses and plants for the capture of carbon dioxide from flue gases.

Oxy-Combustion Technology:
In the oxy-fuel combustion pathway, Linde provides the air separation unit for the production of oxygen, the CO₂ compression, drying, and purification system as well as an optional liquefaction system. They have entered into a partnership with Vattenfall to test oxy-combustion solutions.

Sequestration Technology:
Linde is also currently in the developmental stages of CO₂ sequestration. They are participating in research into technologies capable of injecting CO₂ into plutonic rock over extended periods of time. The company is further involved in a pilot that is using carbon dioxide to increase natural gas/oil recovery rates via EOR.

Demonstrated? Yes or No

Demonstrations/pilots include:
- CO₂ scrubbing pilot facility at a lignite power plant in Niederaubem, Germany with BASF
- 30MW pilot facility for oxy-combustion technology in Brandenburg, Germany with Vattenfall
- Rectisol proposed at Summit Power’s IGCC Texas Clean Energy Project
- Rectisol proposed at SCS Energy’s Hydrogen Energy California Project

**Process Flow Diagrams**

**FIGURE 2-18: Linde Pre-Combustion Process**  
*SOURCE: Linde, 2012*

**FIGURE 2-19: Linde Post-Combustion Process**  
*SOURCE: Linde, 2012*

**FIGURE 2-20: Linde Oxy-Combustion Process**  
*SOURCE: Linde, 2012*
Mitsubishi Heavy Industries
Yokohama Engineering Headquarters
Mitsubishijuko Yokohama Bldg., 3-1,
Minatomirai 3-chome, Nibhi-KU, Yokohama
Kanagawa, Japan
http://www.mhi.co.jp/en/products/category/co2_recovery_plants.html

**Research & Technology Summary**

Mitsubishi Heavy Industries (MHI) offers a large scale, advanced, and reliable CO₂ recovery process called the Kansai Mitsubishi Carbon Dioxide Recovery Process (KM CDR Process). It uses an advanced solvent called KS-1 to capture CO₂ from a flue gas stack. The flue gas is directed to the KM CDR Process where the KS-1 solvent reacts with and captures the CO₂. CO₂ can then be separated from the KS-1 and compressed for pipeline transport.

This technology was developed through cooperation between MHI and Kansai Electric Power Company. Their CO₂ recovery process reportedly uses less energy when compared to other processes. It is also reported to have lower solvent degradation and low corrosion. The company’s process allows for urea and methanol production as well as the production of dimethyl ether. Other important applications supported by the technology are Enhanced Oil Recovery and capture and storage.

The technology is deployed at two coal plants worldwide. MHI has also delivered nine commercial CO₂ recovery plants in Japan and other countries, with one more currently in construction.

**Demonstrated?**  Yes or No

**Demonstrations/pilots include:**

- Southern Company’s Plant Barry Power Station in Alabama
- J-POWER Matsushima Power Station in Nagasaki, Japan
- Multiple commercial plants, including locations in Malaysia, India, Bahrain, Vietnam, Japan, UAE, and Pakistan.
Process Flow Diagrams

FIGURE 2-21: Flow of the KM CDR Process
SOURCE: MHI, 2012

FIGURE 2-22: Gas Boiler CO2 Capture Plant for 3,000 metric T/D (300MW)
SOURCE: MHI, 2012

Additional Links / Information
- Company Website: MHI, Ltd. Flow of the Standard Process
- Company Website: MHI, Ltd. Commercial Experiences – Commercial Plants in operation
- Company Website: MHI, Ltd. Coal Fired Demonstration Experiences
- Southern Company Website on Plant Barry Project:
  http://www.southerncompany.com/planetpower/demonstration_carboncapture.aspx
MTR has developed a commercially available membrane that separates CO₂ from syngas. Demonstration partners include Southern Company, EPRI, Babcock & Wilcox, and the U.S. DOE.

Membrane Technology and Research (MTR) has developed a commercially available membrane that separates CO₂ from syngas: the Polaris membrane. The membrane is unique because it is highly permeable to CO₂, but it retains hydrogen. With this advance, it is possible to use membranes to remove CO₂ from streams containing hydrogen, such as gasifier streams, PSA tail gas, and various petrochemical process streams.

MTR is currently managing one of ten projects chosen by the Department of Energy to develop advanced technologies for capturing CO₂ from coal combustion flue gas. MTR, with Southern Company, Electric Power Research Institute, and Babcock & Wilcox, will begin their 3-year project to construct a membrane skid capable of 90% CO₂ capture form a 20 TPD slipstream of coal-fired flue gas. This is the equivalent to the CO₂ generated by 1 MW of power generation. MTR’s Polaris membrane will be tested at the DOE National Carbon Capture Center for 6 months, and the data will be used to clarify the process design and economics of the membrane based CO₂ capture from power plant flue gas.

The Polaris membrane permeability allows this technology to be used to recover and purify CO₂ for sequestration, enhanced oil recovery, or for use in chemical and industrial applications. The CO₂ enriched stream can be produced in a gas or liquid form, depending on the final use of the CO₂. The areas in which this technology may be applied are: hydrogen plants, syngas production, methanol production, GTL or CTL for liquid fuel production, gasifier feeding IGCC, and other power plants, and pressure swing adsorption feed / tail gas.

**Demonstrated?** Yes or No

*Proposed demonstrations/pilots include:*
- DOE project with Southern Company, Electric Power Research Institute, and Babcock & Wilcox is in the construction / testing phase
Process Flow Diagram

FIGURE 2-23: CO₂ Removal from Syngas Using Polaris Membrane

SOURCE: MTR, 2012

Additional Links / Information

- Company Website: MTR - CO₂ Removal from Syngas
- Company Website: MTR Case Study: CO₂ Removal from Reformer Gas
Novomer is commercializing a proprietary catalyst system that transforms waste carbon dioxide (CO₂) into sustainable chemicals and materials for everyday applications, such as plastic bottles.

Research & Technology Summary
Novomer is an emerging sustainable chemistry company pioneering a family of high performance, environmentally responsible plastics, polymers, and chemical intermediates. Novomer’s proprietary catalyst technology developed by Cornell University allows traditional chemical feedstocks to be combined with carbon dioxide or carbon monoxide to synthesize sustainable chemicals and materials for everyday applications, including plastics.

The chemicals and materials contain up to 50% carbon dioxide or carbon monoxide and have a significantly reduced carbon and energy footprint compared to the materials they will replace. The materials can sequester the CO₂ and CO for the life of the product, mitigating global warming and climate change.

Novomer received $18.4 million from the US Department of Energy to develop a process for converting carbon dioxide into polycarbonate polymers that could be used to make plastic bottles.

**Demonstrated?** Yes or No

Process Flow Diagram

**FIGURE 2-24: Novomer Technology Process**

**SOURCE:** Novomer, 2012

**Additional Links / Information**
Powerspan
100 International Drive, Suite 200
Portsmouth, NH 03801
http://powerspan.com

Research & Technology Summary
Powerspan offers advanced air pollution control solutions for existing and new coal-fired power plants and large industrial applications that rely on coal for their operation or electricity generation. Their proprietary Electro-Catalytic Oxidation technology, branded with “ECO” nomenclature, is a multi-pollutant control technology line that reduces emissions of sulfur dioxide, nitrogen oxides, oxidized mercury, and fine particulate matter. The original ECO process produces a commercial grade ammonium sulfate fertilizer co-product.

Their carbon capture solution in the ECO line, ECO₂, is a post-combustion process that dries and compresses carbon dioxide for transfer to another site. The ECO2 technology can be installed following conventional SO2 scrubbing technology (such as a limestone forced-oxidation SO2 scrubber) or following their ECO or ECO-SO2 technologies.

Powerspan tested its ECO₂ process from December 2008 through 2010 at a one megawatt pilot facility at FirstEnergy Corp.’s R.E. Burger Plant. During extended runs at the ECO₂ pilot test facility averaged greater than 90 percent CO₂ capture. Powerspan’s carbon capture technology was originally selected by Basin Electric in March 2008 for use at their proposed Antelope Valley Station plant, however Powerspan was replaced with HTC Purenergy in December 2009 before the entire project was cancelled.

In April 2009, Powerspan announced the closing of over $50 million in new financing from a group of new investors including George Soros, Tenaska Energy, AllianceBernstein, and Persimmon Tree Capital along with returning investors NGEN Partners, The Beacon Group, The Tremont Group, RockPort Capital Partners, Calvert, Angeleno Group, Fluor Corporation, and FirstEnergy Corp.

Demonstrated? Yes or No

Demonstrations/pilots include:
• Demonstrated at FirstEnergy Corp.’s R.E. Burger Plant and independently reviewed by WorleyParsons
• Proposed at Basin Electric’s Antelope Valley Station, but replaced with HTC Purenergy
FIGURE 2-25: Power Plant with ECO-SO₂ and ECO₂ Systems Installed
SOURCE: Powerspan, 2012

Additional Links / Information
- Company Website: Powerspan ECO₂ - CO₂ Capture
Siemens has proven pre-combustion and post-combustion solutions along with related products such as turbines, compressors, and air quality controls. Their gasification technology will be used in Summit Power’s IGCC Texas Clean Energy Project.

Research & Technology Summary
Siemens provides multiple technologies and products along the entire value chain of energy production and carbon capture from power generation equipment to solutions for flue-gas cleaning, CO₂ capture, and CO₂ compression for transport and storage. Additional details follow.

Pre-Combustion Technology:
The Siemens IGCC pre-combustion concept incorporates a Siemens oxygen-blown, solid-fuel gasifier and a Siemens combined cycle power plant. The current Siemens fuel gasification technology uses the entrained-flow principle, followed with a direct water quench to cool the produced hot raw gas. It is possible to capture the heat of the hot raw gas in a syngas cooler to generate high-pressure steam for the steam turbine. Both of these processes cool the gas so that it may be directly sent to the gas treatment system. Plants with CO₂ capture and storage find the direct water quench to have advantages as the water / steam that is needed for the shift reaction is already in the raw syngas.

Post-Combustion Technology:
Siemens offers a proprietary post-combustion capture process using amino-acid salt formulations called the PostCap process. The process features several significant environmental and energy efficiency advantages compared to first generation technologies, e.g. the monoethanolamine (MEA) process. For example, the Siemens PostCap process does not require any complex downstream scrubbing of the flue gas after capture. The solvent actually removes any further contaminants contained in the flue gas.

Related Products:
Siemens’ compression portfolio comprises turbomachinery best suited for high-efficiency CO₂ compression required in power plants with integrated gasification combined cycle, oxyfuel or post-combustion capture technology. Their preferred solution is an integrally geared compressor type called STC-GV. A conventional single-shaft solution with single-shaft compressor types (STC-SH/SV) is feasible as well. Together with the CO₂ compressor, Siemens has compression technology for air separation units used in oxyfuel and IGCC plants, including main air compressors, booster air compressors, oxygen compressors, and nitrogen compressors.

Demonstrated? Yes or No

Demonstrations/pilots include:
• Post-combustion CO₂ capture testing lab at Frankfurt Hoechst Industrial Park (fully automated lab plant for CO₂ capture for 24/7 test operations)
• CO₂ capture pilot plant at E.ON’s SPP Staudinger coal-fired power plant in Grosskrotzenburg, Germany
FIGURE 2-26: Siemens Gasification Process Flow

SOURCE: Siemens, 2012

Additional Links / Information

- Company Website: Siemens Carbon Capture Technology
- Company Website: Siemens – Integrated Gasification Combined Cycle
- Company Website: Siemens – Post-Combustion CO₂ Capture
- Company Website: Siemens – CCS Related Products
Skyonic, based in Austin, Texas, is developing systems that capture carbon dioxide by mineralizing the gas into sodium bicarbonate (baking soda), which primarily will be sold as an antacid ingredient for cattle feed.

Specifically, Skyonic has created the “SkyMine” which removes CO₂ and other harmful pollutants from flue gas. Flue gas is moved from the stacks into the SkyMine, where mercury, SO₂, and NOx are removed, leaving CO₂. Sodium hydroxide (salt water) is then introduced to the carbon dioxide causing a chemical reaction producing sodium bicarbonate (baking soda in crystalline form), hydrogen gas, and chlorine gas. Each product is stored separately and can be sold on the market, while the remaining –and significantly less harmful– flue gas is returned to the stacks.

Unlike other carbon-capture systems that require concentrated CO₂, Skyonic’s technology is effective with low concentrations and has been tested as low as 3 percent, according to Skyonic’s CEO.

SkyMine has an adjustable capture rate between 10-90% of CO₂ to accommodate different CO₂ removal configurations. Chlorine gas, hydrogen gas, and sodium bicarbonate can all be sold as byproducts.

Skyonic received $9 million from ConocoPhillips, BP, and other new investors to fund its first commercial facility at a Texas cement plant. It has also funded by $28 million in grants from the U.S. Department of Energy. Other Skyonic backers include Luminant, a unit of Energy Future Holdings Corp., and David Zachry, chief executive officer of Capitol Aggregates’ parent company Zachry Corp.

Demonstrated? Yes or No

Demonstrations/pilots include:

• Operational at Luminant Big Brown Steam Electric Station since 2007
• In the process of developing a demonstration site at the Capitol Aggregates cement plant in San Antonio
Process Flow Diagram

FIGURE 2-27: Flow Diagram of the SkyMine Process
SOURCE: Skyonic, 2012

Additional Links / Information
Research & Technology Summary

Southern Company’s Transport Integrated Gasification (TRIG) technology easily handles low-rank coals that account for more than half of the world’s vast coal reserves. TRIG is an integrated gasification combined cycle technology, which is sometimes referred to as coal gasification. TRIG was developed over the last 15 years at the Power Systems Development Facility in Wilsonville, Alabama—a research facility for the Department of Energy and Southern Company, Mississippi Power’s parent company. As coal is fed into the TRIG gasifier, it is heated at a high temperature and under high pressure. The combination of heat and pressure is what turns the coal into a gas.

A unique feature of TRIG is that it sends coal that is not converted to gas in the initial process back for a second round of gasification. A new IGCC plant project in Kemper County will utilize TRIG. With TRIG, the IGCC facility in Kemper County will turn Mississippi lignite into gas while cleaning emissions of sulfur dioxide, nitrogen oxides, and mercury to near natural-gas levels. It also will produce 65 percent less carbon dioxide emissions than current pulverized coal plants.

In addition to gasification and capture, Southern Company also works with storage and sequestration.

Demonstrated? Yes or No

Demonstrations/pilots include:
- 25 MW plant in operation in Bucks, Alabama
- The Kemper County IGCC Project will utilize the TRIG technology
FIGURE 2-28: Proposed Kemper IGCC Process Flow
SOURCE: Mississippi Power, 2012

Additional Links / Information
- Company Brochure on Kemper IGCC Plant:
  http://www.mississippipower.com/kemper/IGCC_BROCHURE.pdf
- Company Website on Plant Barry Project:
  http://www.southerncompany.com/planetpower/demonstration_carboncapture.aspx
Research & Technology Summary
UOP, a Honeywell Company, partnered with Dow to create a popular line of solvents, SELEXOL, that can be used for selective removal of H₂S, COS, RSH, and CO₂. The treatment technology from Dow was coupled with UOP’s process and technology know-how. SELEXOL is particularly effective in high-pressure, low-temperature, high-acid gas systems.

UOP has also been investigating algae-to-biofuel solutions that use captured carbon dioxide as a feedstock. They were awarded $1.5 million in funding for a project to demonstrate technology to capture CO₂ and produce algae for the use in biofuel and energy production.

Demonstrated? Yes or No

Demonstrations/pilots include:
- SELEXOL demonstrated at Wabash River Plant
- SELEXOL proposed at Southern Company’s Kemper County IGCC
- Coffeyville Resources Gasification Ammonia Complex in Coffeyville, Kansas

Process Flow Diagram

Additional Links / Information
- Meeting Staged CO₂ Capture Requirements with UOP SELEXOL™ Process
- UOP SELEXOL™ Technology for Acid Gas Removal
ADDITIONAL RESOURCES

Other organizations and publications have done an excellent job of explaining the technologies and the state of the market, including:

- **DOE National Energy Technology Laboratory (NETL) CCS Resources**
  - Many other useful documents available at the “Reference Shelf” at: www.netl.doe.gov/technologies/carbon_seq/refshelf/refshelf.html

- **DOE Office of Fossil Energy CCS Resources**
  - Clean Coal Technologies main site: http://fossil.energy.gov/programs/powersystems/index.html

- **Global CCS Institute**

- **MIT Sequestration Resources**
  - Database of projects available at: http://sequestration.mit.edu

- **International Journal of Greenhouse Gas Control**
  - www.journals.elsevier.com/international-journal-of-greenhouse-gas-control

- **Carbon Capture Journal**
  - www.carboncapturejournal.com
LITERATURE REVIEWED


Chen, C. and E. S. Rubin (2008) CO2 control technology effects on IGCC plant performance and cost. 37, 915


Goldberg, D. (2008). "Carbon dioxide sequestration in deep...


CO₂ capture in power plants: Minimization of the investment and operating cost of the post-combustion process using MEA aqueous solution

The post-combustion process based on CO₂ absorption using an amine aqueous solution is one of the more attractive options to drastically reduce greenhouse gas emissions from the electric power sector. However, solvent regeneration is highly energy intensive, affecting the total operating cost significantly. The CO₂ removal target depends on the absorption and desorption processes where the main parameters of both processes are strongly coupled. Consequently, the simultaneous optimization of the whole CO₂ capture process is essential to determine the best design and operating conditions in order to minimize the total cost. This paper presents and discusses different cost optimizations including both investments and operating costs. The impact of different CO₂ emission reduction targets on the total annual cost, operating conditions and dimensions of process units is investigated in detail. Optimized results are discussed through different case studies.

Pilot plant study of four new solvents for post-combustion carbon dioxide capture by reactive absorption and comparison to MEA

Reducing solvent regeneration energy is one of the main challenges in CO₂ capture from power plant flue gases. New tailored solvents are needed to achieve this goal. The present work describes tests of such new solvents in a gas-fired pilot plant which comprises the complete absorption/desorption process (column diameters 0.125m, absorber/desorber packing height 4.2/2.52m, flue gas flow 30–110kg/h, CO₂ partial pressure 35–135mbar). Four new solvents are studied and compared to MEA. Two of the new solvents SOLVENT1 (0.25g/g N-methyl(diethanolamine+0.15g/g N-methyl-1,3-propanediamine+0.6g/g H₂O) and SOLVENT2 (0.25g/g 2-amino-2-methyl-1-propanol+0.15g/g N-methyl-1,3-propanediamine+0.6g/g H₂O) are developed in an EU project; and two other solvents SOLVENT3 and SOLVENT4 are developed by BASF. The four new solvents and MEA are studied in the same way in the pilot plant and detailed results are reported for all solvents. The measurements are carried out at constant CO₂ removal rate by an adjustment of regeneration energy in the desorber. The solvent flow rate is systematically varied. An optimal solvent flow rate leading to a minimum energy requirement is found from these studies. Direct comparisons of such results can suffer from differences in the kinetics of different solvent systems. These differences are experimentally studied by varying the flue gas flow rate at a constant ratio of solvent mass flow to flue gas mass flow and constant removal rate. Taking into account the results from these studies on kinetics allows a reasonable ranking of the solvents. The most promising of the studied solvents is SOLVENT4.

Comparison of two electrolyte models for the carbon capture with aqueous ammonia

Post-combustion carbon capture is attracting much attention due to the fact that it can be retrofitted on existing coal power plants. Among the most interesting technologies is the one that employs aqueous ammonia solutions to absorb the generated carbon dioxide. The evaluation of such process requires the modeling of electrolyte solutions. In this work two thermodynamic models for electrolyte solutions are compared against each other with respect to experimental data. They are the e-NRTL model and the Extended UNIQUAC model, both implemented in the commercial software Aspen Plus 11. Aspen Plus is a registered trademark of Aspen Technology, Inc. (version 7.2). Subsequently, a simple absorption/regeneration layout is simulated employing both models and the process performances are compared. In general, the Extended UNIQUAC appears to describe the experimental data for larger ranges of temperature, pressure and concentration of ammonia more satisfactorily. The energy performances computed with the Extended UNIQUAC models are less promising than with the e-NRTL model.

Post-combustion CO₂ capture by aqueous ammonia: A state-of-the-art review
International Journal of Greenhouse Gas Control, July 2012: Bingtao Zhao | Yaxin Su | Wenwen Tao | Leilei Li | Yuanchang Peng

CO₂ emission by fossil fuel combustion has been considered a leading contribution to the increasing atmospheric CO₂ concentration and the global greenhouse effect. As a chemical absorption method and technology to control CO₂ from post-combustion flue gas, CO₂ capture by aqueous ammonia is paid more and more attention for its advantages of high efficiency, low investment and convenient operation. In this paper, the advances in fundamental research on post-combustion CO₂ capture by aqueous ammonia, focusing on the process chemistry, effect of reaction parameters on absorption efficiency, absorption process intensification and simultaneous capture with other pollutants, were critically summarized and reviewed. In addition, future potential in research and development of CO₂ absorption by aqueous ammonia were also briefly prospected and discussed.
Evaluating the impact of an ammonia-based post-combustion CO₂ capture process on a steam power plant with different cooling water temperatures

The use of aqueous ammonia is a promising option to capture carbon dioxide from the flue gas of coal-fired power plants. Compared to a capture process using monoethanolamine (MEA), the use of ammonia can reduce the heat requirement of the CO₂ desorption significantly, although an additional effort is necessary to provide the cooling of the process. To allow for a fair evaluation of the integration of this CO₂ capture process into a power plant process, an overall process evaluation is carried out. The use of detailed models of the power plant, of the compressor and of the CO₂ capture process enables the calculation of the power loss due to the steam extraction as well as due to the required auxiliary power for CO₂ compression, solvent and cooling pumps and mechanical chillers. To study the influence of the cold end of the process, two power plants with different cooling water temperatures are analyzed. Additionally, two different process configurations of the capture plant, with either one single absorber or two absorbers connected in series where the first absorber captures the majority of the CO₂ and the second limits the NH₃ slip, are evaluated. The influence of the main process parameters (desorber pressure, solvent circulation rate, solvent recycling rate and chilling temperature) are evaluated and the optimal configuration with respect to the overall net efficiency penalty is determined. The study shows that the configuration of the process with absorption at low temperature (approximately 10°C) with or without precipitation of ammonium carbonate compounds leads to a lower net efficiency penalty than an MEA-based process, assuming that low temperature cooling water is available. An estimate of the size of the absorber shows that the absorber columns of an ammonia-based process are significantly higher than the ones required for an MEA-based process.

Pre-combustion capture of CO₂—Results from solvent absorption pilot plant trials using 30wt% potassium carbonate and boric acid promoted potassium carbonate solvent

Pre-combustion capture of carbon dioxide (CO₂) from synthesis gas has been demonstrated using a solvent absorption pilot plant. The plant was designed to capture 30–50 kg/h (~1 tonne/day) of CO₂ from 300 kg/h of syngas. The solvent used in these trials was a potassium carbonate (K₂CO₃) solution. Potassium carbonate shows promise as a solvent for CO₂ capture because it requires lower energy for regeneration and has a low environmental impact when compared with the traditional amine-based solvents. However, the rate of CO₂ absorption in K₂CO₃ is slow and as such there have been several studies evaluating rate promoters for this process. Boric acid has been identified as one such promoter. The pilot plant in this study was successfully operated on a campaign basis for 16 days using both an un-promoted 30wt% K₂CO₃ solution as well as a 30wt% K₂CO₃ solution promoted with 3wt% boric acid. There was no net improvement in the absorption of CO₂ observed in the presence of boric acid. This result is attributed to the boric acid having reduced the pH and therefore OH⁻ concentration of the system, which in turn reduced the rate of the controlling kinetic reaction to form potassium bicarbonate (KHCO₃) from CO₂. Changes in the solvent physical properties, due to interaction with syngas impurities, were found to influence the hydrodynamic performance of the packed columns. Bicarbonate precipitation and vessel level control issues also led to operational difficulties. ASPEN Plus simulations have been developed to predict the performance of the plant. In general the model predicts the performance of the plant well (to within ±5%) and will be important for future process development, design and optimization.

Chemical-looping combustion using syngas as fuel

Chemical-looping combustion (CLC) is a combustion technology where an oxygen carrier is used to transfer oxygen from the combustion air to the fuel, avoiding direct contact between air and fuel. Thus, CO₂ and H₂O are inherently separated from the rest of the flue gases and the carbon dioxide can be obtained in a pure form without the use of an energy intensive air separation unit. The paper presents results from a 3-year project devoted to developing the CLC technology for use with syngas from coal gasification. The project has focused on: (i) the development of oxygen carrier particles, (ii) establishing a reactor design and feasible operating conditions and (iii) construction and operation of a continuously working hot reactor. Approximately, 300 different oxygen carriers based on oxides of the metals Ni, Fe, Mn and Cu were investigated with respect to parameters, which are important in a CLC system, and from these investigations, several particles were found to possess suitable qualities as oxygen carriers. Several cold-model prototypes of CLC based on interconnected fluidized bed reactors were tested, and from these tests a hot prototype CLC reactor system was constructed and operated successfully using three carriers based on Ni, Fe and Mn developed within the project. The particles were used for 30-70 h with combustion, but were circulated under hot conditions for 60-150 h.

Feasibility of integrating solar energy into a power plant with amine-based chemical absorption for CO₂ capture

Solar thermal energy has the potential to supply the thermal demand of stripper reboiler in the power plant with amine-based post combustion CO₂ capture. The performance of a power plant integrated with solar assisted post combustion CO₂ capture (SCC) is largely affected by the local climatic conditions, such as solar irradiation, sunshine hours and ambient temperature, the type of solar thermal collector and CO₂ recovery.
ratio. The feasibility evaluation results about such a power plant show that the cost of electricity (COE) and cost of CO₂ avoidance (COA) are mainly determined by the local climatic conditions. For the locations having higher solar irradiation, longer sunshine hours and higher ambient temperature, the power plant with SCC has lower COE and COA. COE and COA are sensitive to the prices of solar thermal collectors. In order to achieve lower COE and COA compared to the power plant integrated with non-solar assisted post combustion capture, the price of solar thermal collector has to be lower than 150USD/m2 and 90USD/m2 for the solar trough and vacuum tube, respectively.

PROCESS INNOVATION: FLEXIBLE OPERATION

Optimizing post-combustion CO₂ capture in response to volatile electricity prices

Flexible operating CO₂ capture at power plants allows a temporary increase in electrical output, which could help maintain grid reliability, meet peak demand, or improve profitability when electricity prices are high. This article presents a versatile optimization model that maximizes profits at a fossil-based power plant with CO₂ capture by operating in response to volatile electricity prices. The model is demonstrated for a 500MW coal-fired unit using 7 molal monoethanolamine for post-combustion CO₂ capture. The importance of modeling electricity price volatility when valuing flexible capture is demonstrated by comparing model results to those from a first-order electricity dispatch model that does not incorporate price volatility. CO₂ emissions and plant economics are then compared for operation under three 20-year CO₂ price paths and four facility configurations: no CO₂ capture, inflexible CO₂ capture, flexible CO₂ capture that vents CO₂ at partial load, and flexible capture that uses solvent storage to mitigate venting at partial load. Flexible capture improves investment value over inflexible capture while maintaining substantial CO₂ emissions reductions, but economic benefits are greatest at low CO₂ prices where CO₂ capture investment might still be unaffordable. Flexibility provides the greatest economic advantage if CO₂ prices are $40–50 per metric ton of CO₂ for a substantial portion of plant economic life. Solvent storage permits greater operating profits and lower CO₂ emissions than a venting-only flexible capture facility, but benefits can be offset by increased capital costs.

Flexible operation of coal fired power plants with post-combustion capture of carbon dioxide
JOURNAL OF ENVIRONMENTAL ENGINEERING ASCE, JUNE 2009: Hannah Chalmers; Mathieu Lucquiaux; Jon Gibbins; and Matt Leach

Carbon capture and storage is one family of technologies that could be used to significantly reduce global carbon dioxide (CO₂) emissions. This paper reviews the likely flexibility of power plants with post-combustion capture, with a focus on an improved characterization of the dynamic performance of power plants with CO₂ capture. The literature has focused on design and optimization for steady state operation of power plants with capture, often at a single design point. When dynamic behavior is considered, it is possible that designs should be altered for best overall plant performance. Economic trade-offs between improving transport and storage scheme flexibility and constraining power plant operations should also be carefully analyzed, particularly if the captured CO₂ is to be used in another process such as enhanced oil recovery. Another important aspect of real plant operation will be adhering to legislative requirements. Further work is required to identify mechanisms that allow flexible operation without undermining any targets set for storing CO₂ and/or restricting global CO₂ emissions.

OTHER PROCESS INNOVATION

Optimized process configurations of post-combustion CO₂ capture for natural-gas-fired power plant – Power plant efficiency analysis

Carbon dioxide was removed by chemical absorption processes from the flue gases of a natural-gas-fired combined-cycle power plant. The main challenge of chemical absorption processes is reducing the energy requirement. This paper discusses the selection of most important parameters necessary to obtain 90% capture ratio and the lowest energy consumption for the CO₂ capture and compression plants. The integrated capture processes with power plant were evaluated by using the net power-plant efficiency. Several chemical absorption process configurations were analyzed and the design parameters were compared for the different cases. The findings show decreased reboiler energy consumption for the Base case chemical absorption process configuration with 3.74–2.71MJ/kg CO₂ for the modified chemical absorption process configuration of lean vapor recompression with absorber inter-cooling. The net power plant efficiency with CO₂ capture and compression was increased from 49.4% (LHV) for the Base case chemical absorption process to 50.2% (LHV) for the chemical absorption process with absorber inter-cooling and lean vapor recompression. The power output reduction due to CO₂ capture and compression was decreased from 48MW for the Base case chemical absorption process to 42.5MW for the case with absorber inter-cooling and lean vapor recompression.
Comparison of carbon capture and storage with renewable energy technologies regarding structural, economic, and ecological aspects in Germany

For the option of "carbon capture and storage", an integrated assessment in the form of a life cycle analysis and a cost assessment combined with a systematic comparison with renewable energies regarding future conditions in the power plant market for the situation in Germany is done. The calculations along the whole process chain show that CCS technologies emit per kWh more than generally assumed in clean-coal concepts (total CO2 reduction by 72-90% and total greenhouse gas reduction by 65-79%) and considerable more if compared with renewable electricity. Nevertheless, CCS could lead to a significant absolute reduction of GHG-emissions within the electricity supply system. Furthermore, depending on the growth rates and the market development, renewables could develop faster and could be in the long term cheaper than CCS based plants. Especially, in Germany, CCS as a climate protection option is phasing a specific problem as a huge amount of fossil power plant has to be substituted in the next 15 years where CCS technologies might be not yet available. For a considerable contribution of CCS to climate protection, the energy structure in Germany requires the integration of capture ready plants into the current renewal programs. If CCS retrofit technologies could be applied at least from 2020, this would strongly decrease the expected CO2 emissions and would give a chance to reach the climate protection goal of minus 80% including the renewed fossil-fired power plants.

Carbon dioxide storage potential of shales

Options for the geologic storage of carbon dioxide vary from saline aquifers and depleted oil and gas reservoirs to unminable coal seams and abandoned coal mines. Important aspects include the sealing integrity of the cap rock and potential changes in this integrity, owing to the interaction with CO2. In this study, diffusive transport and gas sorption experiments on one well characterized shale sample (Muderong Shale, Australia) and different clay minerals were performed to obtain information on the sealing integrity and the CO2 storage potential of these materials. All measurements were performed under reservoir conditions relevant for CO2 storage (T = 45-50 °C; p < 20 MPa). Repeat diffusion experiments on one shale plug yielded increased effective diffusion coefficients and a decrease in the concentration of the bulk CO2 volume in the sample. The latter is believed to be dissolved in formation water, sorbed to mineral surfaces or involved with geochemical reactions. For the Muderong Shale, bulk volume CO2 concentrations are greater within the experimental time frame (222-389 mol/m3), when compared to coal and cemented sandstone (3-4 and 8-10 mol/m3), respectively. This high CO2 storage potential could not fully be explained by CO2 dissolution in water alone. Thus, gas sorption experiments were performed on crushed shale and various clay minerals. High CO2 sorption capacities (e.g. up to 1 mmol/g for the Muderong Shale) show that the high CO2 concentration is related to a combination of CO2 dissolution in water and gas sorption on clay minerals. Additionally, changes in specific surface areas before and after the sorption experiments and variations in the CO2 sorption and diffusion behavior due to repetitive experiments on the identical sample were observed, possibly related to geochemical alteration of the Muderong Shale and the clay minerals. These could not be quantified however and seemed to occur only at high pressures. Results obtained in this study provide a more positive view on the sealing integrity of intact cap rock formations. Carbon dioxide that migrates from a storage reservoir into the cap rock through the pore network will be immobilized to a certain extent, hence minimizing (slow, diffusion-driven) leakage and providing additional CO2 storage potential.

Brine migration resulting from CO2 injection into saline aquifers – An approach to risk estimation including various levels of uncertainty

Comprehensive risk assessment is a major task for large-scale projects such as geological storage of CO2. Basic hazards are damage to the integrity of caprocks, leakage of CO2, or reduction of groundwater quality due to intrusion of fluids. This study focuses on salinization of freshwater aquifers resulting from displaced brine. Quantifying risk on the basis of numerical simulations requires consideration of different kinds of uncertainties and this study considers both, scenario uncertainty and statistical uncertainty. Addressing scenario uncertainty involves expert opinion on relevant geological features such as caprock properties, faults, and distinct geological layers. This is considered in this work by 6 different scenarios having different characteristic geological features. On the other hand, Monte Carlo methods are a classical approach to address statistical uncertainty. This is not feasible for large-scale 3D models including complex physics. Therefore, we apply a model reduction based on arbitrary polynomial chaos expansion combined with probabilistic collocation method. It is shown that, dependent on data availability, both types of uncertainty can be equally significant. The presented study provides estimates of the risk of brine discharge into freshwater aquifers due to CO2 injection into geological formations and resultant salt concentrations in the overlying drinking water aquifers.
APPENDIX D:
EXAMPLE PROJECTS
### EXAMPLE PROJECTS

Examples of Pre-Combustion Carbon Capture Projects

<table>
<thead>
<tr>
<th>Name</th>
<th>Team</th>
<th>Technology</th>
<th>Estimated Cost</th>
<th>More Information</th>
</tr>
</thead>
</table>
| **Texas Clean Energy Project (TCEP) IGCC Plant** | Summit Power Group, Siemens, Linde Group, R.W. Beck, Blue Source, and the Texas Bureau of Economic Geology | • Siemens gasification and power block technologies  
• Linde Rectisol CO₂ capture technology to capture >90% of the CO₂ produced | Total project cost estimated at $2.4 billion for a 400 MW (gross) plant  
• DOE incentives = $450 million ($350 from Clean Coal Initiative & $100 million from the American Recovery and Reinvestment Act) | In addition to the CO₂ captured, TCEP will also capture 99% of sulfur dioxide, 90% of nitrogen oxide, and 99% of mercury.  
| **Kemper County IGCC Plant in Mississippi** | Mississippi Power, Southern Energy, and KBR | • Transport Integrated Gasification (TRIG) technology developed by Southern Company and KBR in conjunction with the DOE  
• Selexol CO₂ capture technology to capture >65% of CO₂ | Total project cost originally estimated at $2.4 billion for a 582 MW plant (524 MW coal and 58 MW natural gas); cost estimate was raised to $2.8 billion this year  
• $680 million in grants and tax incentives received to date, including a DOE Clean Coal Power Initiative (CCPI) Phase 2 award for $270 million and a $133 million Investment Tax Credit | Plant uses Mississippi lignite coal and natural gas. The proposed transport gasifier has been successfully used for over 50 years in the petroleum refining industry. A scale-up of a test plant is already in operation at the PSDF in Wilsonville, Alabama.  
The plant ran into legal hurdles in March 2012, but is currently re-approved.  
| **Hydrogen Energy California (HECA) IGCC Plant** | SCS Energy acquired the project from initial owners in May 2011; previous project team included: BP, Rio Tinto, Fluor, URS, and GE | • Mitsubishi Heavy Industries’ oxygen-blown dry feed gasification will gasify a blend of coal and petroleum coke to produce hydrogen-rich gas  
• Linde Rectisol CO₂ capture technology | Total project cost: $2.8 billion for a 300 MW plant  
• DOE has invested $54 million – project can access remaining $354 million under HECA’s Clean Coal Power Initiative (CCPI-3) award  
• $55 million previously invested by BP and Rio Tinto  
• California Public Utilities Commission also awarded $30 million | The captured CO₂ will be transported for use in enhanced oil recovery (EOR) in the adjacent Elk Hills Oil Field owned and operated by Occidental of Elk Hills, Inc.  
<table>
<thead>
<tr>
<th>Name</th>
<th>GreenGen IGCC Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>China Huaneng Group (the largest utility in China)</td>
</tr>
<tr>
<td>Technology</td>
<td>• Two-stage gasification technology that has been developed and refined by China Huaneng Group through HCERI (formerly TPRI)</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>Unknown</td>
</tr>
<tr>
<td>More Information</td>
<td>At least $46 million provided by the government and $3.3 million provided by the industry for all of the National 863 Program projects. More information available at: <a href="http://sequestration.mit.edu/tools/projects/greengen.html">http://sequestration.mit.edu/tools/projects/greengen.html</a></td>
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<thead>
<tr>
<th>Name</th>
<th>Sweeny, Texas IGCC Plant</th>
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<tbody>
<tr>
<td>Team</td>
<td>ConocoPhillips had been investigating building an IGCC plant near its refinery in Sweeny, Texas</td>
</tr>
<tr>
<td>Technology</td>
<td>• ConocoPhillips E-Gas gasification process (estimated &gt;85% CO₂ removal) would have been used with Selexol CO₂ capture technology</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>N/A</td>
</tr>
<tr>
<td>More Information</td>
<td>This plant would have been a 680 MW net (Coal + Petcoke). Technology had previously been demonstrated at the Wabash River IGCC. Denbury Resources would have used captured CO₂ for EOR. Cancellation due to financial/regulatory uncertainty. More information available at: <a href="http://sequestration.mit.edu/tools/projects/sweeny.html">http://sequestration.mit.edu/tools/projects/sweeny.html</a> and <a href="http://www.osti.gov/bridge/servlets/purl/992131-jTc6Iw/992131.pdf">http://www.osti.gov/bridge/servlets/purl/992131-jTc6Iw/992131.pdf</a></td>
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<tr>
<th>Name</th>
<th>Taylorville Energy Center IGCC Plant in Taylorville, Illinois</th>
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<tr>
<td>Team</td>
<td>Christian County Generation, L.L.C. (a Joint Venture between Tenaska and MDL Holding Company of Louisville, Kentucky); Siemens</td>
</tr>
<tr>
<td>Technology</td>
<td>• Siemens gasification and power block technologies</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>$3.5 billion for a 716 MW gross (602 MW net) plant</td>
</tr>
<tr>
<td>More Information</td>
<td>Project incentives not approved by Illinois Senate. Unsure if project will move forward.</td>
</tr>
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<tr>
<th>Name</th>
<th>Good Springs IGCC</th>
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<tbody>
<tr>
<td>Team</td>
<td>EmberClear (HCERI’s Exclusive North American &amp; Eastern European partner)</td>
</tr>
<tr>
<td>Technology</td>
<td>HCERI technology (formerly TPRI), PRENFLO gasifier / boiler, ECUST</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>$800 million</td>
</tr>
<tr>
<td>More Information</td>
<td>Plant design changed from IGCC to NGCC in May 2012 for financial reasons</td>
</tr>
</tbody>
</table>
# Examples of Post-Combustion Carbon Capture Projects

## Amine-based Solvents

<table>
<thead>
<tr>
<th>Name</th>
<th>W.A. Parish Plant in Houston, Texas</th>
</tr>
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<tbody>
<tr>
<td>Team</td>
<td>NRG Energy, Fluor, Ramgen/Dresser-Rand, Sargent &amp; Lundy, University of Texas, and University of Texas Bureau of Economic Geology</td>
</tr>
</tbody>
</table>
| Technology | • Fluor Econamine FG Plus technology  
• Ramgen’s supersonic CO₂ compression system |
| Estimated Cost | $334 million  
• DOE share is $167 million (50% of the total cost) from the DOE Clean Coal Project Initiative |

<table>
<thead>
<tr>
<th>Name</th>
<th>Trailblazer Energy Center in Sweetwater, Texas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>Tenaska, Fluor, Arch Coal</td>
</tr>
<tr>
<td>Technology</td>
<td>• Supercritical pulverized coal technology with Fluor Econamine FG Plus technology to capture 85%-90% of the CO₂</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>$3.0 billion for a 765 MW gross (600 MW net) plant</td>
</tr>
</tbody>
</table>
| More Information | CO₂ produced by combustion and deliver it via pipeline to Permian Basin oil fields for use in EOR and ultimately, geologic storage  

<table>
<thead>
<tr>
<th>Name</th>
<th>Boundary Dam Power Station in Saskatchewan, Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>SaskPower, Fluor, Hitachi, Babcock &amp; Wilcox Canada, Neill and Gunter, Air Liquide, and SNC Lavalin-Cansolv</td>
</tr>
</tbody>
</table>
| Technology | • Hitachi’s steam turbine technology  
• Cansolv’s CO₂ capture technology |
| Estimated Cost | $1.5 billion  
• Received $240 million from the federal government |
| More Information | This project was resized from an earlier plan to build a 300 MW clean coal facility near Estevan due to escalating costs. Project construction is scheduled to begin in 2013. This will be a retrofit project. More information at: [www.saskpower.com/sustainable_growth/projects/carbon_capture_storage.shtml](http://www.saskpower.com/sustainable_growth/projects/carbon_capture_storage.shtml) and [http://sequestration.mit.edu/tools/projects/boundary_dam.html](http://sequestration.mit.edu/tools/projects/boundary_dam.html) |

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<thead>
<tr>
<th>Name</th>
<th>Plant Barry Power Station in Mobile, Alabama</th>
</tr>
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<tbody>
<tr>
<td>Team</td>
<td>Southern Energy, Mitsubishi Heavy Industries (MHI), Southern Company, SCARB (US DOE’s Southeast Regional Carbon Sequestration Partnership), and Electric Power Research Institute (EPRI)</td>
</tr>
<tr>
<td>Technology</td>
<td>• Mitsubishi Heavy Industries’ KS-1 solvent</td>
</tr>
</tbody>
</table>
| Estimated Cost | Southern Energy has not provided a cost estimate  
• DOE awarded $295 million for an 11 year CCS contract as part of CCPI  
• Southern Company received $15 million from the US DOE |
| More Information | Plant Barry successfully started capturing CO₂ in June 2011. Stage 1 was 25 MW slipstream of the 2,567 MW plant; Stage 2 was 160 MW – TBD if phase 2 will go ahead. Southern Company’s Plant Barry was originally granted a third round of CPPI funding, but with DOE money came a hard deadline of commitment to the project. Representatives of Southern Company state that due to the nature of the DOE money (coming from economic stimulus) they did not have enough time to perform due diligence in terms of financial ramifications for the company. Finally, due to incomplete negotiations with subcontractors, Southern Company is going ahead with the smaller 25 MW pilot, but the larger 160 MW is still uncertain. More Information at: [http://sequestration.mit.edu/tools/projects/plant_barry.html](http://sequestration.mit.edu/tools/projects/plant_barry.html) |
### Ammonia-based

<table>
<thead>
<tr>
<th>Name</th>
<th>Technology</th>
<th>Estimated Cost</th>
<th>More Information</th>
</tr>
</thead>
</table>
| **We Energies Pleasant Prairie Plant in Milwaukee, WI (Pilot)** | Post-combustion with chilled ammonia                                      | Unknown                 | DOE’s Office of Fossil Energy contributed $7.2 million  
 |                                            |                                                                            |                         | Alstom and AEP contributed $1.4 million for the initial phases  
| **AEP’s Mountaineer Project**             | Alstom’s chilled ammonia process                                          | $100+ million           | DOE’s Office of Fossil Energy contributed $7.2 million  
 |                                            |                                                                            |                         | Alstom & AEP contributed $1.4 million for initial phases  
 |                                            |                                                                            |                         | Geologic investigation of the Mountaineer site will cost $4.2 million  
| **Basin Electric’s Antelope Valley (ND) Project** | Post-combustion with ammonia. Originally Powerspan ECO2, then changed to HTC Purenergy  | $287 million            | Awarded a US $100 million grant from DOE  
 |                                            |                                                                            |                         | Awarded $300 million loan from USDA  
| **Statoil Mongstad, The European CO2 Test Centre Mongstad (TCM)** | Alstom’s chilled ammonia-based technology                                 | $1.02 billion; increased by $462 million in October 2010 | The goal of the TCM is to develop the most cost effective way to capture CO2 with post-combustion technology; they will do this by testing both Aker Clean Carbon and Alstom’s technology.  
## Examples of Carbon Mineralization Projects

<table>
<thead>
<tr>
<th>Name</th>
<th>Big Brown Steam Electric Station</th>
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<tbody>
<tr>
<td>Team</td>
<td>Luminant, Skyonic Corporation</td>
</tr>
<tr>
<td>Technology</td>
<td>Skyonic Skymine</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td></td>
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</table>

## Examples of Oxy-Combustion Capture Projects

<table>
<thead>
<tr>
<th>Name</th>
<th>FutureGen Alliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>FutureGen Industrial Alliance which includes Anglo American LLC, BHP Billiton, Chian Huaneng Group, Consol Energy, E.ON, Foundation Coal, Peabody Energy, PPL Energy Services Group, Rio Tinto Energy America, Xstrata Coal, Exelon, Caterpillar and Air Liquide</td>
</tr>
<tr>
<td>Technology</td>
<td>Oxy-Combustion</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>$1.65 billion; $1.1 billion to report the generating unit &amp; $550 million for the CO₂ pipeline and storage, $1 billion awarded from the Recovery Act</td>
</tr>
<tr>
<td>More Information</td>
<td>FutureGen will equip Ameren’s 200MW Unit 4 in Meredosia, Illinois with advanced oxy-combustion technology. Project partners, are working with the State of Illinois, to establish a regional CO₂ storage site in Mattoon, Illinois and a 175-mile-long CO₂ pipeline network from Meredosia to Mattoon that will transport and store more than 1 million tons of captured CO₂ per year. More Information at: <a href="http://sequestration.mit.edu/tools/projects/futuregen.html">http://sequestration.mit.edu/tools/projects/futuregen.html</a> and <a href="http://www.futuregenalliance.org/">http://www.futuregenalliance.org/</a></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Name</th>
<th>Schwarze Pumpe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>Air Products and Vattenfall AB</td>
</tr>
<tr>
<td>Technology</td>
<td>Air Products Oxyfuel Combustion System</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>$96 million for 30 MW</td>
</tr>
<tr>
<td>More Information</td>
<td>The Air Products oxyfuel combustion system will take flue gas directly off the 30 MW wall-fired boiler, purify, and compress the CO₂, of which a portion will ultimately be transported for sequestration. Project information prior to Air Products joining the pilot: <a href="http://sequestration.mit.edu/tools/projects/vattenfall_oxyfuel.html">http://sequestration.mit.edu/tools/projects/vattenfall_oxyfuel.html</a></td>
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<table>
<thead>
<tr>
<th>Name</th>
<th>Doosan Babcock Clean Combustion Test Facility (Renfrew, Scotland)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>Doosan Babcock, Air Products, DONG Energy, Drax Power Limited, EDF Energy PLC, EON UK PLC, Scottish Power Limited, Vattenfall AB, and UK Coal PLC</td>
</tr>
<tr>
<td>Technology</td>
<td>Air Products Oxyfuel Combustion System</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>Approximately $12.8 million; $2.5 million from DECC</td>
</tr>
<tr>
<td>More Information</td>
<td>40 MW oxyfuel burner test rig; this pilot project is a test rig adapted specifically for testing oxyfuel capture technology (on pulverized coal) and applicable to both new and retrofit supercritical boilers, completed test program in early 2011. More Information at: <a href="http://www.decc.gov.uk/en/content/cms/emissions/ccs/innovation/ccsprojects/ccsprojects.aspx">http://www.decc.gov.uk/en/content/cms/emissions/ccs/innovation/ccsprojects/ccsprojects.aspx</a></td>
</tr>
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<table>
<thead>
<tr>
<th>Name</th>
<th>Datang Daqing Oxy-Fuel Demo Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team</td>
<td>Datang Heilongjiang Power Generation Co. Ltd with Alstom China</td>
</tr>
<tr>
<td>Technology</td>
<td>Oxyfuel Combustion</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td></td>
</tr>
<tr>
<td>More Information</td>
<td>Datang and Alstom signed a feasibility study agreement in November 2011; Project is expected to start operation in 2015. Approximately 1 million tons per year of CO₂ are expected to be captured at the plant; with the CO₂ being transported by pipeline for sequestration in a deep saline formation and use in EOR. More Information at: <a href="http://www.globalccsinstitute.com/projects/27921">http://www.globalccsinstitute.com/projects/27921</a></td>
</tr>
</tbody>
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APPENDIX E:
LISTING OF POWER PLANT CCS PROJECTS WORLDWIDE
# Listing of Power Plant CCS Projects Worldwide (Source: MIT)

## Large-Scale Power Plant CCS Projects Worldwide

### USA

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Leader</th>
<th>Feedstock</th>
<th>Size MW</th>
<th>Capture Process</th>
<th>CO2 Fate</th>
<th>Start-up</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>TCEP</td>
<td>Summit Power</td>
<td>Coal</td>
<td>400</td>
<td>Pre</td>
<td>EOR</td>
<td>2014</td>
<td>Texas</td>
</tr>
<tr>
<td>Trailblazer</td>
<td>Tenaska</td>
<td>Coal</td>
<td>600</td>
<td>Post</td>
<td>EOR</td>
<td>2014</td>
<td>Texas</td>
</tr>
<tr>
<td>Kemper County</td>
<td>Southern</td>
<td>Coal</td>
<td>582</td>
<td>Pre</td>
<td>EOR</td>
<td>2014</td>
<td>Mississippi</td>
</tr>
<tr>
<td>HECA</td>
<td>SCS</td>
<td>Pet coke</td>
<td>390</td>
<td>Pre</td>
<td>EOR</td>
<td>2014</td>
<td>California</td>
</tr>
<tr>
<td>FutureGen</td>
<td>FutureGen Alliance</td>
<td>Coal</td>
<td>200</td>
<td>Oxy</td>
<td>Saline</td>
<td>2015</td>
<td>Illinois</td>
</tr>
<tr>
<td>WA Parish</td>
<td>NRG Energy</td>
<td>Coal</td>
<td>60</td>
<td>Post</td>
<td>EOR</td>
<td>2017</td>
<td>Texas</td>
</tr>
<tr>
<td>Sweeney Gasification</td>
<td>ConocoPhillips</td>
<td>Coal</td>
<td>680</td>
<td>Pre</td>
<td>Saline/EOR</td>
<td>Cancelled</td>
<td>Texas</td>
</tr>
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<td>AEP Mountaineer</td>
<td>AEP</td>
<td>Coal</td>
<td>235</td>
<td>Post</td>
<td>Saline</td>
<td>Cancelled</td>
<td>West Virginia</td>
</tr>
<tr>
<td>Taylorville</td>
<td>Tenaska</td>
<td>Coal</td>
<td>602</td>
<td>Pre</td>
<td>Saline</td>
<td>Cancelled</td>
<td>Illinois</td>
</tr>
<tr>
<td>Antelope Valley</td>
<td>Basin Electric</td>
<td>Coal</td>
<td>120</td>
<td>Post</td>
<td>EOR</td>
<td>Cancelled</td>
<td>North Dakota</td>
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</table>

### Canada

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Leader</th>
<th>Feedstock</th>
<th>Size MW</th>
<th>Capture Process</th>
<th>CO2 Fate</th>
<th>Start-up</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boundary Dam</td>
<td>SaskPower</td>
<td>Coal</td>
<td>110</td>
<td>Post</td>
<td>EOR</td>
<td>2014</td>
<td>Saskatchewan</td>
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<tr>
<td>Bow City</td>
<td>BCPL</td>
<td>Coal</td>
<td>1000</td>
<td>Post</td>
<td>EOR</td>
<td>2017</td>
<td>Alberta</td>
</tr>
<tr>
<td>Project Pioneer</td>
<td>TransAlta</td>
<td>Coal</td>
<td>450</td>
<td>Post</td>
<td>Saline/EOR</td>
<td>Cancelled</td>
<td>Alberta</td>
</tr>
<tr>
<td>Belle Plaine</td>
<td>TransCanada</td>
<td>Pet coke</td>
<td>500</td>
<td>Pre</td>
<td>Undecided</td>
<td>Undecided</td>
<td>Saskatchewan</td>
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### European Union

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<th>Feedstock</th>
<th>Size MW</th>
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<th>Start-up</th>
<th>Location</th>
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<tbody>
<tr>
<td>Longannet</td>
<td>Scottish Power</td>
<td>Coal</td>
<td>300</td>
<td>Post</td>
<td>Saline</td>
<td>Cancelled</td>
<td>UK</td>
</tr>
<tr>
<td>Belchatow</td>
<td>PGE</td>
<td>Coal</td>
<td>250-858</td>
<td>Post</td>
<td>Saline</td>
<td>2015</td>
<td>Poland</td>
</tr>
<tr>
<td>Ferrybridge</td>
<td>SSE</td>
<td>Coal</td>
<td>500</td>
<td>Post</td>
<td>Depl. Oil</td>
<td>2015</td>
<td>UK</td>
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<tr>
<td>ROAD</td>
<td>E.ON</td>
<td>Coal</td>
<td>250</td>
<td>Post</td>
<td>Saline</td>
<td>2015</td>
<td>Netherlands</td>
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<tr>
<td>Compostilla</td>
<td>ENDESA</td>
<td>Coal</td>
<td>323</td>
<td>Oxy</td>
<td>Saline</td>
<td>2015</td>
<td>Spain</td>
</tr>
<tr>
<td>Don Valley</td>
<td>2Co</td>
<td>Coal</td>
<td>650</td>
<td>Pre</td>
<td>EOR</td>
<td>2015</td>
<td>UK</td>
</tr>
<tr>
<td>Magnum</td>
<td>Nuon</td>
<td>Various</td>
<td>1200</td>
<td>Pre</td>
<td>EOR/EGR</td>
<td>2020</td>
<td>Netherlands</td>
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<td>Getica</td>
<td>Turceni Energy</td>
<td>Coal</td>
<td>330</td>
<td>Post</td>
<td>Saline</td>
<td>2015</td>
<td>Germany</td>
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<td>Porto Tolle</td>
<td>ENEL</td>
<td>Coal</td>
<td>660</td>
<td>Post</td>
<td>Saline</td>
<td>On hold</td>
<td>Italy</td>
</tr>
<tr>
<td>Project Name</td>
<td>Leader</td>
<td>Feedstock</td>
<td>Size MW</td>
<td>Capture Process</td>
<td>CO2 Fate</td>
<td>Start-up</td>
<td>Location</td>
</tr>
<tr>
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<td>Goldenbergwerk</td>
<td>RWE</td>
<td>Coal</td>
<td>450</td>
<td>Pre</td>
<td>Saline</td>
<td>On hold</td>
<td>Germany</td>
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<tr>
<td>Janschwalde</td>
<td>Vattenfall</td>
<td>Coal</td>
<td>250</td>
<td>Oxy</td>
<td>Saline</td>
<td>Cancelled</td>
<td>Germany</td>
</tr>
<tr>
<td>Norway</td>
<td></td>
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<tr>
<td>Project Name</td>
<td>Leader</td>
<td>Feedstock</td>
<td>Size MW</td>
<td>Capture Process</td>
<td>CO2 Fate</td>
<td>Start-up</td>
<td>Location</td>
</tr>
<tr>
<td>Montag</td>
<td>Statoil</td>
<td>Gas</td>
<td>350</td>
<td>Post</td>
<td>Saline</td>
<td>2012</td>
<td>Norway</td>
</tr>
<tr>
<td>Karste</td>
<td>Naturkraft</td>
<td>Gas</td>
<td>420</td>
<td>Post</td>
<td>Saline</td>
<td>Delayed</td>
<td>Norway</td>
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<tr>
<td>Rest of the World</td>
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<tr>
<td>Project Name</td>
<td>Leader</td>
<td>Feedstock</td>
<td>Size MW</td>
<td>Capture Process</td>
<td>CO2 Fate</td>
<td>Start-up</td>
<td>Location</td>
</tr>
<tr>
<td>Daqing</td>
<td>Alstom &amp; Datang</td>
<td>Coal</td>
<td>350 &amp; 1000</td>
<td>Oxy</td>
<td>EOR</td>
<td>2015</td>
<td>China</td>
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<tr>
<td>GreenGen</td>
<td>GreenGen</td>
<td>Coal</td>
<td>250/400</td>
<td>Pre</td>
<td>Saline</td>
<td>2018</td>
<td>China</td>
</tr>
<tr>
<td>Project Name</td>
<td>Leader</td>
<td>Feedstock</td>
<td>Size MW</td>
<td>Capture Process</td>
<td>CO2 Fate</td>
<td>Start-up</td>
<td>Location</td>
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<td>Schwarze Pumpe</td>
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<td>Coal</td>
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<td>Oxy</td>
<td>Depl. Gas</td>
<td>2008</td>
<td>Germany</td>
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<tr>
<td>ECO2 Berger</td>
<td>Powerspan</td>
<td>Coal</td>
<td>1</td>
<td>Post</td>
<td>Vented</td>
<td>2008</td>
<td>OH, USA</td>
</tr>
<tr>
<td>Pleasant Prairie</td>
<td>Alstom</td>
<td>Coal</td>
<td>5</td>
<td>Post</td>
<td>Vented</td>
<td>2008</td>
<td>WI, USA</td>
</tr>
<tr>
<td>AEP Mountaineer</td>
<td>AEP</td>
<td>Coal</td>
<td>30</td>
<td>Post</td>
<td>Saline</td>
<td>2009</td>
<td>WV, USA</td>
</tr>
<tr>
<td>Shidongkou</td>
<td>Huaneng</td>
<td>Coal</td>
<td>0.1MT/Yr</td>
<td>Post</td>
<td>Comm. use</td>
<td>2009</td>
<td>China</td>
</tr>
<tr>
<td>Lac</td>
<td>Total</td>
<td>Oil</td>
<td>35</td>
<td>Oxy</td>
<td>Depl. Gas</td>
<td>2010</td>
<td>France</td>
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<td>Puertollano</td>
<td>ELCOGAS</td>
<td>Coal</td>
<td>14</td>
<td>Pre</td>
<td>Recycled</td>
<td>2010</td>
<td>Spain</td>
</tr>
<tr>
<td>Brindisi</td>
<td>Enel &amp;Eni</td>
<td>Coal</td>
<td>48</td>
<td>Post</td>
<td>EOR</td>
<td>2011</td>
<td>Italy</td>
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<td>Buggenum</td>
<td>Vattenfall</td>
<td>Coal</td>
<td>20</td>
<td>Pre</td>
<td>Vented</td>
<td>2011</td>
<td>Netherlands</td>
</tr>
<tr>
<td>Callide-A Oxy Fuel</td>
<td>CS Energy</td>
<td>Coal</td>
<td>30</td>
<td>Oxy</td>
<td>Saline</td>
<td>2011</td>
<td>Australia</td>
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<td>Plant Barry</td>
<td>Southern Energy</td>
<td>Coal</td>
<td>25</td>
<td>Post</td>
<td>EOR</td>
<td>2011</td>
<td>AL, USA</td>
</tr>
<tr>
<td>Ferrybridge</td>
<td>SSE</td>
<td>Coal</td>
<td>5</td>
<td>Post</td>
<td>Depl.Oil</td>
<td>2012</td>
<td>UK</td>
</tr>
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<td>Mongstad</td>
<td>Statoil</td>
<td>Gas</td>
<td>0.1MT/Yr</td>
<td>Post</td>
<td>Saline</td>
<td>2012</td>
<td>Norway</td>
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<tr>
<td>Big Bend Station</td>
<td>Siemens</td>
<td>Coal</td>
<td>1</td>
<td>Post</td>
<td>Vented</td>
<td>2013</td>
<td>FL, USA</td>
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<td>Polk</td>
<td>Tampa Electric</td>
<td>Coal</td>
<td>0.3MT/Yr</td>
<td>Post</td>
<td>Saline</td>
<td>2013</td>
<td>FL, USA</td>
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<td>Belchatow</td>
<td>PGE</td>
<td>Coal</td>
<td>250</td>
<td>Post</td>
<td>Saline</td>
<td>2014</td>
<td>Poland</td>
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<td>Karlshamn</td>
<td>E.ON</td>
<td>Oil</td>
<td>5</td>
<td>Post</td>
<td>Vented</td>
<td>2014</td>
<td>Sweden</td>
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<td>Compostessa</td>
<td>ENDESA</td>
<td>Coal</td>
<td>30</td>
<td>Oxy</td>
<td>Saline</td>
<td>2015</td>
<td>Spain</td>
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<td>Kimberlina</td>
<td>Clean Energy Systems</td>
<td>Coal</td>
<td>50</td>
<td>Oxy</td>
<td>Saline</td>
<td>On Hold</td>
<td>CA, USA</td>
</tr>
</tbody>
</table>
APPENDIX F:
ADDITIONAL SUPPORTING INFORMATION
Additional Supporting Information

The following studies and analyses provide instructive cost data on carbon capture/CCS projects.

Alstom CCS Study

A study released in June 2011 by Alstom Power, based on experience from their 13 pilot and demonstration CCS projects and validated by independent experts, concluded that the cost of generating electricity at commercial scale in 2015 will be below 8.5 eurocents/kWh when burning coal (~10.6 cents/kWh at today’s exchange rates) and below 6.5 eurocents/kWh when burning gas (~8.1 cents/kWh at today’s exchange rates). Alstom’s demonstration pilots proved that the full chain of capture and storage technologies can work to remove carbon (captured 90% of CO₂) and store it safely and reliably. More information available at: http://www.alstom.com/press-centre/2011/6/alstom-power-study-demonstrates-carbon-capture-storage-ccs-efficient-cost-competitive.

DOE/NETL Analyses

In the DOE/NETL’s December 2010 “Carbon Dioxide Capture and Storage RD&D Roadmap”, DOE/NETL analyses indicated that for a nominal 550-MW net output power plant, the addition of CO₂ capture technology increased the capital cost of a new Integrated Gasification Combined Cycle (IGCC) facility by $400 million and resulted in an energy penalty of 20%. For post-combustion and oxy-combustion capture, the increase in capital costs was $900 million and $700 million respectively, and the energy penalties would be 30% and 25%. For a Natural Gas Combined Cycle (NGCC) plant, the capital cost would increase by $340 million and the energy penalty would be 15% (DOE, 2010).

As shown below, the reported Levelized Cost of Electricity (LCOE) for CCS plants ranged from $116/MWh to $151/MWh, depending upon the type of facility and whether the application was for a new plant or a retrofit of an existing plant. This compared to an LCOE of $85/MWh for a new pulverized coal plant and $27/MWh for the existing fleet of power plants.

![FIGURE F-1. Estimated Levelized Cost of Energy for Various Types of Power Plants](source: DOE/NETL, 2010)
**2008 DOE REPORT – COST BASELINES**


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<thead>
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<th></th>
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<th>Supercritical</th>
<th>Ultra-</th>
<th>Supercritical</th>
<th>Ultra-Supercritical</th>
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<td></td>
<td></td>
<td></td>
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</tr>
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<td>No</td>
<td>Yes</td>
<td>No</td>
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<tr>
<td>Flue Gas Cleanup</td>
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<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
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<td>CO₂ Capture</td>
<td>-</td>
<td>792</td>
<td>-</td>
<td>749</td>
<td>-</td>
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<tr>
<td>CO₂ Compression</td>
<td>-</td>
<td>89</td>
<td>-</td>
<td>64</td>
<td>-</td>
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<tr>
<td><strong>Total Plant Cost</strong> ($/kWe)</td>
<td>1,549</td>
<td>2,895</td>
<td>1,503</td>
<td>2,857</td>
<td>1,641</td>
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**COE**

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<th>Ultra-</th>
<th>Supercritical</th>
<th>Ultra-Supercritical</th>
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<tbody>
<tr>
<td>Capital Charges ($/kWh)</td>
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<td>6.81</td>
<td>3.44</td>
<td>6.71</td>
<td>3.86</td>
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<tr>
<td>Operating Costs ($/kWh)</td>
<td>2.99</td>
<td>6.43</td>
<td>2.85</td>
<td>4.33</td>
<td>2.60</td>
</tr>
<tr>
<td>CO₂ TS&amp;M$^\text{e}$($/kWh)</td>
<td>0.47</td>
<td>-</td>
<td>0.40</td>
<td>-</td>
<td>0.38</td>
</tr>
<tr>
<td><strong>Total ($/kWh)</strong></td>
<td>6.60</td>
<td>11.88</td>
<td>6.29</td>
<td>11.44</td>
<td>6.46</td>
</tr>
<tr>
<td>Increase in COE (%)$^\text{f}$</td>
<td>-85</td>
<td>-82</td>
<td>-75</td>
<td>-80</td>
<td>-71</td>
</tr>
<tr>
<td>$/ton CO₂ avoided$</td>
<td>-75</td>
<td>-68</td>
<td>-61</td>
<td>-57</td>
<td>-50</td>
</tr>
</tbody>
</table>

The following are the steam cycle design conditions (steam pressure [psig] / main steam [°F] / temperature [°F]) for the five pulverized coal (PC) power plant types: Subcritical 2400/1050/550, Supercritical 3500/1100/1100, Ultra-Supercritical 4000/1350/1400, Supercritical Oxyfuel 3500/1100/1150, and Ultra-Supercritical Oxyfuel 4000/1350/1400.

**Figure F-2. Estimates of the Cost of CO₂ Capture from Coal-Fired Power Plants and Sequestration in Geologic Formations**

**SOURCE:** DOE/NETL, 2008

A sensitivity study on natural gas prices referenced in the report revealed that the cost of electricity (COE) for an Integrated Gasification Combined Cycle (IGCC) plant was equal to that of a Natural Gas Combined Cycle (NGCC) plant at $7.73/MMBtu, and for pulverized coal, the COE was equivalent to NGCC at a gas price of $8.87/MMBtu. In terms of capacity factor, when the NGCC drops below 60 percent, such as in a peaking application, the resulting COE is higher than that of an IGCC operating as baseload at an 80 percent capacity factor.
2007/2008 DOE REPORT – SCENARIOS

Another DOE report (Ciferno, DOE/NETL-2007/1301) examined, in great detail, the question of whether it is more cost effective to design a new plant in anticipation of future restrictions on carbon emissions so that the plant is CO₂ “capture-ready” or to proceed with no anticipation of a future retrofit. The report created eight different scenarios: four for an Integrated Gasification Combined Cycle (IGCC) plant and four for a pulverized coal (PC) plant, ranging from business as usual (BAU), retrofit, capture-ready, to capture-ready retrofit.

The IGCC scenarios used a plant design with ConocoPhillips “E-Gas” gasification technology and a carbon dioxide recovery system that would remove 90% of the CO₂ via a water-gas shift reactor, CO₂ absorption system, solvent stripping/reclaiming system, and CO₂ compression/purification system. Specifically, the Selexol two-stage acid gas removal process was selected.

The pulverized coal cases utilized a carbon dioxide recovery system to remove 90% of the CO₂ in the flue gas using an amine-based process (Fluor Econamine FG+).

The “Total Plant Cost” for each case from that report is shown in the following figure. It indicates that the total cost for the retrofitted pulverized coal plants was substantially higher than the retrofitted integrated gasification combined cycle plants on an unit basis ($/kW).

![FIGURE F-3. Total Plant Costs for Various IGCC and PC Scenarios](source: DOE/NETL, 2008)
The following figure, also from that report, shows the differences between the levelized cost of energy (LCOE) for all cases. Consistent with reported results elsewhere, the LCOE for a conventional pulverized coal power plant without CO₂ capture was the lowest cost option. However, upon retrofitting for CO₂ capture, the cost of electricity for pulverized coal power plants was estimated to be higher than IGCC.

![FIGURE F-4. Calculated LCOE for Various IGCC and PC Scenarios](Image)

The complete report is available at:

**Front-End Engineering Design Study for Tenaska Trailblazer**

The Front-End Engineering Design (FEED) Study for Tenaska’s Trailblazer plant is also publicly available and contains some very useful cost data. One of the excerpts:

“One of the well-known challenges with CCS is the cost – primarily in terms of the capital cost and energy consumption. Under current market conditions, power plants with CCS cannot compete with those without CCS. The strategic location of the Project provides the ability to sell CO₂ into the mature Permian Basin EOR market. This defrays some of the costs of CCS. However, the current CO₂ market prices are insufficient to cover the entire costs of CO₂ capture. In addition, the CO₂ prices vary as a function of oil prices, which introduces uncertainty in this revenue stream over the life of the Project.”

Summary of Design Studies from Global CCS Institute 2011 Report

The Global CCS Institute’s 2011 Global Status of CCS report included the following useful table that summarized comparison data from “recent” design studies:

TABLE F-1. Summary of Results from Recent CCS Studies

<table>
<thead>
<tr>
<th></th>
<th>POST COMBUSTION</th>
<th>IGCC</th>
<th>OXYFUEL</th>
<th>NGCC</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>WORLEY PARSONS</td>
<td>NETL</td>
<td>IEA</td>
<td>WORLEY PARSONS</td>
</tr>
<tr>
<td>Capacity</td>
<td>546 (net)</td>
<td>550</td>
<td>474</td>
<td>517</td>
</tr>
<tr>
<td>Total overnight cost</td>
<td>4701</td>
<td>3570</td>
<td>3838</td>
<td>4632</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>US$/kW</td>
<td>16</td>
<td>22</td>
<td>14</td>
</tr>
<tr>
<td>Fuel cost</td>
<td>US$/MWh</td>
<td>34</td>
<td>20</td>
<td>13</td>
</tr>
<tr>
<td>Capture rate</td>
<td>%</td>
<td>90</td>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>Efficiency²</td>
<td>%</td>
<td>27.2</td>
<td>26.2</td>
<td>34.8</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>%</td>
<td>85</td>
<td>85</td>
<td>85</td>
</tr>
<tr>
<td>Lead time</td>
<td>Years</td>
<td>4</td>
<td>5</td>
<td>4</td>
</tr>
<tr>
<td>Lifetime</td>
<td>Years</td>
<td>30</td>
<td>30</td>
<td>40</td>
</tr>
<tr>
<td>Discount rate</td>
<td>%</td>
<td>8.8</td>
<td>9.1</td>
<td>10</td>
</tr>
<tr>
<td>Transport¹</td>
<td>US$/MWh</td>
<td>1</td>
<td>n/a</td>
<td>1</td>
</tr>
<tr>
<td>Storage</td>
<td>US$/MWh</td>
<td>6</td>
<td>5.6</td>
<td>n/a</td>
</tr>
<tr>
<td>LCOR²</td>
<td>US$/MWh</td>
<td>131</td>
<td>135</td>
<td>90</td>
</tr>
<tr>
<td>Avoided cost of CO₂³</td>
<td>US$/tonne</td>
<td>81</td>
<td>87</td>
<td>-75</td>
</tr>
</tbody>
</table>

1. IEA estimates only include the cost of capture and compression.
2. Base year in which current dollars are reported.
3. The NETL study includes payroll and property taxes, these taxes are not included in the other studies.
4. The IEA report lower heating value (LHV) net heat efficiency rates, whereas the other two studies report higher heating value (HHV) net heat efficiency rates.
5. Transport distances are assumed to be 100km and 80km by Worley Parsons and DOE NETL studies respectively. For DOE NETL transport costs are included in the storage item.
6. The NETL study includes payments for liability for 30 years.
7. Levelised cost of electricity.
8. Reference facility in all coal technologies is supercritical pulverised coal within each study. Values for DOE NETL studies calculated by Global CCS Institute.

SOURCE: Global CCS Institute, 2011
