REGULATORY ANALYSIS AND ENVIRONMENTAL IMPACT OF CARBON CAPTURE AND SEQUESTRATION USING THE NET Power TECHNOLOGY

by

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May 2013

Master's project submitted in partial fulfillment of the requirements for the Master of Environmental Management degree in the Nicholas School of the Environment of Duke University

2013
Abstract

Regulatory developments in the United States, coupled with low natural gas prices, have altered the economics of electricity generation. Through both court orders and its own regulatory review, the Environmental Protection Agency has made coal combustion especially unattractive for new generation. Low natural gas prices have driven extensive investment in combined cycle and combustion turbine systems. However, natural gas prices have historically been volatile and it is reasonable to assume current low prices will not be the norm. Given that the equipment and techniques needed to sequester carbon dioxide in geologic formations already exist, it is the goal of this paper to show that efficient and low cost carbon capture power plants will be attractive to utilities wanting to maintain a diversity of fuels while complying with new regulations. NET Power's technology will serve as a model for meeting the new environmental regulations.

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Introduction

With increased concern about climate change, technologies are being developed to allow for the utilization of fossil fuel combustion while avoiding greenhouse gas emissions. Carbon capture and sequestration offers to provide a way in which vast and cheap fossil fuel resources can be exploited while minimizing further threats to the climate system. Given the abundance and ease of extraction for many fossil fuels, it is unreasonable to think that these sources of energy will not play an important role in developing economies. Within the context of the United States, fossil fuel combustion for all forms of energy generation accounts for around eighty percent of the greenhouse gas emissions from the United States. Given that fossil fuels (petroleum, natural gas, and coal) have historically provided 1%, 24%, and 44% of the original sources of energy used in electricity generation, if the United States is to seriously curb its carbon dioxide emissions from electricity generation, seventy percent of the electricity source will have to undergo massive changes.

Carbon capture and sequestration (CCS) represents a technology that can serve as a bridge to the development of a cleaner economy. This project will examine the current state of technology for carbon capture and sequestration and the environmental impacts that one can anticipate from different technological options. Of special note will be NET Power, a novel CCS technology funded by 8Rivers Capital of Durham, North Carolina, which will be part of this review and will serve as a further in-depth case study of how up-scaling of CCS technologies will likely unfold through exploration of the regulatory framework that will affect CCS from fuel to sequestration. Key to understanding the rationale for large scale CCS will be an analysis of the current framework of environmental regulations driving changes in the utility sector.

A Primer in Current Environmental Controls for Power Plants

Before one can fully understand the technological and economic challenges that carbon capture poses to electric utilities, it is important to first understand the current environmental control technologies used in power plants. Environmental controls are added because fossil fuels such as coal, natural gas, and petroleum have impurities and also produce harmful byproducts once undergoing combustion. In the case of coal, the most common impurities are sulfur, mercury and other heavy metals, toxic elements such as selenium, and particulate matter. Natural gas is typically processed before entering distribution pipelines so the gas is usually fairly clean. For both coal and natural gas, a major byproduct of combustion is oxides of nitrogen. These form when atmospheric nitrogen is heated to a high temperature such as those found in boilers or turbines. Both of these major pollution sources are controlled by using specially designed equipment.

In the case of coal, particulate matter is removed by an electrostatic precipitator (ESP). The ESP uses a high voltage passed through wired to produce corona discharge. The wires work as an anode emitting electrons, which then pass to the cathode of the collector plate. As the current moves through the field, it picks up the particles in the flue gas and removes them from the gas stream through

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Nitrogen oxides are controlled by a selective catalytic reduction system (SCR). SCRs use a vanadium/titanium catalyst to turn the nitrogen oxides back into nitrogen and water. Ammonia reacts with the flue gas in the presence of the catalysts to facilitate a reaction such as: $4\text{NO} + 4\text{NH}_3 + \text{O}_2 \rightarrow 4\text{N}_2 + 6\text{H}_2\text{O}$.

Figure 2: SCR Schematic; Source: Primasonics

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Flue Gas Desulfurization uses gypsum to absorb sulfur dioxide and create solid sulfur based compounds. These compounds can be used in various applications such as the production of wallboard in construction. FGD units are either wet, meaning the chemistry is aqueous, or dry, meaning the sulfur absorbing compounds are injected in the boiler and captured. Almost 85% of systems installed in the United States are wet systems like the one depicted below.\(^5\)

![Figure 3: Wet Flue Gas Desulfurization; Source: Hamon Enviroserv](image)

All of these technologies require energy to run. One major point of contention in adding environmental controls to power plants is the extent to which the control systems add a parasitic loss to the plant. The energy it takes energy to run environmental control equipment is not available to the wider grid. When first debuted, many of the environmental controls were designed to meet standards set by the Environmental Protection Agency but where not optimized for overall plant efficiency. In a 1986 study, R. Färe et al. found that non-baseload coal plants were especially adversely affected by the increased parasitic loses due to added environmental controls.\(^6\) More recent studies have attempted to quantify the amount of energy “lost” through emission control technologies. A 2007 study found that for coal plants, the addition of sulfur dioxide and nitrogen oxide controls only decreased efficiency by about 2%.\(^7\) For natural gas plants, the loss of efficiency was around 1%.\(^8\)

There is a technical precedence for utilities adapting to emissions standards. Sulfur dioxide was a major environmental pollutant until the 1990 Amendments to the Clean Air Act forced electric utilities to develop control technology. These technologies ended up costing a great deal less than anticipated due to the trading scheme around SO\(_2\) allowances and because of falling low sulfur coal

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8 Ibid.
prices. How the market, regulators, and society decided to deal with carbon dioxide will have significant impacts in the ultimate technological outcome of the transition away from a carbon unconstrained economy to an economy with carbon constraints. Carbon capture and sequestration technologies could serve the need of providing electricity from fossil fuels while avoiding climate damage but these systems are going to be far more complex than any of the emission control technologies previously introduced into the market.

**Carbon Capture and Sequestration**

Carbon capture and sequestration (CCS) represents a strategy that could be employed in maintaining society's use of fossil fuels in a carbon constrained economy. In this report, the technical aspects of the process will be broken down into two technical discussions looking at the current state of the capture of carbon dioxide and its sequestration in a variety of settings. Each of these stages provides distinct environmental challenges that will have to be addressed going forward. The combustion of any fossil fuel provides a number of waste streams or byproducts. The ash left from solid fuel combustion and the gaseous emissions have to be properly managed to comply with various environmental regulations to ensure public health and well-being. On the energy production side, it is these aspects of fossil fuel combustion that have been the source of much concern. Ash can contain high levels of toxic elements; oxides of nitrogen lead to air quality deterioration and carbon dioxide is contributing to global climate change. Any CCS system will have to address not only the carbon dioxide but these other environmental hazards as well without creating novel environmental concerns.

**Carbon Capture Plant Processes**

Currently, a number of different technologies have been proposed or utilized in carbon capture. There are three primary ways in which the carbon dioxide can be removed from the flue gas in a power plant boiler: post combustion capture, pre-combustion separation, and oxyfuel cycles. Each of these techniques has been developed in response to differing needs within industry. Post combustion capture would be ideal in applications where a plant is already constructed and in need of a carbon capture retrofit. Pre-combustion treatment is another alternative retrofit but it could also be incorporated in a new plant design far more seamlessly. Oxyfuel combustion represents the current leading edge of carbon capture technologies and would require such extensive retrofitting of existing infrastructure that it is unlikely to be utilized in existing plants.

Post-combustion capture is by far the most common and most easily implemented in an existing plant. The flue gas, rather than being directly vented, is instead processed using some method of separation to isolate the carbon dioxide from other co-products of combustion. The costs of the retrofits are quite high and, without a price on carbon, it is unlikely that many plants will adopt the technology. Post-combustion systems use a chemical solvent, these are usually a class of organic compounds called amines but any chemical that can trap carbon dioxide and then be heated to release the CO2 is viable. Much like other environmental controls used today, post-combustion systems Southern Company’s Plant Barry is an example of a post-combustion capture plant. Built in Alabama in 2011, the plant uses a solid amine scrubbing method developed by Mitsubishi Heavy Industries to

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11 Irvin, Nick. "Southern Company/MHI Ltd. 500 TPD CCS Demonstration." SECARB 2013. Atlanta, Georgia: Southeast
remove the equivalent carbon dioxide of a 25 megawatt plant from an over 2,000 megawatt capacity plant. The plant’s capture equipment takes the flue gas and concentrates the carbon dioxide component of the gas stream where it contacts the amine scrubbing unit. The captured CO₂ is then sent to a nearby oil field for injection.

Pre-combustion separation is a method that can be incorporated into new Integrated Gasification Combined Cycle power plants. These power plants do not burn the fossil fuel but rather break down the fuel via pyrolysis (high temperatures in the absence of oxygen) to form synthesis gas. Syngas is a combination of carbon monoxide, hydrogen, and carbon dioxide. Once exposed to water, the syngas's carbon monoxide component oxidizes water to produce more hydrogen and carbon dioxide. The lack of air (and therefore nitrogen) means that a gas stream of mostly carbon dioxide is present and this is then removed using a capture process. The hydrogen is then burned in a turbine to produce electricity and water vapor. In the future, fuel cells may replace the turbines and overall efficiency in the plants could be as high as 70%.

The third method attempts to resolve much of the trouble with separating carbon dioxide in post combustion processes. The technical challenges are due to the difficulty in separating the co-produced gases (NOₓ, SO₂) in the flue gas from the CO. Creating an artificial atmosphere of highly concentrated oxygen can remove this problem and allow for post-combustion separation of carbon dioxide at efficiencies comparable to pre-combustion processes. The technology for such operations already exists within the steel industry. The Basic Oxygen Furnace (BOF) is used in the production of steel to carbonize and purify the alloy through the oxidation of impurities by lime and other fluxes to create slag. It employs an "oxygen lance" that is injected into the molten steel and forces oxygen through the melt to react with impurities like phosphorous.

Figure 4: Basic Oxygen Furnace; Source: General Chemistry: Principles, Patterns, and Applications (by Bruce Averill and Patricia Eldredge)
Similar technologies would be employed in the generation of electricity. This would include equipment like an air separation unit that utilizes fractional liquefaction to separate oxygen from the other gases of the atmosphere. The high oxygen environment removes the problem of NOx and also allows for a higher temperature inside the combustion chamber thus increasing the Carnot efficiency of the plant. In order to accommodate the higher temperatures of combustion, the boilers and turbines of the plant will have to be retrofitted or replaced. One crucial limitation to the increase of the temperature of combustion is the increase in the creep temperature of metals. Stainless steel or similar alloys are often used in many parts of a power plant. While these materials are resistant to high heat, long term exposure will cause the metal to slowly deform or “creep,” which means there is a limit to how hot a component can get safely without risk of failure.

**Combustion Processes, Gas Pre-Processing, and Sequestration**

When a hydrocarbon or coal is burned in a standard atmosphere, it produces a great many co-products of combustion. Natural gas represents the simplest model by which the process can be articulated. Natural gas is primarily CH₄ and when burned in the reaction, CH₄ + 2O₂ → 2H₂O + CO₂ creates water and carbon dioxide. At the same time, nitrogen present in the atmosphere will oxidize in the same combustion chamber to produce another class of greenhouse gasses: oxides of nitrogen. The United States Environmental Protection Agency classifies NO₂ as a criteria air pollutant as defined in the Clean Air Act. With any combustion chamber at a high enough temperature, atmospheric nitrogen (dimolecular) will break down and combine with oxygen to form NOₓ. EPA lists respiratory problems from NO₂ exposure and tropospheric ozone exposure from the photo-decomposition of volatile organic compounds with NO₂ as the main reason for regulating exposure. Water present in the flue gas has to be removed or it will corrode piping and the NOₓ must also be neutralized to comply with regulations.

The carbon dioxide, once separated, can then be compressed and sent via pipeline to its eventual site for storage. Petroleum and natural gas have a degree of contamination issues (sulfur) mostly of hydrocarbon molecules. This makes capture much easier if there are fewer contaminating compounds with which to contend. Coal is most problematic for carbon capture and sequestration. The presence of sulfur in the coal, along with trace metals, requires that the flue gas be handled carefully to neutralize these hazards. Studies have shown that the total emissions of sulfur dioxide will actually decrease in a plant equipped with carbon capture because the chemicals used to trap the carbon dioxide will preferentially capture sulfur dioxide. However, this preferential binding to SO₂ in the carbon capture system means a lack of control on the amount of sulfur entering the capture system would contaminate and deplete the carbon absorbing compounds. Therefore, it is imperative that the SO₂ be removed via the normal scrubbing process before the gas stream enters the carbon capture process. The treatment of the flue gas in the plants will require energy to remove the carbon dioxide as well as the sulfur dioxide. These “parasitic” losses will decrease the overall efficiency of the plant, requiring more fuel for energy generation. This increase in fuel consumption will mean more extraction of resource and all of the accompanying environmental degradation associated with mining.

The extent to which the efficiencies of the plants are affected by the extra energy demand for the capture equipment depends on the type of plant. The Intergovernmental Panel on Climate Change found that the decrease in efficiency varied by technology but for natural gas combined cycle plants,
the decrease in efficiency was between 11–22%, for pulverized coal plants it was a reduction of 24–40%, and for integrated gasification combined cycle plants 14–25%. This loss of efficiency means that with large scale use of carbon capture technologies, the consumption of natural gas per power plant could increase by as much as 22% while coal fired power plants might require 40% more coal.

The systems that remove the carbon dioxide are fairly straightforward and comparable to the way in which sulfur dioxide is removed. Effectively, the flue gas from combustion is contained and processed through a water shift phase reaction. An amine solution is utilized as the catalyst for capturing the carbon dioxide. The saturated solution is then heated to liberate the carbon dioxide, which is then captured and moved to the sequestration site.

![Schematic of an Amine CO₂ Scrubber](source: Cooperative Research Centre for Greenhouse Gas Technologies)

Once the gas is cleaned and the carbon dioxide pressurized, it can then enter a pipeline or container to be moved to the site of injection. A number of different methods have been proposed for sequestration. These include:

1. Depleted oil and gas reservoirs
2. Use of CO₂ in enhanced oil recovery
3. Deep saline aquifers
4. Deep unmineable coal seams
5. Use of CO₂ in enhanced coal bed methane recovery
6. Other options such as basalts, oil shales, rock or salt cavities
7. Deep ocean injection

**Geologic Characterization of Desired in Sequestration Formations**

Fundamentally, the geology that one desires for good geological storage is the geology that one looks for when seeking oil or natural gas, only in reverse. Instead of finding hydrocarbon-occupied pore space with an impermeable cap rock, one needs to find rock with high porosity and high permeability with an

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20 Ibid.

The integrity of the cap rock is very important for keeping the carbon dioxide sequestered. The carbon dioxide needs to stay geologically immobilized effectively for thousands of years. In any geologic sequestration, leakage is a serious concern; when site surveys are conducted, it will be important to note all of the risk factors in an area that could lead to a leakage of carbon dioxide.

The transportation of carbon dioxide to these sites will almost certainly be done by pipelines. This will require a build out of lines to collect carbon dioxide and connect sources with the geologic sinks and therefore will take time and have potentially high costs. Already, companies like Denbury Resources are using their enhanced oil recovery operations to build out a carbon dioxide pipeline infrastructure that could be leveraged as part of a future anthropogenic carbon dioxide sequestration network. Analysis of the proper way in which one can site the pipeline infrastructure will be crucial to minimizing these costs and will also have to be integral to the overall environmental impact assessments conducted before projects are implemented.

To an extent the work of characterizing formations and siting pipeline has already been undertaken. In his 2011 doctoral dissertation, Jordan Eccles outlined the numerous geological challenges to a commercially viable sequestration network. Utilizing a cost estimate of sequestration for a series of deep saline aquifers and controlling for those formations in which the carbon dioxide would remain supercritical, Eccles was able to lay the ground work for modeling a base case of the costs involved in onshore sequestration.

In examining individual formations, Eccles found that the estimated costs of placing one ton of carbon dioxide into the ground was relatively inexpensive, ignoring transportation costs for some parts of the United States. However, from the results of the modeling conducted for his dissertation, it became apparent that there was a high degree of heterogeneity with respect to cost of CO2 sequestration within formations. The reasons for the variability of cost are numerous, but physical storage capacity within a formation was the prime driver. Using the same data set, Eccles initially created a model to estimate the capacity for carbon dioxide sequestration in the deep saline aquifers for which he had data.

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The areas with the greatest storage capacity are highly correlated with the areas in which sequestration would be the cheapest.

In a 2012 follow up paper, Eccles and a team from Duke University that included geologist Lincoln Pratson, economist Richard Newell, and environmental scientist Robert Jackson looked at the individual costs within each formation relative to storage capacity and concluded that two formations, the Frio deep saline aquifer on the Gulf Coast of Texas and Mount Simon in Michigan had the lowest costs and the greatest storage potential of the formations outlined. In light of the variability, Eccles et al. recommended that further study be undertaken to optimize the routing of pipelines from sources of carbon dioxide to the ultimate sinks. The reasoning was fairly straightforward: under their model, 19% of the total surface area constituted 83% of the storage capacity. In order to get appropriate scales of economy for sequestration, it would be necessary for planners to construct CO2 pipelines that were routed to these large capacity formations. As data on all sequestration formations improve, pipeline network planning will become more rational.

One limitation of Eccles’ study was that it was limited to non-oil bearing formations. At present, almost all large scale injection projects in the United States are being done in conjunction with the goal of enhancing oil recovery. Because there is not currently a price on carbon, enhanced oil recovery through carbon dioxide injection is serving as the test bed for injection of anthropogenic carbon dioxide into geologic formations. Despite this limitation, Eccles’ research and the work of others show the existence of a large storage potential for carbon dioxide. The use of carbon dioxide in enhanced oil recovery has aided in developing the technical know-how needed for developing sequestration techniques. For these reasons, the ability to sequester carbon dioxide in sedimentary environments has become viable and is improving steadily.

The more challenging geologies for sequestration might also be the more promising formations in terms of overall carbon absorption capacity. Mafic and Ultramafic rock formations have been proposed as key areas for sequestration. Naturally, minerals such as olivine [(Mg,Fe)2SiO4] and pyroxene [XY(Si,Al)2O6 X: Ca, Na, Mg, Zn, Mn, Li; Y: Al, Cr, Fe3+, Mg, Mn, Sc, Ti, V, Fe2+] will react with carbon dioxide and break down to form carbonate compounds. The generation reaction follows.


Table 1: Capacity and Cost of Storage for Deep Saline Aquifers; Source: Eccles et al. 2012

<table>
<thead>
<tr>
<th>Formation</th>
<th>Capacity (tonnes/km²)</th>
<th>Cost (USD/tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mean</td>
<td>Median</td>
</tr>
<tr>
<td>Mt. Simon</td>
<td>1,548,029</td>
<td>1,496,750</td>
</tr>
<tr>
<td>Frio</td>
<td>2,327,130</td>
<td>1,924,250</td>
</tr>
<tr>
<td>Cape Fear</td>
<td>105,068</td>
<td>49,253</td>
</tr>
<tr>
<td>Potomac</td>
<td>1,024,215</td>
<td>951,210</td>
</tr>
<tr>
<td>Oriskany</td>
<td>29,795</td>
<td>23,573</td>
</tr>
<tr>
<td>Lyons</td>
<td>95,332</td>
<td>86,246</td>
</tr>
<tr>
<td>Paluxy</td>
<td>173,160</td>
<td>176,955</td>
</tr>
<tr>
<td>St. Peter</td>
<td>149,463</td>
<td>153,425</td>
</tr>
<tr>
<td>Granite Wash</td>
<td>383,129</td>
<td>241,760</td>
</tr>
<tr>
<td>Fox Hills</td>
<td>180,777</td>
<td>201,030</td>
</tr>
<tr>
<td>Woodbine</td>
<td>312,126</td>
<td>275,980</td>
</tr>
<tr>
<td>Morrison</td>
<td>488,668</td>
<td>483,095</td>
</tr>
<tr>
<td>Repetto</td>
<td>611,236</td>
<td>133,060</td>
</tr>
</tbody>
</table>
as: silicate rock + water + carbon dioxide → soil + cations + bicarbonate.\textsuperscript{28} Large scale studies have been undertaken to determine the extent to which such geo-engineering projects could aid in removing carbon dioxide from the atmosphere. In a 2010 paper, Kohler et al found that if emissions could be reduced to half of their present levels (down to 4 petagrams CO\textsubscript{2} per year) then enhanced weathering of minerals like olivine could have a significant effect in bringing net emissions down significantly.\textsuperscript{29} Kohler et al. 2010 suggested large dunite complexes in the Amazon and Congo basin for their projects. Such a scheme would involve mining the dunite and then weathering the rock to remove carbon dioxide. The author’s acknowledged the impracticality of this proposal but other techniques could be applied. Injecting the carbon dioxide into the rock could be a way of getting the mineralization reaction to move forward without resorting to large scale strip mining. Jordan Eccles came to similar conclusions in his dissertation and proposed using basaltic basement rocks as a target formation for sequestration as well as potentially opening up oceanic crust to sequestration.\textsuperscript{30}

With the experience of handling and injecting carbon dioxide for enhanced oil recovery, industry is starting to cultivate the skill sets needed for carbon sequestration. Studies characterizing the chemical reactions and types of formations needed for CCS have shown that there is a great deal of storage potential. Further study is needed to fully quantify the amount of storage capacity the planet actually has, but from the perspective of using CCS as a transitional technology, it would seem that geologic characteristics are not an overwhelming impediment to sequestration.

Environmental, Technological, and Economic Challenges to CCS

Carbon Capture and Sequestration will have a significant number of benefits for the environment, both local and global. Globally, the adoption of carbon capture and sequestration would do much to reduce global greenhouse gas emissions from the generation of electricity and other point sources. The Intergovernmental Panel on Climate Change estimates that current technology can capture between 85-95\% of the carbon dioxide a plant would have otherwise emitted.\textsuperscript{31} If widely adopted, measures to capture and store carbon dioxide mean that global point sources of emissions of carbon dioxide could be cut drastically.

In 2008, the Energy Information Administration estimated that 81.3\% of all United States greenhouse gas emissions came from the fuels or electricity generation and of that 81.3\%, 40\% was from electricity generation.\textsuperscript{32} By another estimate, the United States Environmental Protection Agency estimated that in 2006, 41\% of all greenhouse gas emissions came from the generation of electricity and were the largest single source of emissions.\textsuperscript{33} Heavy industry also represents a large source of greenhouse gas emissions, and in many cases these processes could also benefit from carbon capture and sequestration technologies to lower emissions further. This is easily the single largest benefit from

\begin{footnotesize}
\begin{itemize}
  \item \textsuperscript{28} Schuiling, R.D., and P. Krijgsman. "Enhanced Weathering: An Effective and Cheap Tool to Sequester CO\textsubscript{2}.” Climate Change. no. 74 (2006): 349-354.
  \item \textsuperscript{29} Kohler, P. J. Hartman, D.A. Wolf-Gladrow. “Geoengineering potential of artificially enhanced silicate weathering of olivine.” Proceedings of the National Academy of Science USA. no. 107 (2010): 20228-20233.
  \item \textsuperscript{31} Metz, Bert, Ogunlade Davidson, Heleen de Coninck, Manuela Loos, and Leo Meyer. "IPCC Special Report Carbon Dioxide Capture and Storage Summary for Policymakers A report of Working Group III of the IPCC and Technical Summary A report accepted by Working Group III of the IPCC but not approved in detail." 2005.
\end{itemize}
\end{footnotesize}
adopting carbon capture and sequestration. It allows for the continued use of fossil fuels to meet energy demands such as base load power where renewable sources are not yet able meet demand.

Other benefits from carbon capture and storage include reduced SO₂ emissions due to the added processing of the flue gas. Other such reductions would be seen in the emission to the atmosphere of mercury, NOₓ, volatile organic compounds, and air toxics. In many respects, carbon capture would necessitate the conversion of most air pollution problems to solid wastes. The sulfur and air toxics emitted through combustion would have to be captured in the same systems that capture and isolate the carbon dioxide. Furthermore, if carbon capture and sequestration is coupled with the combustion of biomass, under the right conditions it would effectively act as a carbon negative process, removing carbon dioxide from the terrestrial environment.³⁴

**Carbon Capture, Utilization, and Sequestration: Economically Viable Options for Sequestration**

Currently, the only way in which any carbon sequestration is economically viable is through carbon capture, use, and sequestration (CCUS). CCUS is any process in which the carbon dioxide is used for industrial processes or for resource extraction before it is sequestered. The added economic benefit or commodity value of the carbon dioxide is what sustains those CCS projects that have already gone forward. The most common form of CCUS at present is in Enhanced Oil Recovery (EOR). EOR uses the carbon dioxide as a means of re-pressurizing wells for petroleum or natural gas production. It has an added environmental benefit as it is more effective than water or steam injection in these applications. Carbon dioxide has also been proposed and tested as a working fluid for hydraulic fracturing of natural gas wells.³⁵ Using carbon dioxide would have the benefit of reducing the amount of water used in fracturing a well, leaving only the “produced water” from the formation left to be treated.

With enhanced oil recovery, there is a high probability for at least some sequestration to take place, even when accounting for the burned petroleum products. Some of the carbon will remain in the reservoir rock, and if this is greater than the amount of carbon released through the combustion of all of the hydrocarbons extracted from the well, the net result will still be a reduction in emissions. Some studies in Norway have shown that it is possible to reduce the emission per barrel of oil if using carbon dioxide-based EOR, but the applicability to other fields is unclear.³⁶ If it is not the case that the carbon stays in the targeted formation, analysis on the means of carbon dioxide escape from the reservoir rock will have to be implemented as well as the emissions from the combustion of the petroleum.

**Foreseeable Limits to the Environmental Performance of Carbon Capture and Sequestration**

Carbon Capture and Sequestration will have a significant number of consequences for the environment, both local and global. Local effects to anticipate with analyzed technologies will include increased demands for water at both the power plants and at the injection sites.³⁷ A study commissioned by the Department of Energy foresaw a number of important changes in the way in which the water at power plants would be utilized.³⁸ In thermo-electric power cycles, water is defined

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as having been withdrawn (pulled from some reservoir) and water that is consumed (evaporated and not available to the local environment or otherwise rendered unusable) in either the cooling or power generation operations of the plant. The Department of Energy study found that by adding carbon capture technologies, pulverized coal plants would increase withdrawals from ~600 gallons per megawatt-hour (gal/MWh) to ~1,200 gal/MWh, consumption would increase from less than 500 to ~900 gal/MWh. The table below shows the full results for super-critical pulverized coal and integrated gasification combined cycle plants.

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Water Withdrawn (gal/MW/hr)</th>
<th>Water Consumed (gal/MW/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Without CC</td>
<td>With CC</td>
</tr>
<tr>
<td>Pulverized Coal</td>
<td>600</td>
<td>1200</td>
</tr>
<tr>
<td>Supercritical PC</td>
<td>550</td>
<td>1050</td>
</tr>
<tr>
<td>IGCC</td>
<td>400</td>
<td>600</td>
</tr>
</tbody>
</table>

Table 2: Water Withdrawals and Consumption Under Different Coal Combustion Scenarios; Source: Ciferno et al. 2010

With almost every technology, there is a doubling or near doubling of both the consumed and withdrawn water. For those regions of the world where freshwater is in short supply, the adoption of carbon capture and sequestration technologies will prove a severe hurdle.

Despite the technological "need" for more water in CCS power plants, broader climate change policy options could result in overall lower uses of freshwater as the electricity sector would re-equilibrate to find the lowest cost of generation. In their 2011 study, Munish Chandel, Lincoln Pratson, and Robert Jackson used a previously introduced bill in the U.S. Congress as a basis for modeling the effect these climate change policy proposals would have on water usage.39 Chandel et al. used a modified version of the National Energy Model (NEMS) to simulate how the market would respond to various prices on carbon. The researchers found that under different carbon prices, the market would shift away from increased electricity generation as the cost of electricity increased. This would decrease water use through the reduced demand for electricity. However, in their conclusions Chandel et al. noted that regional changes in water availability due to climate change could affect the ability to generate electricity.

**Climate Change Could Affect the Performance of Current CCS Technologies**

Issues surrounding water are not limited just to plants that look to add carbon capture equipment. Chandel et al. noted in their conclusions that a possible risk to thermoelectric power generation was increased drought conditions in the United States. Extensive modeling has been done to try and estimate the degree to which increased global temperatures would affect the climate of the United States. While limited in scope to the Western US, David Gutzler and Tessia Robbins’s 2010 paper provides a scorching assessment of the likelihood increased drought in the region. Their modeling efforts of climate in the US West found “that twenty-first century droughts [will be] driven by temperature to a greater degree than historical droughts. Recovery from historically precipitation-driven drought, repeated in these scenarios in the twenty-first century, is inhibited by the increased evaporation implied by warmer temperature in the climate change scenario developed [in the

Some of the scenarios modeled by Gutlzer and Robbins utilized the 1930s Dust Bowl as a case study of what a similar climate anomaly would look like with future climate change. Set in 2030, there would still be sufficient precipitation increase to offset such a severe drought, but by after 2050, the model predicted far worse droughts than experienced in the 20th century.

**Current CCS Systems are Inefficient and Expensive**

Water is not the only resource that will see an increase in demand with carbon capture and sequestration. The fuels that go into the power plants will also increase in demand. The amine scrubbing systems require a lot of energy to remove the carbon dioxide from the flue gas. These "auxiliary" systems reduce overall plant efficiency by as much as 15 to 25%. Much of this depends on what technologies are employed. In a macro-economic analysis of the deployment of CCS in the United Kingdom, researchers estimated that plant efficiencies would decrease between 14 to 30% depending on the technology employed. The net effect will be an increased demand for energy resources with comparable increases in the mining and extraction of fossil fuels. Therefore, while current carbon capture technologies could do much to allow for the continued use of fossil fuels, such technologies would expedite the rate at which resources are used. Land use changes such as increased mountain top removal and accompanying habitat loss would be the main environmental effects that accompany such a technological transition.

The deterioration of performance of fossil fuel combustion is a major impediment to the ready adoption of such technologies into the market. Not only do some proposed CCS plants increase environmental harm due to water use and added fuel inputs, but they also add higher operations and maintenance costs. Fuel costs are certainly increased due to the need to overcome parasitic losses from the capture equipment. The Global CCS Institute estimates that capital expenditures from the construction of a CCS plant would increase the cost per installed Megawatt-hour by over $20 from a non-CCS option estimated at $33 per MW/hr. In general, the capital expenditures of large-scale power plants have tended to increase exorbitantly over the past few decades. Much of this is driven by increases in material and labor costs, but environmental regulations have also added cost through the need to add control equipment such as electrostatic precipitator and bag-houses for sulfur, particulate matter, and mercury reductions respectively.

In 2012, the National Energy Technology Laboratory (NETL) examined the cost of retrofitting plants in the United States with CCS technologies. The analysis was based on the following criteria: base plant efficiency, whether or not the unit had a sulfur scrubber, the efficiency of the sulfur scrubbers, water availability, and space availability for the CO₂ capture and compression equipment. In its analysis, NETL found that under an 85% capacity factor assumption, a cost of $41 per metric ton of CO₂ captured were a likely median price.

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Table ES-1. CO₂ Capture Retrofit for U.S. Coal-fired Power Plants, Summary Capture Cost and LCOE results (based on 85% Capacity Factor)

<table>
<thead>
<tr>
<th></th>
<th>Cost of CO₂ capture ($/mt CO₂)</th>
<th>Cost of CO₂ avoided ($/mt CO₂)¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>10th percentile</td>
<td>34</td>
<td>73</td>
</tr>
<tr>
<td>50th percentile</td>
<td>41</td>
<td>90</td>
</tr>
<tr>
<td>90th percentile</td>
<td>57</td>
<td>107</td>
</tr>
</tbody>
</table>

¹ Includes cost and GHG emissions for make-up power which varies by the region. Median cost value is 7.6 cents/kWh (min/max 1.1/9.9).

Table 3: Results of NETL’s 2011 CCS Retrofit Study; Source NETL

The NETL study found a number of different impediments to cheaper retrofitting for CCS. The lack of other emission control technologies was especially striking as these systems had to be installed before the CO₂ capture systems could be added as well. It should be noted that future EPA regulations will probably force all operating coal plants to install the needed environmental controls. Despite this, the cost of retrofitting coal plants for carbon capture will remain very high and the addition of currently proposed carbon capture systems to power plants would only exacerbate the current trend of cost escalation. There is a very serious need in the market for a cheaper carbon capture technologies.

Cost Escalation of Conventional Power Plants Not Utilizing Natural Gas

The example of Duke Energy's Cliffside Unit 6 plant has served as an example of the challenges industry faces in building large power plants. In 2007 Duke Energy Carolinas proposed to the North Carolina Utility Commission a $1.8 billion plant with two boilers.⁴⁵ After several delays and permitting challenges, Duke Energy was forced to build only one boiler because the NCUC would not allow it to recover cost for anything more. The NCUC also required Duke Energy to offer an energy saving program to customers and required retirements of equal capacity of older coal plants to offset the new coal plant.⁴⁶ Finally, in 2011 the project neared completion, but in its filings to the NCUC, Duke Energy placed the final cost of building one boiler at its Cliffside station at $1.8 billion, the same as its initial cost for two boilers.⁴⁷ The Cliffside plant is also important to note because it represents one of the more advanced coal fired power plants in the United States. With new environmental regulations affecting fossil fuel power plants being issued by the Environmental Protection Agency, any new coal plant would have to be similar to the Cliffside plant. A number of reasons have been advanced for the run-up in costs: an uncertain or changing regulatory climate, lawsuits by environmentalists and “not in my backyard” groups, growing demand in the developing world for raw materials such as steel and concrete, and also growing demand for the services needed to build power

plants. In some measure, each of these factors is likely playing a role in causing the vast increases in cost seen in power plant construction. What this means is that much like large scale nuclear plants, large scale coal projects are becoming increasingly more cost prohibitive and there seems to be a paradoxical dis-economy of scale to such large projects.

The massive increase in the cost of infrastructure is not limited to coal plants. Nuclear plants have increasingly grown in expense as well. In the nuclear industry, the reasons for cost escalation have less to do with environmental controls and more to do with the added levels of physical security that have been required in response to perceived terrorist threats and natural disasters. The industries history of cost overruns is notorious but the Union of Concerned Scientists was especially scathing in their criticism. The UCS gathered data on historical cost overruns for new nuclear power plants and found that during the first of the industry from 1966 to 1977, the average cost overrun was 207%.

In 2009, the USC released a report equating the financing of nuclear power projects to the set up for another bailout like the one the US Treasury had just undertaken for Wall Street. More recently, Mark Cooper took a critical view of the “nuclear renaissance” in the United States when he examined cost overruns and the source of the added costs. Specifically, Cooper cited the Levy County Nuclear station as a poster child for escalating costs. The stations was originally expected to cost $5 billion, as of 2012, the price had risen to between $17 and $22 billion before any construction had begun. The Levy County’s plight is not unique to the industry. So far, only the Vogtle Plant in Southern Company’s operating territory and the SCE&G operated V.C. Summer plants have broken ground. Costs are still to be determined for the new reactors. All of these new reactors are the “state of the art” AP1000 design commissioned by Westinghouse. The Nuclear Regulatory Commission proposed streamlining the permitting process by signing off on standardized designs like the AP1000 and issuing combined construction and operating permits based on those designs. Despite the attempt to streamline the construction and commissioning process, there is still a lot that remains to be determined about the future of nuclear energy.

The cost escalation of nuclear and coal plants has stymied interest in building either on a large scale. Looking at the age of existing power plants shows a number of interesting trends in the evolution of fuel sources for generating capacity. Most coal plants in the United States are thirty to sixty years old. Even absent the accelerated retirement of power plants due to new environmental regulations, a large portion of the coal fired fleet would stand a good chance of being retired over the next decade simply because the plants are old and wearing out.

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What one can see clearly from the age distribution is that natural gas and wind power represent the overwhelming majority of newly installed capacity in the United States. With most of the natural gas generating capacity in the United States less than ten years old, it stands to reason that more capacity will start to come from natural gas to offset the loss of coal capacity.53

Natural gas plants, on the other hand, have experienced the reverse economics. The technology that goes into a natural gas plant can be thought of as a very large jet engine. In the case of a combustion turbine, the system consists of a natural gas combustor and a gas turbine. Because the temperature of a Brayton cycle (combustion turbine) is so high, the flue gas is often used to run a Rankin cycle (steam turbine) to further increase the efficiency of the power plant. Combustion turbines such as those produced by Siemens have electrical efficiencies between 30% to almost 40%.54 With Siemens' largest combined cycle turbines, efficiency is nearly 60%.55 Coal plants typically run at half of the efficiency of a natural gas plant, so the energy efficiency factor favors natural gas.

Lastly, when it comes to capital expenditures, natural gas plants have become much cheaper than coal plants. A large coal plant is quite often a bespoke design. In contrast, a natural gas plant can be made from off-the-shelf components assembled in assembly line fashion. The Energy Information Administration estimates used in the Annual Energy Outlook model help to illustrate the cost differential.

53  Ibid.
Coal plants have over twice the cost per kilowatt installed than any of the natural gas turbine technologies incorporated into EIA's projections. Combined with the recent lows in natural gas prices and estimated extent of the resource, the cost alone provides justification for utilities to invest almost exclusively in natural gas systems. For comparison, one can see that the installed costs of nuclear plants are even higher than that of a coal plant, making nuclear plants less competitive on a dollar per installed capacity basis.

Any carbon capture and sequestration technology that enters into the current electric utility market will have to be able to compete on price with conventional natural gas plants. Absent a price on carbon, there is not sufficient market incentive to induce utilities to build CCS plants above the cost of a natural gas combined cycle plant. A CCS plant also must be able to perform better than existing technology in terms of reduced fuel use through reduced parasitic losses and lower rates of water consumption. It is this framework that carries through in the analysis of this paper.

Recent Regulatory Developments

The United States electric utility sector has seen recent changes in a number of environmental regulations pertaining to fossil fuel power plants. These range from regulations affecting warm water discharge to toxic metal releases to coal ash disposal procedures. Even in the event that a new regulation has not been proposed or implemented, the threat of future regulation (in the case of greenhouse gases) has caused the industry to reconsider its options. These regulatory changes and updates have been driven largely by the Clean Air Act. First enacted in 1963 and updated and expanded in 1967, 1970, 1977, and 1990, the Clean Air Act is the defining legislation for regulating air pollution in the United States. In its current form, the CAA is driving either innovation or closures in the electric utility sector based on four defined sets of pollutants: mercury and air toxics, particulate matter, ozone, and greenhouse gases. In some cases, the EPA’s regulatory authority has been granted or thrust upon it by court decisions. Otherwise, the Agency's authority stems from the Clean Air Act's establishment of “criteria air pollutants” and the National Ambient Air Quality Standards (NAAQS) that regulate the amount of exposure to a pollutant permissible by EPA. Despite the contested nature of the current regulatory roll out, industry has already responded to the new environment.

Perhaps one of the most striking examples of such a change in thought is evidenced by the

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Integrated Resource Plans (IRPs) developed by Duke Energy and Progress Energy before the companies' respective merger. One can use these as a model for understanding the impact of recently deployed regulations on utilities. In Duke Energy's 2012 IRP, the company cited the EPA's Mercury Air Toxics Standard (MATS) as having rendered the construction of new pulverized coal facilities, "not currently...technologically feasible..."\(^57\) The MATS has also increased the cost of running a conventional coal fired power plant. As the Duke IRP states, "the Company expects its compliance with the MATS rule to drive the retirement of several non-scrubbed facilities in the Carolinas, as well as various changes to units that have been modified over the last several years..."\(^58\) In Progress Energy's IRP, all of the planned capacity additions from 2013 to 2027 were either natural gas combustion turbines, combined cycle plants, or nuclear power plants.\(^59\) In all, the company expected to add 4,722 megawatts of new generating capacity of which roughly 66% was combined cycle, 22% combustion turbine, and 11% nuclear generation.\(^60\)

Related to MATS and of high importance is the update of the Maximum Available Control Technology or MACT rules updated by EPA beginning in 2010. In the context of new sources of emissions, the Clean Air Act defines the maximum achievable control technology as, "the average emission limitation achieved by the best performing 12 percent of the existing sources."\(^61\) Specifically EPA's efforts have targeted mercury emissions from power plants in recent years but a whole host of emissions covered under the Clean Air Act are also being revised at this time. The new need for added environmental controls is affecting both the retirement of old coal generation as well as the viability of constructing new fossil generation that is not natural gas combine cycle.

**Mercury**

Regulation of mercury over the past decades has been contentious. In 2000, the Clinton Administration's EPA found mercury to be a "hazardous air pollutant" under the 1990 Clean Air Act amendments and therefore coal- and oil-fired power plants had to be regulated under Section 112 of the Clean Air Act.\(^62\) In 2005, the Bush Administration EPA invalidated the 2000 finding by stating that:

"The criteria for listing major and area sources established in section 112(c)(1) and (c)(3) do not apply to Utility Units because Congress treated Utility Units differently from other major and area sources. Indeed, Congress enacted a special provision for Utility Units in section 112(n)(1)(A), which governs whether Utility Units should even be regulated under section 112."\(^63\)

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\(^{58}\) Ibid.


\(^{60}\) Ibid.


\(^{63}\) Ibid.
This touched off a series of lawsuits, which often resulted in EPA having to change its regulatory scheme and by extension left industry unsure of where to properly deploy capital to meet regulatory expectations.

Under the Bush EPA, the regulation of Hazardous Air Pollutants for electric generating units (EGUs) was largely left in stasis. One could be inclined to say that the Bush Administration's industry-friendly bias led its EPA administration to more or less retreat on those regulations that were seen as especially onerous to industry. While this narrative likely has more than a kernel of truth to it, it would be unfair to characterize all of the Agency's actions during this time period as solely politically or ideologically biased. What was apparent in the Bush EPA was a bias toward promulgating regulations with “market based” mechanisms present in their implementation.

In its approach of market-based environmental regulating, the Bush EPA did pursue controls to the amount of mercury emitted by electric generating units. In 2005, the Bush EPA issued the Clean Air Mercury Rule (CAMR) in conjunction with its Clean Air Interstate Rule (CAIR) as a way of establishing a “voluntary” market-based approach to capping and trading emission credits of mercury. Despite the voluntary nature of opting into the trading scheme, CAMR required that states have at least as stringent a State Implementation Plan as would be required if the state had joined the trading market. Ultimately, what the Bush EPA sought to circumvent from the 2000 EPA CAA Section 112 finding regarding mercury was the technology-forcing standard of the defined maximum achievable control standard.

The Clean Air Mercury Rule was challenged by fifteen states and tribes, and ultimately the final court decision was rendered by the Court of Appeals of the District of Columbia; the D.C. Circuit is considered the court of expertise in environmental cases. In its ruling, the Court vacated EPA's de-listing of the regulation of mercury from electrical generating units because “Congress... undoubtedly can limit an agency’s discretion to reverse itself, and in section 112(c)(9) Congress did just that, unambiguously limiting EPA’s discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.” The Clean Air Mercury Rule was invalidated “Because coal-fired EGUs are listed sources under section 112, regulation of existing coal-fired EGUs’ mercury emissions under section 111 is prohibited, effectively invalidating CAMR’s regulatory approach.”

The Obama administration was left to develop a new set of standards for the control of mercury emissions. In 2011, the Obama EPA finalized its Mercury and Air Toxics Standard (MATS) rule which established the standards that the EPA thought appropriate for controlling emissions of mercury, acid gases, particulate matter, and other toxic metals.
In its analysis, EPA determined that most power plants should be able to meet the standards by added environmental controls that have become standard on all newer power plants. EPA also determined that the rule would only adversely affect 40% of coal fired power plants and that many of these plants were smaller units. EPA also determined that the rule would only adversely affect 40% of coal fired power plants and that many of these plants were smaller units. Concerns raised about grid reliability issues resulting from the closure of plants prompted by the issuance of the MATS rule were largely deemed to be unfounded in both EPA and the Department of Energy’s findings on the matter. In its more detailed analysis, DOE found that even under the most stringent application of the standards, only 27 gigawatts of capacity would retire. In DOE’s estimation, this would not be enough of a capacity retirement to cause serious concern for grid stability.

The MATS rule has been updated a number of times since its debut in response to public comments. In November of 2012, EPA updated the emission limits for new power plants while leaving the standards in place for existing units. EPA updated its standards after data was presented through public comment that showed that the original standard exceeded the best performing power plants. EPA’s last update came in March of 2013 limits for mercury, particulate matter (PM), sulfur dioxide (SO2) and other acid gases, as well as individual metals. These updates have largely left the core

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Table 5: EPA Mercury and Air Toxic Rule Standards; Source: Federal Register

<table>
<thead>
<tr>
<th>Subcategory/Pollutant</th>
<th>Coal-fired EGUs</th>
<th>IGCC</th>
<th>Liquid oil, continental</th>
<th>Liquid oil, non-continental</th>
<th>Solid oil-derived</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>2.0E-1 lb/MMBtu</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>3.0E-1 lb/MMBtu</td>
</tr>
<tr>
<td>Total non-mercury metals</td>
<td>5.0E-1 lb/MMBtu</td>
<td>NA</td>
<td>8.0E-5 lb/MMBtu</td>
<td>NA</td>
<td>3.0E-1 lb/MMBtu</td>
</tr>
<tr>
<td>Antimony, Sb</td>
<td>8.0E-1 lb/Btu</td>
<td>1.4E0 lb/Btu</td>
<td>2.2E0 lb/Btu</td>
<td>2.2E0 lb/Btu</td>
<td>2.2E0 lb/Btu</td>
</tr>
<tr>
<td>Arsenic, As</td>
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<td>1.3E0 lb/Btu</td>
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<td>2.6E0 lb/Btu</td>
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<td>Beryllium, Be</td>
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<td>2.0E-1 lb/Btu</td>
<td>2.0E-1 lb/Btu</td>
</tr>
<tr>
<td>Cadmium, Cd</td>
<td>3.0E-1 lb/Btu</td>
<td>1.3E0 lb/Btu</td>
<td>3.0E-1 lb/Btu</td>
<td>3.0E-1 lb/Btu</td>
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</tr>
<tr>
<td>Chromium, Cr</td>
<td>2.0E-3 lb/Btu</td>
<td>2.9E0 lb/Btu</td>
<td>5.5E0 lb/Btu</td>
<td>5.5E0 lb/Btu</td>
<td>3.1E0 lb/Btu</td>
</tr>
<tr>
<td>Cobalt, Co</td>
<td>8.0E-1 lb/Btu</td>
<td>1.2E0 lb/Btu</td>
<td>2.1E0 lb/Btu</td>
<td>2.1E0 lb/Btu</td>
<td>1.1E0 lb/Btu</td>
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<tr>
<td>Lead, Pb</td>
<td>8.0E-1 lb/Btu</td>
<td>1.9E0 lb/Btu</td>
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<td>Manganese, Mn</td>
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<td>2.5E0 lb/Btu</td>
<td>2.5E0 lb/Btu</td>
</tr>
<tr>
<td>Mercury, Hg</td>
<td>5.0E-2 lb/Btu</td>
<td>3.0E-2 lb/Btu</td>
<td>5.5E0 lb/Btu</td>
<td>3.1E0 lb/Btu</td>
<td>3.1E0 lb/Btu</td>
</tr>
<tr>
<td>Nickel, Ni</td>
<td>3.5E-1 lb/Btu</td>
<td>6.5E0 lb/Btu</td>
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<td>4.7E0 lb/Btu</td>
</tr>
<tr>
<td>Selenium, Se</td>
<td>5.0E0 lb/Btu</td>
<td>2.2E1 lb/Btu</td>
<td>3.5E0 lb/Btu</td>
<td>3.5E0 lb/Btu</td>
<td>1.2E0 lb/Btu</td>
</tr>
</tbody>
</table>

NA = Not applicable
* Includes Hg

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73 Environmental Protection Agency. "Reconsideration of Certain New Source Issues: National Emission Standards for
objectives of the rule in place. Barring a court decision overturning MATS, all power plants in the United States will be built with advanced pollution controls. Any plants retrofitted or modified will also have to install more advanced emission controls. As Duke Energy cited in its North Carolina IRP, the MATS rule is a major determinant in whether or not new coal fired power plants will be built in the United States.

Inter-State or Downwind Air Pollution Regulations

Concurrent with CAMR was the Bush EPA's Clean Air Interstate Rule (CAIR), conceived as another cap and trade program designed to combat remaining sulfur dioxide emissions not captured in the 1990s cap and trade SO2 program for power plants. Added to CAIR was also a series of measures designed to combat NOx for the purpose of reducing cross-state air pollution to ozone non-attainment areas. Cross-state air pollution has been a recognized problem since the inception of the Clean Air Act. But because each state has had its own “State Implementation Plan” or SIP it can cause conflicts as one state may be left out of attainment through no particular fault of its own if it is downwind of another more polluting state. One often cited example is the effect that the coal plants of the Ohio River Valley have upon the air quality of New England and upstate New York. To counter this, CAIR sought to induce states to develop State Implementation Plans for air quality that took into account downwind affects. However, while CAIR included measures to reduce downwind pollution, it also carried within it a market-based mechanism that would allow trading of pollution credits between different sources and between states.

It was the trading scheme that proved to be CAIR's undoing. A number of states filed suit and the cases were organized around North Carolina's contention that the allowance of trading while not, “per se unlawful,” failed “to assure that upwind states [would] abate their unlawful emissions as required by section 110(a)(2)(D)(i)(I).” In July of 2008, the Court of Appeals for the District of Columbia ruled in North Carolina v. EPA that CAIR had, “more than several fatal flaws in the rule,” and therefore vacated it entirely. The reasoning of the decision was based on the Court's understanding that emissions trading could create situations in which an upwind state could qualify as meeting the requirements of CAIR while a downwind state would see no real improvement in its air quality.

While the Court decided that North Carolina's challenging of the structure of CAIR was valid, in being vacated, EPA was left with a serious problem. It had spent years developing the Federal Implementation Plan and worked with states to create the State Implementation Plans that under-girded the Agency's regulations of SO2 and NOx. EPA requested and was granted a rehearing by the Court of Appeals and argued that vacating the rule, however imperfect it may have seemed to the court, was worse than leaving CAIR in place for the time being. Judge Rogers noted in the Court's decision that, “This court has further noted that it is appropriate to remand without vacatur in particular occasions where vacatur “would at least temporarily defeat . . . the enhanced protection of the

76 Ibid.
environmental values covered by [the EPA rule at issue].”78 As a result, the Court allowed CAIR to proceed while requiring that EPA develop something better.

It would be left to the Obama Administration to develop “a rule consistent with [the Court's] opinion.”79 After several years of planning and modeling, the Obama EPA created what was at first called the Clean Air Transport Rule (CATR) and then later called the Cross State Air Pollution Rule (CSPAR.) CSPAR (pronounced like the friendly ghost) required, “states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.”80 CSPAR was designed to apply to the Eastern United States where most of the problems with cross-state air pollution have arisen. Through measurements of ambient air quality and measurements of power plant emissions and air flow, EPA developed a state-level requirement for reductions that would affect both intrastate and interstate air quality. Under CSPAR twenty states were required to manage NOx, SO2, and ozone, five for ozone only (NOx during warm weather and volatile organic compounds,) and three states for SO2 and NOx. Delaware and the New England states were the only unaffected Eastern states.

![Figure 10: CSPAR State Pollution Controls; Source: US Environmental Protection Agency](image)

EPA set up a framework for air quality management that worked under the “good neighbor” requirement of the Clean Air Act. After having established its goals for pollutants in the various states, EPA then used air transport models to determine the likely source of pollution.81 Once an upwind state

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78 Ibid.
79 Ibid.
81 Environmental Protection Agency, Technical Support Document (TSD) for the Transport Rule. Raleigh, North Carolina:
was identified, EPA used another model to determined how much pollution an upwind state’s power plants could eliminate if the plants applied all applicable environmental controls given a certain cost-per-ton of pollution reduced.82

Like CAIR, CSPAR was challenged in court and was also overturned. The D.C. Appellate Court ruled that EPA had overstepped its authority on two grounds: upwind states might have been forced to reduce emissions beyond their “significant contribution” to downwind states’ non-attainment, and EPA did not allow states a chance to draft State Implementation Plans before finalizing the Federal Implementation Plan.83 In a 2-1 decision, the Appellate Court decided that EPA's modeling was potentially flawed because it set an a priori reduction in emissions that might have been more than what the state was actually contributing to downwind air quality. Even more fundamentally, the Court decided that EPA had overstepped the authority given to it by Congress under the Clean Air Act when it drafted a Federal Implementation Plan without consulting with the states. Under the Clean Air Act, the United States' divided Federalism model is extended such that EPA sets the standards and the states draft implementation plans unless they decide to not comply at all. Only when a state abdicates its right to regulate can the EPA directly regulate a state's emissions. In the case of CSPAR, the NAAQS for ozone, sulfur dioxide, and nitrogen oxides acted as a blunt instrument to get all of the states to comply under the EPA plan without first allowing states to create plans to reduce cross-state emissions.

Having vacated both CAIR (but leaving it in place as a backstop until a new regulation came along) and then vacating CSPAR (the anticipated successor to CAIR) the Court left EPA in a very awkward position. It was still clearly violating the law in its mission to protect the public health per the CAIR decision but it was also being rendered unable to use CSPAR. The Court specifically ordered that CAIR continue to be administered until a new regulation was issued.84 The Court did allow EPA a way out of its current dilemma, if EPA did set a standard for reductions; the Court saw that, “analogous to setting a NAAQS. And determining the level of reductions under the good neighbor provision triggers a period during which States may submit appropriate SIPs.”85 Through this opening, EPA could use its findings for reduction requirements under the CSPAR modeling regime but would have to wait the required three years for submission of State Implementation Plans for the affected states. Instead, the EPA continued its challenge of the Court decision asking for a rehearing. This time, EPA was not granted a rehearing with the Court. In January of 2013, the D.C. Appellate decided to stand by its August 2012 decision.86

While it is hard to make a prediction about what is likely to happen post CSPAR, looking at the goals set by the EPA under CSPAR, it is possible to get a feel for the sort of reductions the current EPA is trying to achieve. In particular, EPA under CSPAR sought to reduce SO2 by 73% and NOx by 54%.87
All of these targets are relatively ambitious and would greatly affect the kinds of technologies deployed by utilities to control emissions. It would also restructure the investments utilities would want to make in future generation to ensure they comply with regulations. CSPAR's vacatur does not mean an end to EPA's efforts to reduce emissions. In both the CAIR and CSPAR rulings, the court made it clear that EPA has the authority to regulate and is currently not doing enough to reduce emissions while working under existing law and precedence. Even if an Administration unfavorable to environmental regulation were elected after President Obama's second term, EPA would still be required to do something about cross-state air pollution. Lastly, it should be noted that CAIR and CSPAR both tried to address non-attainment of NAAQS that were established in the last decade. All of these standards might become more stringent before the end of the Obama Administration.

The History of Greenhouse Gas Regulation

The final major regulatory driver comes from regulations of greenhouse gases. Whereas all of the previously introduced regulations have precedence in affecting existing infrastructure and planning regimes, the decisions that EPA makes on greenhouse gas emissions will have long-term and profound effects on the make-up of electric utility generators in the United States. But regulation of greenhouse gases is also the one regulatory situation that is most fraught with political risks. The way in which it was determined that EPA had the authority and the imperative to regulate greenhouse gases is unique in the field of environmental regulations. What started the process was the United States Supreme Court's decision in *Massachusetts v. EPA*. In a 5-4 decision, the Supreme Court Justices determined that in their estimation, carbon dioxide and other greenhouse gases could be regulated under the Clean Air Act because they were a “pollutant” that could “endanger” public health and welfare.

The path that led to the Court's decision was somewhat circuitous. In 2003, the International Center for Technology Assessment filed a petition that sought to have the EPA regulate greenhouse gas emissions from automobiles under the Clean Air Act. The Bush Administration EPA denied the

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petition because, “Congress has not granted EPA authority under the Clean Air Act to regulate CO2 and other greenhouse gases for climate change purposes,” and, “EPA has determined that setting GHG emission standards for motor vehicles is not appropriate at this time.”91 A number of legal challenges to the decision ensued.

The cases were combined with the Commonwealth of Massachusetts leading the petitions to the court and eventually the case appeared before the D.C. Court of Appeals. The D.C. Court of Appeals challenged the standing of many of the petitioner's ability to sue.92 By determining that many did not have standing, the legally defined ability to be able to launch a suit in the first place, the Court simply dismissed many petitioners' arguments out of hand. The Court also noted that many of the petitioners had taken an EPA General Counsel's legal opinion to be a “final decision” which the Court found to be an incorrect interpretation. The Counsel’s lawyer, Robert Fabricant, had overturned the advice of the Clinton Administration's EPA legal counsel that EPA could regulate greenhouse gas emissions under the Clean Air Act. The Court was swift to point out in its opinion that Mr. Fabricant's memorandum, while informing the EPA Administrator's decision, could not be used as evidence of EPA's “final decision” in the matter.93 This and other legal missteps on the part of the petitioners likely colored the Court's view, but in a first for the Appellate Court it did not reject the petitioner's case because the “injury” the petitioners claimed to have sustained was based on damages that were going to happen in the future, such as sea level rise. This ran counter to some legal arguments that one could not sue over something that had not yet happened.

Focusing just on the question of whether or not EPA had “properly declined to exercise authority,” the Court gave deference to EPA for denying the petition on a number of grounds. The Court cited a 2001 report of the National Academy of Sciences that stated that the link between human activity and climate change could not, “be unequivocally established,” as one of the reasons why EPA was in the right to deny the petition.94 In the Court's estimation, the question of standing aside, it was clear that EPA could reasonably say that it did not have to regulate greenhouse gas emissions.

The petitioners then appealed to the Supreme Court to have the case heard. The case was heard in November of 2006. Presenting on behalf of the Petitioners, attorney James Milkey argued that the Commonwealth of Massachusetts had standing because rising “sea levels are already occurring from the current amounts of greenhouse gases in the air.”95 He later emphasized that the harm was “because [the] harms are cumulative, and while reducing U.S. emissions will not eliminate all the harm we face, it can reduce the harm that these emissions are causing.”96 Effectively the rational was that because automobiles in the United States contribute about 6% to global emissions, and the effect of emissions from anywhere contributes to the degree to which the coastline of Massachusetts would be lost, then any reduction was better than no reduction in reducing harm.

In 2007 Justice Stevens rendered the majority opinion of the court stating that with regard to the incremental nature of the challenge, “While it may be true that regulating motor-vehicle emissions will not by itself reverse global warming, it by no means follows that we lack jurisdiction to decide whether EPA has a duty to take steps to slow or reduce it.” In a bold admonition of the EPA, the majority

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91 Ibid.
93 Ibid.
94 Ibid.
96 Ibid.
opinion stated, “We have little trouble concluding that [emissions of greenhouse gases], contribute to climate change.” As a result the majority concluded that EPA did have the ability to regulate greenhouse gases because they were a class of pollutants causing negative impacts.

“The Clean Air Act’s sweeping definition of “air pollutant” includes “any air pollution agent or combination of such agents, including any physical, chemical . . . substance or matter which is emitted into or otherwise enters the ambient air . . .” §7602(g). On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through the repeated use of the word “any.” Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons are without a doubt “physical [and] chemical . . . substance[s] which [are] emitted into . . . the ambient air.” The statute is unambiguous.

- Massachusetts v. EPA Majority Opinion, (emphasis added)

Given the Supreme Court's view that EPA’s authority was “unambiguous,” it required that the EPA revisit its decision, effectively forcing EPA to conduct a study that would result in an “endangerment” finding.

The Bush EPA worked to comply with the Supreme Court's remand but nothing was completed when the Administration’s term ended. The ultimate issuance of an Endangerment and Cause or Contribution Finding came under the newly installed Obama EPA. In its findings, the Obama EPA concluded that, “The Administrator finds that the current and projected concentrations of the six key well-mixed greenhouse gases — carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) — in the atmosphere threaten the public health and welfare of current and future generations.” EPA attributed the pollution to, “new motor vehicles and new motor vehicle engines.” The immediate result of this finding per the Supreme Court's decision was to collaborate with the National Highway Transportation Administration to create the first revision of the Corporate Average Fuel Economy regulations with greenhouse gas emissions as part of the determinant of compliance. In a last ditch effort a number of states and industry groups attempted to challenge the science of the endangerment finding. The D.C. Court of Appeals ruled on multiple suits in a single case that EPA's actions post Massachusetts v. EPA were both reasonable and within the law. Without any recourse, the Court's decision made certain that greenhouse gas regulation in the United States became a reality.

EPA’s Response to Regulating Greenhouse Gas Emissions

The broader implication of the endangerment finding was that under the Clean Air Act, once a pollutant is identified from one source it must be regulated from all sources. As a result of the

http://www.epa.gov/climatechange/endangerment/.
99 Ibid.
100 Ibid.
Supreme Court's decision, the EPA has now added a whole new class of pollutants and (officially) created a whole new form of environmental degradation that it will have to regulate. EPA has moved cautiously because Congress could amend the Clean Air Act to preclude EPA from regulating greenhouse gas emissions. Also, one cannot discount the political realities of the implementation. Having faced a weak economy for much of his term and entrenched Republican opposition to even the idea of climate change, President Obama has been unable to direct much effort at the problem without being attacked. On arguments of competitiveness, Conservatives have stated a belief that without the developing world joining in, the U.S. will lose its industrial base as it ratchets up greenhouse gas regulations. Irrespective of whether or not this would be the case, the argument has stuck and colored the political calculus.

Because of the political constraints, the actions that EPA has formally taken to address climate change have been fairly calculated. The two regulations released that have had the greatest effect on electric utilities have been the Tailoring Rule for Title V of the Clean Air Act and the regulations regarding the Prevention of Significant Deterioration (PSD). Title V of the Clean Air Act establishes the way in which EPA can permit, regulate, and fine pollution sources. EPA realized that if it issued greenhouse gas regulations to cover every single source, the policy would be unworkable and very expensive. Also, EPA was limited in that it could not issue a rule that applied to existing sources until it determined the standard for new sources. Therefore, the Tailoring rule was created to cover new sources that emitted more than 100,000 tons per year of all greenhouse gases and 75,000 tons per year for modified sources. EPA defined carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride as the key pollutants it would regulate under its greenhouse gas regulations based on their global warming potential. Some of the synthetic gasses listed as greenhouse gases by EPA have greater heat trapping properties than carbon dioxide. To make the standard uniform in mitigating climate change, the gases were all measured in an equivalent heating value of carbon dioxide (CO₂e) and therefore all EPA greenhouse gas regulations are defined in terms of the CO₂ equivalency.

The final rule published in the Federal Register in 2010 clearly outlined EPA’s justification for targeting the largest sources. Under a strict interpretation of the Clean Air Act, EPA would have had to regulate sources that emitted more than 100 to 250 tons per day of greenhouse gas emissions. These emissions levels are consistent with other pollutants such as lead, sulfur dioxide, and nitrogen dioxide but EPA reasonably determined that creating a standard that would require millions of permits was “absurd.” The three step process outlined in the Tailoring Final Rule started with only sources that were subject to the PSD program and required them to determine a Best Available Control Technology for greenhouse gas emissions. After the period of 2 January 2011 – 30 June 2011, step 2 of the rule came into effect requiring new sources that emitted more than 100,000 tons per year of greenhouse gases to become a criteria for regulation under the CAA even if the plant emitted no other pollutants. Sources that were modified fell under the CAA if they emitted more than 75,000 tons per year. Step 3 opened the door to research and public comment on expanding the program to include more sources after July 1, 2012.


104 Ibid.


106 Ibid.
With its plan for dealing with the regulating greenhouse gas emissions set, EPA next had to create its standards for New Source Performance Standards. The NSPS establishes the amount of a pollutant classes of sources can emit into the environment. It is also the basis for determining what technologies will become “best available controls” for the regulated pollutant. On 27 March 2012, EPA issued its Proposed Rule for the NSPS of electric generating units.\(^\text{107}\) The rule established a standard of 1,000 pounds of carbon dioxide per megawatt hour for plants larger than 25 megawatts electric output.\(^\text{108}\) Under this standard, all recently built natural gas plants would qualify but coal plants would have to be built at least “ready” for carbon capture in order to meet a 30 year target for coal fired power plants to qualify. EPA determined in its regulatory analysis that even without the proposed NSPS, coal plants were unlikely to be built because of other environmental regulations.\(^\text{109}\)

April 13, 2013 should have been the day that EPA finalized the rule, but the Agency decided on April 12, 2013 to delay the issuance of a final rule.\(^\text{110}\) The proposed NSPS was roundly attacked by Republicans and coal state Democrats because of the effects it would have had on the economies of their districts. Rick Santorum probably encapsulated this sentiment best when he said of the proposed NSPS, “Obama’s environmental agenda kills American jobs, creates higher energy prices, and weakens our nation’s security. America is the Saudi Arabia of coal, and we could create our own energy if the government would let us.”\(^\text{111}\) Even within the EPA, many were concerned about the effects of the proposed NSPS. New England Regional Administrator Curt Spaulding, speaking at a forum at Yale in June of 2012, “You can’t imagine how tough [issuing the proposed NSPS] was, because – you got to remember – if you go to West Virginia, Pennsylvania, and all those places, you have coal communities who depend on coal. And to say, ‘we just think those communities should just go away’ – we can’t do that. But [Administrator Jackson] had to do what the law and policy suggested and it’s painful.”\(^\text{112}\)

In the confirmation hearings for EPA Administrator nominee Gina McCarthy, Democrats used the platform as an opportunity to argue over greenhouse gas regulations while Republicans used it to argue about EPA policies they perceived as “killing jobs.” Senator John Barrasso (R-WY) said at the hearings, "I haven’t heard yet any plain statements from EPA – hopefully we will today from this nominee – about the negative health impacts and lives lost from chronic unemployment caused by the EPA policies. This is a serious health epidemic and it seems to go unnoticed by the EPA.”\(^\text{113}\) Senator Bernard Sanders (I-VT) tried to bring the conversation back to climate change saying the debates at the hearing were really about, “a debate about global warming, and whether or not we are going to listen to the leading scientists of this country, who are telling us that global warming is the most serious planetary crisis.”\(^\text{114}\) Few could criticize Ms. McCarthy’s qualifications to be Administrator.

At present, it is hard to determine what EPA might do to change its proposed NSPS to make it

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\(^{114}\) Ibid.
less offensive to various vested interests. In an open letter to the EPA, Democratic Senators from West Virginia, Indiana, North Dakota, and Louisiana all wrote to oppose having the same standard for coal plants as for natural gas plants.\textsuperscript{115} This might be the most likely outcome for EPA's final rule. Any standard is going to face a court challenge but a combined standard would be especially vulnerable to attack. There is no precedence for regulating coal and natural gas plants under a combined standard. For this reason, such a final rule could be ruled invalid by the courts. At present, it is hard to say what the final rule will entail.

**Other Federal Regulations of Note**

One also needs to mention the new regulations that EPA has in various stages of development related to cooling water and coal combustion byproducts. Section 316(b) of the Clean Water Act requires plant operators to change their water intake systems to reduce the amount of fish, larvae, turtles, and other aquatic organisms being killed through entrapment.\textsuperscript{116} This resulted from a court challenged launched by various environmental groups. As of this writing, EPA is still working on developing a final rule.

Coal combustion byproducts entered the national spotlight when the Kingston Fossil Plant's coal ash impoundment collapsed in 2008.\textsuperscript{117} The failure dumped 5.4 million cubic yards of ash into the downhill valley and ultimately the Emory River. As a result of the spill and preexisting concerns about the potential for pollution from coal ash, EPA has begun developing rules to deal with the waste. EPA proposed a rule in 2010 that would have reclassified coal ash as a “special waste” subject to regulation under Title C the Resource Conservation and Recovery Act (RCRA).\textsuperscript{118} Classification of coal combustion wastes will be tricky for EPA as they are used in some applications to offset uses of virgin material such as in cement production. IF EPA found coal combustion wastes to be “hazardous” the byproducts would probably be unusable to other industries. However, it is clear that EPA cannot determine these wastes to be perfectly safe. At present, EPA has not taken any public actions beyond a 2011 Notice of Data Availability that added more information on various topics to the public record.\textsuperscript{119} In the end, any regulation of coal wastes will add cost to operating coal power plants.

**Kemper County CCS Plant: A Case Study in the Role of Public Utility Commissions and CCS**

Most electricity markets in the United States are still regulated markets. In these markets, the state has granted a monopoly to a company or companies to produce and sell electricity to customers ensuring that they have a guaranteed rate of return on their investment. The formula used for determining cost recovery (or the rate for electricity) is as follow:

\[
\text{Electricity rate} = \text{operation costs} + \text{taxes} + \text{depreciation} + \text{rate of return} \times \frac{(\text{rate base} - \text{depreciation})}{112}
\]

\textsuperscript{115} Goad, Ben. "Coal state Dems press Obama to scale back EPA emissions rules." The Hill, March 18, 2013.


test year sales)\textsuperscript{120}
*Rate base is all of the utilities hardware – the depreciation (money already paid back) (Rate base is lot like the principle of a loan and the amount of principle paid down is the depreciation)  
*Sales are largely based on the weather and other use factors there is no guarantee that the utility will sell the amount of power used in the “test year sales”

This formula means that the Public Utility Commission has to approve any new capital expenditures as they contribute to the final cost of electricity that rate payers will see in their bills.

Southern Company’s Kemper plant provides the clearest example of what large scale CCS projects might look like in terms of their regulation by Public Utility Commissions. Southern Company subsidiary Mississippi Power proposed to build a $2.8 billion plant in Kemper County, Mississippi. The plant is an advanced integrated coal gasification and combined cycle plant, which is using grey water recovered from a local municipal waste water treatment plant to run its operations and a lignite from a nearby mine.\textsuperscript{121} The plant will use the TRIG (Transport Integrated Gasification) technology to gasify the coal and burn the gas while capturing 65% of the plants greenhouse gas emissions. The capture CO\textsubscript{2} will then be piped to an oil well owned by Denbury.

The plant was given approval in 2010 by the Mississippi Public Service Commission in a 2 to 1 vote. The plant was seen as a way of providing jobs in an area with 14.1% unemployment and also as a way of insulating rate payers from natural gas prices shocks. The plant even received endorsement from then Secretary of Energy Steven Chu.\textsuperscript{123} The plant went forward with construction but it was challenged by the Sierra Club on the grounds that the expensive project violated the MPSC’s responsibility to keep electricity rates as low as possible. Instead, the Sierra Club said other alternatives like natural gas should have been considered. The Mississippi State Supreme Court ruled in favor of the Sierra Club citing the Sierra Club’s argument.\textsuperscript{124} However, the MPSC decided to ignore the court’s ruling and instead reinstated the certificate to build the Kemper plant.\textsuperscript{125} An agreement was reached that forced the cost recovery Southern could derive to be no more $2.88 billion. Southern has reported of the plant, “Earthwork has been completed at the water reservoir and lignite delivery facility areas. Concrete work is 93% complete. Underground piping is 93% complete. Electrical utility installation continues with electrical duct bank installation 98% complete. Structural steel erection is 71% complete. Construction is complete on the three 115kV line rebuild projects, and the East and West 230kV lines are complete and energized. Construction is complete on seven substations, the mine service line, and the Sweatt-Sykes fiber line. The treated effluent pipeline installation is 99% complete, and the natural gas pipe line is 100% complete and ready for operation. The CO\textsubscript{2} pipeline system installation is 96% complete.”\textsuperscript{126} Despite this, many including the Sierra Club still do not believe that

\textsuperscript{121} Mississippi Power, "Kemper County Energy Facility." Accessed March 20, 2013.  
\textsuperscript{124} Eileen, O’Grady, and . "Miss. Supreme Court reverses Southern Co coal project approval." Reuters, .  
\textsuperscript{125} Eileen, O’Grady. "Mississippi allows Southern Co to keep building $2.8 billion coal plant." Chicago Tribune, March 30, 2012.
http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=303610.
the project is on schedule.

The Kemper plant represents both the best of current CCS technology but also its worse pitfalls. As CCS plants more forward, it is going to be increasingly important for those building the plants to engage both the rate payers and the utility commissions in order to build wide spread support for the projects. The Kemper plant was nearly scrapped by the Mississippi Supreme Court and only through extraordinary effort was the project saved. When it comes to the make-up of the nation’s electricity generating sector, the roll of states cannot be underestimated. States are largely responsible for implementation of Clean Air and Clean Water Act regulations, and in regulated markets they are also the ones that decided what sorts of power plants are appropriate for their rate bases. State government engagement is going to be a very important part of any future CCS projects.

Current Market Trends in Electricity Generation

After a century and a quarter of expansion and development, the United States has become a mature market for electricity services. Despite the recent proliferation of electric devices, future market growth is expected to remain in the range of 1%. Growth in demand for electricity is expected to remain flat. However, as the generating fleet in the United States continues to age, the slow growth for new capacity will be overshadowed by more build out of plants to make up for retired capacity. Currently, low natural gas prices are driving much of the investment in the utility sector. On a dollar per British Thermal Unit (BTU) basis, natural gas prices have been lower than coal prices creating an accelerated switch in fuels from coal to gas. This price differential has reversed but the switch to natural gas is likely to be reinforced by new environmental regulations that have favored natural gas because of its cleaner burn.

Concerns about natural gas prices are largely based on the long term productivity of hydraulically fractured natural gas wells. When considered as a globally tradable commodity, natural gas prices in the United States are much lower than the rest of the world. This market arbitrage is proving to be a strong inducement to spur investment in natural gas export terminals. Companies like Cheniere Energy have started to literally reverse engineer liquid natural gas terminals that were originally designed to accept imports. Debate rages about the effect that natural gas imports would have on the American economy. Deloitte’s analysis in 2011 concluded that the price increase domestically from 6 billion cubic feet per day exports would typically be less than $0.22 per million BTUs. More analysis is needed to understand these effects but it is clear that utilities are starting to move toward more natural gas based generation for a variety of reasons.

Future Demand for Electricity Generation

Overall, United States demand for electricity is expected to grow by 0.9% annually from 2013 to 2040. This will mean that generating capacity will grow from 3,841 billion kilowatt-hours in 2011 to 4,930 billion kilowatt-hours in 2040, a percent change of roughly 28% in three decades. EIA's current modeling projects that the growth will be met by expansion of a combination of natural gas

130 Ibid.
(5%) and renewable sources (3%).\textsuperscript{131} In the past half century, the growth in demand for electricity in the United States has slowly decreased. Compared to previous decades the growth rate of the last decade was near 1.5% and during the Great Recession negative.\textsuperscript{132}

![Figure 12: Three Year Moving Average for Electricity Demand; Source: EIA](image)

One can reasonably assume that the United States has become a “mature” electricity market based on the overall growth projections. This means that when making long-term planning decisions, electric utilities are likely to limit new installations to “replacements” of installed infrastructure. In the Energy Information Administration's recent reporting, the EIA found that most US coal plants were built before 1980 and most natural gas plants were installed after 2000.\textsuperscript{133} Coal plants are especially old with many units over 60 years old still in operation. The bulk of coal capacity is between 30 and 40 years old and therefore likely to be retired in the next twenty years.\textsuperscript{134}

![Figure 13: Installed Generating Capacity since 1930; Source: Energy Information Administration](image)

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure13}
\caption{Current (2012) capacity by initial year of operation and fuel type}
\end{figure}

\begin{table}[h]
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\begin{tabular}{|c|c|c|}
\hline
Fuel Type & Capacity & Year of Operation \\
\hline
Coal & 60 gigawatts & 2012 \\
Nuclear & 50 gigawatts & 1960 \\
Natural Gas & 40 gigawatts & 1980 \\
Petroleum & 30 gigawatts & 1990 \\
Other & 20 gigawatts & 2000 \\
Hydro & 10 gigawatts & 2010 \\
\hline
\end{tabular}
\caption{Installed generating capacity by fuel type and initial year of operation}
\end{table}

\textsuperscript{131} Ibid.
\textsuperscript{134} Ibid.
It is also important to consider the capital cost of conventional power plants in understanding the long term planning that utilities are considering. Much has been written about the effect of new safety equipment and strengthening of regulations driving up the cost in both material and labor at nuclear power plants. In much the same way, conventional pulverized coal facilities are facing the same sorts of constraints from both regulators and installation costs. As early as 1981, Charles Komanoff wrote a book detailing the capital expenditure risks and price increases associated with building nuclear and coal-fired power plants. While the details of Komanoff's projections are “wrong,” his core thesis was prescient. Overall, Komanoff found that with large projects, the ability of engineers to accurately predict cost was almost non-existent, with practically every plant increasing substantially in cost. Furthermore, regulatory creep or changes in regulations resulted in identical plants costing significantly more over time and also took longer to construct meaning that the increase in cost was at least partially endogenous to the increase in the length of time it took to construct the plant. Looking at trends in the type of new power plants constructed since 1930, EIA's data sets show an industry bias toward natural gas plants in the 1990s and continued installations even as natural gas prices rose and then collapsed in the 2000s. Natural gas plants have smaller capital expenditures than pulverized coal or nuclear power plants making them a more attractive capacity addition than other options.

**Historic Natural Gas Regulations in the Utilities Sector**

Concurrent with the worries of escalating plant costs for coal and nuclear power plants, natural gas prices have also played a role in the investment choices of utilities. Historically, when there was a perception in the United States that natural gas was growing increasingly scarce, plant construction decreased. In 1978, Congress passed The Powerplant and Industrial Fuel Use Act (FUA) which established that “no new electric powerplant may be constructed or operated as a base load powerplant without the capability to use coal or another alternate fuel as a primary energy source.” Much of this was done in response to the Oil Embargo of 1973 while the United States sought to remove all fuel oil electric generating facilities from the fleet. The perceived scarcity of natural gas made the decision to exclude natural gas as a primary fuel for baseload generation much easier. The effect of the Fuel Use Act was to largely preclude development of natural gas power plants and infrastructure. From 1978 until the Fuel Use Act's repeal in 1987, 172 gigawatts of capacity were added to the United States' electric generating fleet. Of that, 81 gigawatts were coal-fired and almost 45 gigawatts were nuclear plants. Of today's coal-fired power plant capacity, 26% was installed during the period of the Fuel Use Act. The accident at Three Mile Island in 1979 was responsible for the meltdown of the civilian nuclear power industry in the United States thus any of the nuclear capacity installed during the period of the Fuel Use Act was the result of projects already slated before 1979.

During the period of the Fuel Use Act, natural gas prices largely stayed flat and over time a glut of supply developed on the market. This signaled to Congress that the FUA was unnecessary and it

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139 Ibid.

140 Ibid.
was repealed in 1987. After its repeal, the United States added 361 gigawatts of capacity to the grid.\textsuperscript{141} Most of the new capacity (70\%) was in the form of cheap natural gas combustion and combined cycle plants with only 11\% of the addition coming from coal.\textsuperscript{142} This sent an early signal to the market that the future of coal was highly uncertain.\textsuperscript{143} Such pessimism about the future of coal has been largely founded as the introduction of new EPA regulations for coal plants have strengthened.

\textit{Coal Plant Retirements in Response to EPA Regulations: Effects on Grid Stability}

The effect of EPA regulations combined with low natural gas prices has resulted in utilities more or less giving up on coal-fired generation. In 2012, over 9,000 megawatts of installed coal capacity were retired from the fleet.\textsuperscript{144} Reuters recently reported in that between 60,000 to 100,000 megawatts of capacity would be retired based on various industry estimates. At the start of 2013, 36,000 megawatts of capacity had already been announced for decommissioning or conversion to natural gas.\textsuperscript{145} Most of the plants slated for retirement are older, less efficient (sub-critical) plants that were already being driven to the margins by cheap natural gas. EPA’s roll out of stricter regulations simply proved the deciding factor in shuttering the plants. The result of cheap natural gas and stricter regulation has been a major shift in the nature of the electric utility market.

This shift in the fuel source of the bulk of new generation capacity has only just begun and started to make many within industry and regulators very nervous. In its 2011 data collection from electric Utilities, the Energy Information Administration found overwhelmingly that utilities were planning on retiring coal generation within the coming four to five years.\textsuperscript{146}

\begin{table}[h]
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\begin{tabular}{|c|c|c|c|c|c|c|c|}
\hline
 & \textbf{Existing Coal Capacity}\textsuperscript{1} & \textbf{Reported coal generator retirements} & \\
\hline
\textbf{Total Net Summer Capacity (MW)} & 317,469 & 529 & 1,528 & 2,517 & 8,880 & 2,098 & 4,715 & 9,865 \\
\textbf{Number Of Units} & 1,387 & 12 & 35 & 31 & 57 & 14 & 34 & 61 \\
\textbf{Average Net Summer Capacity (MW)} & 228 & 44 & 44 & 81 & 156 & 150 & 139 & 182 \\
\textbf{Average Test Heat Rate (Btu/kWh)} & 12,821 & 12,200 & 12,879 & 10,714 & 10,897 & 13,922 & 11,067 & 10,659 \\
\textbf{Average Age at Retirement} & N/A & 50 & 54 & 62 & 56 & 55 & 57 & 57 \\
\hline
\end{tabular}
\caption{Planned Retirements of Coal Fired Plants; Source: EIA's 2011 Form EIA-860, "Annual Electric Generator Report."}
\end{table}

The large scale retirement of coal from the fleet has significant implications for the broader reliability of the electric grid. The North American Reliability Corporation (NERC) has expressed concern since 2010 that EPA’s new environmental regulations have the potential to drive capacity below reserve margins. NERC’s reserve margins are the amount of capacity the organization believes necessary to provide a safe buffer in “peak of peak” periods for electricity demand. These would include the coldest nights and the hottest days. Having a reserve margin above the peak of peak demand means that in the event there is a problem within the system (say a plant has to go into emergency shutdown) there is still enough capacity left in the grid for other plants to be dispatched to prevent a disruption in service.

\textsuperscript{141} Ibid.
\textsuperscript{142} Ibid.
\textsuperscript{145} Ibid.
NERC uses as a reference for reserve margins: 15% in areas where most of the power comes from thermo-electric sources and 10% in regions where most of the power comes from hydroelectric resources. Using this metric, NERC has concluded that many regions could face the possibility of having capacity retired much faster than replaced resulting in regions dropping below reserve margins between 2013 and 2018. Within industry, there is also a growing consensus that new projects are not going to offset retirements. In its own reserve capacity estimates, American Electric and Power concluded that all NERC regions would be inadequately shored up against failure by 2018.

In its 2011 Report, NERC concluded that new environmental regulations had the potential to reduce operating capacity below reserve margins. Oddly enough, when NERC looked at the effect of individual regulations, it cited Clean Water Act Section 316(b) as having the greatest effect on power plant retirements in the future. The MACT rule was listed next in its overall effects and in the short and long term would have the same cumulative effect as NERC’s model suggest the cooling structure rules would have by 2018. NERC’s previous 2010 retirement estimates were found to be far less than what was projected in the 2011 report.

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In both assessments, NERC factored into its assessments what CSPAR would do to the utility sector. It found that CSPAR had less of an effect than MACT and 316 (b). This is consistent with the view of many in the investment community. In their 2010 report FBR Capital Market’s concluded that out of all of the upcoming regulations, MACT would be the one that would drive the greatest change in the utility sector.\(^{150}\) Debate has raged over the degree to which MACT specifically has contributed to plant retirements. Many have argued that low natural gas prices have actually caused the transition away from coal and MACT simply accelerated what was already going to happen.

**Coal Markets and Economics**

Looking at construction trends in the utility sector, much of the investment in new generation has been targeted toward natural gas over the past ten years.\(^{151}\) The increase of natural gas production in the Marcellus and other shale formations has greatly altered the economics of natural gas both domestically and globally. Historically, coal was one of the more stable energy commodities. Its supply chain in the United States was fairly contained and the resource was usually purchased on contracts. However, as the United States started to adopt measures to curb sulfur dioxide emission to combat acid rain, a shift occurred in the coal market. Low rank (meaning low heat content) bituminous and subbituminous coals suddenly became far more desirable for use in electricity generation if they were low in sulfur content. As a result, resources like the Powder River Basin opened up to large scale export to power plants in the Eastern United States as they attempted to control their SO\(_2\) emissions.

The switch between coal sources meant that coal prices have largely flat-lined over the past three years. Electricity generation represents 90% of the end uses for coal. Any decrease in coal consumption in the utility sector is immediately felt throughout the coal industry.\(^{152}\)

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The coal industry as a whole has experienced a great deal of decline with some producers such as Patriot Coal have been forced into bankruptcy.\textsuperscript{153} This has spurn the industry to seek new markets for

its products. The People’s Republic of China is an obvious market for Powder River Basin coal but many environmental groups have geared up for a hard fight to stop coal export projects in the Pacific Northwest. The Governors of Washington and Oregon both petitioned the White House to reconsider the Army Corps of Engineer’s permitting of a coal export terminals in the Pacific Northwest. Environmental think tanks like the Sightline Institute have looked at the long term viability of Asian coal markets to make the argument that the terminals would not benefit the region in the long term.

Regardless of how one looks at the benefits or risks of coal export terminals, it is clear from EIA’s data that exports are becoming a major component of the domestic coal industry. Others have also written that the allowance of coal exports undermines the accomplishments for greenhouse gas emission reductions in the United States. Think about coal as a fungible commodity like oil lends one to understand the nature of the problem. If the US does not burn the coal but instead exports it, there is really no benefit derived from reducing emissions domestically.

![U.S. coal exports and imports](source: U.S. Energy Information Administration)

**Figure 18: Coal Imports vs. Exports; Source: EIA**

**Natural Gas Markets in the Era of Hydraulic Fracturing**

Natural gas’s meteoric rise in production, and collapse in price, has been hailed as both an environmental good and as a great evil. It depends largely on where one looks at the benefits and the risks. Growing concern about the effects to ground water is one of the major determinants to the overall environmental impact of growing shale gas production. Researcher such as Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson has shown that in sites of active drilling,
there are greater concentrations of methane which match the chemical and isotopic signatures of the natural gas produced in nearby wells.157 Questions are still outstanding about the role fugitive emission from production wells might contribute to further climate change. Methane is around twenty five times more potent a greenhouse gas than carbon dioxide so even small emission rates could have significant affects for the climate system. Despite these concerns, the market price is very much in natural gas’ favor.

Natural gas prices are currently at historic lows. As recently as July of 2008, the wellhead price for natural gas was $10.79 per thousand cubic feet.158 Whereas coal’s price history has largely been one of stability, natural gas prices have been far more unstable. Starting in 2000, the price of natural gas started to increase as fears grew about future availability of supply. For almost a decade, the price remained elevated while following larger macroeconomic trends. With the collapse of the economy in 2009, prices fell precipitously but they have remained low since then despite economic growth because of the increase in supply due to hydraulic fracturing of shale formations for natural gas.

Figure 19: Natural Gas Prices (1973-2013); Source: EIA

Globally, natural gas prices have also experienced market volatility because the resource is hard to transport and it is used in a variety of applications such as home heating, industrial processing, and chemical manufacturing. Between these localized markets, there exist potentially large price spreads. As company have developed liquid natural gas terminals and ships capable of hauling LNG, it is now technologically possible to export or import natural gas. The coupling of natural gas markets globally could result in much higher domestic prices for natural gas.

With the United States expanding its natural gas generating fleet and decreasing coal and nuclear capacity, the price of electricity in the US will have increasing upside risks to natural gas price volatility. This could negatively impact the economy if the US were to experience a natural gas price shock that was passed onto electricity consumers.

**Low Natural Gas Prices are Affecting Nuclear Power Plants**

Even nuclear power is suffering in the face of declining natural gas prices. As stated earlier, nuclear power in the United States has proven extraordinarily expensive and is fraught with a history of cost overruns. This has largely prevented the construction of new plants but even existing plants are now being considered for phase out due to low natural gas prices. After it was damaged during maintenance, Duke Energy’s Crystal River station in Florida was idled to assess the cost of repairs. Duke’s engineers concluded that the costs could be as high as $3 billion. Given that a comparable natural gas plant could be built for much less and have it operation in 2018, before the estimated time for the length of repairs to the nuclear plant. The situation has become so bad that a Wall Street Journal article asked the question, “Can gas undo nuclear power?”

Despite having been touted as the fuel source that would one day be “too cheap to meter” in the 1950s, the industry is now facing some serious economic problems. In deregulated markets especially, nuclear plants are increasingly having a harder time competing on the open market when natural gas prices are low. In October of 2012, Dominion Energy Resources announced that it would close its Kewaunee station in Wisconsin despite having a 20 year operating license extension. Other plants are also under consideration for shut down as a result of poor cost performance. This is especially troubling because nuclear plants are the primary low greenhouse gas emission power source in the United States. Recently, in a study coauthored by James Hansen, a determination was made that the

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161 Ibid.
deaths from future nuclear disasters would be far outweighed by the number of deaths resulting from climate change related events.\textsuperscript{162}

**Market Projection based on the Price Differential Between Natural Gas and Coal**

Between low natural gas prices, stronger EPA regulations on coal plants, and escalating costs of nuclear power plants, it is becoming increasingly difficult to project where capital should be allocated in meeting the projected demand for new power plants. Even with a weakened NSPS for greenhouse gas emissions, the other environmental regulations on mercury, particulate matter, NO\textsubscript{x}, and SO\textsubscript{2} are still a major constraint in the expansion of coal. Natural gas prices have historically been volatile and with the large price spreads between US natural gas and global prices, it is likely that a concerted effort will be mounted to expand exports. Such a push would carry political risk due to the competitive advantage the US is enjoying as a result of cheap energy prices so one cannot say that a coupling of US natural gas to the global market is inevitable. However, on the balance, there are more reasons to cite that would cause the price of natural gas to rise rather than continue to fall. Drawn by low energy prices, increased domestic manufacturing would compete for natural gas with utilities, the production of wells over an extended period of time is yet to be determined, natural gas companies could make more money by selling the resource overseas, any and all of these scenarios are possible.

If the economics of natural gas change and the economics of coal, nuclear, and renewables do not allow for rapid growth, then there exists the distinct possibility that US electricity prices will increase in the medium term. Carbon capture and sequestration technologies have the potential to change this picture to some extent. At, the price differential between natural gas and coal fuel switching for power generation is fairly narrow. As was shown in a recent study by Lincoln Pratson, Drew Haerer, and Dalia Patiño-Echeverri, under current regulations the natural gas to coal price ratio only needs to move to 1.8 for coal to become the cheapest energy source.\textsuperscript{163} However, the authors also noted that under proposed regulations the price differential between the fuels would have to be greater than 4.8 to cause a switch back to coal. This means that with greater regulatory pressure, the price differential between the fuel costs coal and natural gas will become less relevant as the greater environmental control costs associated with coal will be the driving utilization factor.

Overall, what is happening in the United States is a condensing of the base load generation market toward natural gas generation with some nuclear plants. Even absent a price on carbon, coal’s performance in the market is greatly hampered by the cost of environmental controls. As long as natural gas prices remain low, this will send a signal to the market to continue investment in natural gas generation for baseload power. However, if natural gas markets remain volatile as they have in the past, there is a far greater risk to the larger economy if the price of electricity spikes unexpectedly.

**Potential Affects to State Economies: Kentucky as an Example**

States that have low cost electricity to draw in manufacturing and industrial development are especially worried about the shift toward a single fuel source, natural gas, for base load generation. In a recent presentation on the topic Dr. Leonard Peters, Kentucky’s Secretary of Energy and Environment, outlined the problem Kentucky faces when planning for both its energy and economic future.\textsuperscript{164} Electricity in Kentucky is overwhelmingly coal (~90%) with a small amount of natural gas,


petroleum, and hydroelectric power. Power sources in the Commonwealth have not changed much in thirty years past thirty years. Whereas national electricity consumption has been driven by residential growth, Kentucky’s growth has been largely driven by growth in manufacturing. Since the 1990s Kentucky has had some of the lowest electricity costs in the United States. The low cost of electricity has served as a driving factor in companies making further investment in the Commonwealth. This has resulted in Kentucky having one of the most electricity intensive economies of any state. For these reasons, the price of electricity in Kentucky is crucial to maintaining the Commonwealth’s economy. In contrast, a state like New York has a very low electricity intensive economy and therefore the Commonwealth’s economy is less dependent on the price of electricity. The role of manufacturing in a state economy plays a major role in how a state is likely to view changes fossil fuel combustion regulations. In Kentucky’s case, there has not been a favorable reaction to new EPA regulations.

In a place like Kentucky, one could make an argument that the increase in electricity prices would not matter because companies would just become more efficient in its use. However, as Dr. Peters pointed out, Kentucky’s manufacturing is not inefficient. He cited the fact that Toyota has paid the same amount for electricity despite its growth through energy efficiency as support that the larger manufactures have already worked hard to maintain high levels of efficiency. What is problematic is the nature of the industries that have moved to Kentucky. Aluminum smelting is a highly energy intensive process. Large arch-furnaces are used to smelt the bauxite and refine it into pure aluminum. These systems require a great deal of electricity. Due to Kentucky’s low electricity prices, the industry have moved into the state.

However, there is growing friction between the regulators and industry. In a recent rate case involving Big Rivers Electric Corporation, two of the area’s biggest electric customers, both aluminum smelters, baulked at having rates increased by as much as 15% to offset lost load when another aluminum plant left the Commonwealth. Century Aluminum and Rio Tinto Alcan both challenged the rate increase in court because they had signed long term power purchasing agreements with Big Rivers. The Public Utility Commission in Kentucky ruled that neither smelter could get out of the rate increase and would therefore pay more in electricity. Both companies stated their position that the rate increase placed them at a distinct competitive disadvantage with the rest of the global aluminum market.

It is the balance between economic growth and the cost of electricity that will have to be carefully considered as utilities and states with regulated markets make planning decisions going forward. The environmental controls necessary to meet EPA standards coupled with the ever decreasing probability of more nuclear power coming online means that natural gas is becoming the default fuel for base load generation. In and of itself, this would not be a bad outcome where it not for the greater macroeconomic risk such a situation presents. It makes the price of electricity more likely to be volatile and experience price shocks if the history of natural gas is any indication of some of its future performance. One also needs to keep in mind that in the United States, most of the coal produced goes toward producing electricity. There are not many other competing demands on the resource. In contrast, natural gas is used in home heating, the petrochemical industry, and in a variety of manufacturing processes. Any change in demand for these other end uses, say an especially cold winter, would have an effect on the market price of electricity and be passed on to end users.

Kentucky’s utility commission has attempted to model these sorts of scenarios. In his work with the commission, Aron Patrick used data from Kentucky’s employment figures to show what

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changes to the price of electricity did for the greater economy.\footnote{Patrick, Aron. “Modeling an Energy-Intensive Economy in the Face of Uncertainty.” Duke University. Durham, North Carolina. April 24, 2013.} The model is based on a maximum of 15,000 direct jobs in Kentucky from the fuel mix current fuel mix. This would include jobs such as operating a power plant or working in a coal mine, but constitute an overall small number of jobs in the state. In contrast more than 210,000 jobs are drawn from the manufacturing sector. Put another way, coal’s maximum GDP contribution to Kentucky’s economy was 3%, while manufacturing was over 20% of total GDP. The support jobs that accompany the rest of the economy constitute over 2 million jobs. Manufacturing was found to be most sensitive to changes in the electricity price, 25% increase in price led to around a 30,000 job reduction in a range of 12,000 to 50,000 possible job losses. The modeling done by Mr. Patrick also showed that Kentucky would have stayed a coal state but new environmental regulations over the next three decades will result in natural gas combined cycle plants becoming the most likely absent a large nuclear project. Further refinement of the modeling with a Monte Carlo simulation on price shocks showed that every time a price shock occurred, Kentucky would likely lose jobs even if the duration of the shock was relatively short.

The research in Kentucky shows that the distribution of the portfolio of generating sources is highly dependent on regulatory signals. At present, the market signal being sent by low natural gas prices, high costs of environmental controls for coal plants, and extremely high costs for nuclear plants means that the trend toward more natural gas generation for baseload operations is likely to endure in the short term. It cannot be emphasized enough that these transitions are happening absent any sort of control or price on carbon. While utilities know such a situation is probably evitable, they have to make investments today with the information at hand. If carbon capture technologies were introduced to the market at a competitive price, it would blunt the upside risks of natural gas prices by allowing for construction of coal plants if only to be held as reserves. Cost competitive carbon capture technologies could provide a very lucrative and competitive option for utilities’ fleets.

### NET Power – Technology Overview and Place in the Market

NET Power is a startup funded by 8Rivers Capital in Durham, North Carolina. The company is working to commercialize an oxyfuel combustion plant with a number of unique features.\footnote{Allam, Rodney, Miles Palmer, G. William Brown Jr, Jeremy Fetvedt, David Freed, Hideo Nomoto, Masao Itoh, Nobuo Okita, and Charles Jones Jr. “High efficiency and low cost of electricity generation from fossil fuels while eliminating atmospheric emissions, including carbon dioxide.” Energy Procedia. (2012). https://www4.eventsinteractive.com/iea/viewpdf.esp?id=270035&file=\DCFILE01\EP11\Eventwin\Pool\office27\docs\pdf\ghgt-11Final01021.pdf (accessed December 1, 2012).} From the initial stages of development, NET Power sought to design a system that captured 100% of all emissions from the combustion of fossil fuels. The plant turbine designs use the carbon dioxide produced from combustion of the fossil fuel and pure oxygen mixture as the working fluid. This stands in contrast to other thermoelectric plants which either boil water to produce steam for a working fluid or use a fuel air mixture to produce a combustion gas working fluid. Rather than use heat from combustion to burn water, the NET Power system functions like a combustion turbine in that it uses hot gas as a working fluid. Unlike a combustion turbine, the denser carbon dioxide allows for more power to be captured from the movement of the gas. The high purity of the combustion gas is achieved through the use of an air separation unit. The ASU super-cools atmospheric gases and fractionally removes oxygen based on its boiling temperature. This oxygen is what is used in the combustion chamber of the plant.

After moving through the turbine, the hot carbon dioxide is sent through a heat exchanger to
transfer its heat to a recirculating flow of CO$_2$ returning to the combustor. This process is similar in concept to a combined cycle plant but it avoids the inherent thermodynamic losses associated with a Rankin cycle. The cooled gas is then sent to a condensing system that removes latent water from the combustion gas and then compresses the almost pure carbon dioxide for return to the combustor to re-burn any remaining hydrocarbon. Due to the mixing of fuel and oxygen at the start of the cycle with the recycled gas, a higher net CO$_2$ product is created. This highly purified carbon dioxide is further compressed by the system and is finally removed from the system after recirculation so that it can be sent via pipeline to a sequestration site.

Figure 21: Schematic of NET Power's Natural Gas Plant Design; Source: NET Power

NET Power’s technology can also be used for coal combustion. In these applications, the coal is formed into a slurry and then burned. The impurities in the coal: H$_2$S, COS, CS$_2$, NH$_3$, and HCN are oxidized in the combustion reaction. The oxidized species are then removed from the final gas stream in the same process that removes water and creates the purified carbon dioxide gas. The coal processing technology has been demonstrated by Vattenfall’s Schwarze Pumpe pilot plant in Germany.

Figure 22: Schematic of NET Power's Coal Plant Design; Source: NET Power
NET Power’s technology has gone through advanced modeling and at present it is estimated that the plants will be roughly 58% efficient for natural gas and 51% efficient for coal. The increased efficiency for coal combustion is especially important to consider when the plant average in the United States is only 35%. By integrating all of the capture capabilities into the operation of the main plant, NET Power’s design is projected to reduce costs compared to other carbon capture technologies. The company projects its installed costs will be between $1500 and $1800 per kilowatt for coal and less than $1100 for natural gas. This is less than the EIA’s base case estimate for a conventional pulverized coal plant that does not capture carbon. The plants are also much smaller than conventional power plants taking up about 1/3 of the size a similar natural gas combined cycle plant and 1/6 the space of a conventional pulverized coal plant. Given that NETL has found real estate to be a constraint on many existing coal plants installing CCS equipment, a reduce plant footprint is a strong advantage.

NET Power has a unique set of advantages to its technology that could allow it to readily break into the market. Because of growing concerns over the increasing dependency on natural gas, NET Power’s technology could provide a way of diversifying fuel costs while also decreasing the capital costs of power plants. If commercialized at the anticipated prices, NET Power’s plants could compete with all coal plants without carbon capture and even nuclear technologies on a price basis. Natural gas plants are going to be harder to beat; however, with the company’s current cost and efficiency projections, NET Power would still be highly competitive with these low cost systems.

**NET Power - Environmental Permitting and Regulatory Assessment**

In light of the NET Power design, it is a potential answer to many of the current and evolving regulatory challenges to continued fossil fuel combustion. The technology has the ability to “solve” many of the regulatory challenges imposed on new fossil fuel generation. Given the similarity in efficiency of the NET Power natural gas design to that of conventional combined cycle natural gas plants, it will only be in those areas where NOx and ozone are out of attainment that a clear environmental advantage will be presented absent regulation on carbon dioxide. In a carbon constrained economy, NET Power’s design has the distinct advantage of maintaining the high efficiency of a natural gas combined cycle plant while readily allowing for the sequestration of a highly pure carbon dioxide gas stream. The company’s current combustion testing suggests that their system will produce extremely low levels of NOx and CO, such that even if a NET Power plant were to emit its combustion gas stream, its emissions levels would be well under the EPA thresholds that trigger Title V and NSR/PSD permitting requirements.

With coal combustion, NET Power's technology will clearly excel in the current US regulatory environment. Even with CSPAR overturned, the Court's decision still shows that EPA will eventually have a mechanism in place for further regulating sulfur dioxide emissions. Rather than building out more expensive and stringent scrubbing systems, it could be more economical to simply decommission the old plant and install a NET Power plant instead. With a small physical footprint (1/6 the size of a pulverized coal plant) and an estimated capital cost range of $1500-$1800 per kilowatt installed, NET Power has a number of distinct advantages over competing technologies.

EPA’s proposed NSPS sets a very high target for new plant performance. The proposed NSPS would more or less preclude the construction of new coal fired generation with its limit of 1,000 pounds CO2 per megawatt-hour. In its analysis of the economic impacts of the NSPS, EPA argued

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that even absent the NSPS, “[natural gas combined cycle would] be the predominant choice for new fossil fuel-fired generation even absent this rule.” Given the current state of the art in deployed CCS projects in the United States, it is likely that NET Power would be able to best the emissions standards for these technologies at lower costs than current CCS technologies. For example, the Kemper County integrated gasification combined cycle plant is projected to cost $2.8 billion and have a total output of 585 megawatts. This means that the plant will cost close to $4,786 per kilowatt installed. Also, the Kemper plant will only be able to capture 65% of its greenhouse gas emissions while NET Power’s plant design would capture all of the emissions. In this respect, if EPA updated its standards for maximum available control technology, and if NET Power plants were deployed, they would be part of the top 12% of sources that would serve as the benchmark that the rest of the fleet would have to meet. NET Power’s technological flexibility allows plants to be built that burn either coal or natural gas and still allow for carbon capture. This would be advantageous to utilities in that it could allow utilities to maintain a diversity of fuel sources in their fleets. If natural gas prices were to increase, a utility could idle its natural gas fleet and ramp up generation from its coal fleet. This would benefit consumers by insulating them from price shocks and prevent the serious economic hardships about which states like Kentucky are concerned.

In meeting the standard of becoming a “best available control technology,” NET Power’s technology does provide an immediate benefit over other natural gas systems assuming both types of plant vent to the atmosphere. A NET Power plant would not generate any NOx and therefore be able to get a permit in an ozone none-attainment area in preference to a conventional gas plant. If the ability to easily sequester carbon dioxide enters into EPA's determination of BACT, NET Power would have a likely advantage. However, it must be remembered that EPA's authority in mandating BACT is usually limited, as most states are the ultimate permitting agents for power plants. The determination for any one plant meeting BACT is based on a number of economic, environmental, and technical factors.

It should be noted that NET Power’s design could generate some emissions under unusual circumstances. The one mode in which direct atmospheric emissions would occur would be in case of an emergency at the plant that required the system be evacuated rapidly. Further modeling of the plant emergency shutdown procedures will be required to fully determine the “potential to emit” but it could be possible to make the argument that such events would happen so irregularly that there is a potential to emit well below the threshold.

**Discussion**

Combustion of fossil fuels for electricity generation is not likely to end any time soon. Despite the many deleterious effects of fossil fuel extraction, the fuels do provide a reliable and cheap source of energy in a world that is increasingly become more energy intensive. Renewable energy technologies have so far been too intermittent to provide baseload generation. Until the problem of large scale energy storage is solved, intermittent renewable energy sources such as solar and wind power will not be able to provide the sort of steady electrical supply needed for a stable grid. Advancements in improving the efficiency of the electrical grid, such as North Carolina State University's FREEDM Center's work on solid state transformers and smart metering do have the potential to improve the flow of information and electricity but these systems are still far from wide scale adoption.

Ultimately, there is a need for a substantial overhaul in the way that fossil fuel power plants are designed to comply with new regulations. Rather than assuming that regulations are static when

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building a plant and building it “to code,” utilities should become more proactive and anticipate the likely regulatory challenges that a plant will face during its lifetime. Accomplishing this will mean that both electric utilities and state regulators will have to move out of typical comfort zones and be willing to permit “experimental” plants.

Considered outside of an American context, NET Power also represents a development mechanism that sidesteps some of the more intractable problems of energy in the developing world. In a country like the People's Republic of China, where air pollution has become dramatically worse in the last few years, NET Power's technology could provide a way of allowing the country to continue to use is abundant coal resources without fouling its airspace. In countries trying to electrify broadly for the first time such as Nigeria, operating NET Power plants could reduce the rate of growth of greenhouse gas emissions dramatically compared to the current estimates.

**Conclusions**

The Supreme Court's decision in *Massachusetts v EPA* has proven the single greatest driver of climate change policy in the United States. Absent the Court's ruling, any attempt thereafter to try and regulate greenhouse gas emissions would have been even more contested than it has already been demonstrated. In general, most of the environmental regulations that have driven changes in the make-up of the national fleet of electric generation units have been ordered by the Courts. Absent a successful legislative push to remove EPA's authority to regulate mercury, air toxics, sulfur dioxide, oxides of nitrogen, and now greenhouse gases, the technological future of electricity generation in this country will be quite different.

The debut of technologies to cheaply extract natural gas through hydraulic fracturing, this has driven coal to the margins as a fuel source. The overall age of the coal fleet means that many generating units will face a serious prospect of retirement over the next twenty years simply because the plants and equipment will be worn out. Already, there are plants with a sixty year operating history and the economics of continuing to run these plants have been seriously challenged. This simple fact all but guarantees that new investments will have to be made in building new power generation in the United States.

Utilities have invested so much in natural gas generation that the fleet's capacity exceeds that of any other fuel source. However, it is still more efficient to use coal and nuclear for base-load generation and therefore this “excess” capacity is seldom fully utilized. At least in theory, the utility sector could transition completely away from coal-fired generation in response to EPA regulations. But, there is a massive upside risk to this decision. It would make the utilities heavily dependent on a single fuel for much of their generating capacity. Natural gas prices are projected to remain low for some time but with the opening of liquid natural gas export terminals, the current North American natural gas market could become integrated into a more global natural gas market with a much greater price for the fuel. A price shock in natural gas would have deleterious effects on the economy and consumers.

Because of this risk, and due to the historical memory of many Public Utility Commissions, there is a serious reluctance to allow utilities in regulated markets to build nothing but natural gas plants. However, with current EPA regulations, options are limited. Renewable sources of energy such as wind and solar can help meet demand, but additional energy sources are also needed. New nuclear plants seem unlikely to develop in any large scale as the construction costs have risen so sharply in the last two decades. The deployment of modular nuclear reactors could assist in meeting demand but the technology for manufacturing and running a modular reactor is mostly vaporware.
Given, nuclear is too cost prohibitive, natural gas carries too many future price risks, and conventional coal combustion is too dirty, the market needs to develop technologies that can cheaply accomplish carbon capture and sequestration to maintain diverse sources of baseload generation. If the goal of our national energy economy is to have stable prices while preventing damage to the global climate, carbon capture and sequestration makes sense as part of the solution. Furthermore, CCS technologies, including NET Power's technology, represent both a transitional power source and could serve as a long term sustainable source of energy. Chemists are working to develop methane derived from solar energy. If that methane was burned in a NET Power or similar plant, and the carbon still sequestered, it would remove carbon from the atmosphere. Between the various assessments of deep-saline aquifers, continental flood basalts, and oceanic basalts, there is storage capacity for carbon dioxide. Carbon capture is certainly not the only solution to climate change, but it can play a major role in helping to fix the problem.

Whereas most other CCS technologies discussed in this paper are “add-ons” to existing power plant designs, NET Power's technology provides a new platform for electricity generation. With capital expenditures estimated in excess of half a billion dollars (adjusted for inflation) for a CCS retrofit to a 600 megawatt coal plant, utilities might conclude it better to build a new more efficient plant rather than retrofit. One can see from the experience of the utility sector’s response to the introduction of the new mercury regulations that plant closure is often seen as a better option to retrofitting a plant. NET Power's system’s higher thermal efficiency for coal combustion compared to existing facilities could also make it more attractive by reducing plant lifetime fuel costs. Due to the plant costs and operator benefits, introduction of NET Power’s technology could result in a more market-driven, adoption of CCS, as opposed to being driven solely by regulation. Such a situation would be far less prone to political attack and far more palatable to Public Utility Commissions. Its efficiency with natural gas is comparable to existing combined cycle plants with the added benefit of controlling for NOx and carbon dioxide without severe parasitic loses. Through efficiency of fuel use and ability to control pollution, NET Power's system is a highly attractive technology that provides the flexibility to keep the fuel supply of the grid resistant to over-dependence on a single fuel. This and its environmental benefits are the technology’s greatest potential strengths.

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