Carbon Dioxide Regulation

and its Impact on the Electric Utility Industry

Mind Powered: Insight with Impact.

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Control of greenhouse gases such as carbon dioxide (CO_2) is receiving a great deal of attention within the U.S. Congress. While the science of global warming can be debated, there is no doubt that the ambient concentrations of CO_2 are increasing, in part as a result of growth in the combustion of fossil fuels by vehicles, industry and power plants.

Over the past 160 years, atmospheric levels have risen from approximately 280 parts per million (ppm) to 360 ppm[1]. There are numerous bills introduced for greenhouse gas control both in the U.S. Congress as well as many of the state legislatures. Certain states such as California have already promulgated legislation basically eliminating the use of coal without carbon capture and sequestration to control greenhouse gases. Other northeastern states have signed a Memorandum of Understanding to cap greenhouse gas emissions. Some 300 bills, proposals and resolutions have been introduced in 40 states.

The predominant sentiment is that regulation is inevitable and only the timing and method of regulation is not presently known. The two possible primary methods of regulation are either a tax imposed on emissions or some form of a cap and trade system comparable to what presently exists for SO_2 and NO_X emissions (auctioning allowances under a cap and trade system is equivalent to a tax on emissions).

This paper explores the potential cost impacts of carbon regulation on the electric utility industry and offers certain observations on the future winners and losers depending on the type of regulation ultimately established in the U.S.

CO_2 Emissions

Figures 1 and 2 illustrate the U.S. 2006 CO_2 emissions by economy sector type and CO_2 emissions in the power sector, respectively[2]. The 2006 emissions as reported by the Energy Information Administration (EIA) are approximately 6 billion metric tons. Power, with approximately 2.4 billion metric tons, is the most dominate sector followed by transportation with approximately 2 billion metric tons.

Of the power sector emissions, approximately 2 billion metric tons or 83 percent are from the use of coal. In contrast to 1990 emission levels, total U.S. CO_2 emissions were approximately 5 billion metric tons with the power sector emissions at approximately 1.9 billion metric tons. The 1990 levels are used as targets to be achieved by year 2020 in much of the proposed legislation in Congress.

[1] Power Magazine, Vol. 151, No. 4, April 2007.
[2] Annual Energy Outlook 2007 from the Energy Information Administration (eia.doe.gov)

Figure 1: U.S. CO_2 Emissions

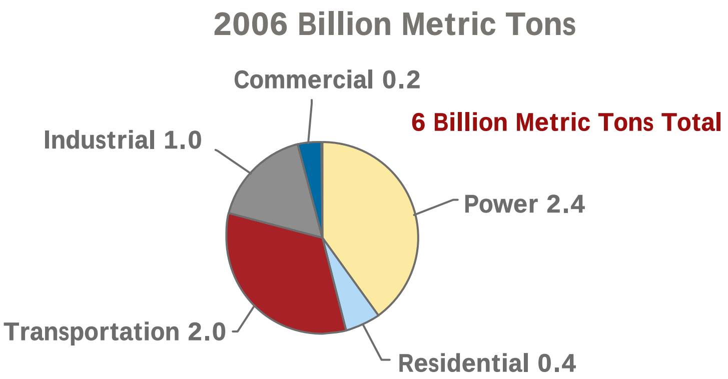
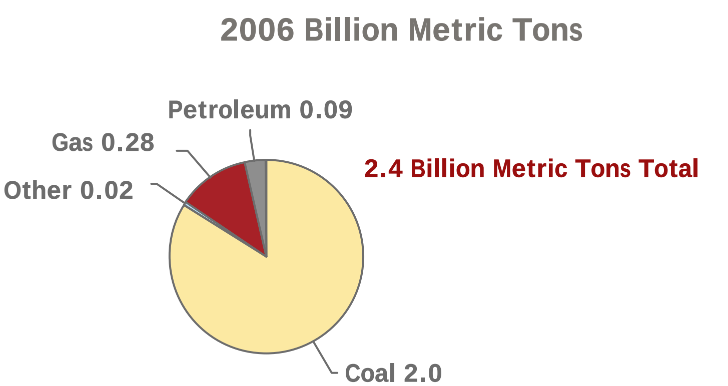


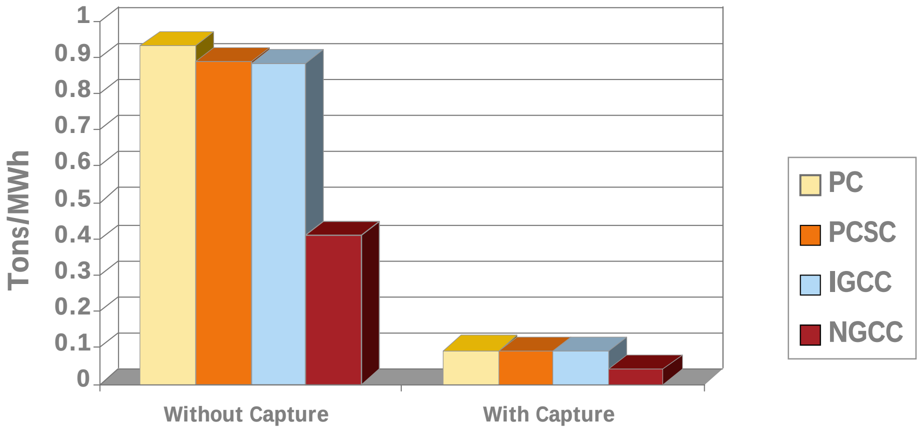
Figure 2: U.S. CO_2 Emissions from Power Generation



Since this paper deals with the impacts to the power industry as a result of CO_2 regulation, figure 3 shows approximate CO_2 emission rates from various technologies and fuels for uncontrolled and controlled emission cases. For the controlled case, 90 percent removal efficiency is used to represent a likely maximum in CO_2 control from power generation units. These estimates should be used as approximate estimates as the exact emission rates will vary with technology type (efficiency) and fuel characteristics (heating value and carbon content).

For a sub-critical pulverized coal-fired unit (PC) an uncontrolled, or without capture, emission rate of 0.93 tons/MWh is shown, for supercritical units (PCSC) 0.89 tons/MWh is shown, for Integrated Gasification Combined Cycle (IGCC) units 0.88 tons/MWh is shown and for Natural Gas Combined Cycle (NGCC) 0.41 tons/MWh is shown. For uncontrolled units the difference in emission rates among different technologies is the result of differences in system efficiencies when similar fuel is fired. The controlled, or with capture, emission cases show emissions that are 10 percent of the uncontrolled emissions at 90 percent control efficiency.

Figure 3: CO_2 Emissions by Technology/Fuel Type



Carbon Capture Options

Carbon capture options from power plants can generally be categorized as post combustion, pre combustion or oxy-fuel combustion technologies.

Post combustion technologies involve the capture of CO_2 from the flue gas after the combustion of fuel in the boiler and generally involve some type of scrubbing process followed by a purification process that results in the recovery of CO_2 to allow sequestration

Pre combustion technologies involve the capture of CO_2 prior to combustion of the fuel typically seen in IGCC processes and perhaps the steam reforming of natural gas and water shift conversion to result in the formation of hydrogen and carbon dioxide.

In the pre combustion technologies, the CO_2 is removed from the fuel by some type of scrubbing process and the resulting hydrogen is burned as fuel in a combustion turbine. The advantage of the pre combustion processes is that the CO_2 is captured in a richer CO_2 stream under pressure than the post combustion process, thus resulting in a relatively easier and less costly removal process. The disadvantage, however, is that the cost to gasify the fuel is higher than the costs to burn the fuel in a conventional power plant.

Commercial technologies are available for the capture of CO_2 for both pre combustion and post combustion capture. Many of these processes have been utilized in commercial and industrial applications. Alkanol-amines are presently considered by many to be the most appropriate for use with post combustion capture.

Amines are ammonia based chemical compounds where the hydrogen atoms are replaced by one or more organic radicals. Amines act as chemical absorption reagents to capture the CO_2 from the flue gas. Amine processes have been used in the gas processing, chemical and petroleum industries. The CO_2 is chemically bound to the amine solvent by an exothermic reaction of the gas with the amine. Physical absorption is better suited for CO_2 capture for more rich CO_2 streams under pressure such as those present with the utilization of IGCC.

Processes such as Rectisol and Selexol have been used with IGCC installations and other chemical processes. The greater binding strength of CO_2 with the amines as a result of using chemical solvents for capture (required due to the low CO_2 concentrations in the flue gas after combustion) results in greater energy needed to strip the CO_2 in the regeneration step than the energy needed to strip the CO_2 from the physical solvent processes used on IGCC plants. This fact is a key advantage of the IGCC plants in capturing CO_2 more economically than in pulverized coal units.

Oxy-fuel combustion involves the combustion of coal with pure oxygen rather than air which eliminates the presence of nitrogen resulting in a substantially pure CO_2 stream. Only moisture needs to be removed with other trace contaminants. Since the presence of nitrogen is eliminated, the formation of NO_X is virtually eliminated. A CO_2 stream is recycled to control temperatures in the boiler. The disadvantage of the process is the energy penalty incurred to separate oxygen from air is offset by the advantage of eliminating the need to separate the CO_2 from the flue gas.

There are other prototype capture technologies being investigated by the Department of Energy (DOE) and private entities in an attempt to lower capture costs. These technologies include amine-based solid sorbents, aqueous ammonia scrubbing and aqueous ammonia multi-pollutant capture. It has been reported that the capture costs using ammonia are less than using amines due to the lower binding energies thus requiring lower energies to strip the CO_2 from the ammonia solvent.

Sequestration Options

There are four primary sequestration options which include the injection and storage of the captured CO_2 in some type of geologic formations – oil/gas reservoirs, deep and unmineable coal seams, saline aquifers and deep oceans.

Table 1 presents the estimate storage capacity for these options as reported by DOE[3].

Sequestration Option	Estimated Storage Capacity (BMTons)
Oil/Gas Reservoirs	82.4
Deep and Unmineable Coal Seams	156-183
Saline Aquifers	919-3,378

Injection of CO_2 in oil/gas reservoirs for enhanced oil recovery has been used successfully to increase the recovery of oil in exhausted reservoirs. The CO_2 lowers the viscosity of oil therefore making it easier to flow and be recovered more economically.

The other options are not yet demonstrated fully. Even at the lower storage capacity estimates, based on the estimated 2.4 billion metric tons per year emissions, there is more than 400 years of storage capacity. The location of these geologic formations is widespread in the U.S. and found near most existing coal-fired power plants.

The greatest storage potential appears to be the saline formations. Saline formations assessed for storage are defined as porous and permeable body of rock containing water with total dissolved solids greater than 10,000 parts per million below 2,500 feet deep.

[3] According to the National Energy Technology Laboratory report on Carbon Sequestration Atlas of the United States and Canada

Unmineable coal seams are coal seams uneconomical for mining. All coals have varying amounts of methane adsorbed on porous surfaces and wells can be drilled to recover this methane. Additional recovery can occur by injecting CO_2 into the coal bed. The CO_2 replaces the methane adsorbed on the coal. Depending on the coal type, three to 13 molecules of CO_2 replace one molecule of methane, thus providing a storage place for the CO_2 while enhancing methane recovery.

Definition of Capture/Sequestration Costs

In defining the capture and sequestration costs used as input to the market modeling conducted and presented herein, we assumed the use of amine scrubbing for pulverized coal-fired power plants and the use of either the Rectisol or Selexol process for the IGCC power plants.

Estimates given for natural gas-fired combined cycle plants involve the decarbonization of the fuel through steam reforming and shift reactions to result in hydrogen and CO_2. The natural gas combined cycle case with capture is not evaluated in the market analysis presented herein since it is unlikely to be a viable option given the lower CO_2 emissions from natural gas and costs to decarbonize the fuel.

Primary references used to define costs were the Massachusetts Institute of Technology (MIT) study on coal use[4], information developed by the DOE[5] and Bechtel[6] and augmented by R. W. Beck's construction costs data base for various types of power plants. Costs include the transportation of the CO_2 approximately 10 miles for sequestration.

Costs Impacts of Capture Technology Deployment

Figure 4 shows a schematic of a typical 1,000 MW pulverized power plant equipped with SO_2, NO_X and particulate controls (SCR, SO_2 scrubber and baghouse).

[4] According to the March 15, 2007 Coal Utilization Research Council memorandum on MIT Rollout of the "Future of Coal" Report

[5] U.S. Department of Energy Office of Fossil Energy, National Energy Technology Laboratory: Technical Facts bulletin on "System Analyses of CO_2 Capture Technologies Installed on Pulverized Coal Plants", December 2005.

[6] Bechtel Technical Paper on "Technical and Economic Comparison of CO_2 Reducing Technologies for Power Plants", November 5, 2002.

Figure 4: PC Schematic without Sequestration and Capture

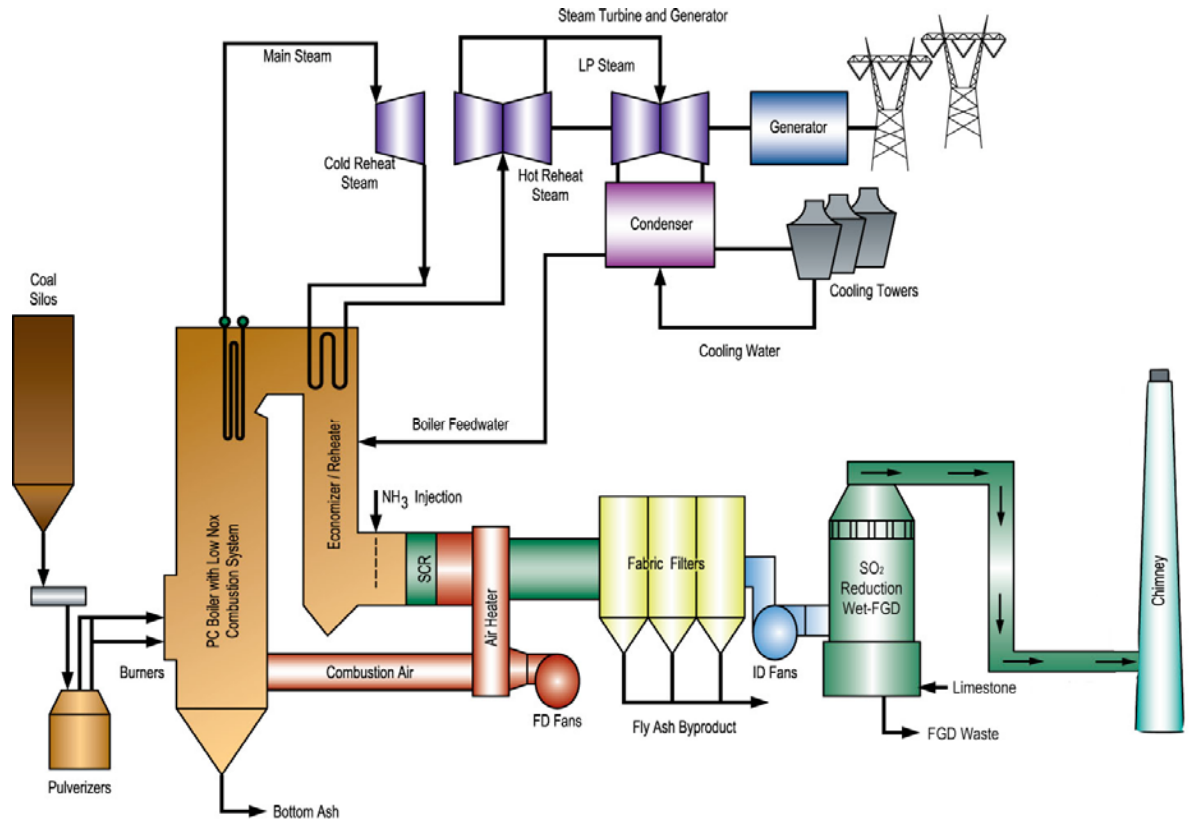
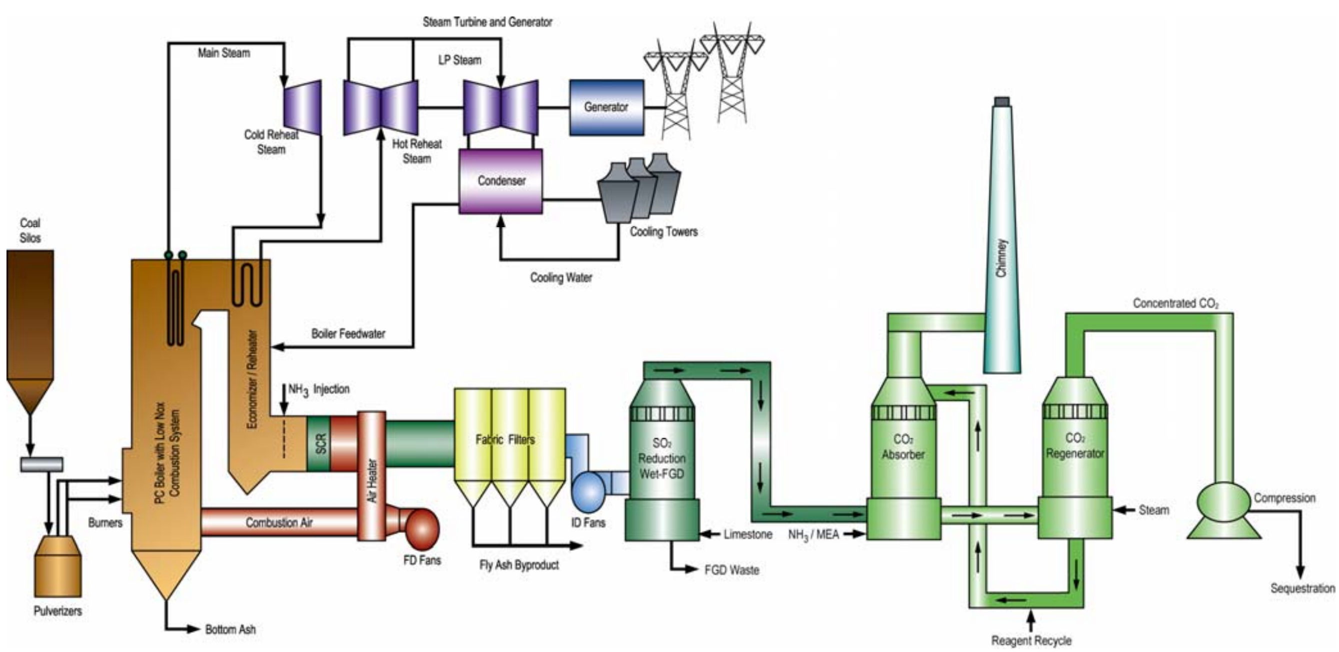


Figure 5 shows the same typical pulverized power plant equipped with CO_2 controls.

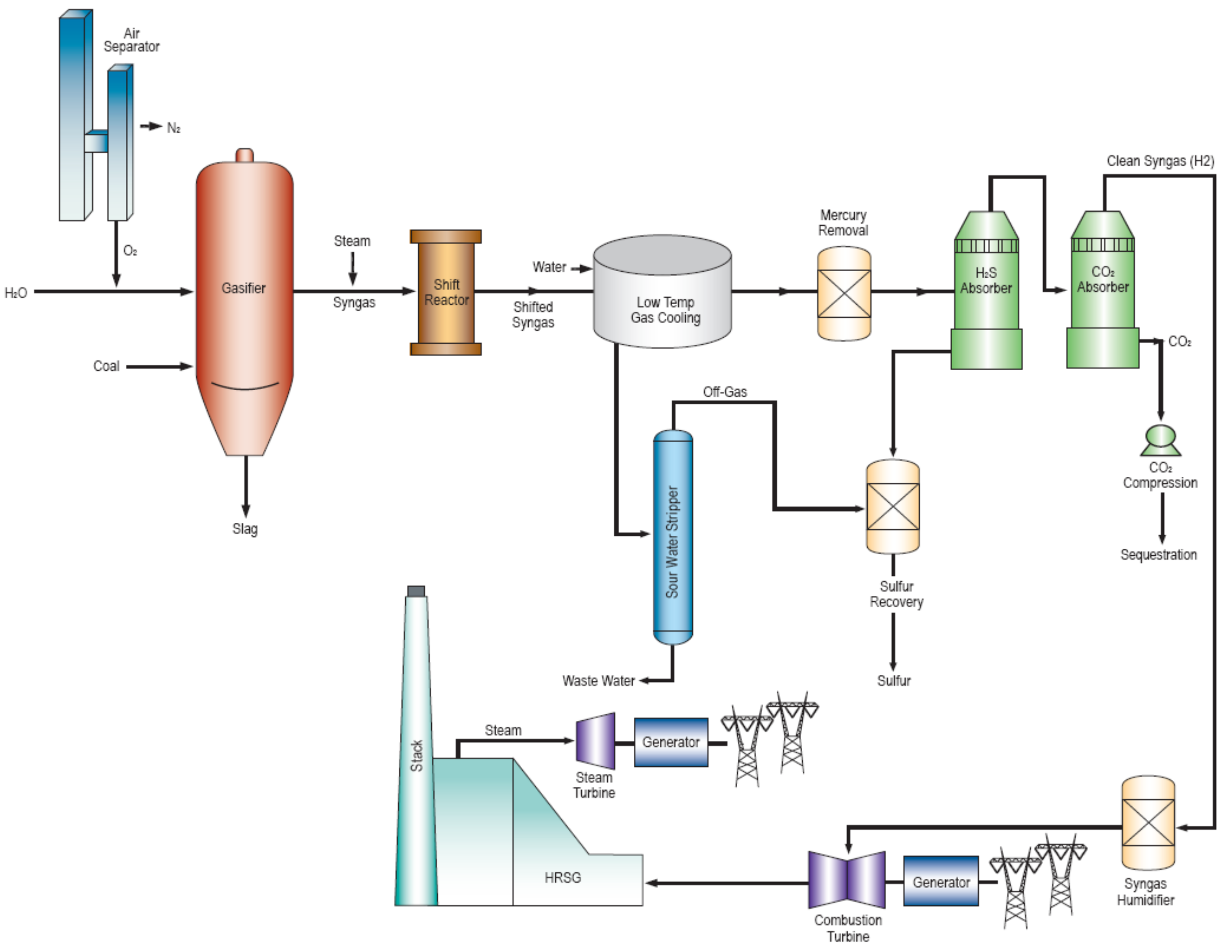
Figure 5: PC Schematic with Sequestration and Capture



The main components of the controls include an amine absorber to capture the CO_2 from the flue gas after the SO_2 scrubber, a CO_2 regenerator to regenerate the CO_2 from the amine solution for recirculation back to the absorber and compression equipment to compress the CO_2 for sequestration. The auxiliary power needed for compression and ancillary equipment and steam needed for regeneration lowers the net output of the power plant.

Figure 6 shows a schematic of an IGCC plant with carbon capture indicating removal of the CO_2 from the synfuel prior to combustion in the combustion turbine.

Figure 6: IGCC Schematic with Capture and Sequestration



Figures 7, 8 and 9 show the impacts of CO_2 capture and sequestration on the plant's heat rates, capital costs and non fuel O&M costs.

Figure 7: Heat Rate Impacts – Including Sequestration

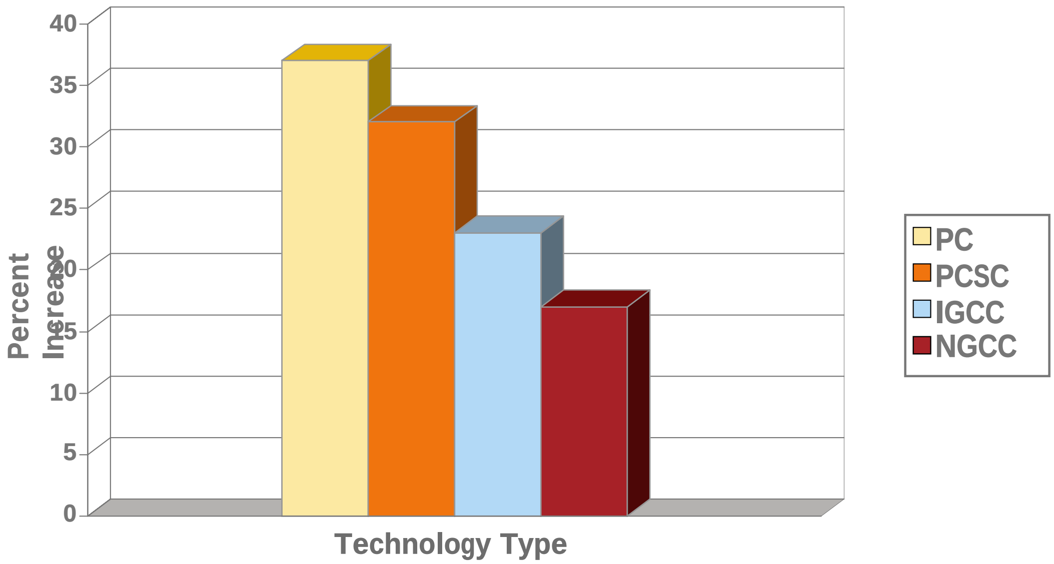


Figure 8: Capital Cost Impacts – Including Sequestration

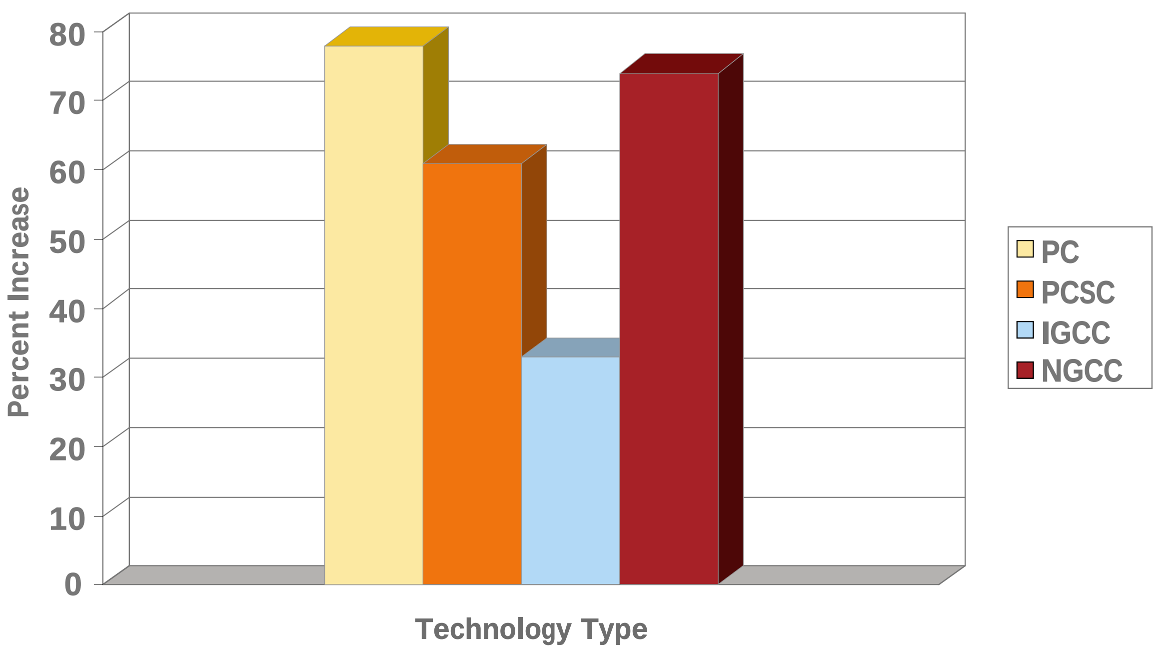
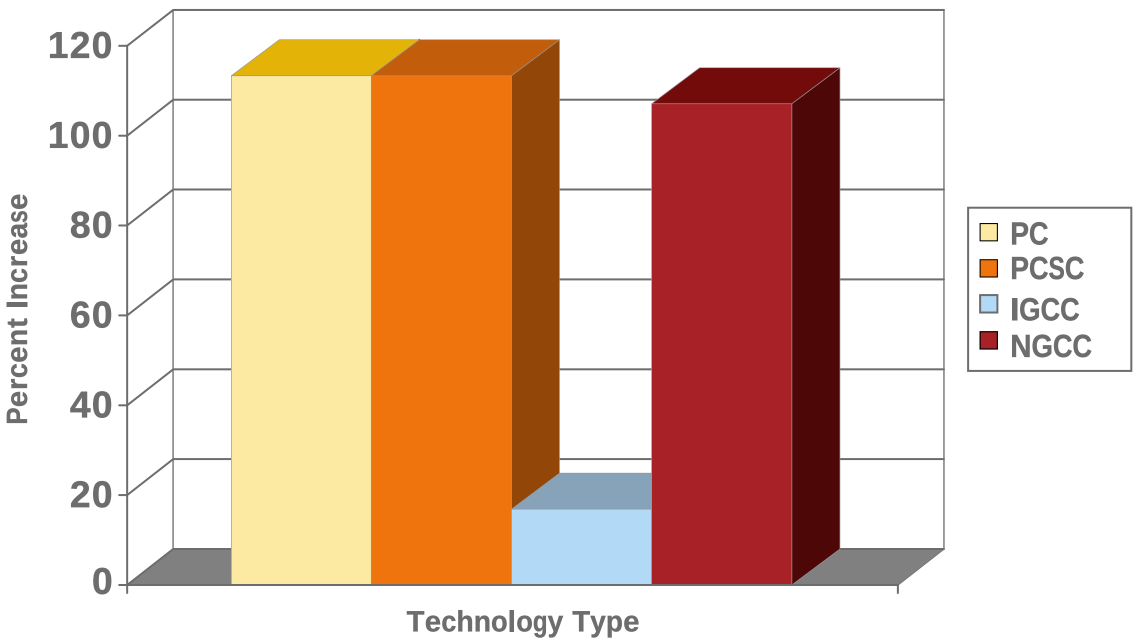


Figure 9: O&M Cost Impacts – Including Sequestration



Market Analysis

R. W. Beck has used the cost impacts noted above for capture and sequestration as inputs to proprietary simulation models to predict the likely impacts to the power market. The standard R. W. Beck approach includes the use of power market simulation models Market Power^{TM} and ProMod^{TM} and a proprietary natural gas market forecasting model. Demand response to price increases (demand elasticity of 0.2) is included.

Our analysis did not include any induced changes as a result in major changes in transmission, changes in fuel prices other than natural gas, changes in SO_2 and NO_X allowances, changes in technology and the use of offsets to satisfy in part carbon control.

R. W. Beck also assumed real equivalence between a carbon tax and a cap and trade system resulting in an allowance price to generate same new builds, retrofits, prices, emissions, etc. Additionally, R. W. Beck assumed no constraints on the ability to finance new builds or retrofits and no second-order effects related to the use of tax revenues. In other words, R. W. Beck assumed that whether the regulatory scheme used to control carbon emissions is a tax or a cap and trade system, the same effect would result.

Three scenarios were analyzed as follows:

- No carbon tax – business as usual with no tax/cap and trade system.
- Moderate carbon control – \$30 per ton (2007\$) CO_2 tax/allowance price which triggers IGCC with capture over uncontrolled PC in new builds.

- Aggressive carbon control – $50 per ton (2007$) CO_2 tax/allowance price which triggers retrofit of existing PC units.

- While we consider unlikely that any regulations would be implemented by 2012, the assumption was made in our modeling that such carbon regulations would be in place by 2012. Many of the proposed bills in Congress have 2011 and 2012 initiation dates.

- The analysis of the three scenarios noted above is not intended to suggest that such scenarios are likely or will result from any legislation but rather to indicate the tax/allowance price levels needed to achieve the level of reduction identified in the various potential legislative proposals.

The key findings of our market analysis are as follows:

- CO_2 power sector emissions are not greatly affected by a carbon tax of $30/ton. In fact, emissions do not approach the 1990 levels. Under the $30/ton tax scenario, cumulative new builds by 2024 are primarily IGCC plants with capture, gas-fired combined cycle plants and gas-fired combustion turbines.

- Approximately a $50/ton tax is required to trigger the retrofit of existing power plants for CO_2 capture. Under this scenario CO_2 emissions would be significantly reduced well below 1990 levels (less than 1 billion metric tons per year).

- Electricity demand grows at approximately 2 percent per year for the base case, 1.5 percent per year for the $30/ton tax case and 1.3 percent per year for the $50/ton tax case.

- By 2024 U.S. average power prices increase by approximately 9 percent from the 2008 average power prices of $54.22 (expressed in 2007 $/MWh) for the base case, approximately 57 percent for the $30/ton tax case and approximately 70 percent for the $50/ton tax case.

- Under the $50/ton tax case by 2024 a significant amount of coal-fired capacity is retrofitted resulting in the loss of output capacity as a result of operating the capture processes.

- Under the $50/ton tax case by 2024, some cumulative nuclear capacity would be installed, the new coal capacity would be primarily IGCC with capture with the remaining capacity being gas-fired combined cycle. and gas-fired combustion turbines.

- In contrast, under the base case of no carbon tax by 2024, the primary installed coal capacity would be pulverized coal with no capture.

- Through 2024, the cumulative amount of wind and other renewables built under the various tax levels is approximately constant due to the fact that the economic renewables are exhausted in meeting state renewable portfolio standards.

- In terms of winners and losers under the various tax scenarios, the winners are considered to be renewable technologies, IGCC with capture for moderate and high tax levels, nuclear under aggressive tax levels, gas-fired generation in the short term, transmission developers, and investment banks. Losers are considered to be pulverized coal and the consumers that would bear the burden of the costs.

In summary, when the results of the market analysis are examined with present capture technologies, higher tax/allowance prices than what most believe are required to achieve substantial reductions in CO_2 emissions to 1990 levels. At moderate tax/allowance price levels (approximately $30 tax/allowance price), the primary coal technology would be IGCC with capture. Aggressive tax/allowance prices (approximately $50 tax/allowance price) would be required to trigger the retrofit of existing coal units. To the extent that future capture technologies are developed at lower costs, the findings presented herein would occur at lower tax/allowance price levels.