

Integration and operation of post-combustion capture system on coal-fired power generation: load following and peak power

by

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Abstract

Coal-fired power plants with post combustion capture and sequestration (CCS) systems have a variety of challenges to integrate the steam generation, air quality control, cooling water systems and steam turbine with the capture system. A variety of engineering studies have been completed that cover these aspects when a plant is operating at full load while operating at a 90 percent capture rate. These studies investigate the basic integration of the these systems, the energy penalty and the effect of capital costs; however, none of these studies comprehensively explore the ability of the capture plant and the balance of the integrated system to respond dynamically to changes in load or capture rate. These load changes occur due to a change in demand for electricity in the system, generation by variable, intermittent resources, or if the plant is equipped with the ability to store solvent to implement price arbitrage. The integrated carbon capture system can be broken down into three general modes: full capacity, load following and peak power generation. Each of these modes presents unique challenges to integration with the CCS system.

The load following mode requires the ability to accommodate different ramp rates that are reflected in flue gas flow and composition. Operation at partial load will affect the quality of steam sent to the solvent regeneration unit. Depending on the setup of the steam turbine system, at lower loads multiple extraction points may be necessary or an increase of the amount of extraction steam will be required due to the reduction in steam quality. Using Aspen Dynamics, a CO₂ capture system using a monoethanolamine (MEA) absorption process is simulated at various plant loads to determine the overall effects on the efficiency of the CCS unit and the balance of the system. In addition, the dynamic behavior of the CCS unit on power output and emissions is shown to demonstrate that the capability of a coal-fired power plant to load follow is not hindered by the addition of a carbon capture unit.

The solvent storage mode can be further broken to two operation modes. The first is peak power production, which occurs when the solvent is capturing CO₂ from the flue gas, but is minimizing or delaying regeneration to a future time through storage. This mode is used to take advantage of peak power prices by maximizing power output of the plant and maintaining a 90 percent capture rate. The regeneration mode entails the solvent being released from the storage tanks and sent to the reboiler column. Solvent storage has been shown in previous studies to have the ability to increase operating profits, but these studies have neglected to incorporate the capital costs associated with this type of operation mode and the operational issues and complexity associated with the large swings in quantities of steam required for the solvent regeneration. By including the capital costs, this study determines that a system with large duration solvent storage is not economically viable given the flexible demands of the system and current electricity price spreads.

This thesis presents a framework for considering the flexible operations of a coal-fired power plant with an integrated carbon capture and sequestration system. By exploring the operational limitations of the integrated system and the economic costs, an evaluation is made of the viability of different CCS operational schemes. This study finds that the CCS unit can match the dynamics of the base coal plant and also increase the operational flexibility of the system. The increased capital expenditure to meet peak demand is viable for larger steam turbine configurations in electricity systems with high peak prices and plants with short duration solvent storage.

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List of Acronyms

ACI	Activated carbon injection
AEO	<i>Annual Energy Outlook</i>
AQCS	Air quality control system
BTA	Best technology available
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CCGT	Combined cycle gas turbine
CCR	Coal Combustion Residuals Rule
CCS	Carbon capture and storage
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO ₂	Carbon dioxide
COE	Cost of electricity
CSAPR	Cross State Air Pollution Rule
DCC	Direct contact cooler
DOE	U.S. Department of Energy
DSI	Dry sorbent injection
EM	Entrainment Mortality
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FC	Fuel cost
FGD	Flue gas desulfurization
GW	Gigawatt
HHV	Higher heating value
HRSG	Heat recovery steam generator
HHS	Heat stable salts
IEA	International Energy Agency
IM	Impingement mortality
IP	Intermediate pressure
kg	kilogram
kPa	kilopascal
kW	kilowatt
kWh	kilowatt-hour
L/G	Liquid to gas ratio
LCOE	Levelized cost of electricity

LP	Low pressure
MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics Rule
MC	Marginal cost
MEA	Monoethanolamine
MMBtu	Million British thermal units
MPa	Megapascal
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NH ₃	Ammonia
NO _x	Nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPR	New Source Performance Standards
NSP	New Source Review
O&M	Operation and maintenance
O ₂	Oxygen
PC	Pulverized coal
PI	Proportional-integral
PM	Particulate matter
ppm	parts per million
RCRA	Resource Conservation and Recovery Act
SCR	Selective catalytic reduction
SNCR	Selective noncatalytic reduction
SO ₂	Sulfur dioxide
SO _x	Sulfur oxides
TBtu	Trillion British thermal units
TOC	Total overnight cost
TPC	Total plant cost

1. Introduction

Carbon capture and storage (CCS) is a potential long-term technological solution to reduce emissions of carbon dioxide from power generating facilities. The addition of CCS technology to a fossil-fuel burning facility can greatly reduce the emission profile by capturing nominally 90 percent of the emissions that would otherwise be emitted. The widespread deployment of CCS technology depends on the ability to operate in the complex system of the electric power grid and meet the dynamic demands required.

Pulverized coal (PC) combustion and combined cycle gas turbines (CCGT) are the predominant methods for electricity generation in both United States and internationally. Post-combustion amine chemical absorption is currently the most technologically mature technology choice. The main focus will be on these combined technologies as a means for CO₂ removal.

The current knowledge foundation for CCS is built upon techno-economic analysis at steady state, nameplate capacity. These studies associate the coal- and natural gas-fired power generation facilities with baseload power generation. This analysis is important because it acts as baseline of information. While the type of operation is commonly associated with coal and natural gas generation as baseload generation, there are dynamic demands put on these power plants by the electricity system that extend beyond these simplifying assumptions. Plants must be able to ramp up and down depending on demand and electricity prices and start-up and shut down on reasonable timescales. These dynamics affect the power output of the plant, the marginal cost of generation, and the emissions profile.

These dynamic challenges occur because a fossil fueled power plant is fundamentally different than an amine separation unit. An amine-based CO₂ separation unit is typically deployed in a chemical processing plant with the process equipment being designed to accommodate those needs. Electricity production is a much more transient process because of the physical nature of electricity and lack of storage. Due to the different type of production processes that these respective technologies were designed to serve, the integration causes some challenges that must be addressed to maintain a properly functioning system for the production of power.

Perhaps the largest difference between these two technologies is the range of operating points and the dynamics that each undergo in their respective applications. Chemical processing facilities are designed to run at nameplate capacity for a maximum amount per year, with little variation from the design mode,

so that the product produced has the correct chemical properties and purities. A significant shift from this nameplate capacity can lead to an irregular, unsalable product. Power production is fundamentally different in nature because the output has to be produced in real-time in response to the changing electricity demand and thus takes on a more variable operation and larger operation ranges.

These different operational philosophies for these two units would not create difficulties in the combined facility if there were no integration between the power plant steam cycle and the carbon capture unit. Carbon capture requires real-time integration with significant output from the steam cycle that directly affects the output of electricity from the power generation facility. Because of this, successful integration will affect the both the revenue and profits generated by the power plant because of the effect on capital, and fixed and variable operating and maintenance costs (O&M).

It is important to understand the effects on the integration of the system are not limited to differing steady-state effects (i.e. a reduction in efficiency from one operation point and another), but also the dynamic effects and timelines to reach these steady states. The limitations in operation of the coal plant and the CCS plant are important to characterize in order to determine how the two integrated systems can operate effectively in these ranges. With characterization of these integration issues, the design and operation of the capture plant can be changed to make the process more thermodynamically and economically efficient.

This study is aimed at understanding if the dynamic response of the capture plant represents any significant hurdles to the implementation of CCS in the real-time environment. In addition, bypassing the capture system has the potential to increase revenue and overall profits of electricity generation if the right price signals exist. This would entail the additional capital expenditure to increase the operation flexibility of both the power facility and the integrated CCS plant. An investigation of this trade-off and the possibility of using this operational scheme to speed deployment of CCS are performed.

The objective of this study is to develop a full understanding of the dynamic response and operation strategies of an integrated power plant and post-combustion capture system. This entails the investigation of three key issues:

- *Characterization of the dynamic response of the CCS system.* The variable and dynamic nature of power production results in changes to the operation of the CCS system, including how the system responds effects the emissions profile and ability to supply power to the grid.

- *Evaluation of different integration strategies with dynamic operation.* The deployment of CCS technologies results in different integration strategies with the steam cycle as a result of the dynamic demands of the system. The tradeoff between marginal cost efficiency and system robustness are key variable in system design.
- *Operation strategies to enhance revenue.* Different integration schemes and operation modes that include solvent storage require a tradeoff in increase capital expenditure to enhance operating revenue. Depending on the relative size of these two parameters, certain operation strategies may prove to enhance profit and increase the attractiveness of carbon capture and storage.

To assess the viability of dynamic operation, carbon capture is evaluated through the creation and assessment of a dynamic simulation model using Aspen Dynamics. This allows the simulation of different disturbances to the capture system that are typical to the normal operation of coal and natural gas plants. System ranges and responses can be tested and performance of power production and environmental emissions can be evaluated. The output of this simulation can be combined with capital costs estimates and electricity price data to determine if solvent storage is a worthwhile endeavor.

A profile of current and future baseload generation is discussed in Chapter 1. This is to provide a framework on why it is important to explore technological implementation of CCS with both of these fuel sources. Chapter 3 will provide an overview of some of the proposed regulations currently affect coal-fired power generation. A technological process description of carbon capture, including integration schemes and dynamics is provided in Chapter 1. A description of the model simulation methodology and results are also presented in Chapter 5. Chapter 1 discusses the economic model development and results that show the costs of CCS flexible operation. Chapter 7 discusses the conclusions and further research necessary.

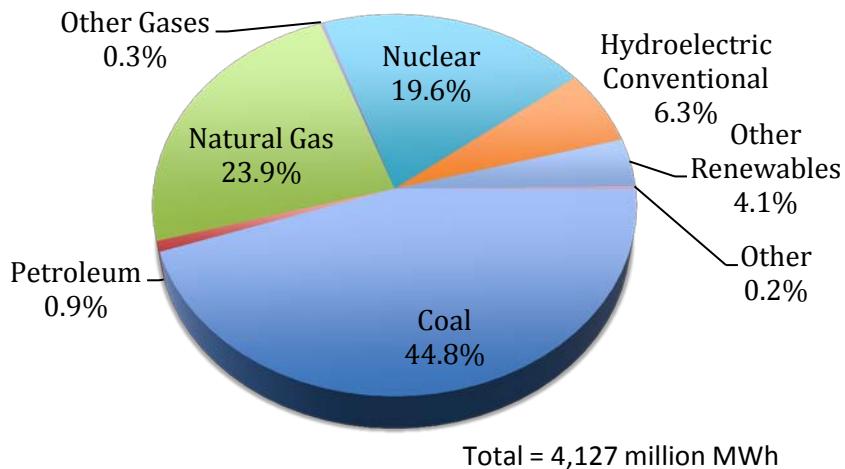
2. Profile of baseload power generation

Baseload power generation in the United States overwhelmingly is provided by thermal generation. The technology choices for this type of generation are nuclear, coal, and natural gas combined cycle. These plants are built and designed to run at constant, stable maximum output for maximum efficiency and maximum economic value. The current profile of baseload generation is shifting in the United States from one traditionally dominated by coal-fired power generation to natural gas as the fuel of choice. As more renewables come online for the electricity generation, the variable and intermittent nature of this generation will increase the need for flexible plants, putting additional strain on coal-fired generation. An evaluation of the current and future landscape of baseload power generation and operation abilities for generation technologies is provided.

2.1. Current and future landscape of baseload power generation

There are many different ways that electricity is produced in the United States. These generators utilize different fuel sources and technologies depending on the relative costs. These sources include fossil fuels, nuclear, and renewable resources. While the generation mix may differ in different parts of the United States the overall breakdown is shown below in Figure 2.1.

Figure 2.1 2010 U.S. electric power industry net generation¹



¹ “Electric Power Annual 2011 with data from 2010.” (2011) Energy Information Administration. November 2011.

While this data shows electricity production for all periods throughout the year, it does not distinguish between the different types of generation and the role that each performs to meet demand.

The type of demand served defines electricity production technologies. The three broad categories are baseload, intermediate, and peak. Baseload demand is classified as the minimum amount of power produced during all hours of the year². Plants that serve this load have minimum capacity factors of 60 percent. These plants are designed for constant and stable output at maximum generating capacity. Capacity factors for intermediate load power plants are in the range of 40 to 60 percent. The types of generation that serve intermediate load are called load following technologies. These plants are more easily able to change output with the real-time demand for electricity. Peaking plants come online for short durations to supply electricity during peak demand have capacity factors below 20 percent.

While Figure 2.1 shows the total breakdown of electricity generation in the US, the percentage of baseload generation provided by coal was approximately 70 percent in 2009³. This number decreased in 2011, with coal generation decreasing to its second lowest levels since 1990 primarily due to lower natural gas prices and depressed demand⁴.

The forecasted reduction in natural gas prices along with environmental restrictions by the EPA is projected to further decrease the amount of electricity provided by coal-fired generation. These same factors also depress the amount of new built coal-fired generation as baseload capacity in favor of natural gas-fired generation. New coal plants would not be able to recover investment costs if the production levels and capacity factors drop to levels typical for intermediate load plants because of the high capital costs. Increased cycling costs due to reduced overall production also put pressure on coal-fired generation.

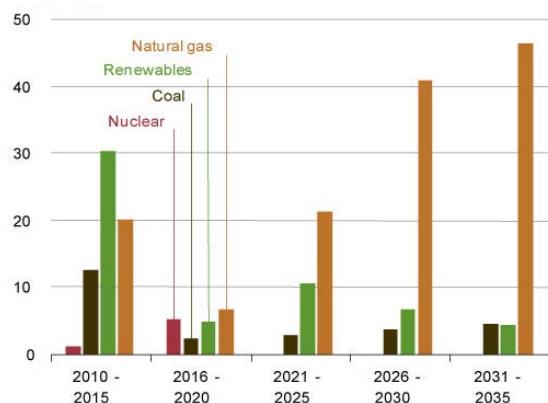
The Energy Information Administration (EIA) uses data from announced projects, future projections of capital costs, fuel costs, and demand to forecast the new built capacity in the US. As shown in Figure 2.2, natural gas dominates all other technologies for new built projects, largely because of the decrease in fuel costs of natural gas and the increased capital costs of emissions controls on coal-fired generation.

² Energy vortex energy dictionary. http://www.energyvortex.com/energydictionary/_baseload_base_load_baseload_demand.html.

³ “The Future of Coal.” Burns & McDonnell Engineering. http://www.easterncoalcouncil.net/2011-Presentations/ECC%20Presentation%20_Megan-D-Parsons.pdf. May 2011.

⁴ “Electric Power Monthly.” Energy Information Administration. March 2012.

Figure 2.2 Electricity generation capacity additions by fuel type, 2010-2035 (GW)⁵



Natural gas fired plants account for 60 percent of all capacity additions through 2035, while coal and nuclear will account for 11 and 3 percent, respectively. The generation mix is shifting away from a large percentage of coal to a greater dependence on natural gas for baseload power generation.

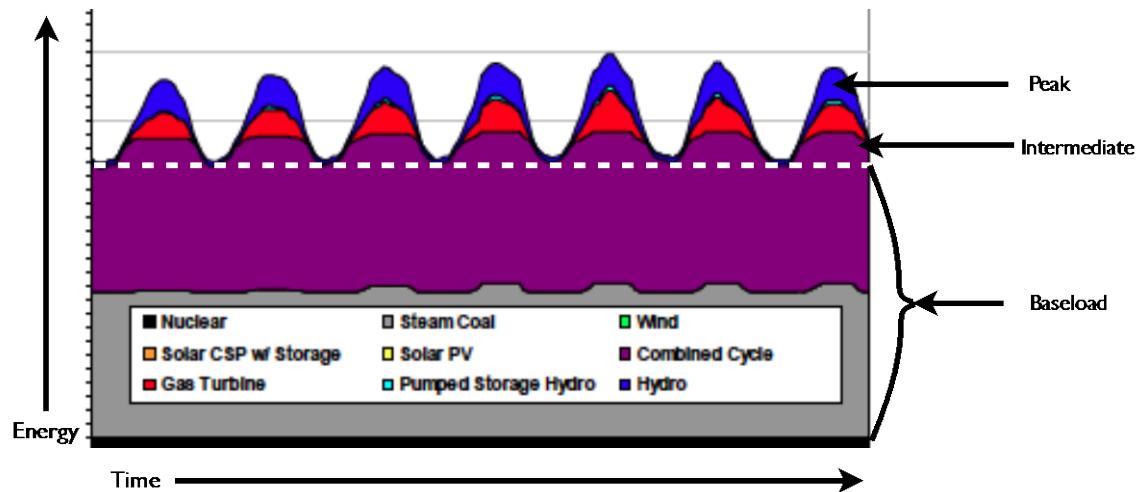
2.2. Dispatch of electricity generation

2.2.1. Without renewables

The dispatch of generating facilities is done in increasing order of marginal costs. The marginal cost is the price that is necessary for the generator to recoup the operating costs of the plant. This is determined primarily by the relative price of fuels and the respective efficiency of the generating facility. The lowest marginal cost plants are dispatched first with higher marginal costs coming online, as the lowest cost generators cannot satisfy the demand. The historic dispatch order in the US has been nuclear, coal, followed by natural gas. This is illustrated in the figure below in Figure 2.3.

⁵ “AEO Outlook Reference Case.” (2011) Energy Information Administration. April 2011

Figure 2.3 Dispatch of generation technologies (no renewables)⁶



Nuclear generation maintains stable output for all operating hours shown. Coal goes through some cycling as shown by the change in energy near the intersection of the coal and combined cycle areas, but has a largely stable output. The more prominent load following during intermediate demand occurs with combined cycle gas turbines (CCGT). Simple cycle gas turbines (SCGT) and hydroelectric generation is used for peak demand.

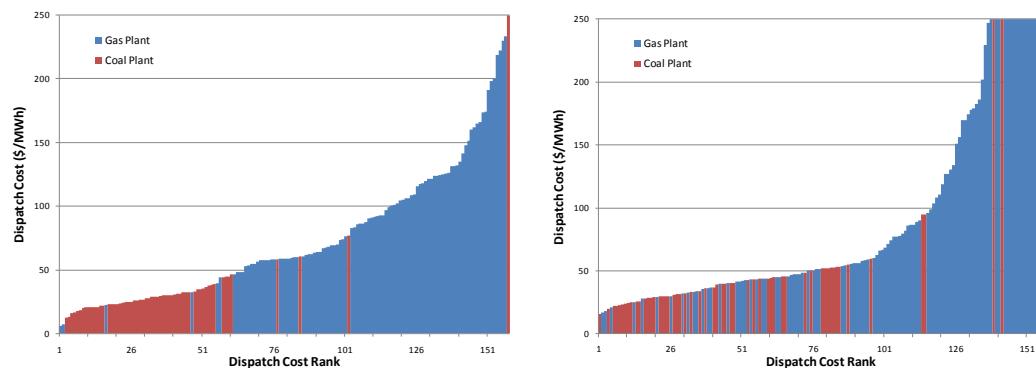
As the relative prices of coal and natural gas fluctuate this dispatch order can reverse. Natural gas comes online before older, less efficient coal plants with higher marginal costs. This has occurred as natural gas prices have dropped from a peak of \$14/MMBtu in July of 2008 to a price of \$3.73/MMBtu in January of 2012 for gas delivered to power generation facilities⁷. Coal has undergone the reverse price trend. Coal delivered for power generation has increased by 25 percent from \$1.91/MMBtu to \$2.41/MMBtu in the same period⁸. The Southeastern region of the US provides a vivid illustration of these price effects as shown in Figure 2.4.

⁶ Western Wind and Solar Integration Study. Prepared for the National Renewable Energy Laboratory, GE Energy. May 2010.

⁷ “Electric Power Monthly.” Energy Information Administration. January 2012.

⁸ Ibid.

Figure 2.4 Dispatch of fossil plants in the southeastern U.S., 2007 and 2009⁹



The average cost of generation for coal-fired and natural gas-fired generation was \$22/MWh and \$61/MWh in 2007, respectively in this region of the US. The majority of coal dispatched first with natural gas following. This average spread decreased from \$39.2/MWh to \$10.2/MWh by 2009, with natural-gas generation electricity costs decreasing by 37 percent and coal generation costs increasing by 30 percent. The dispatch order for coal and natural gas became much more stratified, with coal being dispatched much farther to the right of the curve. This decreases the ability for the traditional coal baseload power plants to recover costs because of the higher order in the dispatch curve and increased cycling of the plants.

2.2.2. With renewables

Along with lower natural gas prices and reduced electricity demand in the recent years, the impact of renewable generation will have profound effects on the operation of baseload power generation.

Renewable generation is intermittent generation. Intermittent generation is classified as having limited-control variability and partial unpredictability¹⁰. The limited-control variability comes from the nature of the source of generation. The operator cannot control wind availability and speed and solar radiation as it can with coal and natural gas flows to the generator. Unpredictability arises from the partial lack of ability to know with certainty the wind and solar resource at any given time.

This intermittent resource can have significant effects on the operation of fossil generation facilities. Because marginal cost of renewable resources is near zero, below the marginal cost of fossil generation,

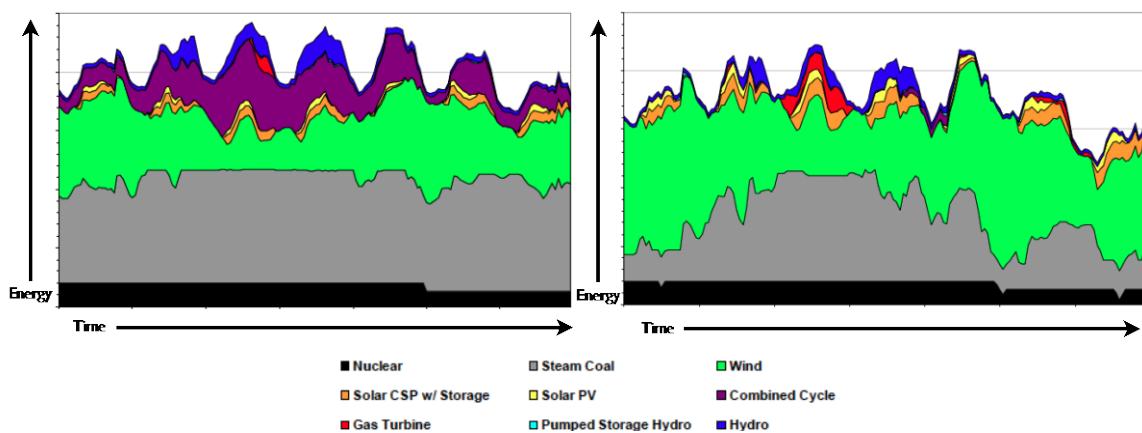
⁹ “US Power Generation Mix Through the ‘Aught’ Decade: A Look at the Data and the Story Tells It All.” Electric Power Research Institute. October 2011.

¹⁰ “Framework Paper: Managing large scale penetration of intermittent renewables.” 2011 MITEI Symposium Paper. Pérez-Arriaga, I.

and priority dispatch for renewable is mandated by law, the system operator must accept the electricity produced from renewable sources onto the grid. Fossil generation must respond to this change in electricity supply by ramping up and down output in real-time with the renewable generation.

At low levels of renewable penetration, the coal and natural gas baseload generators do not realize the larger system effects. The small changes in supply are dwarfed by the fluctuations in demand¹¹. As penetration increases, the fossil generating facilities must respond. This is reflected by increased number of startups and shutdowns, faster ramping rates, and inefficient operation at points away from nameplate, design capacity. A 20 and 30 percent penetration of renewables case is shown in Figure 2.5.

Figure 2.5 Baseload response to 20 and 30 percent renewable penetration¹²



As illustrated in the figure above and compared to Figure 2-3, the consistent and steady output of coal and nuclear generation is affected by the increase of wind penetration. Natural gas combined cycle plants are ramped at faster rates, while nuclear remains largely constant. The order of ramping follows the inverse of the dispatch order. Higher marginal cost plants (combined cycle above) are required to ramp down and possibly shutdown until that ability is exhausted. Once this ability is exhausted coal plants are required to ramp and potentially shutdown. Although the scale is not shown, the change in output from peak to through for coal is on the order of 5 GW and 14 GW for the 20 and 30 percent penetration cases, respectively. For the 20 percent penetration case, this implies that some coal plants are ramping down to minimum levels to avoid costly shutdowns. In the more extreme case to the right, coal plants are required

¹¹ "Harnessing Variable Renewables: A Guide to the Balancing Challenge." (2011) International Energy Agency.

¹² Western Wind and Solar Integration Study. Prepared for the National Renewable Energy Laboratory, GE Energy. May 2010.

undergo more extreme ramp rates and shutdown for extended periods of time. Nuclear generation is forced to cycle during these times of high renewables.

While Figure 2.5 provides one illustrative example, the effects on the ramping or shutdown of different generating units can vary given the type of generation mix. Renewable energy technologies such as wind and photovoltaic solar historically have shorter construction and deployment times than fossil fuel or nuclear facilities. This affects the long-term planning and operations of the power system and causes existing facilities to accommodate the new renewable capacity that is built. The in place generating facilities were not planned and built for the increased ramping and shutdown operations that renewable generation requires.

2.3. Flexible capabilities of different technologies

The increasing penetration of renewables places operational pressure on generating facilities to accommodate the intermittent nature though increased flexibility. The ability to ramp up and down quickly, to have large power cycling output ranges, and to have fast startup and shutdown capabilities are all part of flexible operations. Baseload plants are designed to operate at all times with little variation in output, but this can differ dramatically across technology type and within each respective technology. There is a difference between technical capabilities and the economic costs associated with wear and tear on equipment. Faster startup, shutdown, or ramping incurs additional operation and maintenance costs on the equipment, while it may be technically feasible. The baseline capabilities for ramping and startup are provided for the three major generating technologies. These serve as a benchmark for each generating technology and establish the context of integrating the fossil generation with CCS.

2.3.1. Nuclear

For economic and technical reasons, nuclear power has always been associated with baseload generation. Given the large up front capital costs of nuclear power, consistent output near nameplate capacity must be achieved to recover capital costs. While this establishes the economic justification for nuclear power, it does not speak to the technical capacity to respond to changes in demand. The common perception of nuclear power is that it cannot respond or operate flexibly to changes due to technological limitations, yet in some systems these power plants often undergo limited cycling.

Nuclear plants have the technical capability to respond to decreases in real-time demand or to increases in generation from renewables. Ramp rates to reduce power in nuclear generation are around 20%/hour¹³. The ability to ramp back to full load at minimum stable levels can take considerably longer at 6 to 8 hours. The ability to ramp down nuclear plants varies widely across systems and countries. Table 2.1 shows that data the performance produced a wide array of results from a survey performed by the International Energy Agency (IEA) of power generating facilities.

Table 2.1 Reported flexible capabilities of nuclear thermal stations¹⁴

	Min	Max
Ramping capability (MW/min)	0*	5
Start up and shut down (hours)	10	36
Min stable level (% of max)	100	40
Flexibility (% capacity)		
15 mins	0*	8
1 hr	0*	33
6 hrs	0*	40
36 hrs	0*	100

*In the Spanish system, ramping is not performed for reasons of system security

The plant operators of nuclear facilities do not completely use automated controls to manipulate the power output. There is human intervention in combination with the automated controls to initiate and control ramping¹⁵. This has the potential to add human error into the operation. This increases the safety concerns for nuclear power and decreases the desire for ramping, such as the case for the Spanish system.

2.3.2. Coal

Given the issues outlined above with natural gas prices and increased penetration of renewables, coal plants are to be operated increasingly in load following duty. In addition, as plants age and the thermal efficiency of the plant decreases with respect to the rest of the generating units within the fleet, load following duty becomes more prevalent.

¹³ “Managing Large-Scale Penetration of Intermittent Renewables.” MIT Energy Initiative Symposium. April 2011.

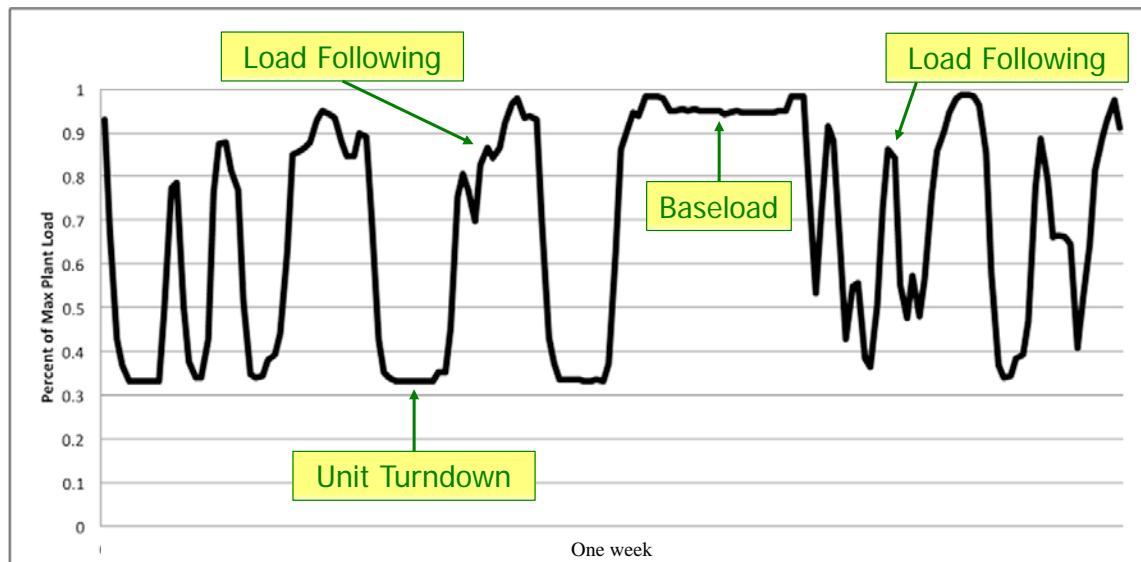
¹⁴ “Harnessing Variable Renewables: A Guide to the Balancing Challenge.” (2011) International Energy Agency.

¹⁵ Ibid.

When coal plants are required to operate in this mode, there are certain physical restrictions that prevent fast ramp rates. Thermal stresses on the boiler parts are limited to approximately 93°C/hour (200°F/hour) with the potential to increase these thermal stresses up to 204°C/hour (400°F/hour)¹⁶. These thermal limitations translate into ramp rates of 2%/min and 4%/min. At the upper limits of the ramp rates, the damage rate increases on the boiler pressure parts, which will lead to increased operating, maintenance, and required downtime for service. Coal plants have a wide flexibility and can operate at ranges as low as 30 percent of nameplate capacity without supplemental fuel firing with natural gas, although typical ranges are around 50 percent¹⁷. Typical startup times for coal plants are 6 hours from a cold start with shorter durations for hot and warm restart.

A representative profile of a coal power plant operating in a range of operating duties is shown in Figure 2.6. This profile represents a weeklong operation of a nameplate 700 MW plant in the ERCOT region of the US.

Figure 2.6 Generation modes for coal power plant¹⁸



From the figure above, each operating mode is shown. Baseload generation is shown by the constant output during the middle portion of the week. Load following operation is shown by the increases and

¹⁶ Ibid.

¹⁷ “Harnessing Variable Renewables: A Guide to the Balancing Challenge.” (2011) International Energy Agency.

¹⁸ ERCOT

decreases in generation from near 100 percent of capacity down to 30 percent operational minimum, to avoid shutdown. The startup and shutdown cycles of the plant are not represented in the figure.

There is a distinction of the type technology among coal plants. The two main types of coal plants in operation today are subcritical and supercritical plants. These designations refer to the temperature and pressure of the steam entering the steam turbine for power generation. Older plants are generally subcritical with lower efficiencies, while more modern high efficiency plants utilize supercritical steam conditions (i.e., higher temperatures and pressures). With these different steam conditions, the ability of the plant to change output differs. Supercritical steam plants do not have the thermal storage of a steam drum. Due to this lack of thermal storage, supercritical plants can respond to required load changes more quickly than the subcritical counterpart. Startup for supercritical plants involves much more complex control systems, which expose these plants to reliability issues. Because of these factors, it is typically subcritical plants that operate in two-shift operation (i.e. shutdown at night). While these issues are true across these two broad categories of steam conditions, there are other contributing factors that must be taken into account such as size, coal type, control systems, and specific location of the beginning and end of the ramp that can affect the ability of the coal plant to ramp and startup¹⁹.

2.3.3. Combined cycle gas turbine

Combined cycle gas turbines, while becoming increasing part of the baseload generation mix have operated in intermediate and load following duty due to faster ramp rates. Typical CCGTs have the ability to ramp at a rate of 8%/min, nearly double the top ramp rates of coal plants. CCGT plants also have the ability to startup at faster rates than coal plants. A typical CCGT plant can achieve full load operation within 60 to 80 minutes. Newer CCGT technologies have reported to be able to achieve ramp rates above 10%/min and startup times of 30 minutes until full load because of more robust integration and control between the gas turbine and steam generating units^{20,21}.

¹⁹ Personal communication with Don Langley, B&W.

²⁰ “FlexEfficiency* 50 Combine Cycle Power Plant.” <http://www.ecomagination.com/portfolio/flex-efficiency>

²¹ “Operational flexibility enhancements of combine cycle power plants.” Siemens AG. Available at <http://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/combined-cycle-power-plants/OperationalFlexibilityEnhancementsofCombinedCyclePowerPlants.pdf>

3. EPA regulations on fossil generation facilities

In the United States, the Environmental Protection Agency is in the process of promulgating regulations that have a direct effect on the environmental performance and cost of coal-fired power generation. The five main regulations are the final Cross-State Air Pollution Rule (CSAPR), the proposed Mercury and Air Toxics Standards for Utilities (Utility MACT), the proposed Coal Combustion Residuals (CCR), the proposed Cooling Water Intake Structures (316(b) rule) and the proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (NSPS for CO₂). These finalized and proposed rules will force new coal plants to add significant environmental controls that were previously not required, force existing coal plants to retrofit to become compliant, or force the closure of existing plants because the additional capital expenditure cannot be recovered. These proposed regulations are expected to force coal plants to come under compliance with overlapping time frames within the next five years. This section will investigate each of these proposed regulations and explore the effect on coal-fired generation and the implications these regulations have on decisions for plants to implement carbon capture and storage.

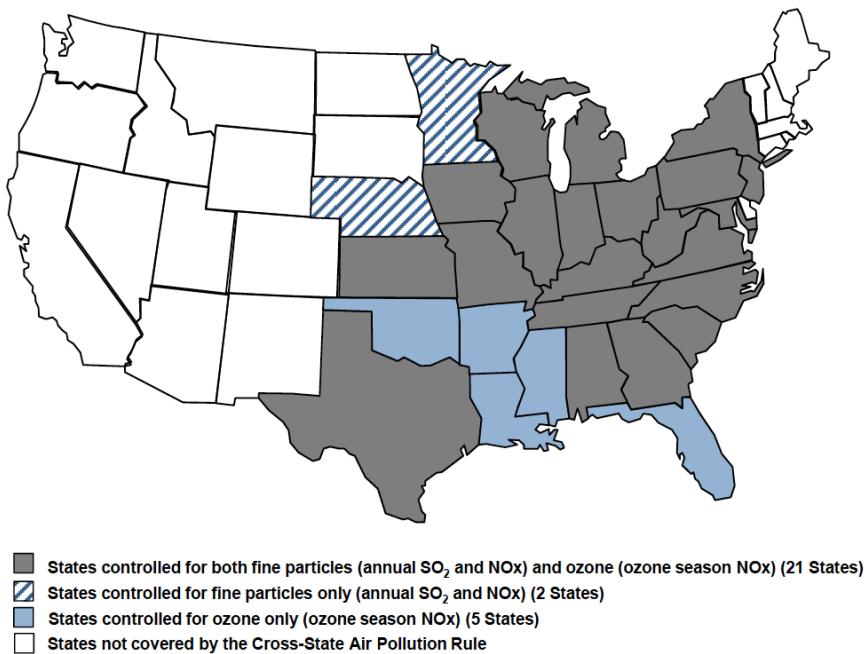
3.1. Cross-State Air Pollution Rule (CSAPR)

The EPA promulgated CSAPR following the issuance of the Clean Air Transport Rule (CAIR) that was vacated by the D.C. Circuit court and sent back to the EPA for revisions. The main goal of the CSAPR is to reduce the sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from power plants in the Eastern and Midwestern states that affect the ozone and particulate matter air quality in downwind states²². The regulation affects both existing and new built facilities. By 2014, the regulations are estimated to reduce total SO₂ emissions by 73 percent, reduce total NO_x emission by 54 percent with 25 percent of these reductions occurring during the more restrictive ozone season.

Figure 3.1 shows the states that are affected by the regulation and the compliance regime.

²² <http://www.epa.gov/airtransport/basic.html>

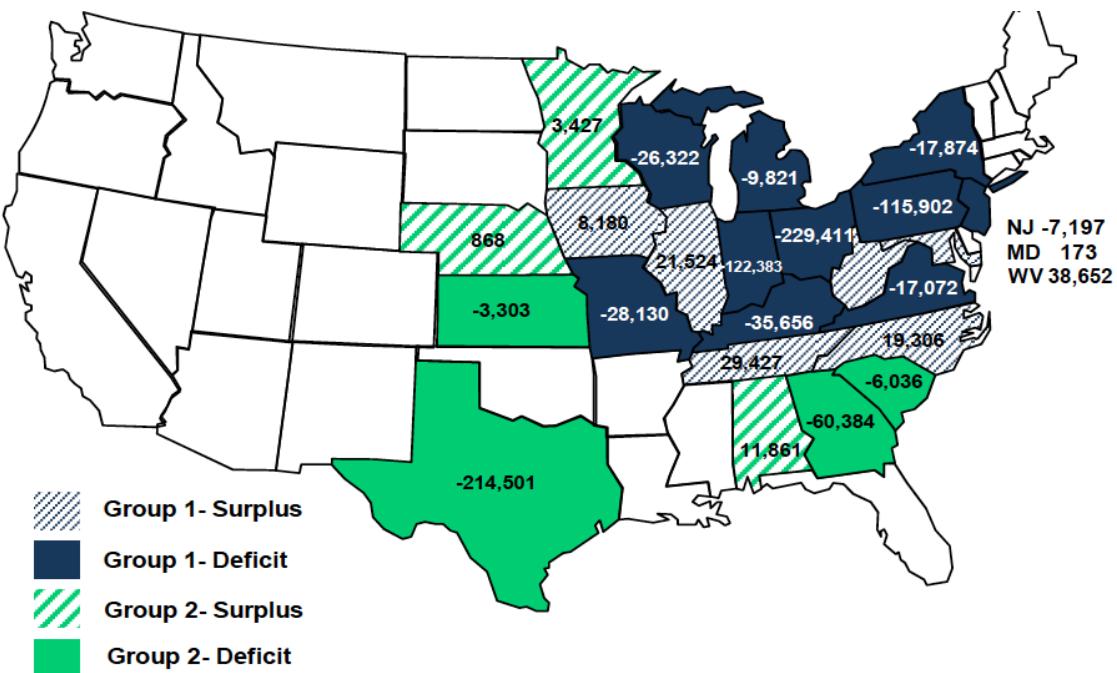
Figure 3.1 CSAPR State Programs²³



The CSAPR establishes a cap-and-trade regime with specific allowances for both annual and seasonal emission for each pollutant given to each state. States may engage in interstate trading to come in compliance with the cap set. The rule does not put a performance or technology standard for generation units that have to be met by emissions reduction control equipment. The total emissions reductions may occur through retrofitting plants with better emission controls, fuel switching to utilize lower sulfur fuel sources, or to reduce operating hours in the year. The caps set for each individual states create significant emission reductions on a few concentrated states. The states are divided into two groups. Both groups must begin to reduce SO₂ emissions starting on January 1, 2012. The Group 1 states must make addition reductions by 2014 to be in compliance. Group 2 states do not have phased reduction periods. The estimate reductions for each state are shown in Figure 3.2. All reductions are in total tons.

²³ National American Electric Reliability Corporation. *Potential Impacts of Future Environmental Regulations*. November 2011

Figure 3.2 2010 SO₂ State Emissions versus 2012 CSAPR Allowance



The caps placed on each state and the surplus or deficit created from such caps largely determine the locations where each coal plant retrofits take place for SOx and NOx. The amount of reductions required and the feasibility of the plant for retrofit are determined on a plant-by-plant basis.

There are four main options for each plant. The plant can continue to operate without emissions reductions control at a reduced capacity factor. This limits the total emissions of the plant, but will not reduce the performance of the plant on a ton/MWh basis. By reducing the capacity factor, the plant emits less and will reduce the amount of permits needed to purchase. The plant can retrofit the emission control system to reduce the emissions profile of the plant. This requires installing pollution abatement equipment such as a flue gas desulfurization (FGD) unit, a baghouse, and selective catalytic reduction (SCR) equipment. This increases the capital expenditure required for these plants while reducing plant efficiency and increasing the variable cost of electricity generation. The third option is to repower the plant with natural gas. This entails removing the boiler and emissions control equipment and installing a gas turbine for power production. Some plant equipment remains, such as the steam turbine and electric switchyard, which reduces the total capital expenditure necessary when compared to a greenfield site. Either the entire or part of the plant can be retired be in compliance with the regulation. The last option is to retire and decommission the plant. Older, smaller plants without emissions control equipment will be the plants most likely to retire.

The plant specific variables to consider are the age of the plant, the size of the plant, the existing control equipment. Exogenous factors to consider are the clean and dark spark spread for the cost of electricity generation, the forecasted electricity demand, and the timing of the various environmental regulations. Natural gas prices in the US have decreased steadily to around \$2.00/MMBtu, while coal has remained relatively constant over the past few years. If coal growth in Asia and other parts of the world continues to grow, the price of coal may face upward pressure, further reducing the economic viability of older, less efficient coal plants. Other factors such as the renewable energy mandates in each state may also play a key role.

Since the proposed regulations in CSAPR affect 91 percent of the coal-fired generation in the US²⁴, a determination of engineering and construction resources is also a crucial factor. The ability to retrofit many of the plants is limited by the engineering, manufacturing and permitting capability of the system at any given time. Not all plants where it may be economically efficient can be retrofitted at once because of these limitations. In addition, all potential retrofits could not be shut down for construction because of the potential impact on system reliability.

3.2. Mercury and Air Toxics Rule (MATS or Utility MACT)

The Utility MACT Rule is an emissions control program for mercury, acid gases, and arsenic for existing and new built coal and oil fired generation facilities. Unlike CSAPR, which is a cap and trade program, the Utility MACT rule establishes an emissions performance standard that must be met by all facilities. The performance standard is determined by the Maximum Achievable Control Technology (MACT), which the EPA defines as the average emissions rate of the 12 percent lowest emitting facilities.

The proposed emissions limitations are 0.002 lbs of hydrochloric acid per MMBtu of fuel input, or as a proxy; 2.0 lbs SO₂/MWh. These limitations will require plants to install some type of desulfurization control equipment. Depending on the type of coal used, this required either wet FGD with dry sorbent injection or a spray dry scrubber (dry FGD). Reducing the capacity factor of the plant is not an option for the Utility MACT Rule. In this sense, the MACT rule significantly limits the options for a plant to retrofit, repower or retire.

²⁴ Ibid.

The particulate emissions rate is used as a proxy for the non-mercury metals limits. The limit is set to 0.03 lbs/MMBtu fuel input. This requires plants to remove 99.6 to 99.8 percent of particulate matter. Given the current technologies available, the only option is to install a fabric filter (baghouse) for compliance. Electrostatic precipitators (ESPs) cannot meet this emissions requirement. Currently over 75 percent of all coal plants in the US do not have this technology installed.

The mercury emissions limit is set at 1.2 lbs/TBtu (trillion Btu) for non-lignite burning coals and 4.0 lbs/TBtu for lignite burning coals. The difference performance metrics are because lignite coal can have mercury concentrations in excess of an order of magnitude higher than non-lignite coals²⁵. This may require the use of activated carbon injection (ACI) systems for plants that burn coals with high mercury content. The other type of pollution abatement equipment is a determination on the need for ACI. Plants that have wet FGD systems, baghouse, and SCR may be compliant without ACI.

3.3. Coal Combustion Residuals (CCR)

The Coal Combustion Residuals Rule is currently only issued in draft form and no final ruling has been issued. Currently coal ash is designated as a special waste, but the draft proposal states that the EPA is considering designating coal ash and FGD byproducts as a Subtitle C or Subtitle D Hazardous Waste under the Resource Conservation and Recovery Act (RCRA). This would effectively designate coal ash as a hazardous waste and force a change in the way coal ash is stored on site and landfilled. It would also reduce the potential for coal ash beneficial use in cement and road applications. The motivation for this regulation is to prevent an event similar to the coal ash pond release that occurred in Kingston, TN, where over 5.4 million cubic yards of wet coal ash was released into the surrounding community²⁶.

The aim of this regulation is to eliminate the wet handling of coal ash and the use of ash ponds in favor of dry ash storage in lined landfills²⁷. The designation of coal ash under Subtitle C of RCRA would allow the EPA to require waste management permits for monitoring and enforcement of the permits. If coal ash were regulated under Subtitle D, no such federal permitting process and enforcement would exist although new coal ash ponds would be required to install specific liners to prevent leaching of toxic

²⁵ NETL Cost and Performance Baseline for Fossil Energy Plants. Volumes 1 and 3.

²⁶ New York Times. "Tennessee Ash Flood Larter than Initial Estimate." Available at <http://www.nytimes.com/2008/12/27/us/27sludge.html>.

²⁷ Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010.

chemicals into soil and groundwater²⁸. The main difference between designations under Subtitle C versus Subtitle D is that Subtitle C would effectively phase out coal ash ponds. These differences are shown in Table 3.1.

²⁸ EPA. “Frequent Questions: Coal Combustion Residues (CCR) – Proposed Rule.” Available at <http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/ccrfaq.htm>

Table 3.1 Coal Combustion Residuals – key difference between Subtitle C and Subtitle D²⁹

	SUBTITLE C	SUBTITLE D
Enforcement	State and Federal enforcement	Enforcement through citizen suits; States can act as citizens.
Corrective Action	Monitored by authorized States and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit Issuance	Federal requirement for permit issuance by States	No
Requirements for Storage, Including Containers, Tanks, and Containment Buildings	Yes	No
Surface Impoundments Built Before Rule is Finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments	Must remove solids and retrofit with a composite liner or cease receiving CCRs within 5 years of effective date and close the unit
Surface Impoundments Built After Rule is Finalized	Must meet Land Disposal Restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No Land Disposal Restrictions
Landfills Built Before Rule is Finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills Built After Rule is Finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for Closure and Post-Closure Care	Yes; monitored by States and EPA	Yes; self-implementing

²⁹ EPA. "Coal Combustion Residuals – Key Difference Between Subtitle C and Subtitle D Options." Available at <http://www.epa.gov/osw/nonhaz/industrial/special/fossil/CCR-rule/CCR-table.htm>

Depending on the final designation of coal ash, the type of retrofits for coal ash handling and the cost of land disposal are greatly affected. The main effect will be on the total cost of disposal, which is addressed in the economic impact subsection.

3.4. Cooling water intake structures (Section 316(b) Rule)

Cooling water intake structures are regulated under Section 316(b) of the Clean Water Act. This requires plants to use the Best Technology Available (BTA) to minimize adverse environmental impacts. Before the proposed update to the rule, there were no regulations to mandate EPA regulations on existing power plants. The update is to create a national standard for the BTA for cooling water intake structures. Under this section of the Clean Water Act, the EPA is permitted, but not required to use cost-benefit analysis in determining BTA. Cooling water intakes affect the impingement mortality (IM) and entrainment mortality (EM). The IM is the mortality rate of aquatic species caught in the intake structure screen and entrainment mortality is the mortality rate of species caught in the flow of the cooling water system. While the specific numbers are important consideration for each specific facility, the determination of BTA will be the most important factor for steam driven generation units.

The 316(b) Rule will apply to all existing and new nuclear and fossil generating facilities, which account for over 83 percent of the generation in the US³⁰. The Energy Information Administration (EIA) has identified 754 coal units that would be impacted by the legislation along with 42 nuclear plants, which account for over 60 GW of generation. Peaking plants, hydroelectric facilities, and renewable energy facilities (wind and solar) are not subject to the rule because they do not use water to cool plant processes.

The strictest BTA analysis and the highest compliance cost for facilities would be the determination that flow reduction has to be that of a closed cycle cooling system. This would require all plants with once through cooling to retrofit the plant to a closed cooling water system. Closed cooling water systems recirculate water within the facility and reduces withdraw from the water source by 95 to 98 percent³¹.

The EPA considers four issues that will affect the determination of BTA and the implementation of a national standard. Those issues are energy reliability, increased air emissions on a local basis, land availability, and remaining useful life. Energy reliability is determined on a local basis by the effect of retirements (both coal and nuclear) on the system from the proposed rule, as opposed to any specific plant

³⁰ National American Electric Reliability Corporation. *Potential Impacts of Future Environmental Regulations*. November 2011

³¹ EPA. “Clean Water Act Section 316(b) Existing Facilities Proposed Rule Qs and As”. March 28, 2011

retirements. If reliability is compromised from the determination of BTA, site-specific determinations can occur that will result in different treatment options for each facility. Increased air emissions may result from the plant efficiency derating because of the additional power requirements of a closed cycle cooling system as compared to once through cooling. EPA does not estimate this to be of major concern because of the Utility MACT Rule that will force specific emissions reduction, but leaves this issue open as an exception. Closed cycle cooling systems require specific land siting that may not be available to all facilities. A possible exemption is left in place for sites that may not be able to incorporate closed cycle cooling on the premises. The remaining useful life of a facility also affects the determination of BTA. The specific example cited by the EPA makes a determination between facilities that have 3 years versus 20 years left of remaining life. Specific exemptions are less likely to be granted for facilities that have few remaining years, which may facilitate the closure of the plant on an earlier timeline.

3.5. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (NSPS for CO₂)

On April 13, 2012, the EPA drafted proposed regulations for the emissions of CO₂ from new generating facilities. This proposed regulation would affect all new electricity generating units that produce more than a third of the output for sale to the grid or for units that generate more than 25 MW. Simple cycle gas turbines, or “peaking plants,” are exempt from the ruling. The specific limit set is 1,000 lbs/MWh CO₂ for natural gas units on a 12-month annual average. For coal and oil fired units, the limit is 1,800 lbs/MWh CO₂ for the first ten operating years of the facilities on an annual average basis and 600 lbs/MWh CO₂ beginning in the eleventh year of operation. Over the 30-year average period proposed, the emissions rate is limited to 1,000 lbs/MWh CO₂. The first ten-year average period essentially, although not formally, requires the use of supercritical stream conditions because subcritical units cannot achieve this emissions rate. The eleventh and subsequent year averaging requires the use of carbon capture and storage technology. It is important to note that the proposed regulation sets limits on the unit level basis and cannot be averaged across multiple units.

The proposed NSPS for CO₂ does not affect existing generation units and in the draft rule the EPA states that at this time it has no plans to regulate existing units. However, “Section 111(d) of the Clean Air Act requires states to develop plans for existing sources of noncriteria pollutants (i.e. a pollutant for which there is no national ambient air quality standard, such as CO₂) whenever EPA promulgates a standard for

a new source³².” So while EPA has expressed no current plans for regulation of existing sources, it is required to by law once new source standards have been enacted.

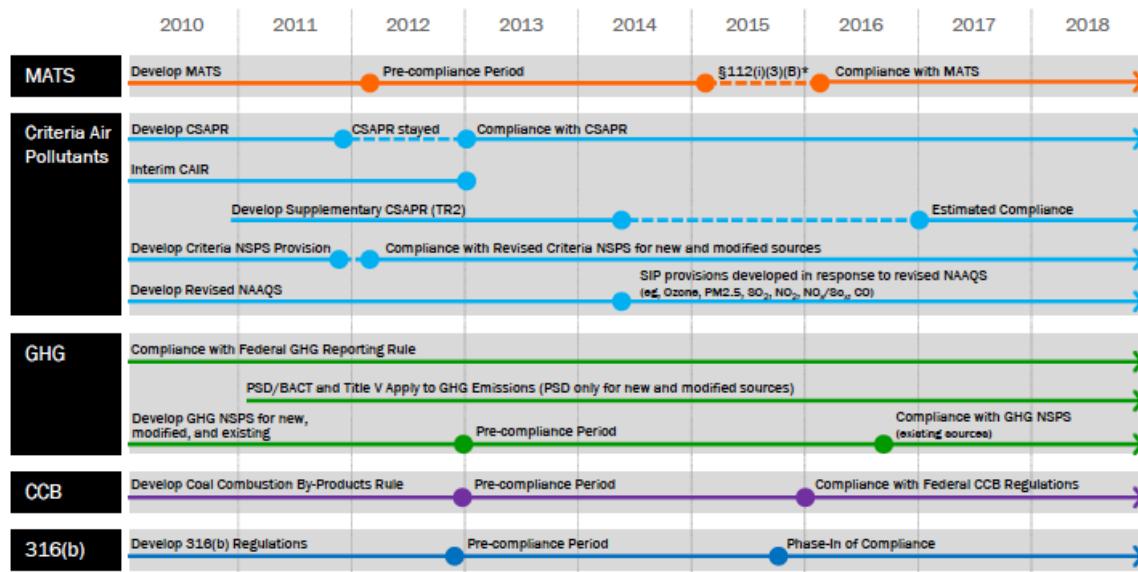
As part of the draft proposal, there is a provision that New Source Review (NSR) will not trigger the NSPS for CO₂ if the power plant unit is retrofitting to comply with other EPA regulations. For example, an old subcritical coal plant will not be required to meet the 1,800 lbs/MWh limit if it retrofits an FGD system to comply with CSAPR. This has the effect of keeping older coal assets in place. New coal plants would be exposed to the NSPS for CO₂, and would be required to install carbon capture system. By retrofitting older plants to comply with CSAPR, Utility MACT, 316(b), and CCR, the plant's life could be extended beyond that of the ten year capture retrofit requirement for new coal plants, generating significant savings. This assumes that existing coal plants will not be regulated for CO₂ in the near future.

3.6. Timing of proposed regulations

Each of the proposed regulations has different time schedules for plants to retrofit the required emissions control or to repower or retire the unit. Many of the proposed regulations were not issued in final form, are currently awaiting public comment, or are stayed by the courts, effectively delaying implementation. The current timeline is shown in Figure 3.3.

³² <http://www.epa.gov/region07/air/rules/111d.htm>

Figure 3.3 Compliance periods for proposed regulations³³



The CSAPR rule was finalized on July 6, 2011 with the compliance period beginning on January 1, 2012 for Phase I. Phase II of the compliance period for the more stringent SO₂ reduction for Group I states begins January 1, 2014. However, on December 30, 2011, the DC Circuit Court of Appeals indefinitely stayed the implementation of CSAPR pending further court review on the determination of economic and system reliability. The court told the EPA to keep implementing the Clean Air Interstate Rule (CAIR), which puts a cap and trade mechanism in place for SO₂ and NO_x. CAIR placed fewer restrictions on the emission caps placed on facilities within each state. CSAPR was intended to replace CAIR. The court's ruling to stay CSAPR creates uncertainty in the electricity industry on the final regulations and emissions limits for each facility.

The final Utility MACT Rule was published on February 16, 2012. Following this publication, plants will have three years to comply, with the possibility of a one-year extension. Full compliance for all regulated generating facilities will take place in early 2016.

The CCR draft rule was issued June 2010. To this date, there has been no final rule issued. As stated above, there is significant uncertainty on the stringency of the final regulation and the cost implications on each power plant. A final rule is expected in 2012, with the pre-compliance period starting in 2013 to 2015, with full compliance required by 2018.

³³ M.J. Bradley & Associates. "CSAPR & MATS: What Do They Mean for Electric Power Plants". January 31, 2012.

The EPA issued the draft ruling for the 316(b) Rule in 2011. As part of litigation between the EPA and effected parties, the final rule is to be issued on July 27, 2012 with implementation to begin by 2013.

The NSPS for CO₂ draft rule was issued on March 27, 2012 and is currently in the comment period. There is no current timeline for compliance given the pending nature of the regulation.

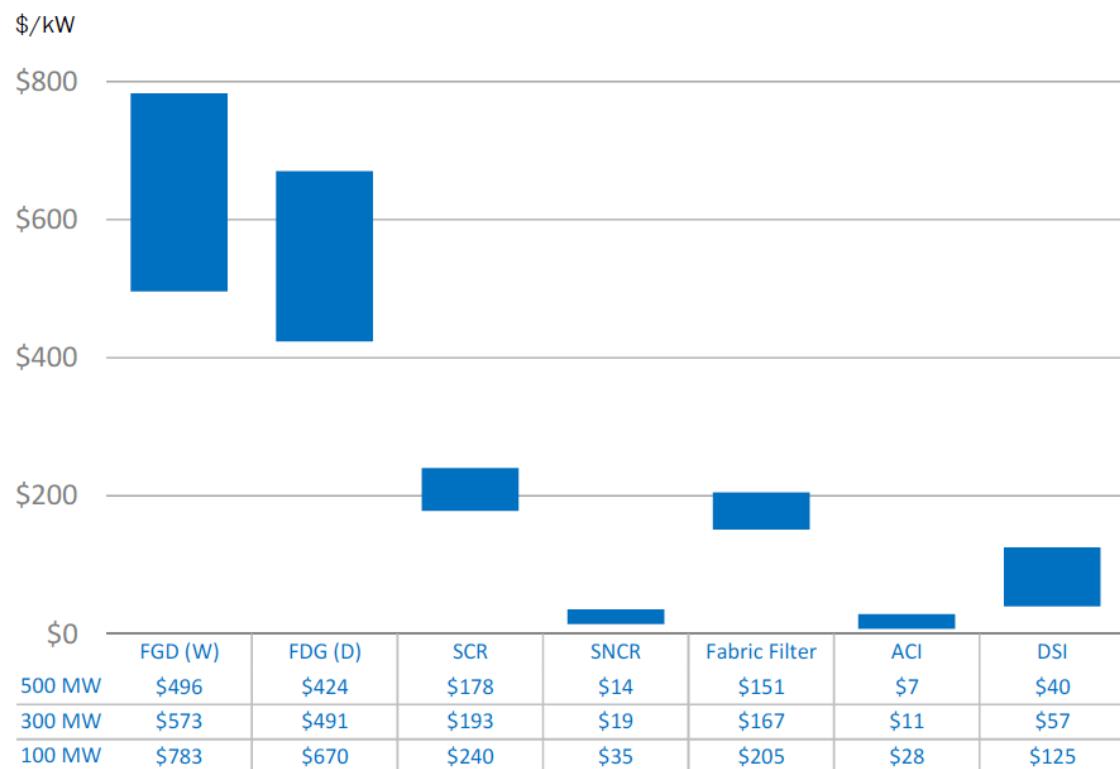
These five regulations issued by the EPA have considerable effect on the current coal generation fleet in the United States. The final regulations will ultimately determine the decision to retrofit, repower, or retire. For all of the proposed regulations there is significant uncertainty on the final stringency of the rule and the compliance period. This uncertainty creates difficult in the determination to retrofit each coal plant. If a decision to retrofit is made, the plants should optimally upgrade all pollution control equipment at once necessary for the proposed rule. Since no such regulations are finalized, the staggering of adding pollution control equipment may add to the total downtime for each of the phased ruling and affect the economics of each plant.

3.7. Plant economics of proposed regulations

Each of the proposed regulations has varying cost estimates associated with them. The age, size and existing control systems for each unit determine the specific costs associated with retrofit. The sum of these costs for compliance will ultimately drive the decision for each plant to retrofit, repower with natural gas or retire.

Since CSAPR and the Utility MACT rule effectively regulate the same pollutants, the retrofit costs for each plant will be similar. The estimated cost for the required control technology is shown in Figure 3.4.

Figure 3.4 Estimated capital cost for control technologies³⁴



The cost for retrofit for each plant varies by size. As plant size increases, the total average capital cost of retrofit decreases due to economics of scale. For the proposed CSAPR and Utility MACT rules, the total capital cost to retrofit is determined largely by the unit size and the existing control equipment.

For the Coal Combustion Residuals Rule, the cost to retrofit ash ponds with liner or switch to a dry ash handling system will have significant ranges. Bottom ash conversion from wet handling to dry handling is assumed to cost around \$30 million per unit (\$60/kW for a 500 MW plant). In addition to the ash handling system, alternative wastewater treatment facilities would have to be built at a cost of \$80 million (\$160/kW) to \$120 million (\$240/kW) per unit because of the closure of ash ponds, which are a source for wastewater processing. The total retrofit costs can range from \$220 to \$300/kW for each facility. The closure of ash ponds would increase this cost by \$30 million per pond³⁵.

If the 316(b) final determination of BTA is the elimination of once-through cooling and the requirement of closed cycle cooling, the capital costs are determined by the size of the facility (which directly relates

³⁴ Ibid.

³⁵ National American Electric Reliability Corporation. *Potential Impacts of Future Environmental Regulations*. November 2011

to the pumping rate) and the constraints on the site location. Sites that are constrained by the total available land increase capital costs by 25 percent. The average capital costs range from \$650/kW for smaller units to \$150/kW for units above 500 MW³⁶.

The ruling on NSPS for CO₂ just issued by the EPA has considerable uncertainty associated with the costs. The ruling is only applied to new facilities. The phased average approach would create a phased investment plan for the unit. The initial design of the plant as non-capture ready or capture ready affects the initial investment costs by 0.5 percent to 3 percent³⁷ from a baseline of approximately \$2,000/kW for greenfield pulverized coal plants. The addition of post-combustion carbon capture increases costs by approximately \$1,000/kW based on the previous net rating of the plant³⁸. The total cost of a new pulverized coal plant with carbon capture is approximately \$3,000/kW³⁹.

3.8. Coal plant closures

Given the potential cost of the regulations to coal-fired power plants, many are at risk for closure. These plants are the older, smaller, and unscrubbed power plants that would be required to install the most costly emissions control systems. Of the total US coal-fired capacity, it is estimated that approximately 129 GW of capacity is at risk for retirement. The majority fall within the Midwest and Eastern US, where the bulk of the coal-fired capacity is and the states that must comply with CSAPR. The assets at risk are shown in Figure 3.5.

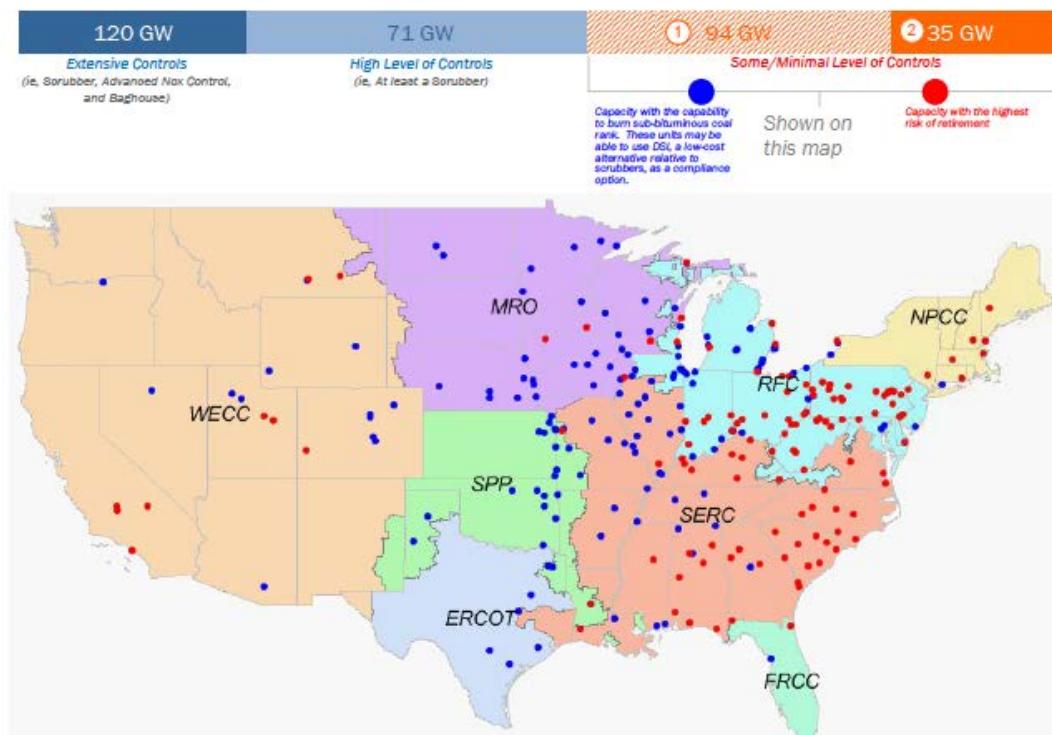
³⁶ Ibid.

³⁷ IEA. “CO₂ Capture Ready Plants.” May 2007

³⁸ MIT Energy Initiative. “Retrofitting Coal-Fired Power Plants for CO₂ Emissions Reductions.” March 23, 2009.

³⁹ NETL Cost and Performance Baseline for Fossil Energy Plants. Volumes 1 and 3.

Figure 3.5 Coal plants at risk for closure due to pending regulations⁴⁰



The North American Electric Reliability Corporation (NERC) estimates that between 36 GW to 59 GW are economically vulnerable for retirement depending on the stringency of the regulations. 234 GW to 258 GW are expected to retrofit by the end of 2015. The impacts of these regulations do not consider the projected lower cost of natural gas and any regulations for greenhouse gas emissions. The price of natural gas has a major effect on the decision to retrofit or retire coal plants. The combined effects of low natural gas prices (\$2.00/MMBtu) and more stringent environmental regulations could drive the total retirements to 72 GW (over 20 percent of the entire coal fleet) by 2030, while high natural gas prices (\$6.60/MMBtu with escalation) and less stringent environmental regulations would reduce the total retirements near 36 GW by 2030.

⁴⁰ M.J. Bradley & Associates. "CSAPR & MATS: What Do They Mean for Electric Power Plants". January 31, 2012.

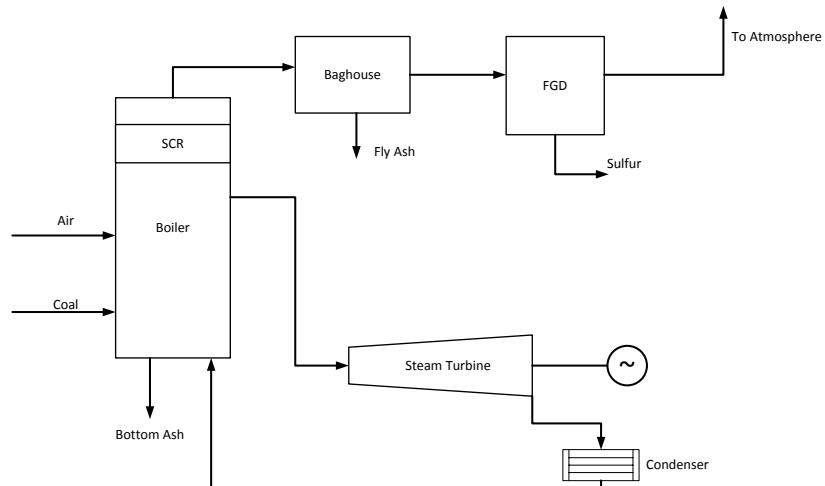
4. Technology process description

The two main methods of power generation in the United States are from coal and natural gas fired generation. The carbon dioxide produced by these power plants exits with the flue gas, which is at atmospheric pressure. Carbon dioxide concentrations range from 3 to 15 percent (gas plants on lower end, coal plants on the higher end). Today's standard process to capture this CO₂ is a chemical absorption process using monoethanolamine. The basic process structure and integration challenges are discussed below for steady state operations.

4.1. Pulverized coal plant

Coal is combusted to produce steam, creating the flue gas containing mostly nitrogen, carbon dioxide, water vapor, and smaller amounts of sulfur oxides (SOx), nitrous oxide NOx, and particulate matter (PM). The flue gas is sent to the air quality control system (AQCS) to remove these criteria pollutants. This system utilizes a variety of process equipment to remove the criteria pollutants (SOx, NOx, and PM) from the flue gas stream before it is vented to the atmosphere. A flue gas desulfurization unit is used to remove SOx, a selective or nonselective catalytic (SCR or SNCR) reduction unit removes NOx, and an electrostatic precipitator (ESP) or bag house is used to remove PM. All of these AQCS must comply with performance standards set by various EPA regulations. A basic schematic of a pulverized coal plant is shown below in Figure 4.1.

Figure 4.1 Pulverized coal plant block diagram



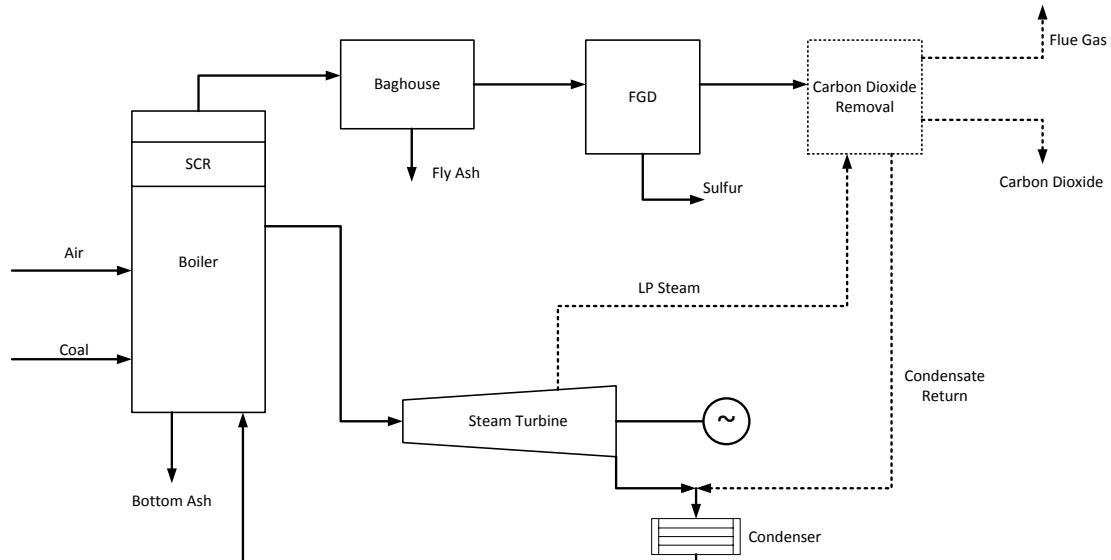
The steam generated in the boiler is sent to the steam turbine to generate electricity. The temperature and pressure of the steam produced is the greatest contributor to the efficiency of the plant. Other factors such as coal quality and temperature of the cooling water effect efficiency. As is shown in Figure 4.1, there is no integration of the steam turbine with the standard AQCS. Typical efficiencies for coal-fired plants range from 33 percent to 43 percent (HHV), with subcritical plants on the low end and supercritical plants on the high end of the scale⁴¹.

4.1.1. Pulverized coal with CCS

A post-combustion capture system is added on to the back end of the AQCS. The flue gas leaving this system is sent to the capture unit to separate a portion of the CO₂. In post-combustion capture systems, a high affinity chemical solvent such as monoethanolamine (MEA) or ammonia (NH₃) is used in a reversible absorption process to capture and release the purified CO₂. The capture system uses heat in the form of steam, extracted from the steam turbine, to release the CO₂ from the solvent. The overall process schematic can be shown in

Figure 4.2. The dashed lines indicate new process equipment and flows from the base plant. The steam used for the capture process is returned to the condenser for use in the boiler feedwater system.

Figure 4.2 Pulverized coal plant with post combustion capture block diagram

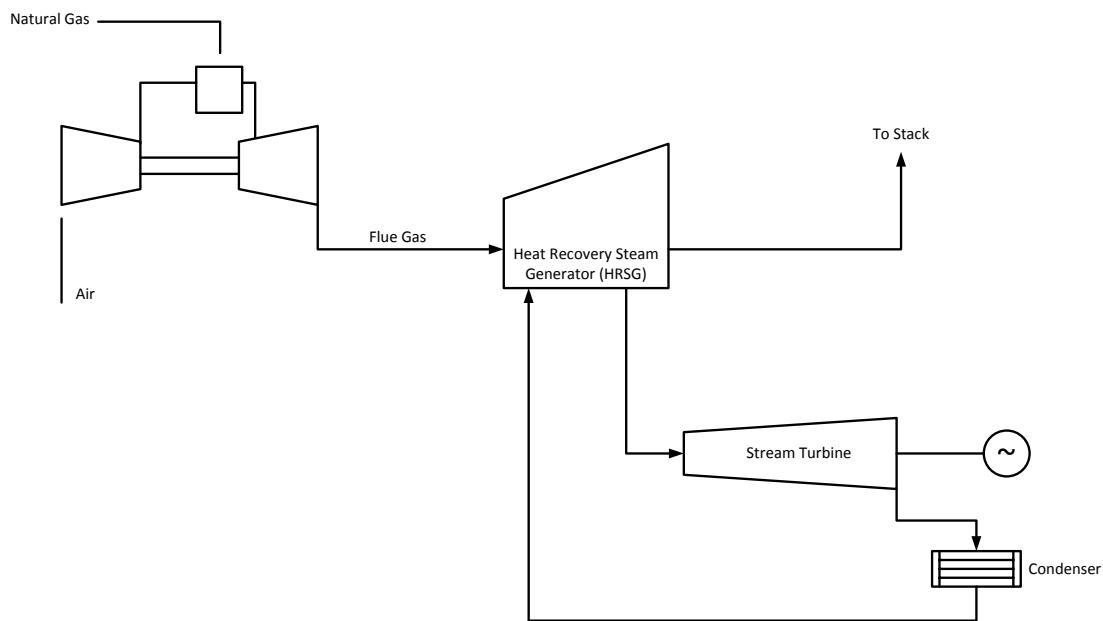


⁴¹ MIT “Future of Coal”

4.2. CCGT

The process for power generation with natural gas is similar to that of coal-fired generation. The process flow diagram for CCGT is shown in Figure 4.3. The main difference is the implementation of a gas turbine. Instead of directly combusting the natural gas at atmospheric pressure to create steam and drive a turbine, the CCGT process combusts the fuel at elevated pressures. Air and natural gas are pressurized through the use of a compressor and combusted to create high temperatures. This hot gas at pressure is then expanded in the gas turbine. The flue gas leaving the gas turbine has enough thermal energy to generate steam in the heat recovery steam generator (HRSG). This is the part of the process that is similar to the coal combustion plant. The steam is sent through the gas turbine for additional power generation.

Figure 4.3 Combined cycle gas turbine



Natural gas is a cleaner burning fuel because of the inherent low sulfur content. Before the fuel is sent to the power plant it is nearly void of sulfur compounds and no particulate matter exists because of the gaseous nature. This enables the CCGT plant to have no emissions controls for sulfur removal or PM emission, although the firing of natural gas can generate NOx emissions. Modern gas turbines have advance combustion systems to prevent the formation of NOx during combustion. If these systems cannot keep NOx levels below the regulated amount allowed, the CCGT has to employ the use of an SNCR or SCR system.

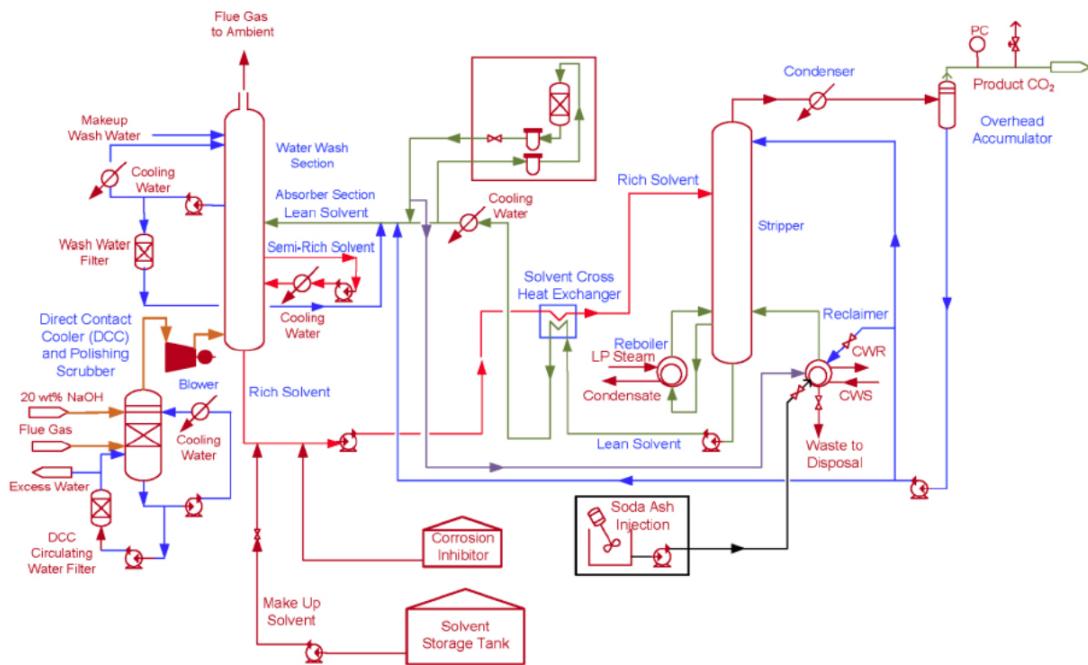
The integration of carbon capture system to a CCGT is identical to that of a coal-fired plant. The capture system is deployed after the HRSG to remove the CO₂ from the flue gas. Steam is extracted from the turbine to provide the heat necessary for desorption from the chemical solvent. This process is not shown because of the similar process flows when compared to the coal plant.

4.3. Carbon capture system

A more detailed schematic of the capture process is shown in Figure 4.4. This process diagram is from the Fluor Econamine FG+ system, but is consistent with most amine based capture systems. The flue gas at atmospheric pressure and containing concentrations of 3 to 15 volume percent of CO₂ enters the absorber column. Coal combustion typically has higher concentrations of CO₂ than natural gas combustion because more excess air is required for complete combustion. This has effects on the efficiency of the overall capture system that will be addressed later.

Before the flue gas can enter the main capture system, it must go through a preprocessing step to remove most of the remaining sulfur (for coal combustion) down to 10 ppm, and to remove most of the water vapor from the combustion process, and to reduce the temperature entering the absorber to facilitate adsorption. The temperature at the exit of the preprocessing stem is approximately 50°C. As the flue gas enters the bottom of the absorber column the amine solvent enters the top of the column contacting the flue gas. The solvent preferential adsorbs the CO₂ in the flue gas.

Figure 4.4 Process flow diagram of post-combustion carbon capture system



The rich solvent enters heat exchanger to increase the temperature of the solvent stream and reduce steam extraction from the turbine, at the intermediate pressure/low pressure (IP/LP) turbine crossover pipe. From the heat exchanger, the solvent goes to the stripper where heat is added to capture system by steam extraction from the turbine. The heat causes the CO₂ to desorb from the solvent. The CO₂ is dried and compressed for pipeline transport. The lean solvent leaving the stripper is cooled then recirculated to the absorber column to complete the loop.

4.3.1. Integration of carbon capture with base power plant

The standalone capture process presents few technical and operational challenges beyond scale-up. This process has been employed by the petro-chemical industry for decades. However, the integration of the capture process with the power plant presents considerable challenges for deployment. The large quantity of steam required for solvent regeneration fundamentally changes the steam turbine design and operation, especially when new-build, retrofit, and off-design modes are considered. Considerable capital equipment must be added to the process for carbon dioxide removal because of the large volumetric flue gas flow. The main challenges of the integration are shown in Table 4.1.

Table 4.1 Steady state integration challenges⁴²

Steady state integration challenges
Additional flue gas desulfurization
Multiple trains absorber columns and CO ₂ compressors
Integration of LP steam with CO ₂ stripper
Modified/operational changes of steam turbine
Carbon dioxide compressors
Larger cooling water system

The most common option for additional flue gas desulfurization is with a polishing scrubber shown in Figure 3.4. This is to prevent the formation of heat stable salts (HSS) with the amine present in the solvent. Besides the addition of capital equipment, cooling water, and chemicals (sodium hydroxide) needed for the process, this extra polish step does not present additional process challenges to the system.

Multiple absorber columns are necessary due to the large volumetric flow entering the unit. For a 550 MW_{net} supercritical coal-fired power plant, these flows are in excess of 4.5 million Nm³. Because of manufacturing size limitations and the necessity to evenly distribute the solvent throughout the column, two absorber trains are used. This creates additional operating and process control complexity to the system because of the multiple trains to the solvent stream entering the stripper column.

4.3.2. Steam turbine integration

The integration of the steam turbine and the capture plant is the most challenging process and operational consideration. Without integration, the maximum achievable efficiency is reduced if steam is required from a process external to the base power plant⁴³. This has considerable design implications on the steam turbine, specifically the low pressure steam turbine after the extraction point. The extraction of steam at the IP/LP crossover pipe is in the range of 40 to 70 percent of total flow, dependent on the system efficiency and the regeneration energy of the specific solvent.

⁴² Hildebrand, A.N. MIT Master's Thesis.

⁴³ Bashadi, S. MIT Master's Thesis

The most optimal design if a plant was to operate at full load and 90 percent capture at all times would be to size the LP according to the constant flow reduction required. No challenges exist for maintaining constant flow, temperature and pressure to the LP steam turbine or the solvent stripper.

If the decision space for operation is limited to only on and off operations of the capture unit, the design of the steam turbine becomes critical. While the capture unit is operational, the amount of steam to the LP section of the steam turbine is reduced and when it is not operating the steam flow will reach a maximum. Two options exist for this issue. The LP turbine could be oversized to handle the maximum potential flow when the capture unit is off or the coal plant could reduce fuel burn when the capture unit is down.

If the capture unit is not operating and the plant is running at full load, an oversized LP section of the turbine will be able to handle the increased flow. This would increase the capital expenditure of the system because of the oversizing of the turbine. While the capture unit is on, the flow through the turbine will not be at maximum capacity. This will reduce the efficiency of the LP section of the turbine.

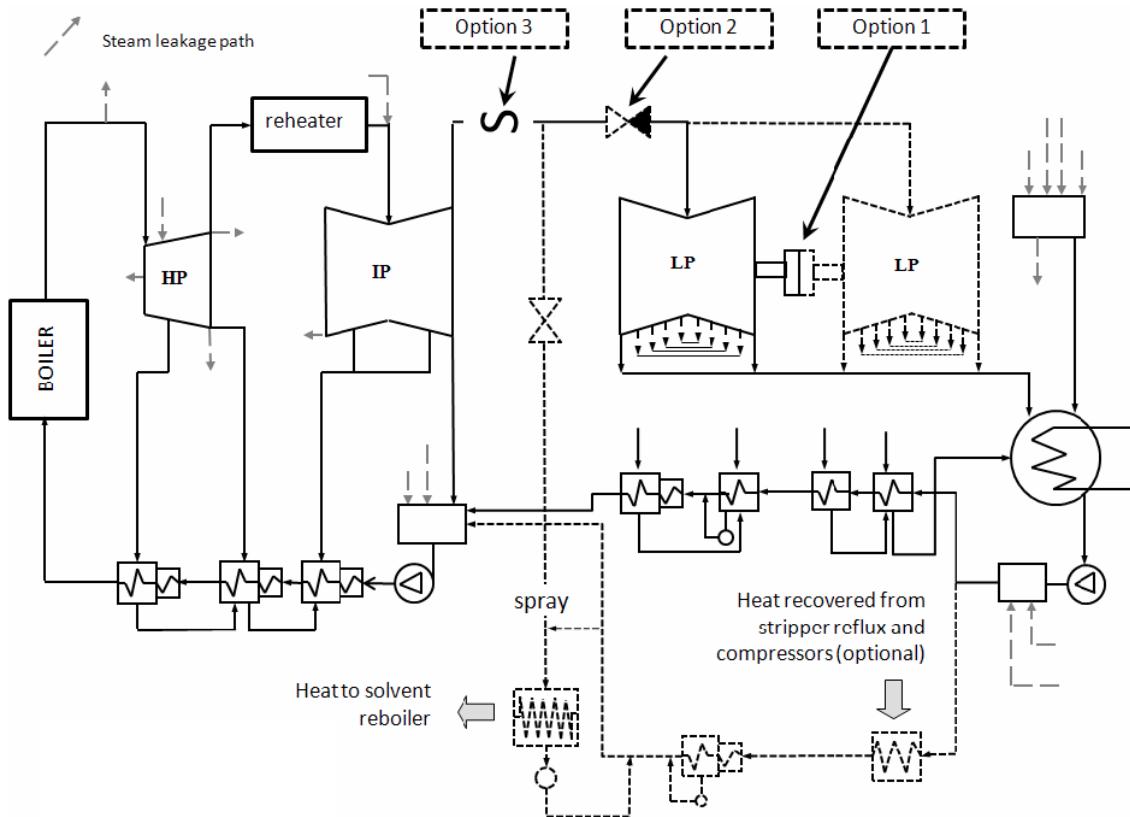
The clutch option could be used to increase the efficiency of the on/off modes. The clutch system could decouple a section of the LP turbine while the capture unit is running and steam is at reduced flow. When the capture unit turns off, the clutch could conversely bring online the other section of the LP turbine. Again, this creates tradeoffs between system efficiency and capital costs. The clutch system increases the efficiency in both design modes. Capital cost of the clutch system would be greater than the strictly oversized turbine design.

The two other modifications to maintain control over steam conditions are throttling the stream for consistent temperature and pressure to the LP turbine (Option 2) or allowing the steam conditions to float (Option 3). Figure 4.5 shows the modifications to the steam turbine design that could be used. The clutch option is shown as Option 1.

The use of the throttling valve has an effect of decreasing overall system efficiency when the capture plant is not in operation. When the capture system is operating, the steam temperature and pressure are reduced because of the flow to the capture unit. The steam entering the LP turbine is at the design point. The throttle value can be fully opened and no system efficiency penalty is incurred. When the capture plant is not in operation the throttling valve is adjusted to meet the design conditions of the LP

turbine. The throttling will decrease the pressure ratio and subsequently reduce the total extractable power from the low pressure steam.

Figure 4.5 Steam turbine integration options⁴⁴



Option 3 is to allow the temperature and pressure at the crossover pipe to float. The LP turbine would be designed to allow for the maximum temperature and pressure that occur when the capture unit is not operating. When the capture unit is operational, the pressure is reduced and the steam turbine efficiency is lower because it is not operating at the design point.

The last option would be to reduce the flue burn rate to decrease the total amount of steam through the LP turbine of the section. When the capture unit is not in operation, the burn rate would be reduced to match the amount of steam normally extracted. The high pressure and intermediate pressure section of the turbines would be at below maximum flow and the efficiency of these sections is reduced.

⁴⁴ Lucquiaud, M., et al. Capture-ready supercritical coal-fired power plants and flexible post-combustion capture. Energy Procedia 1 (2009). 1411-1418.

It is important to consider that if the carbon capture unit is not running enough time and the turbine is in maximum flow mode for a majority of the time, there is little reason to build the CCS unit. If the capture unit were running for the majority of the time, the reduction in fuel burn rate would decrease the capital costs of the system over the other options. An accurate forecast of the electricity prices and the subsequent time dispatched would be required for an accurate valuation of the increased capital costs.

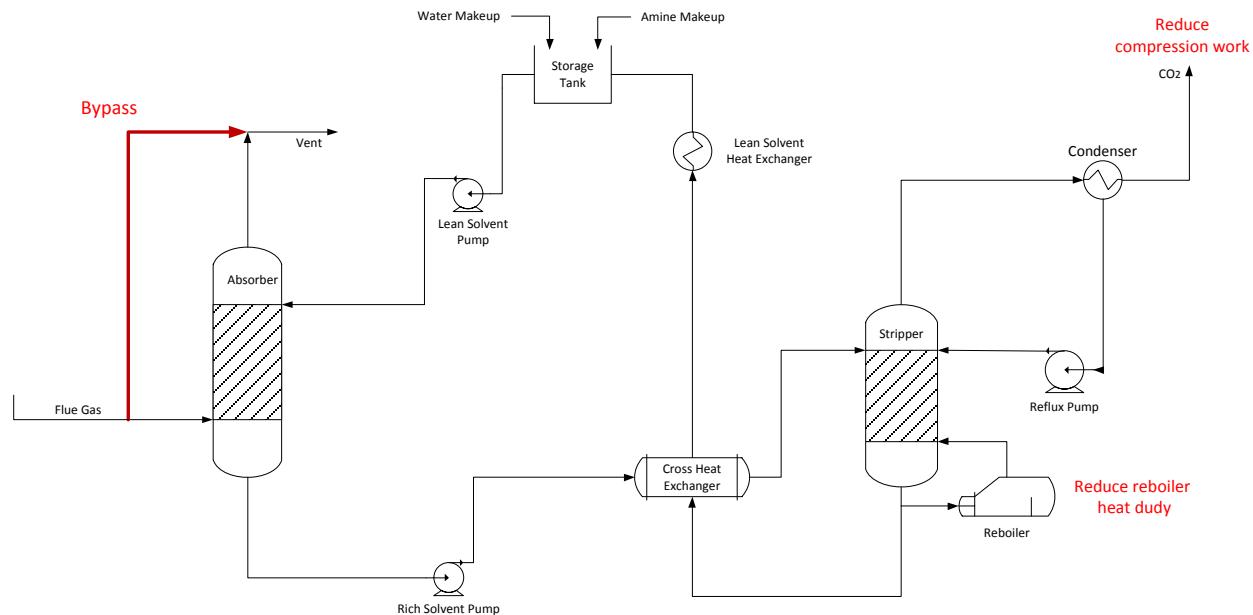
4.4. Part load, partial capture and stripper bypass configurations

The integrated carbon capture system can be operated in different modes from the simply turning the capture system on and off. The capture unit is able to operate at partial load with a reduction in flue gas to the absorber unit, partial capture mode, or capture unit can utilize a desorber system bypass configuration.

4.4.1. Partial load and partial capture

The capture system can be configured to bypass a portion or all of the flue gas entering the absorber. The system is designed for full flow at 90 percent capture and a bypass flow duct is installed before the direct contact cooler (DCC). The configuration is shown in Figure 4.6. The DCC is not shown in the figure below.

Figure 4.6 Bypass configuration



This configuration is utilized for increased power production. By bypassing a portion or all of the flue gas to the absorber, the energy required for the pumping of the amine solvent, steam from the crossover pipe, and CO₂ compression is reduced proportionally by percent bypassed when a 90 percent capture rate is maintained. By bypassing the flue gas and directly venting to the atmosphere, the increase in power output causes an increase in emissions of the plant. The increase in capture rate is shown in Equation 1.1. For example, a 30 percent bypass and a 90 percent capture rate increase emissions by a factor of 3.7. The system captures 63 percent of the CO₂ in the flue gas from the base case of 90 percent.

$$\text{Capture rate} = 1 - [\% \text{ bypass} + (1 - \% \text{ bypass}) \times (1 - \% \text{ capture})] \quad \text{Eq. 1.1}$$

The price of electricity and the price of carbon emission are the key factors to determine if venting is economically justifiable. In bypass mode, the solvent storage tanks would have to be sized to accommodate the reduction in flow to the absorber, although this is not a major issue as the tanks would have to be size to hold all of the amine solvent for times the capture unit is not operational and for system maintenance.

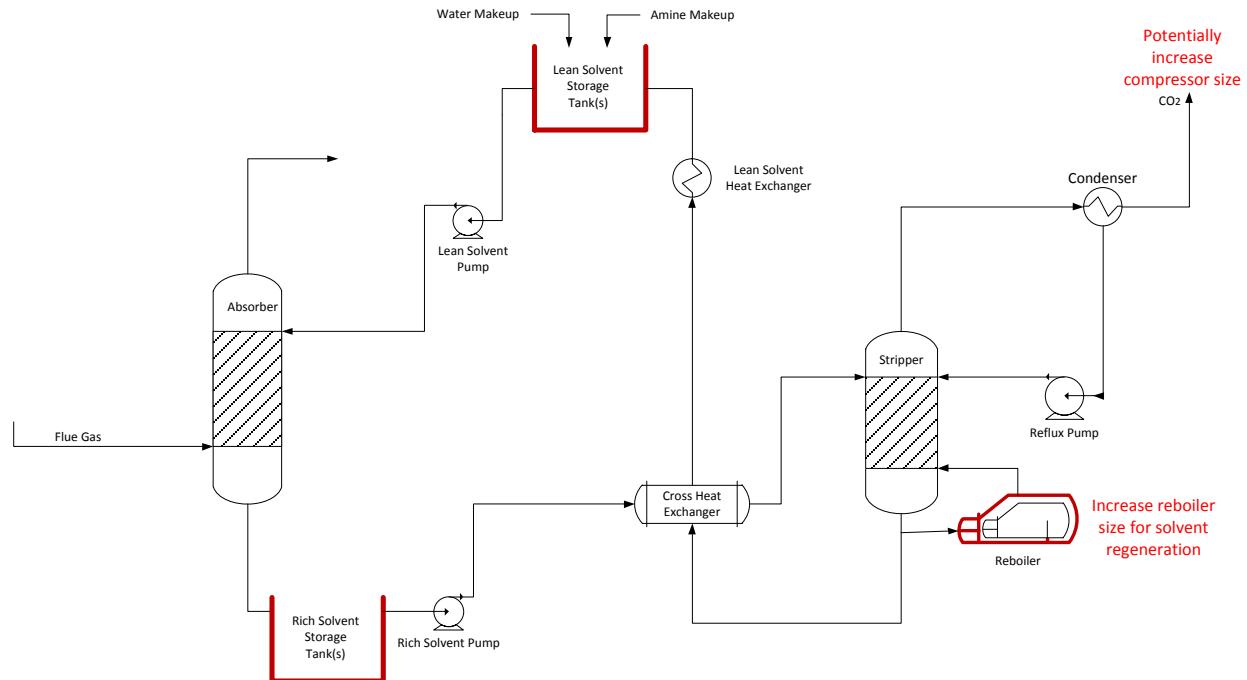
Another option is to reduce the capture rate of the unit. There are two main methods to control the emissions rate. The first method is to reduce the flue gas flow rate to lean amine liquid solvent flow rate (L/G). By reducing the L/G ratio, the amount of CO₂ absorbed by the solvent is reduced directly

proportional to the change in the L/G ratio. The power required for pumping and compression and the amount of steam extracted from the turbine system is also reduced directly proportional to the L/G ratio, increasing the total output of the integrated plant. The second method is the decrease the steam sent to the stripper while holding the L/G ratio constant. This causes the lean amine solvent loading to increase. This reduces the amount of CO₂ that can be absorbed by the lean amine, increasing the capture rate. While the steam extraction and CO₂ compression power is reduced, the total pumping power required pumping for the capture unit remains constant.

4.4.2. Stripper bypass configuration

Another option to increase power output during peak demand is to create a bypass system that diverts rich solvent flow from the absorber to a storage tank instead of routing to the stripper column as shown in Figure 4.7. This system has the benefit of not increasing the emission profile of CO₂ during times of solvent storage for increased power production. By storing the rich solvent, no extraction steam or compression work is required. When system electricity demand is reduced and the cost of the energy penalty is lower, the stored rich solvent is released and sent to the stripper column for regeneration and the capture unit requires additional steam and CO₂ compression.

Figure 4.7 Stripper bypass configuration with solvent storage



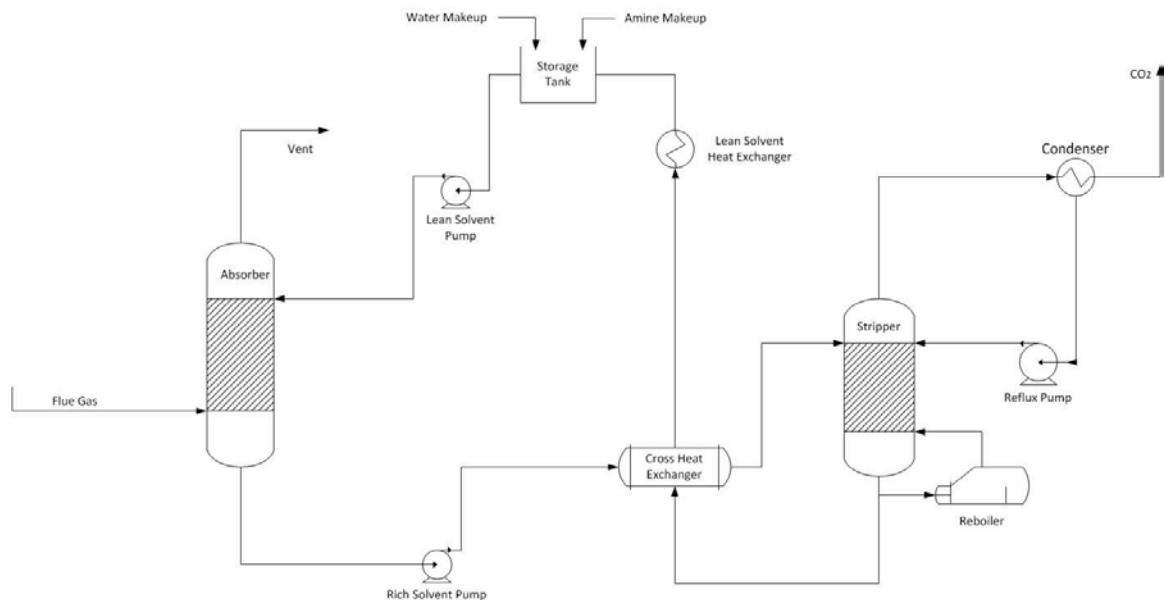
To accommodate the increased flow of rich solvent to the stripper, the capture unit requires an increase in size of all process equipment downstream of the absorber column. The major items are the solvent storage tanks, the stripper reboiler, and the CO₂ compressor. The sizing of this equipment and the increased capital expenditure of the system require evaluation of the duration of solvent storage, the regeneration rate, and the valuation of electricity prices during times of storage and regeneration. All of these factors determine the viability of the solvent storage system and the optimal duration of solvent storage.

5. Model description and simulation results

5.1. Steady-state simulation

A steady-state rate-based process model⁴⁵ for a nominal 500 MW coal-fired power plant with 90 percent capture was developed in Aspen Plus Version 7.3. The steady-state model was used for development and verification. All equipment sizing was based on these two main process specifications. The two main process units modeled are the absorber and the stripper column. The system was modeled as a single train, closed loop process. Most large-scale power plants require two absorber columns and a single stripper will be necessary. The main process units modeled are shown in Figure 5.1.

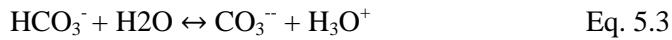
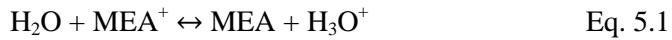
Figure 5.1 Process flow diagram model for post-combustion capture



The flue gas enters the absorber after compression from the direct contact cooler (DCC) at 126 kPa and 81°C. The flue gas is comprised of 12 percent CO₂, 14 percent water, 70 percent nitrogen and 4 percent balance oxygen. These concentrations may vary slightly depending on the type of coal burned, the amount of excess oxygen required for combustion, and the temperature of the cooling water entering the DCC.

⁴⁵ Based on the work of Kothandaraman, A. MIT Ph.D. Thesis.

The absorption and desorption process is modeled as five reversible chemical reactions as shown in Eq. 5.1 to 5.5.



The electrolyte non-random two-liquid (ELECNRTL) property method was used for the CO₂/H₂O/amine vapor-liquid equilibrium. The absorber column is modeled as 30 equilibrium stage RadFrac packed column and a 10 kPa pressure drop through the column. The dimensions of the absorber are 17 meters in height by 12 meters in diameter. Eq. 5.6 defines the loading of an amine solvent stream. The lean amine entering the top of the absorber has a loading of 0.2 mol CO₂/dry mol amine and the rich amine exiting the bottom of the absorber has a loading of 0.5 mol CO₂/dry mol amine.

$$\text{Loading} = \frac{\text{Moles of all CO}_2 \text{ species}}{\text{Moles of all MEA species}} \quad \text{Eq. 5.6}$$

The rich amine solvent is pumped to 177 kPa before entering the lean/rich solvent heat exchanger. The rich amine solvent is heated from 59°C to 100°C. This temperature was chosen to prevent flashing in the cross heat exchanger. The lean amine solvent from the bottom of the stripper is cooled from 124°C to 77°C in the process and further compressed to 140 kPa and cooled to 40°C. The rich amine continues to the stripper where heat is sent into the reboiler operating at 200 kPa. The pressure drop down the column is assumed to be 25 kPa. The stripper is modeled as 20 equilibrium stage RadFrac column with a reboiler internal to the unit and an external condenser. The dimensions of the stripper were set to 15 meters in height by 7 meters in diameter.

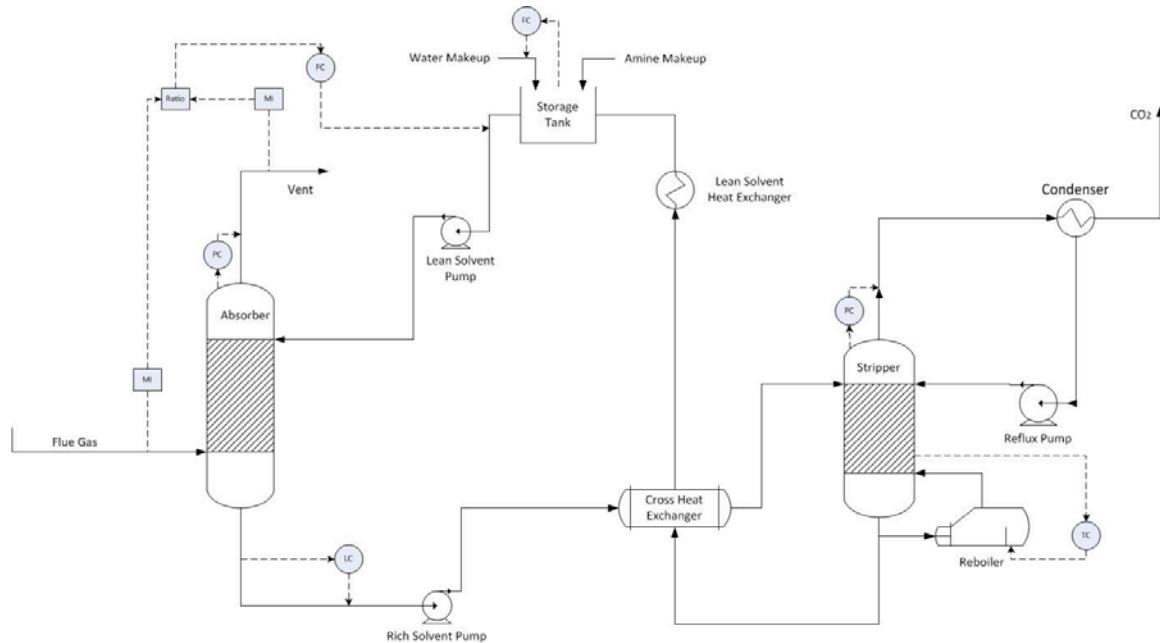
The overhead stream of the stripper exits at 175 kPa and 96°C, containing about 50 percent of both CO₂ and H₂O. Before this stream can be sent to compression it must be cooled and dried. The overhead stream is cooled to 43°C, which reduces H₂O to 8.6 volume percent. The CO₂ stream is finally compressed to 1.4 MPa. The CO₂ compression process was not modeled.

The process temperatures, pressures, flows, and compositions establish a baseline for the dynamic simulation to match at steady state and for the same process conditions.

5.2. Dynamic simulation

The steady-state simulation was converted to Aspen Dynamics Version 7.3 flow driven model. For dynamic simulation, a control structure is required to measure changes to process conditions and manipulate the relevant process variable. The control structure for the system is shown in Figure 5.2.

Figure 5.2 Capture system process flow diagram with control structure



The system has two primary control loops. The first is to maintain the set point of the capture ratio of CO₂. This control loop measures the incoming mass flow of CO₂ to the absorber and the exit mass flow from the top of the absorber. The flow from the solvent storage tank is adjusted to maintain the desired capture set point. For example, as the flue gas flow changes from 100 percent flow to 90 percent flow, the controller system decreases the flow rate of the lean amine solvent to maintain a constant capture rate. The flow rate cannot undergo the same step change as the flue gas because of the dynamics of the storage tank, the lean solvent flow gradually decreases until the set point is achieved. The baseline set point for the capture ratio is 0.1, which equates to a 90 percent capture level. The control system utilizes a direct proportional-integral (PI) controller to maintain the required flow rate.

The lean solvent loading is one of the key parameters for carbon capture. This is achieved by the heat applied in the form of steam to the reboiler. The temperature has a direct relationship to the lean loading as the pressure of the column is fixed. The steady state simulations determined that the energetic optimum for lean load is 0.20 mol CO₂/dry mol amine⁴⁶. A direct measurement of the lean loading requires costly off-stream analysis and results cannot be calculated in real time. The proxy indicator for lean loading is column stage temperature⁴⁷. The reboiler stage (stage 20) set point is 124°C to achieve optimal lean loading. The lean loading control loop uses a reverse PI controller. Reverse simply indicates that as the temperature of the reboiler increases, this requires a reverse action by the controller, a reduction in the steam to the system.

Five other secondary control loops are necessary to maintain process set points. The absorber and stripper columns have pressure controls (located at the top of the columns). The flow leaving the top of the column is changed to maintain constant pressure. The water makeup controller ensures that the mass balance of water is maintained throughout the system. Level controls for the column sumps are maintained by controlling the flow exiting the column bottoms. The stripper sump control is not shown in Figure 4.2.

5.2.1. Model caveats

There are simplifying assumptions in this model that differ from the complete process flow diagram of the Fluor Economic FG+ Unit shown in Figure 4.4. The DCC that removes most of the process water, decreases the temperature to approximately 50°C to facilitate absorption, and decreasing sulfur concentrations to 10 ppm before entering the absorber is assumed as an upstream process to the capture system. The system is modeled as a single absorber/stripper train. While this does not significantly affect the dynamics of the system, the total turndown for the capture system is limited. The absorber column has a minimum liquid load before weeping occurs. The single column train reduces total turndown to approximately 30 percent of total flue gas flow compared to the minimum 15 percent of flue gas flow for a two absorber column system. The SO_x, NO_x, and O₂ that are present in the flue gas are assumed to be inert. The SO_x and NO_x are substituted by nitrogen. Because of this assumption, the monoethanolamine reclamation system oxygen degradation is not modeled. The water wash section at the top of the absorber is not modeled. This process is used to recover some of the water vaporized due to

⁴⁶ Ibid.

⁴⁷ Panahi, M. and Skogestad, S. 2011. Economically efficient operation of CO₂ capturing process part I: Self-optimization procedure for selecting the best controlled variables. *Chemical Engineering and Processing: Process Intensification*. **50** (3); 247-253.

the heat of absorption in the column. This process will only affect the amount of makeup water to the system and is assumed not to affect the overall process dynamics. In addition, the temperature and pressure of the steam extraction is assumed to be constant, ignoring the fluctuations in steam quality as coal plant load changes.

5.3. Carbon capture system dynamics

To determine the dynamics of the carbon capture system, the series of simulations were performed to determine the response time to steady state. There are two operational modes that were investigated. The first is the ability of the CCS unit to ramp up and down to changes in the fuel burn rate. This is the main way that coal plants change electricity output to the grid. As less electricity is demanded, coal plants reduce fuel burn, which directly reduces the output. The carbon capture unit has to respond to the reduced flue gas flow entering the system. As more electricity is demanded, the converse operation occurs. For this type of operation, a strict emissions performance rate of 90 percent capture is maintained at all times. The second operational mode is the power generation for peak demand. To operational schemes can be used to increase the power output of the plant. By reducing the capture rate of the plant below the 90 percent set point, less solvent circulation is required, which reduces the amount of pumping power and the amount of steam extracted from the turbine. The second scheme is to increase the lean loading of the solvent exiting the stripper bottoms. During this mode, the solvent circulation remains constant but the reboiler temperature set point is reduced. This reduces that amount of steam extracted from the turbine, increasing power output.

5.3.1. Disturbance to flue gas flow

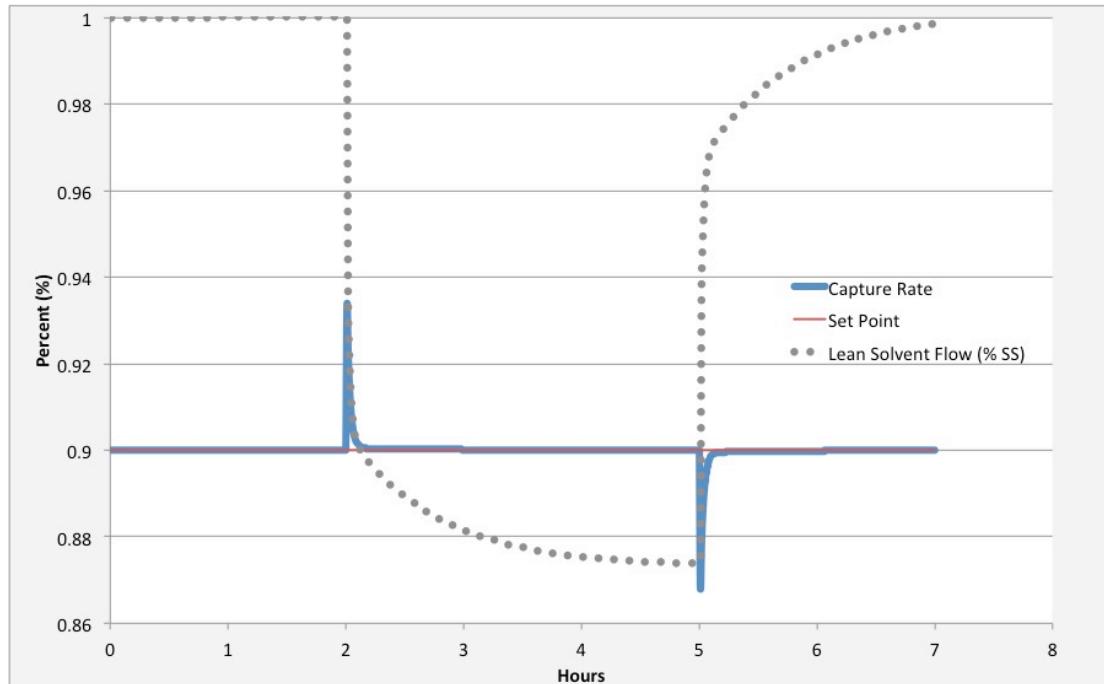
To analyze the dynamics of the system for a change in fuel burn rate, a negative 10 percent step change was made to the incoming flue gas flow. Once steady state was achieved for this disturbance, a positive 10 percent step change was induced, bring the plant back to the baseload operation. The disturbance to the system is shown in

Figure 5.3.

Figure 5.3 Flue gas flow rate step change

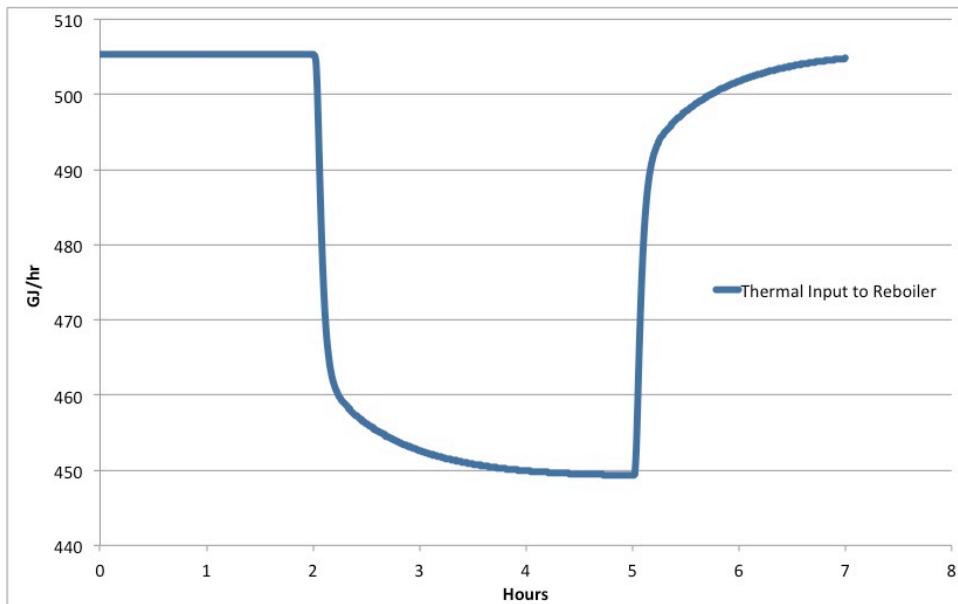
The system was run for two hours to ensure steady state of all process conditions. The negative step change induced at 2 hours and the positive step change was induced at 5 hours. The capture rate and normalized lean solvent flow are shown in Figure 5.4.

Figure 5.4 Capture rate and lean solvent flow dynamics for flue gas flow step change



As the 10 negative percent step change is induced, the lean solvent to flue gas flow ratio, which during steady state is at 2.5, temporarily spikes to 2.8. The increase in this ratio causes the capture rate to spike to 93.3 percent. As the flow controller decreases the lean solvent flow, the capture rate returns to the set point of 90 percent after approximately 9 minutes. The lean solvent flow rate decreases by 12.6 percent (total flow changes from 1,859,530 kg/hr to 1,625,930 kg/hr) to maintain the capture rate of 90 percent, but the flow does not reach steady state until three hours after the step change. Total thermal input to the reboiler tracks with the total solvent flow rate as shown in Figure 5.5. The reboiler duty maintained the reboiler set point temperature of 124°C with a maximum deviation of 0.2°C.

Figure 5.5 Thermal input to the reboiler for flue gas flow step change



There is a three-minute lag in the system before the disturbance in flue gas flow causes a change in the reboiler temperature. While this result will be unique to this particular system and the specific model set up, linked process controllers could alleviate this lag to deal with smaller changes in flue gas flow disturbance and reach steady state at a faster rate. This lag in the system was shown to have no major affect on the overall dynamics of the system.

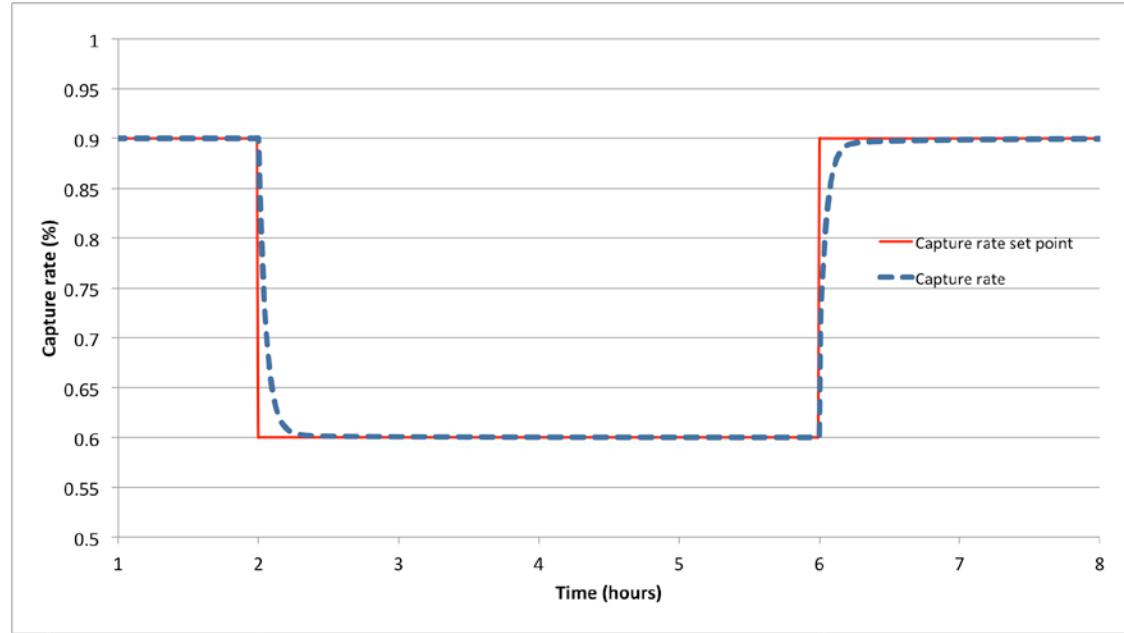
As the reboiler temperature and lean solvent flow rate process control takes nearly three hours to reach steady state, this will have a direct effect on the power plant to produce consistent power to the grid over this range. The extraction steam and pumping and compression power will vary over this time range along with these process variables. The reboiler thermal input and lean solvent reaches the within 2 percent of the final steady state output within 30 minutes after the step change and the remainder of the time to steady state is to achieve the remaining two percent. An integrated control system with the power plant and the capture plant would be necessary to reduce the time to steady state power output.

5.3.2. Disturbance to capture level

The dynamics of the system to changes in deviation from the set point capture level were simulated by creating a negative 30 percent (absolute) step change to the capture level followed by a positive 30 percent (absolute) step change as shown in Figure 5.6. This was disturbance was chosen to investigate the ability of the capture plant to increase power output during times of peak demand. This increase in

power output comes as a tradeoff to the emissions performance of the capture system. By lowering the capture rate, the capture unit vents more CO₂ by reducing the lean solvent flow rate causing a subsequent reduction in steam required to maintain reboiler temperature set point. This reduction in steam extraction directly increases power output of the LP section of the steam turbine. The system was run until steady state was achieved and at two hours the negative step change was induced. At 6 hours simulation time, the system was returned to the 90 percent capture rate.

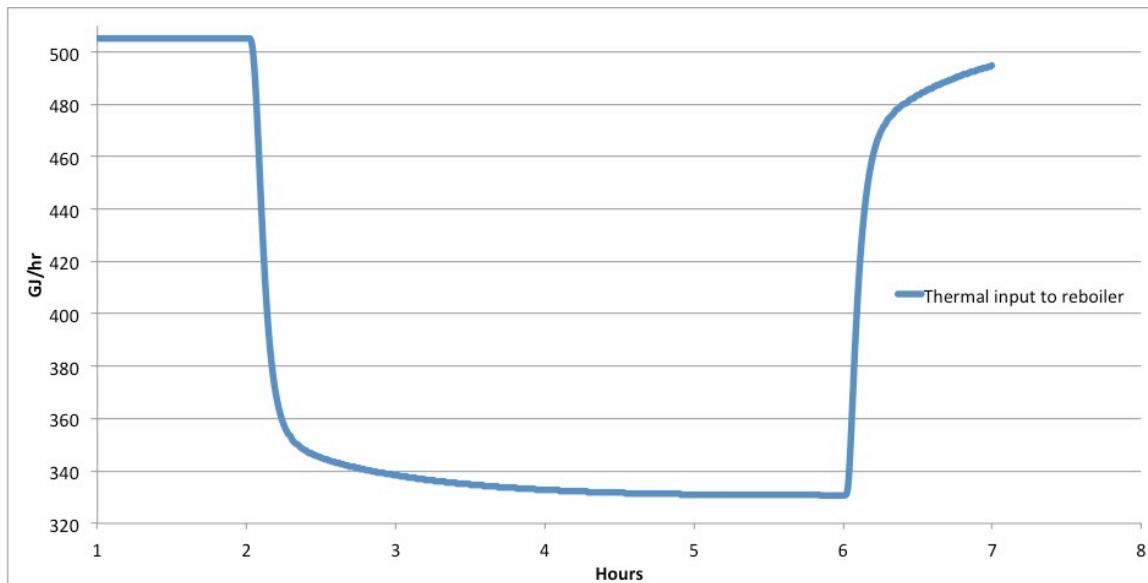
Figure 5.6 Capture rate dynamics



As can be seen in Figure 5.6, the step change in capture rate provides a similar response as the change in flue gas flow. Steady state was achieved within 24 minutes (about three times of that necessary for a third of the step change for the flue gas flow disturbance) for both the positive and negative step change. The lean solvent flow rate reached steady state after 37 minutes and changed from a flow of 1,859,270 kg/hr to 1,203,500 kg/hr, a 35 percent reduction.

Figure 5.7 shows the reboiler duty dynamics for the capture rate step change. The total reduction of thermal input to the reboiler is directly proportional to the change in capture rate. This demonstrates that changes in capture rate can track more directly to power output than changes to flue gas flow rate. The total reduction of thermal input to the reboiler is 35 percent for a 30 percent reduction in the capture rate. For a 500 MW plant at 90 percent capture, this reduction in the capture rate of 30 percent increases total power output by 58 MW.

Figure 5.7 Thermal input to the reboiler for capture rate step change



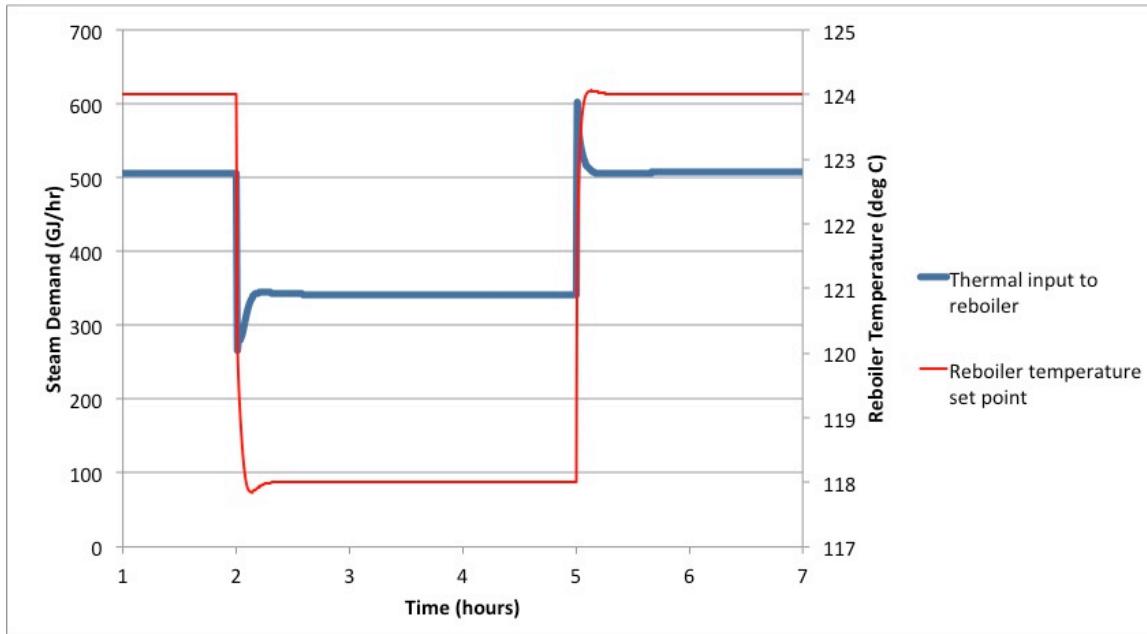
Once again, the four hours it takes to reach steady state can have significant consequences on the power output of the plant. Integrated control systems would be required to maintain a set level of power output.

5.3.3. Disturbance to reboiler temperature

Another operational strategy that can be used to increase power production during peak demand is to reduce the steam demand required for the reboiler, increasing flow through the LP turbine and generating more power. In the control structure set up, this requires a reduction in the set point of the reboiler temperature as this acts as an indirect manipulation of stream demand. For this series of simulations, the reboiler temperature was reduced from 124°C to 118°C. This temperature reduction was used to correspond roughly to a capture rate of 60 percent for comparison with capture rate step change test.

The system was run until the system reached steady state and at 2 hours the negative step change to 118°C for the reboiler temperature was induced. At 5 hours the reboiler temperature was set back to 124°C. During this simulation, the lean solvent flow rate controller was turned off to maintain constant solvent circulation throughout the system. Figure 5.8 shows the change in reboiler temperature set point and reboiler thermal input.

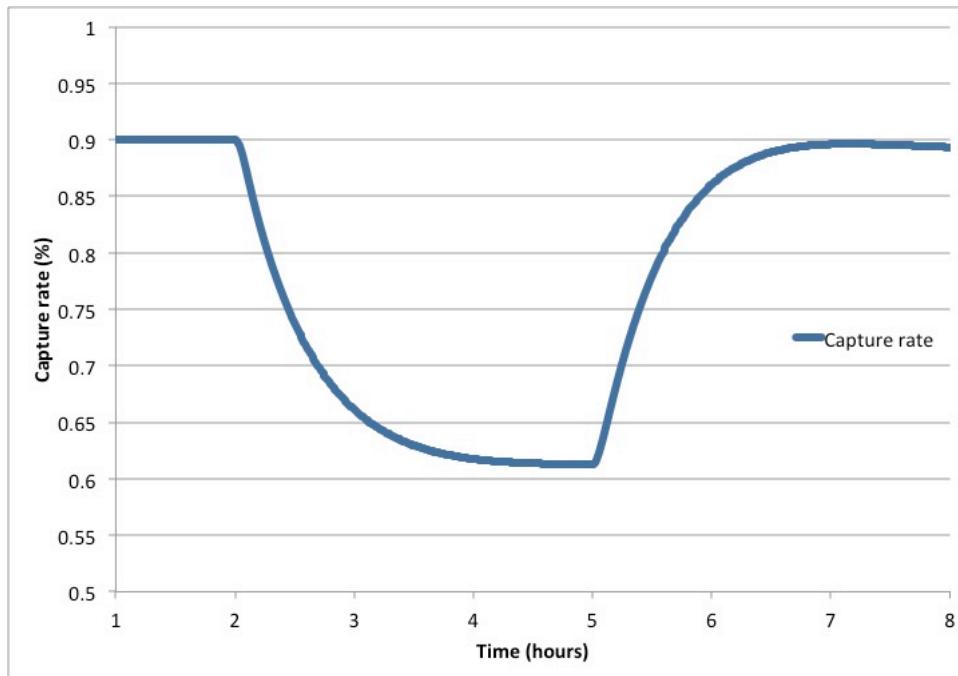
Figure 5.8 Reboiler dynamics for reboiler step change



The negative step change in reboiler temperature decreases total thermal input by 32 percent. Steady state was achieved for reboiler temperature and total thermal input to the reboiler was achieved within 20 minutes. This increases power output of the baseline 500 MW power plant by 53 MW.

The decrease in reboiler temperature increased the lean loading of the solvent by 50 percent, from 0.20 to 0.30 mol CO₂/dry mol amine at steady state. The increase in lean loading causes a decrease in the capture rate while maintaining constant solvent flow throughout the system. The capture rate is shown in Figure 5.9.

Figure 5.9 Capture rate for step change to reboiler temperature



The capture rate decreases from 90 percent to 61 percent from the negative reboiler step change. Capture rate steady state was achieved within three hours. Lean loading leaving the stripper bottom achieves the value of 0.30 mol CO₂/dry mol amine within 20 minutes of the step change. The lag in the capture rate occurs the holdup in the system causes the richer lean solvent to gradually mix with the 0.20 mol CO₂/dry mol amine lean loaded solvent.

5.4. Discussion of simulation results

The objective of the simulations and the various disturbances tested was to understand the dynamic response of the carbon capture unit. For the flue gas disturbance, the capture rate disturbance, and the reboiler temperature disturbance, the capture unit is able to respond dynamically on time scales similar to the maximum coal ramp rate of 4 percent per minute.

The flue gas flow rate disturbance is most similar to the current operation of coal-fired power plants, as power output is directly adjusted by the fuel burn rate. This directly affects the amount of flue gas produced from the plant boiler. As fuel burn rate decreases, the flue gas flow rate decrease proportionally. The system is able to achieve a steady state emission profile of 90 percent capture within maximum ramp rate for fuel changes. If emissions capture rates are restricted to 90 percent for all operating times, the capture unit is able to maintain this benchmark for decreases in flue gas flow to the

reboiler. For increases in flue gas flow, the system has the potential to capture above the 90 percent rate until the increase in flue gas flow is initiated and the lean solvent flow rate is adjusted accordingly to maintain the emissions benchmark. The capture plant is stable down to levels of 30 percent of flue gas flow, which is equal to the minimum achievable fuel burn rate of the base coal plant. The power and steam requirement of the system can be achieved by integrating the boiler controls and the capture unit controls to achieve steady state power production within this 4 percent per minute threshold.

The capture rate disturbance creates more flexibility of the integrated system by increasing the power output range. By decreasing the capture rate and emitting more CO₂ to the atmosphere, the capture unit requires less steam, pumping power, and CO₂ compression. The 30 percent step change induced shows similar responses times to return to steady state as the flue gas flow step change for both capture rate and thermal duty of the reboiler. By reducing the capture rate by 30 percent the total power output of the plant is increased by 12 percent. Similar results are achieved for various capture levels below 90 percent. The dynamics of the capture rate disturbance are within the threshold of the limit set by the coal boiler and this operational mode presents no hindrance to integrated plant operation.

The reboiler temperature disturbance is another operation choice for the production of peak power. This method to increase power production has beneficial effects over manipulating the capture rate disturbance. The thermal input to the reboiler reaches steady state in 12 minutes compared to 3 hours for the capture rate disturbance. Pumping power remains constant throughout the reboiler temperature disturbance. In addition, the capture rate maintains higher levels for longer time scales. This is due to the holdup of the amine solvent. Due to the holdup of amine in the system, the lean loading is gradually increased until the new steady state level is achieved. While the lean loading remains below the final steady state of 0.30 mol CO₂/dry mol amine the capture rate is above the final capture rate of 62 percent.

6. Economics of flexible operation

The lifetime-installed cost for coal-fired power generation with and without CCS has been extensively studied^{48,49}. The focus of these analyses is on the change in overall costs between a new coal plant without CCS and one with CCS. These studies conduct an economic analysis to determine the leveled cost of electricity (LCOE) for the lifetime of the plant, typically assumed to be 20 to 30 years. The LCOE for a coal plant with CCS is a useful screening method to determine the overall financial viability of the plant given assumptions on capital costs, fuel costs, and capacity factor. In addition to LCOE, the short-term marginal cost of production is an important metric for determining plant unit commitment and dispatch. This chapter explores the intersection of LCOE, marginal cost of production, and dynamic operations of the plant.

6.1. Baseline LCOE analysis

The conventional way to establish a baseline LCOE for coal-fired power plants is to determine the total plant cost for a conventional coal-fired plant on a \$/kW basis and then determine the cost of a similar sized plant with carbon capture and sequestration. The increase in total overnight cost (TOC) for a noncapture and a capture supercritical 550 MW_{net} plant is estimated to be \$2,024/kW and \$3,570/kW, respectively⁵⁰. The LCOE is \$75/MWh for the noncapture plant and \$135/MWh for the capture plant, including capital, fuel, and O&M. The 80 percent cost increase is due to the decrease in efficiency of the plant, which requires larger plant equipment and a higher fuel burn rate to achieve the same nominal power output in addition to added capital cost of the carbon capture unit. The carbon capture unit accounts for 30 percent of the total plant cost (TPC) of the entire coal plant.

6.2. Marginal cost analysis

The marginal cost (MC) of production is the variable costs to produce power. The MC does not include the recovery of capital and investment costs. The marginal cost is a function of the fuel price (FC), plant efficiency (η), the variable O&M cost (OM), and the emission rate (ER) of the plant and the carbon price (CP) if applicable. If the plant employs CCS, the capture rate is factored in as an emission reduction. The MC equation is shown in Equation 1.1 and Equation 6.2 for a plant without and with carbon capture, respectively.

⁴⁸ IEA. Cost and Performance of Carbon Dioxide Capture from Power Generation.

⁴⁹ NETL Cost and Performance Baseline for Fossil Energy Plants. Volume 1.

⁵⁰ Ibid.

$$MC = \frac{FC}{\eta} + OM + \frac{ER}{\eta} \cdot CP \quad \text{Eq. 6.1}$$

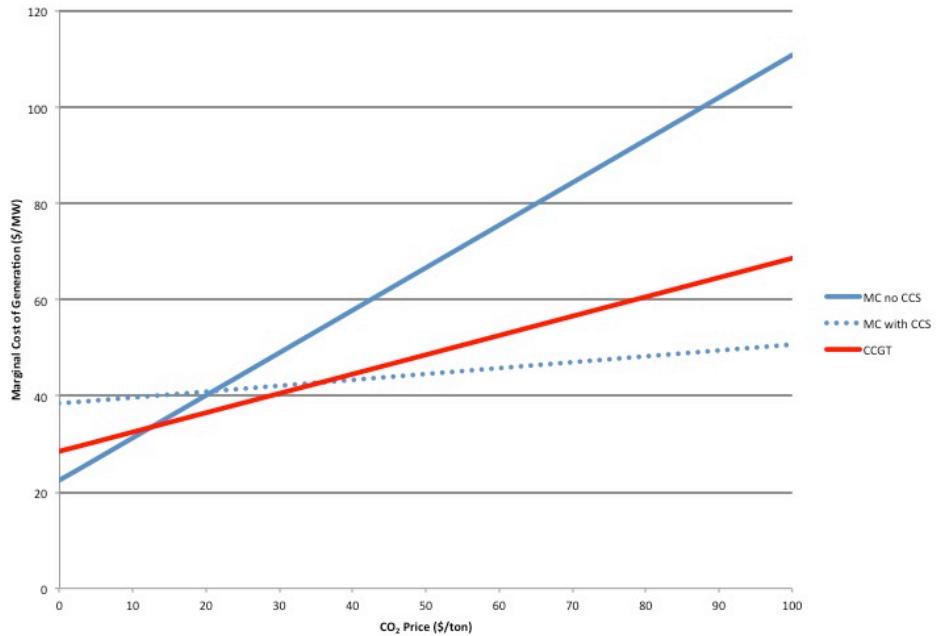
$$MC = \frac{FC}{\eta} + OM + \frac{ER \cdot (1 - CR)}{\eta} \cdot CP \quad \text{Eq. 6.2}$$

The marginal cost curves for a supercritical plant with and without capture are in Figure 6.1. The assumptions used for are shown in Table 6.1. The price assumed for fuel costs are \$2.00/MMBtu for coal and \$4.00/MMBtu for natural gas

Table 6.1 Costs and performance characteristics for power plants

	SC PC no capture	SC PC capture	CCGT
Fuel Cost (\$/MW _{h-thermal})	6.86	6.86	13.65
efficiency (% HHV)	39.3	28.4	50.2
OM (\$/MW _e)	5	14.3	1.3
ER (ton CO ₂ /MW _{th})	0.348	0.348	0.202
CR	0	0.9	0

Figure 6.1 Marginal cost curves for different CO₂ prices

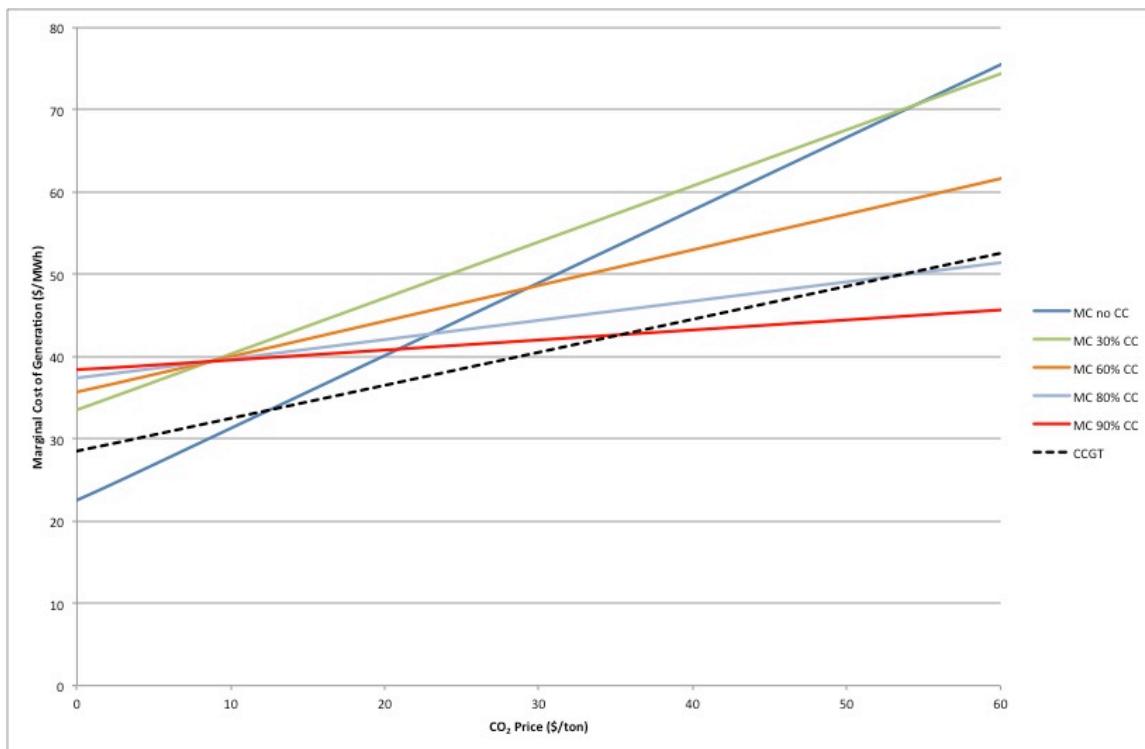


For any given CO₂ price, the lowest curve in Figure 6.1 is the lowest marginal generating unit and it is dispatched first in the merit order. The marginal cost curves for the capture and noncapture plant intersect

at a CO₂ price of approximately \$20/ton. At a CO₂ price below this point, the noncapture plant is least expensive plant to operate and is dispatched first in the merit order. At prices above this level, the capture plant is less expensive to operate and is dispatched before the noncapture plant. The CCGT plant is shown as a reference point. At the natural gas price of \$4.00/MMBtu, the CCGT unit is dispatched before the supercritical capture plant without capture until a CO₂ price of approximately \$15/ton. The capture plant is dispatched before the CCGT plant at a CO₂ price above of \$35/ton.

As shown from the process model, the carbon capture unit is able to ramp up and down from 90 percent capture down to 30 percent capture. This has the effect of improving system efficiency by reducing the steam and power requirement of the capture unit. The efficiency change was assumed to be linear with a change in capture ratio⁵¹. From Figure 6.2, the marginal cost of generation is shown for the various capture levels.

Figure 6.2 Marginal cost curves for different capture levels



⁵¹ Chalmers, et al. (2009). Flexible Operation of Coal Fired Power Plants with Postcombustion Capture of Carbon Dioxide. *Journal of Environmental Engineering* **135** (6); 449-458.

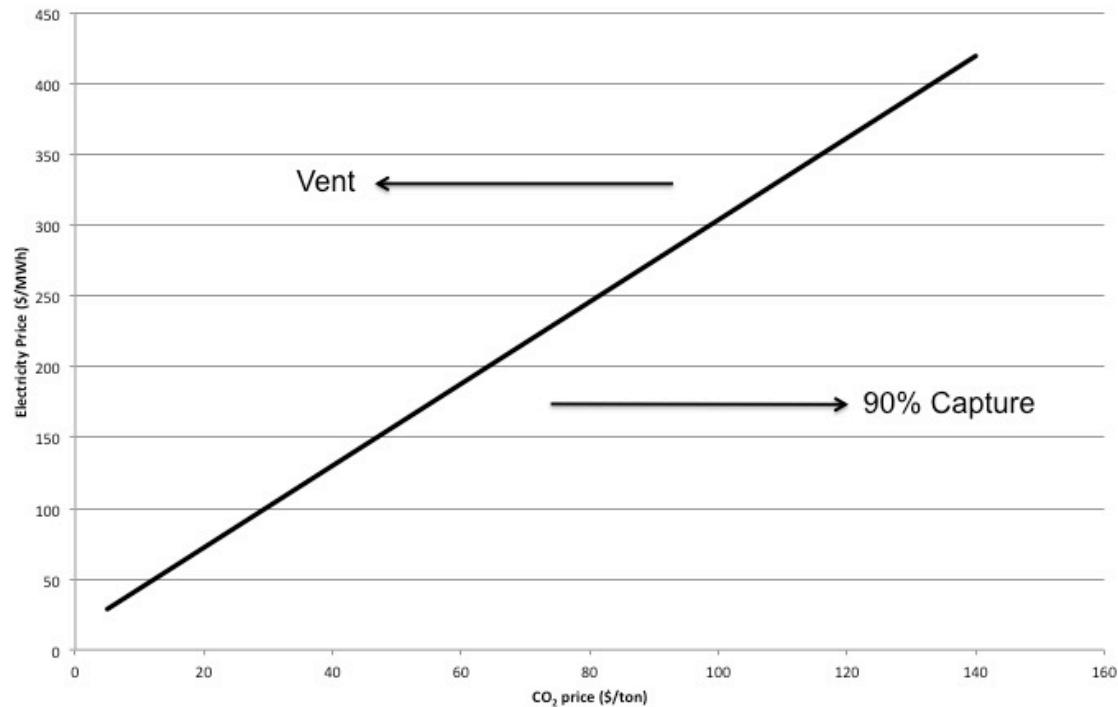
This figure shows that partial capture at levels below the baseline of 90 percent is only economically justified at CO₂ prices below \$10/ton. Below this value, the 90 percent full capture operation is the least expensive generation unit. Therefore, it is unlikely in any carbon price scenario where venting of CO₂ via means of flue gas bypass or reduced L/G ratio would be justifiable using CO₂ price as the lone metric for economic dispatch.

An increase in CO₂ venting by a coal-fired power plant may be justified at lower CO₂ to electricity price ratios. As the electricity prices increase, the plant with flexible capture has the potential to increase revenues during peak demand by supplying more power to the grid. The revenue neutral curve is calculated by comparing the increased revenues from supplying more power to the grid against the increased costs of emitting more CO₂. In Eq. 6.1, MC is the marginal cost, PO is the power output, FC is full capture, and PC is partial capture.

$$\text{Revenue Neutral Curve} = \frac{\text{MC}_{\text{FC}} \cdot \text{PO}_{\text{FC}} - \text{MC}_{\text{PC}} \cdot \text{PO}_{\text{PC}}}{\text{PO}_{\text{FC}} - \text{PO}_{\text{PC}}} \quad \text{Eq. 1.3}$$

At \$50/ton price of CO₂, the marginal cost of generation is \$44/MWh and \$57/MWh for full capture and 60 percent capture respectively. The power output for the full capture is the baseline output of 500 MW and the power output for the partial capture of 60 percent is 563 MW. At this CO₂ price, venting is economically justified above an electricity price of \$159/MWh. For the assumed noncapture and carbon capture system, the electricity prices needed to justify venting CO₂ are shown in Figure 6.3.

Figure 6.3 Required electricity prices for venting



The area to the left of the curve is a regime where venting is economically and to the right of the curve full capture is the most revenue enhancing. Because of the linearity assumed for the efficiency, this curve is true for all capture levels below 90 percent. The power output desired by the plant would have to match the demands of the grid to determine the required power output and thus the necessary capture rate. CCS will require CO₂ prices above \$80/ton. To justify venting at this CO₂ price, the electricity prices have to exceed \$250/MWh. For the ERCOT system in the years 2007 through 2010, the electricity prices exceeded the threshold price of \$250/MWh for venting approximately 1 percent of the time⁵², making a venting strategy unlikely to significantly increase revenues given the short duration available to deploy the strategy unless peak prices reach levels significantly above the required electricity price. The effect of CO₂ prices of \$80/ton will increase electricity prices, but is likely to significantly increase the economical venting duration.

If a carbon price is not the main factor driving carbon capture but a performance standard such as the proposed NSPS for CO₂ that enables emissions averaging over the plant lifetime, then operational flexibility may be able to enhance revenue. Given the proposed NSPS of a 1,000 lb/MWh average over

⁵² Potomac Economics. (2011). 2010 State of the Market Report for the ERCOT Wholesale Markets.

30 years, a supercritical coal plant with a noncapture baseline emissions rate of approximately 1,8000 lb/MWh needs to average a capture rate of approximately 45 percent over the 30-year lifetime of the plant. This creates important design considerations of the plant were built today with carbon capture. This creates the potential for three design points for the capture system. The first is to install 45 percent capture over the entire 30-year lifetime of the plant. This plant would not have the flexibility to increase power production during times of high electricity prices. The second option would be to install a capture system after a certain number of years and run the capture rate by the required amount above 45 percent to meet the performance standard. For example a plant that installs carbon capture after 10 years of operation would be required to capture 66 percent of the remaining emissions. Once again this plant would not have the flexibility to increase power production with the capture plant installed. The third option is to install a capture unit capable of rates over 45 percent and operate the plant flexibly while meeting the binding constraint of the overall emissions performance standard. To evaluate the tradeoffs for each of these options, a forecast of the electricity prices and the fuel price spreads of coal and natural gas would have to be determined over the lifetime of the plant to evaluate the capital expenditure and maximize the net present value of the entire facility. The decision space is complicated by the various options of capture levels and initial year of operation of the capture plant. The additional factors such as the potential for a carbon price or other regulatory scheme uncertainty create the potential for misallocation of resources.

6.3. Stream turbine cost analysis

For a plant to be able to increase power production due to reduced capture rates, the steam turbine has to be oversized to accommodate the increased flow through the LP turbine. If the capture plant withdraws 45 percent of the main steam flow for solvent regeneration, then the LP steam turbine can be sized for the 55 percent flow when the capture plant is operating or for 100 percent flow when the capture plant is nonoperational. If the smaller turbine design is chosen, then the plant can only operate at 65 percent fuel burn rate when the capture unit is off. If the larger turbine design is chosen, then maximum fuel burn rate can be achieved at all times. This will require larger sizing of other components such as the steam turbine condenser and the cooling water system because of the increased load on these units. The tradeoff occurs with the increased capital expenditure of the larger turbine and the projected decrease in potential revenues if the turbine is undersized. For the larger turbine option on a 500 MW coal fired power plant, the increase in power output is 190 MW. All other plant units are designed for maximum fuel burn rate.

To perform this analysis, assumptions have to be made on the availability of the capture plant and the projected capacity factor and the operating factor of the coal plant. If the availability of the capture plant

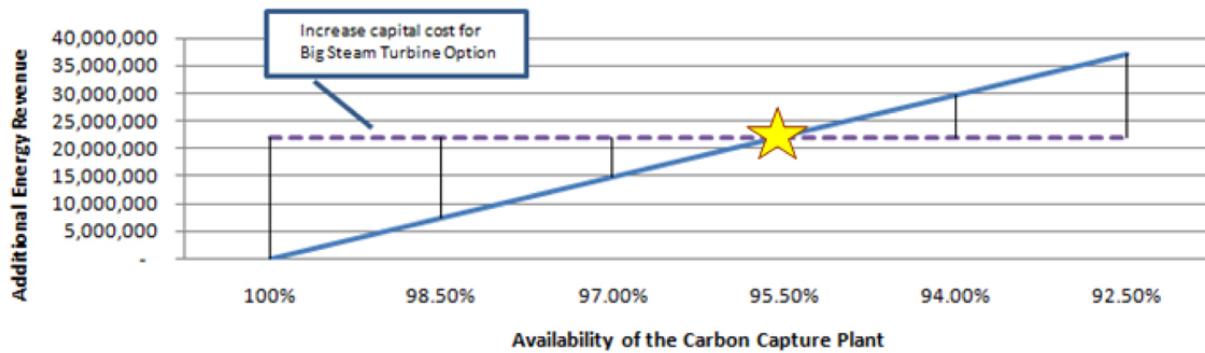
is below a certain threshold, then the plant will utilize the oversized portion of the steam turbine for longer durations and be able to sell more power to the grid. This analysis does not incorporate a CO₂ price because all current coal plants with carbon capture do not currently face this additional cost. With a CO₂ price, it was shown in Figure 6.3 that there is little economic incentive to operate at partial capture rates or with the capture unit turned off, except at high electricity to CO₂ price ratios.

A simplified analysis is performed assuming that the plant is running at 100 percent capacity during all operating times and the capture unit only operates in on or off modes. This limits the design space to the smaller LP turbine or the oversized turbine. A recent FEED study on the proposed Tenaska Trailblazer Plant in Texas was performed and made public by the Global Carbon Capture and Storage Institute⁵³. For this specific project, the estimated cost difference of the steam turbine options was \$22 million, with \$2 million increase for the size of the turbine and the remaining \$20 million for the increase in condenser size and auxiliary cooling water equipment. While the size difference of the turbines was assumed to be 35 percent, the dollar per kilowatt price was only 10 percent less, a scaling factor of 0.2, which is outside of the normal industry range 0.6 to 0.8. This is largely due to the unconventional configuration of the smaller steam turbine option.

To recover this additional capital cost, the plant would have to operate in peak power mode (i.e., capture plant turned off) 4.5 percent of the time as indicated by the starred point. The results are shown in Figure 6.4. The dashed line indicates the capital expenditure for the large turbine option.

⁵³ Tenaska Trailblazer Partners, LLC. Steam Turbine Generator Configuration and the Impacts of Carbon Capture System Availability.

Figure 6.4 Cost benefit analysis of steam turbine configurations⁵⁴



This analysis does not take into account the difference in electricity prices throughout the day. With the capture unit cycling to take advantage of higher electricity prices, the assumed capacity factor of the capture unit could be driven below the threshold value of 95.5 percent since there is not currently a price on carbon and only a long term performance standard. The required 4.5 percent down time is not unreasonable for a plant operating flexibly to meet intermediate and peak power demand. Peak plants typically operate 10 to 15 percent of the time⁵⁵, so a flexible capture plant could help fill this role. If peak electricity prices are high enough, then it is possible for down times below 4.5 percent to be economical. Other factors such as the first-of-a-kind deployment of the technology could drive this capacity factor level lower in the early lifetime of the plant and speed up the cost recover of the additional capital expenditure. The uncertainty associated with this type of plant and the ability to increase plant output make the flexibility of the larger turbine option attractive coal plants with CCS.

6.4. Stripper bypass with solvent storage cost analysis

Another option to increase power production without increasing the capture rate is to deploy a stripper bypass system with solvent storage. The configuration for the solvent storage system is shown in Figure 4.7. This system bypasses the stripper/compressor system and sends the rich amine to a solvent storage tank while releasing additional lean solvent. During solvent storage, the steam sent to the stripper during normal operation is routed to the LP steam turbine for increased power production. The capture rate remains nominally 90 percent because the lean amine solvent is still sent to the absorber for continuous capture. When the rich amine solvent is released from the storage tanks, the reboiler has to be able to handle the normal flow rate of the rich amine plus that rate released from the solvent storage tank. The

⁵⁴ Ibid

⁵⁵ Cordado, M. (2008). Understanding Base Load Power: What it is and why it matters.

excess lean solvent is stored in the lean solvent storage tanks. This system allows a shift in the energy consumption of the capture system from periods of peak demand and high electricity prices to periods of low demand and depressed electricity prices.

To deploy the solvent storage system, all of the process equipment downstream of the absorber has to be oversized to account for the increased solvent. This includes all heat exchangers including the addition of lean and rich solvent storage tanks, the lean amine cooler and cross-heat exchanger, the oversized stripper and reboiler, oversizing of the steam turbine, and the CO₂ compression system. Additional amine solvent is recirculated throughout the system. The increased cost of the process equipment and amine solvent is dependent on the storage duration and the solvent rate of release. For a base case base case normalized regeneration capacity of 100 and a stripper design mode of 85 percent of base capacity, the stripper is oversized by 17 percent. For a one-hour solvent storage time at this overdesign capacity, it would take almost 12 hours to regenerate the stored rich solvent while the plant is operating at full load. The evaluation of the stripper and other process equipment is highly dependent on the estimated time operating away from the base case capacity. If the plant is forecasted to operate in base case the majority of the time, then the optimal design point will be near the base case capacity. The tradeoff of increased capital costs and more flexible operation is similar to that of the oversized steam turbine. The amount of extra amine solvent is linearly dependent on the time of solvent storage. From the normalized base case of 100, each additional hour of solvent storage will require a 100 percent increase in the amount of solvent for the system.

The capital costs of the system are dependent on the duration of solvent storage and the time required for generation. A system that stores solvent for one hour and has a regeneration cycle of one day (23 hours to regenerate) has a lower capital cost than a system that stores solvent for one hour and regenerates over half a day (11 hours to regenerate). The increase in capital costs of this example system will come from the increase in size of all equipment except for the storage tanks.

The additional capital costs increase scales by an exponential factor of 0.4 for every additional hour of solvent storage with a daily regeneration cycle⁵⁶. The baseline capital cost for a post-combustion MEA system is \$852/kW⁵⁷. The complete power plant with carbon capture has a total overnight cost of \$1,963 million dollars or \$3,570/kW. For a system with one hour of solvent storage and a 23-hour regeneration

⁵⁶ Patiño-Echeverri, D and Hoppock, D. (2012) Reducing the Energy Penalty Costs of Postcombustion CCS System with Amine-Storage. *Environmental Science & Technology* **46** (2); 1243-1252.

⁵⁷ NETL Baseline Report Volume 1

cycle, the increase in capital cost for the capture system is \$124/kW or a total of \$68.3 million dollars, an increase of 3 percent above the baseline capture case. The increase in capital costs for increasing levels of solvent storage and LCOE is shown in Table 6.2.

Table 6.2 Capital costs of solvent storage

	Solvent Storage (hours)				
	Baseline	1	2	3	4
Total Capture Level Costs	468,600	536,869	554,139	572,451	591,960
Total Capture Level Costs (\$/kW)	852	976	1,016	1,045	1,068
Total Overnight Costs (\$1000)	1,963,000	2,031,269	2,048,539	2,066,851	2,086,360
Total Overnight Costs (\$/kW)	3,570	3,694	3,734	3,763	3,786
LCOE (\$/MWh)	135.20	135.68	136.65	138.10	140.03

For the reference 550 MW_{net} plant, the initial charge of MEA solvent is 2.06 million pounds. At a cost of \$1.13/lbs for solvent, this equals \$2.32 million dollars increase to the initial charge of MEA. For each additional hour of solvent storage this charge has to increase by the corresponding solvent storage duration. The incremental capital and amine costs have a small effect on the overall LCOE of the system. For a system with four hours of solvent storage, the total LCOE increases by 3.5 percent. The LCOE analysis of the solvent storage system represents an initial screening method for the solvent storage system.

To determine whether solvent storage can increase operating profits over the base case, a lifetime discounted cash flow analysis would be necessary. This would require forecasting the electricity prices and CO₂ prices over the entire operating lifetime of the plant. This analysis would require a economic dispatch/unit commitment model to optimize the operating points of the solvent storage system (i.e. solvent storage or regeneration mode) for each of the electricity prices and demand levels for the system. A preliminary analysis based on the ERCOT system found that profit is maximized for solvent storage for just 22.5 minutes⁵⁸. This is close to the design point of the baseline plant and would not require considerable overdesign of the capture system to accommodate this level of storage. For this short duration, the thermal inertia in the reboiler is likely to keep temperatures near the operating point, creating smaller lag times to return to set point lean loadings.

⁵⁸ Cohen, et al. (2011).

The value derived from the ERCOT study is highly dependent on the durations of the peak demand periods and the prices along with the corresponding trough periods. If wind accounts for an increasing share of the generation mix, electricity prices fluctuate more than a system without wind. The variability of the output of each plant and the fluctuating prices is shown in Figure 2.5. This could have implications on the future viability of solvent storage as some state renewable portfolio standards aim to achieve 20 percent renewables by 2020.

7. Conclusions and future work

The objective of this work is to evaluate the technical capability of a post-combustion carbon capture unit to operate in two regimes: load following and peak power. In addition, this work conducts an economic evaluation of these different operation modes for an integrated carbon capture and storage plant. The two major categories of operation that should be assessed are the dynamic effects of adding CCS to a coal-fired power plant and the potential for flexible operation to accelerate the deployment of CCS.

7.1. Conclusions

Integration of a carbon capture unit with coal -fired power plants can be successfully operated dynamically to meet the current load following requirements of coal-fired power plants while maintaining 90 percent capture rates.

While performing load following, coal-fired power plants typically employ ramp rates of 2 to 4 percent per minute. The dynamic simulation studies performed on the post-combustion MEA capture system demonstrate that the capture plant can achieve these maximum ramp rates with only slight disturbances to the set point capture rate of 90 percent. When these maximum ramp rates are simulated, the capture plant returns to the steady state set point at a rate of approximately 1 percent per minute. The capture rate temporarily deviates from the set point by 3.3 absolute percent per 10 percent change in flue gas flow rate. These rates and deviations do not hinder the ability of the integrated coal-fired power plant to perform load following.

If a plant must maintain a nominal capture rate emission minimum (such as never dropping below 90 percent capture), different operational strategies exist. The capture plant has the capability to capture above the nominal set point of 90 percent capture. If the plant is ramping up, the capture plant can “overcapture” to account for the expected increase in flue gas flow to prevent the rate from never dropping below 90 percent.

Integration of the power and capture plant creates a wider range of power outputs than a plant without carbon capture.

With an integrated capture system on a 500 MW_{net}, the power output of the plant can increase to 690 MW or decrease to 100 MW. This contrasts the typical supercritical power plant that can

operate at only 5 percent above nameplate capacity (525 MW) and down to 30 percent of nameplate capacity (150 MW). This increased power output flexibility may aid the economics of a coal-fired power plant, although the correct prices signals must exist. By increasing the power output during times of peak demand, plants can sell more electricity at the higher peak prices. This has to be weighed against the increase cost of emissions if there is a CO₂ price. At ratios of CO₂ price (\$/ton) to electricity price (\$/MWh) below approximately 3.3, for a supercritical coal plant, venting is economical. If the CO₂ price is \$80/ton, then the required electricity price is in excess of \$250/MWh before venting operations increase revenues, which occurs only 1 percent of the time in the ERCOT system. This limits the viability of venting strategy to increase revenues even at the relatively low cost of oversizing the steam turbine. If emissions performance standards are required for CO₂, this may further limit the ability to operate in peak power modes. The stringency and the averaging of the emissions profile over the life of the plant are the key drivers in the current NSPS for CO₂ and a longer-term operation and planning model over the lifetime is required to determine the viability of flexibility.

The lower level of power output achievable for system with carbon capture can help avoid costly shutdowns and start-ups. This may be beneficial to coal plants in systems with high penetration of renewables that force coal plants to shutdown more often. If the coal plant can cycle at lower output, this can prevent the coal plant from shutting down during times of extreme low demand. Operation at lower load does not require the extra fuel cost and penalty of not selling power to the grid during the typical shutdown and start-up cycle. Plants will also reduce wear on the boiler pressure parts and the increased expense of maintenance if shutdown can be avoided.

Operation of the capture plant can be used to meet peak power using a variety of methods.

To meet peak power demand, the capture plant can increase the emission rate. There are three control mechanisms available to increase the power output of the integrated power plant. The capture system can be turned off, which increases the power output of the plant to that of one without carbon capture. Another strategy is to reduce the solvent flow rate to flue gas flow rate ratio (L/G). By decreasing the solvent flow rate, the capture rate decreases by a proportional amount and total power output increases by a proportional amount. For the 30 percent decrease in the capture rate simulated, the steam required for the reboiler decreases by approximately 35 percent increasing steam flow through the LP turbine and power output of the integrated plant. The third control mechanism is to decrease the reboiler temperature set point. By decreasing the

temperature set point, less steam is required for the reboiler. This causes the lean solvent loading to increase and a subsequent decrease in the capture rate. A 5 percent reduction in reboiler temperature causes the steam required to the reboiler to decrease by 32 percent and the lean loading to increase to the point where 60 percent of the CO₂ is captured. While these last two control strategies are analogous, the reboiler temperature change has a faster response time for total steam demand and a better emissions profile than the capture rate change. The feasibility of these strategies depends on the environmental requirements or the costs faced by higher emissions.

Operation of the CCS plant determines the economic viability of designing a system with increased low pressure (LP) turbine sizing.

The availability of the capture system is a key driver in determining the sizing of the LP turbine. While the power plant is operational, if the capture plant is not in operation for over 5 percent of the time then an oversized turbine designed for full flow increases revenues of the integrated plant. This value is highly system dependent and depends not only on the duration of peak electricity prices but the value of these prices. At higher peak prices the capture plant may be able to operate a larger percent of the time and still make oversizing of the steam turbine economical. For a first-of-a-kind CCS plant at commercial scale, the operational uncertainty of the capture system may warrant an oversized LP turbine. In addition, if the price signals of electricity and CO₂ or the environmental performance standards allow for a variable emissions profile the plant may operate in peak power mode for greater than 5 percent of the time. Peak power is generated for approximately 10 to 15 of the time, but the required ratio of CO₂ to electricity prices for CCS occurs on a much more limited basis. Integrated CCS plants may be able to enhance revenues and operating profits by producing peak power during these times although this is highly system dependent.

Solvent storage is untenable given the current state of knowledge of integrated CCS systems and electricity prices

The operational complexity increases with solvent storage that strays significantly from current coal-fired power plant operation. Solvent storage system increases the overall capital and operating costs of the system when early stage deployment of CCS has focused on driving costs down. The lack of high enough electricity price spreads during peak and trough do not support

the additional capital expenditure of long duration solvent storage. There may be potential for short duration (less than 30 minutes) as this will not increase the operational complexity of the system too greatly from the flexible operation required of current coal-fired power plants. The uncertainty of future natural gas and coal prices, and the corresponding changes to dispatch order, create too high of a risk environment for the additional capital cost. These uncertainties diminish the ability to forecast the recover of incremental costs.

7.2. Future work

While this study represents an important step in understanding the dynamic response of a post-combustion capture system and the range of process configurations available, there remains work to be done. The results of the dynamic simulation represent an idealized standalone system. A fully developed and integrated coal plant, capture system, and CO₂ compression train would better understand the dynamics of the overall plant. The interactions of the boiler, emissions control systems, and steam turbine with the capture plant would be able to create a global control structure to minimize system costs and maximize profits. The effects on the overall electricity system with flexible carbon capture are an active area of research that has yet to integrate to dynamics of the capture system with the rest of the coal plant. One of the greatest risks with flexible carbon capture is the increase in capital costs for an uncertain return on capital. Full system models can determine expected profitability of these systems. Work on control strategies for technologies with faster ramping rates, such CCGTs with carbon capture, can be explored, especially if current natural gas prices remain low. Models for novel solvent systems and the dynamics of these systems can be explored to determine the benefits of new systems beyond energy penalty and LCOE analyses.

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