Using Auxiliary Gas Power for CCS Energy Needs in Retrofitted Coal Power Plants

by

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ABSTRACT

Post-combustion capture retrofits are expected to a near-term option for mitigating CO_2 emissions from existing coal-fired power plants. Much of the literature proposes using power from the existing coal plant and thermal integration of its supercritical steam cycle with the stripper reboiler to supply the energy needed for solvent regeneration and CO_2 compression. This study finds that using an auxiliary natural gas turbine plant to meet the energetic demands of carbon capture and compression may make retrofits more attractive compared to using thermal integration in some circumstances. Natural gas auxiliary plants increase the power output of the base plant and reduce technological risk associated with CCS, but require favorable natural gas prices and regional electricity demand for excess electricity to make using an auxiliary plant more desirable. Three different auxiliary plant technologies were compared to integration for 90% capture from an existing, 500 MW supercritical coal plant. CO_2 capture and compression is simulated using Aspen Plus and a monoethylamine (MEA) absorption process. Thermoflow software is used to simulate three gas plant technologies. The three technologies assessed are the gas turbine (GT) with heat recovery steam generator (HRSG), gas turbine with HRSG and back pressure steam turbine, and natural gas boiler with back pressure steam turbine. The capital cost of the MEA unit is estimated using the Aspen Icarus Process Evaluator, and the capital cost of the external GT plants are estimated using the Thermoflow Plant Engineering and Cost Estimator. The gas turbine options are found to lead to electricity costs similar to integration, but their performance is highly sensitive to the price of natural gas and the economic impact of integration. Using a GT with a HRSG only has a lower capital cost but generates less excess electricity than the GT with HRSG and back pressure steam turbine. In order to generate enough steam for the reboiler, a significant amount of excess power was produced using both gas turbine configurations. This excess power could be attractive for coal plants located in regions with increasing electricity demand. An alternate capture plant scenario where a greater demand for power exists relative to steam is also considered. The economics of using auxiliary plant power improve slightly under this alternate energy profile scenario, but the most important factors affecting desirability of the auxiliary plant retrofit remain the cost of natural gas, the full cost of integration, and the potential for sale of excess electricity.

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AEO *Annual Energy Outlook*
Btu British thermal unit
CCGT Combined cycle gas turbine
CCS Carbon capture and storage
CEPCI *Chemical Engineering* Plant Cost Index
CO_2 Carbon dioxide
COE Cost of electricity
DOE U.S. Department of Energy
EIA Energy Information Administration
EPRI Electric Power Research Institute
FGD Flue gas desulfurization
GJ Gigajoule
GT Gas turbine
GW Gigawatt
HHV Higher heating value
HRSG Heat recovery steam generator
IGCC Integrated gasification combined cycle
IP Intermediate pressure
kW Kilowatt
kWh Kilowatt-hour
LP Low pressure
LHV Lower heating value
MEA Monoethylamine
MMBtu Million British thermal units
MPa Megapascal
MW Megawatt
NETL National Energy Technology Laboratory
NSR New Source Review
NGCC Natural gas combined cycle
NO_X Nitrogen oxide
O&M Operating and maintenance
OECD Organisation for Economic Co-operation and Development
PC Pulverized coal
PCC Post-combustion capture
PEACE Plant Engineering and Cost Estimator
ppmv Parts per million by volume
SCR Selective catalytic reducer
SO_2 Sulfur dioxide
T&S Transportation and storage
TPC Total Plant Cost
USCPC Ultra-supercritical pulverized coal
VFD Variable-frequency drive

1 INTRODUCTION

Carbon capture and sequestration (CCS) encompasses a group of technologies that address the problem of climate change by reducing manmade carbon dioxide (CO_2) emissions from large stationary sources such as fossil fuel-based power generation. Coal plants produce 49% of the electricity used annually in the United States (1). Coal represents a significant portion of annual CO_2 emissions; conventional pulverized coal plants generate approximately one-third of U.S. CO_2 emissions (2). In addition, CCS is attractive for coal-fired plants relative to natural gas or petroleum-based firing due to higher carbon emissions per kWh of electricity from coal. Major demonstration projects are currently underway worldwide that are designed to capture up to 90% of the CO_2 emissions from coal-fired power plants (3). In most CCS technologies, the CO_2 produced from combustion or gasification is chemically captured, separated into a CO_2 stream, and either used commercially or deposited in a geological formation capable of long-term storage. As fossil-fuel use will be a part of the near-term energy picture, coal plants will need technologies that mitigate greenhouse gas emissions while still generating affordable electricity if climate change is to be addressed.

The need for CCS for existing coal-fired power plants becomes more striking when taking into account global electricity generation trends. Electricity usage worldwide is expected to increase by 44% between 2006 and 2030, and coal consumption is estimated to increase by 49% to meet much of this demand. The largest growth in electricity demand is expected in non-OECD countries, particularly in China and India (Figure 1-1). Together the two countries are projected to represent 28% of global electricity demand, up from 19% today, exceeding the 17% share of the US in 2030. To China's 350 GW of coal-fired electricity production as of early 2006, another 600 GW of capacity is expected to be added by 2030 (4). By comparison, the U.S. coal-fired fleet capacity is currently less than 350 GW (5). Few expect China or India to slow its rate of building new coal plants as the countries have large reserves of coal and robust economic growth will require an increased energy supply. Global CO_2 emissions reduction goals will require non-OECD countries to become partners in addressing coal plant emissions in the near-term. Once CCS technologies are demonstrated to be a viable tool for combating climate change, the use of

CCS becomes integral to climate change policies intended to produce substantial near-term CO_2 emissions reductions.

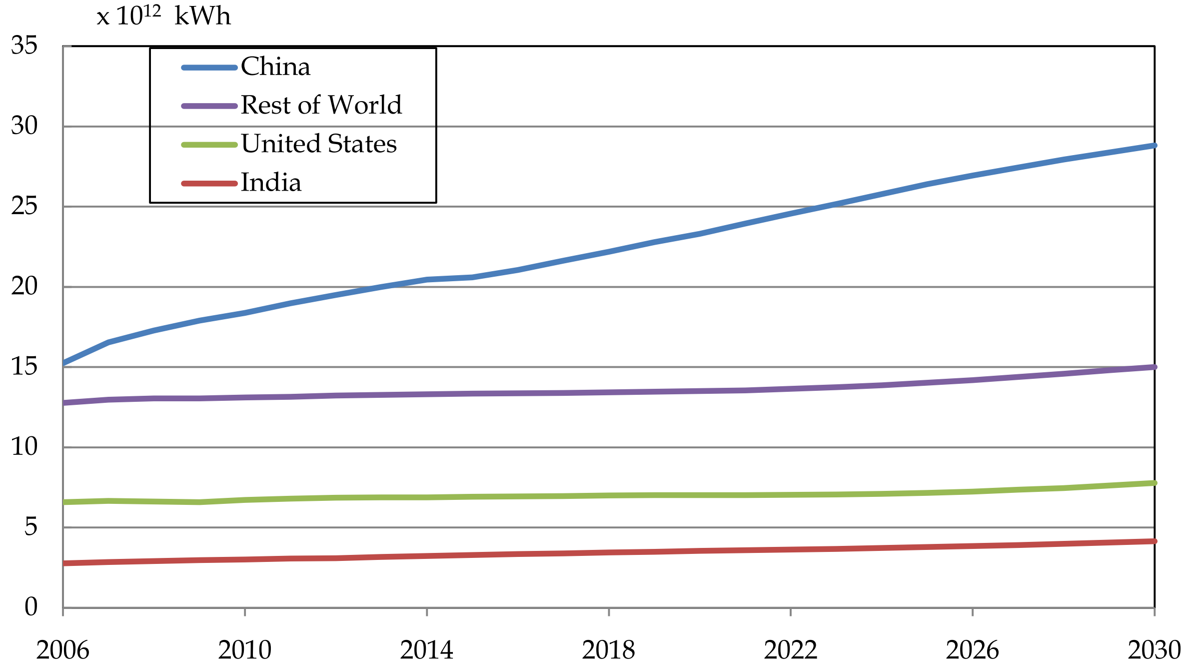

Figure 1-1. EIA Projected Electricity Demand Increase through 2030 by Region (4).

A picture of the U.S. coal fleet today is useful in understanding both the motivation behind prolonging their use and how plants may be suited to various types of CCS technologies. The total capacity of coal-fired plants in the United States is 336 GW (5). 71% of the total capacity comes from generating units that have a minimum capacity of 300 MW (2). The average coal plant is over 35 years old, with most being between 20 and 55 years old. The older plants tend to have lower capacities than newer ones. Of the generating units that are less than 35 years old, the average capacity is near 550 MW. Many of these plants could potentially remain in operation with minor improvements for an additional 30 years (6).

Most coal-fired plants in operation utilize pulverized coal combustion boiler technology. Plants are generally classified according to the conditions of the boiler. Most plants in the U.S. have subcritical boilers that operate below the supercritical point of water, or below 3200 psi. These plants have on average an efficiency of 32% (HHV) and tend to characterize older plants. A minority of plants use supercritical boilers, with even fewer in the ultra-supercritical category, that operate at higher temperatures and above the supercritical point of water. The higher steam cycle operating conditions contribute to efficiencies of up to 42% in supercritical plants, with even higher values reported for ultra-supercritical plants. However, overall plant efficiency is dependent upon multiple factors, including coal type, steam conditions, size of plant, and elevation of site. In addition to the cost advantage, higher efficiency plants have the environmental benefit of lower CO_2 emissions for a given amount of electricity production. A relatively newer technology, supercritical plants account for 75 GW of the U.S. coal-fired plant capacity, or roughly 23% (2).

Despite the lower efficiency and higher emissions of older, subcritical plants, their continued use appears probable from an economical and political standpoint. For older plants, the capital cost has already been paid off, making them highly profitable to operate. Due to the low cost of coal, they have favorable dispatch rates compared to newer plants. Even if government regulations force a high cost for carbon emissions, retrofitting or rebuilding existing subcritical plants is attractive because the location has already been secured, permits have been obtained, and an infrastructure exists around the plant. At the same time, political opposition to closing existing plants will make it to difficult to substantially alter the energy picture in the foreseeable future. The Department of Energy (DOE) projects in its *Annual Energy Outlook 2009* (AEO) only 2.3 GW of coal plant capacity to be retired in the next twenty years, or 0.7% of current capacity. As a result of regulatory uncertainty, AEO expects little capacity to be added to the existing fleet in the next two decades. Under the current regulatory environment, the AEO predicts only 24.8 GW of new coal-fired capacity by 2030, or a 7% increase from 2007; interestingly, the same report foresees an 18% increase in coal-fired electricity generation in the same time period (1). One way this scenario could feasibly be realized is if existing plants continue to be operated for the next twenty years and are upgraded with efficiency-improving technologies.

The MIT Energy Initiative convened a symposium entitled “Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions” on March 23, 2009 to discuss options for reducing CO_2 emissions from existing coal plants. The participants included representatives of utilities, research institutions, government agencies, public interest groups, and industry. Some of the key findings from the symposium discussion include:

- Substantial CO_2 emissions reductions to address climate change cannot be achieved without addressing emissions from existing coal plants in the U.S. and China.
- Post-combustion capture and efficiency improvements are the two best near-term options for mitigating emissions in the short term.
- A successful CO_2 mitigation policy strategy should include multiple technological alternatives that may be applied to plants of varying sizes, types, and locations.
- Government research programs should redistribute research funds and spend more resources on technologies applicable to existing plants (e.g. PCC retrofits) relative to those for new plants.

As power plant operators begin to understand the technological and economical impacts of applying PCC to existing power plants, a number of unattractive possibilities emerge about the risk and profit loss they may have to undertake. The changes to the existing power plant in order to power the post-combustion capture unit may involve costly design modifications and downtime needed for reengineering. Furthermore, power output may be reduced substantially due to the energy required for CO_2 capture, hurting the operators' bottom line. The path forward for retrofits may still require substantial research on how the existing coal plant and capture island may be integrated in order to reduce the economic impact felt by the investment in post-combustion capture.

This study explores whether using an auxiliary natural gas plant to meet the energy needs of post-combustion capture retrofits is a feasible option. To this end, the objectives of this analysis include:

- Investigating the technical changes necessary when using the traditional integration approach to PCC retrofits
- Comparing the external plant option to an integration approach
- Understanding the policy implications of the auxiliary natural gas plant approach

The comparison of integration and auxiliary plant approaches involves modeling of the capture unit and different external plant technologies that could potentially supply power to the capture island. The overall analysis includes an assessment of their economic and technical performance as well as the tradeoffs of different auxiliary plant designs and their appropriateness to various plant characteristics and locations.

The CO_2 mitigation options facing utilities, including the current approach to post-combustion capture, are discussed in Chapters 2 and 3. Chapters 4 and 5 present the auxiliary plant technologies and cases considered and outline the methodology used to compare integration with the auxiliary plant option. Chapter 6 provides the result of the study and assesses the sensitivity of those results to fuel and integration costs. Chapter 7 studies the policy implications of the various options. Chapter 8 offers the study’s conclusions and suggestions for future work.

2 Options for Reducing CO_2 Emissions from Existing Coal Plants

In order to continue operation of coal plants in a carbon-constrained environment, a number of solutions have been proposed that would reduce CO_2 emissions at existing plants. Most can be grouped into one of the following categories:

1. *Fuel Replacement*: plants are repowered to fire with biomass or natural gas.
2. *Increased efficiency*: options range from minor boiler and turbine modifications to rebuilding the plant to use next-generation ultra-supercritical or integrated gasification combined cycle (IGCC) technologies.
3. *CCS:* a high percentage of CO_2 emissions can be captured while continuing coal-firing operations.

The following sections discuss each of the options available to an operator of an existing coal plant. In addition to technical considerations, the development of a new regulatory framework for CO_2 emissions will play a large part in helping utilities decide among their various options.

2.1 Fuel Replacement

Repowering coal plants to use natural gas or biomass (i.e. a fuel of non-fossil biological origin) has been suggested to combat CO_2 emissions costs that have become particularly high. Both natural gas and biomass can have lower life-cycle CO_2 emission rates per kWh of electricity than coal, and biomass-fired plants can have negative life-cycle CO_2 emissions with the addition of CCS. The capital costs are low if repowering with biomass because the older generating units can be used. The primary obstacle to widespread biomass use is its potential to have negative social, environmental, and economic impacts worldwide due to the increased demand for biomass feedstocks. Supply issues and high fuel costs of biomass make it more attractive as a co-firing fuel in low amounts. Fuel replacement with natural gas and biomass may have greater potential in older plants which tend to be smaller and consequently less suitable for retrofit and rebuild options (2) (7) (8).

Repowering with natural gas at existing coal-fired plants would allow use of existing permits and infrastructure and, if desired, make installation of more efficient natural gas combined cycle technology more affordable. The economic advantages to repowering with natural gas are subject to the stability of the price of natural gas, which has been a historically volatile market. It is estimated that repowering all coal plants would require a 60% increase in the natural gas supply, which would have a dramatic impact on natural gas prices. Repowering to cogenerate both heat and electricity could increase efficiency to near 80%, more than double the average efficiency of subcritical plants (9). This high efficiency is possible when a large heat "host," on the scale of an oil refinery or chemical plant, is nearby and can use the heat generated. Nonetheless, using NGCC or cogeneration would reduce CO_2 emissions, but a high enough CO_2 emission price would make installation of CCS at gas plants attractive. Natural gas-firing would also require substantial new capital investment compared to an add-on retrofit. Like biomass repowering, the natural gas option holds more potential for older coal plants or other sites where CCS retrofits or rebuilds are not technologically feasible.

2.2 INCREASED EFFICIENCY

Modest-to-major improvements in efficiency can be made with a concomitant investment in engineering and capital. This approach is best suited for low efficiency plants, typically subcritical plants, because the most gain can be realized per dollar invested and other options may not be feasible, e.g. due to a smaller plant size or limited space. Higher efficiencies reduce CO_2 emissions by burning less fuel while producing the same amount of electricity. Older, subcritical plants tend to be designed for lower steam temperatures and pressures, and thus are typically the least efficient of all pulverized coal plants.

Efficiencies can be improved by making a wide range of modifications to the existing plant. Some of the improvements possible include (10) (11):

- Steam turbine modifications (e.g. replacement of nozzles, blades, and seals)
- Boiler modifications
- Control systems to monitor combustion completeness and optimize flowrates

- Higher-efficiency and/or variable-frequency drive (VFD) motors for major equipment
- Pulverizer modifications (e.g. to improve particulate size distribution)
- Cooling tower optimization
- Condenser upgrades (e.g. to improve back pressure)

Modifying the steam cycle and turbines to operate at higher steam temperatures and pressures can increase efficiency by up to 2 percentage points without major capital investment (2). This amount of efficiency gain translates into a roughly 5% CO_2 emissions reduction (10). While effective for modest near-term emission reductions, higher CO_2 prices would necessitate a more significant reduction in emission rates. In addition, a major impediment to making significant improvements is the fear of triggering a New Source Review (NSR) by the Environmental Protection Agency under the *Clean Air Act*. This review process requires that the utility install a number of new and costly emissions controls if emissions are significantly increased. An NSR is required when a utility makes a change in the plant that results in a significant net emissions increase of a pollutant regulated by the Act. Efficiency improvements can bring on an NSR if the modifications increase the plants hours of operation resulting in higher overall emissions.

In a carbon-constrained regulatory environment, in addition to using CCS, using advanced technologies to increase the efficiency of the base plant may be economically justified. This is due to the high parasitic losses from CCS, particularly on subcritical plants—potentially a 40% decrease in net electrical power produced (6). Ultra-supercritical PC (USCPC) and integrated gasification combined cycle (IGCC) technologies show some promise and a few plants have been built, mostly outside the US. USCPC plants use steam conditions of 4350 psia and 1,112°F superheat, yielding efficiencies over 44% (12). Despite the substantial capital investment necessary for USCPC, the cost per kW for an ultra-supercritical boiler rebuild with CCS is close to the cost of a subcritical retrofit (6). Additional research on materials and equipment designs that can accommodate the high temperature and pressure steam cycle will potentially facilitate its broader use. Ultra-supercritical technologies may become a superior option for existing coal-fired plants that cannot add on CCS technologies in the future as the power industry gains more experience with the technology.

Integrated gasification combined cycle (IGCC) plants use coal gasification to produce a gas mixture primarily of CO and H_2, or syngas. From this high-pressure stream, major contaminants are removed. Due to the higher pressure, clean-up is less energy-intensive relative to low-pressure flue gas in traditional PC boilers. The cleaned syngas powers a gas turbine, and additional heat energy from the combustion is captured via a steam cycle, producing additional electricity, giving rise to the “combined cycle” description. IGCC plants typically have efficiencies in the mid-40s, though higher values are foreseeable.

The major challenges from IGCC arise from reliability and availability concerns when operated in a dynamic load environment as opposed to a steady-state level. Much of the research and development efforts have been geared towards resolving operational issues with the gasification block and process integration. In addition, the cost of IGCC has limited diffusion due to its expensiveness relative to using a conventional coal-fired plant.

For some types of plants, efficiency improvements appear to be a practical solution to mitigating emissions, and have the added benefit of higher plant power output that could be used to meet growing electricity demand. In addition, CCS retrofits become more affordable as the base power plant efficiency increases. When CCS is applied to plants with higher efficiencies, there is less CO_2 to capture per kWh, resulting in lower costs. Efficiency improvements could potentially provide an additional return on investment by expanding the plant’s future options for continued operation.

2.3 CCS

In a carbon-constrained regulatory environment, carbon capture and sequestration technologies have the potential for widespread application at new and existing coal plants based on its cost-effectiveness and advanced technological development. The IEA estimates that without CCS, the cost of addressing climate change increases by over 70% through 2050 (13). Decades of research and investment have pushed the technology to the forefront of tools to address climate change, and confidence has built as each phase of CCS has become commercially proven and deployed. The critical next step will require all of the elements of CCS to be demonstrated on a large-scale at commercial power plants.

As the likelihood of some type of carbon price on emissions increases, the power industry must compare the characteristics of their own generating stations to the range of CO_2 capture technologies available. The cost of CO_2 capture is expected to be the largest component of CCS (14). Most CO_2 capture technologies being developed can be classified into one of three broad categories: (1) Oxy-combustion (2) Pre-combustion capture and (3) Post-combustion capture. Oxy-combustion technologies involve burning coal with a pure oxygen stream in order to form mostly CO_2 and water. The water in the combustion product stream is condensed leaving the CO_2 for commercial use or storage. This approach requires energy and capital to produce the pure oxygen stream rather than to separate CO_2 from the flue gas. Because of potentially necessary modifications to the boiler, oxy-combustion may be considered to be somewhere between a retrofit and rebuild (2). Pre-combustion capture processes apply primarily to integrated gasification combined cycle plants that utilize coal gasification to produce synthesis gas. Pre-combustion capture technologies use a water-shift reaction to produce CO_2 and H_2 from the syngas and separate the CO_2 prior to electricity generation. Implementation of this technology is currently constrained by the high cost of building new gasification plants. The final technology, post-combustion capture, is discussed in detail below.

2.3.1 Post-Combustion Capture Description

Post-combustion capture technologies applied to pulverized coal boilers separate low concentration CO_2 from the products of coal combustion. Leading technologies today rely on chemical absorption from solvents such as monoethylamine (MEA). Once the CO_2 is separated from the flue gas, the high purity stream is compressed in preparation for transport via pipeline to a sequestration site. Figure 2-1 gives a diagrammatic representation of the overall post-combustion capture process, and Figure 2-2 illustrates the major components of the CO_2 capture island.

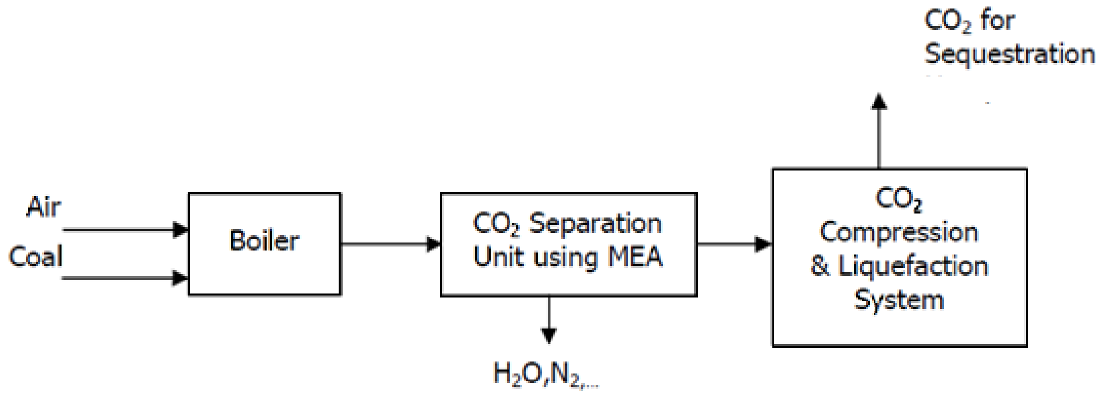

Figure 2-1. Simplified Diagram of Post-Combustion Capture of CO_2 Using MEA Solvent (15)

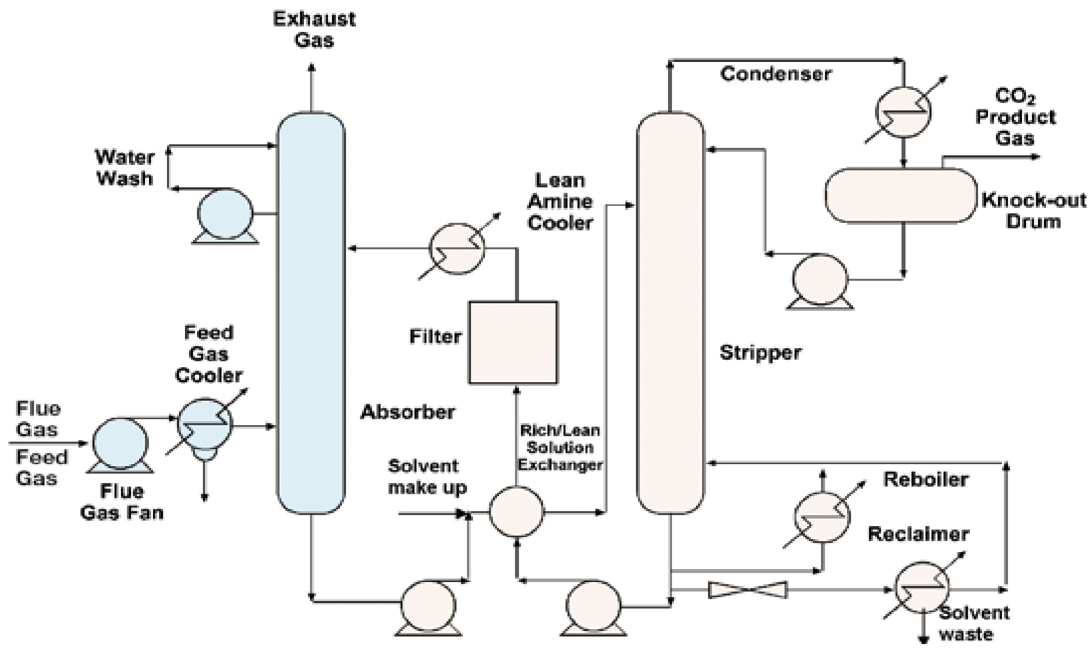

Figure 2-2. Process Schematic of Flue Gas Removal of CO_2 Using an Amine Solvent System (14).

The MEA capture process proceeds as follows: after combustion, impurities which can negatively affect the rest of the system are removed prior to being sent to the capture unit. The MEA system is particularly sensitive to SO_2 with which it can form stable salts that cause corrosion and fouling of the system. The flue gas is sent to a flue gas desulfurization (FGD) system to reduce the SO_2 concentration to a level tolerated by the MEA system (less than 10 ppm) (16). Though low sulfur coal or FGD equipment may already be used at a coal plant, additional upgrades may be necessary to reach this requirement. In addition, particulate matter should be removed using electrostatic precipitation, fabric filter, or other method. The MEA system is also sensitive to NO_x in the flue gas, and NO_x control equipment such as a selective catalytic reduction (SCR) may be necessary.

Once the flue gas enters the capture island, it goes through a blower fan before being contacted with the MEA solvent in an absorption column. There the CO_2 is preferentially absorbed, and the remaining gas (primarily N_2, O_2, and H_2O) is vented. The CO_2-rich MEA solution is sent to a desorption column to release the CO_2 gas and regenerate the solvent. The reboiler of the desorption column uses large quantities of thermal energy in three ways: sensible heat is needed to raise the temperature of the rich MEA solvent to the desorption column temperature, heat is needed to break the MEA-CO_2 bond, and heat is used for steam production for stripping. After desorption, the resulting high concentration CO_2 gaseous stream is compressed to supercritical pressures (about 2000 psia) in order to prepare it for transportation via an underground pipeline to a sequestration site or industrial use. About half of the cost of CCS is attributable to separating the CO_2 from the flue gas; one-quarter of the cost is derived from the energy-intensive CO_2 compression process, and the rest of the cost is primarily from transportation and injection into geological storage sites (2).

2.3.2 Limitations of Post-Combustion Capture

Post-combustion capture (PCC) retrofits are expected to be one of the best near-term options for mitigating CO_2 emissions from existing coal-fired power plants. PCC utilizes chemical absorption technology that has been in use for decades in natural gas processing and other industries (14). However, when designed for electricity producing plants, several factors complicate the practicality of building a PCC unit. When using an amine based solvent, flue gas desulfurization (FGD) and selective catalytic reduction (SCR) upgrades for SO_x and NO_x control, respectively, are required to prevent the formation of salts in the amine-based capture system. These are typically not installed on smaller, older subcritical units (2). In addition to the substantial area needed for CO_2 capture and compression (for example, a 500 MW base plant would require about six acres of land), space must be available for the new SO_x and NO_x control equipment (2). Furthermore, the coal plant should be within the proximity of a sequestration site to make transportation and storage feasible.

The loss in efficiency resulting in lower revenues for plant operators remains a formidable challenge to be overcome in order to improving the attractiveness of the post-combustion capture option. In a new supercritical plant, installation of PCC is estimated to cause a relative efficiency decrease of 24% (2). A 2007 NETL study found an absolute efficiency decrease of 12% in new pulverized coal plants, regardless of whether subcritical or supercritical boilers were used (17). The efficiency penalty and costs are expected to be higher in existing plants, however, relative to newer ones (14). The losses in efficiency and other factors mentioned above decrease the number of plants considered potential PCC retrofit sites. Using the criteria of a heat rate less than 12,500 Btu/kWh, proximity to a sequestration site, and combined unit capacity greater than 100 MW, a recent NETL study reported that 85% of existing capacity in the U.S. (282 GW of 331 GW total) met these characteristics (18). EPRI analysts have suggested that at most 59% of installed capacity could potentially install PCC retrofits (2). However, refurbishing existing plants and then using a retrofit may be a cheaper option for many plants compared to a new construction of a supercritical unit with CO_2 capture for existing plants (18). Thus, while the applicability of PCC retrofits to plants are subject to a number of constraints, uncertain future economic conditions has the ability to change the attractiveness of the post-combustion capture option for a particular plant.

3 INTEGRATING POST-COMBUSTION CAPTURE WITH EXISTING POWER PLANTS

3.1 PCC ENERGETIC NEEDS

As mentioned previously, a non-trivial amount of electricity and thermal energy is needed to capture and compress the CO_2 in the flue gas. The vast majority of the thermal energy (i.e. steam) is used in the reboiler of the desorption column to provide sensible heat, stripping steam, and break the solvent-CO_2 bond. The mechanical energy is used primarily for compression, with lesser amounts used in blowers in advance of the absorption column and pumps throughout the process. For MEA scrubbing, one of the most commercially advanced CO_2 capture technologies, the energy costs are expected to be particularly high (19). MEA is used in Fluor Daniel's Econamine FG™ and FG Plus™ technologies, and researchers attempting to model the system generally give CO_2 regeneration energy requirements of around 4 GJ/ton CO_2 captured (20). The energy costs of an amine plant are expected to have a greater impact on the bottom line than the capital cost (21). The decrease in electricity production from the base plant due to the diversion of steam from the low-pressure (LP) turbine has been reported to cause a 20-30% decrease in the base plant's net power output (2) (21) (22). Much of the research on the amine process centers on reducing the parasitic energy losses in the base plant.

A representative analysis of the breakdown of energy needed for 85% capture using the MEA absorption process is given in Figure 3-1. The regeneration energy is dependent upon a number of factors, including CO_2 partial pressure in the flue gas, percentage capture, solvent blend, and reboiler temperature. The compression energy required also varies with the reboiler conditions, as a higher pressure reboiler will lead to a higher pressure at the top of the desorption column and consequently less compression energy needed. The auxiliary energy is used in the blowers, pumps, and other ancillary equipment.

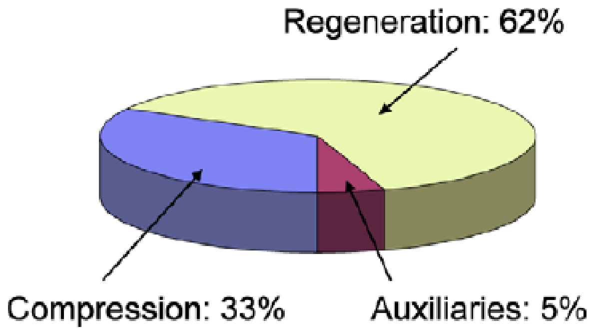

Figure 3-1. Distribution of Energy Requirements in MEA-Based Absorption Process (23).

3.2 GENERAL INTEGRATION CONSIDERATIONS

Though some understanding exists about the task of extracting steam from the power cycle in a retrofitted plant, the issues surrounding its practical implementation are significant and deserve considerable attention. In addition to the space and capital cost requirements of steam integration, power plant operators face a number of decisions and uncertainties about the optimal way to proceed. Optimization of the integration parameters will be necessary to reduce the energy penalty from reduced flow through the steam turbines that results in less electricity for sale. Additional research and experience can be expected to contribute to lower energy requirements, which will imply less steam extracted from the power cycle. In the meantime, operators must design a steam integration process facing a number of options and scenarios for the future, each with their own strengths and weaknesses.

Integrating the base plant power cycle with the steam needed in the capture island, i.e. primarily the reboiler in the desorption column, will requires safeguards to protect the operation of the steam turbines. The steam entering the cylinders must be pure and free of contaminants in order to prevent damage to the turbines. Because the diverted steam enters a reboiler where there is a potential for solvent contamination, the reboiler condensate before being sent through the deaerator will have to enter a filtration system followed by a demineralizer to remove all contaminants (24). In order not to damage the resin in the demineralizer, the liquid is cooled to 80-110°F, with a maximum allowable temperature of 140°F. This will cause a loss in efficiency due to the rejection of heat to the cooling system, unless the waste heat is used in another part of the plant.

One of the key parameters guiding the turbine modifications that will be necessary is the steam pressure and temperature usable in the desorption column reboiler. For an MEA absorption system, a consensus exists that the reboiler temperature should be approximately 120-125°C in order to prevent solvent degradation and corrosion. Assuming a 124°C temperature in the reboiler and ten degree pinch, the reboiler should use saturated steam at 134°C and approximately 3 bar. Steam should be extracted from the turbines as close as possible to this pressure to maximize the amount of power generated in the steam cycle. However, the potential for higher and lower pressure steams in the reboiler arising from solvent improvements make it difficult for plant operators and engineers to choose a system configuration. If solvents such as ammonia or aqueous piperazine, which have reboiler temperatures around 150°C, become the dominant technology, higher steam pressures should be utilized to maximize efficiency (25) (26). This improvement results from a greater temperature swing between the absorber and desorber and a desorption column operating at a higher pressure, translating into a CO_2 stream at a higher pressure at the top of the column and less compression stages and energy needed. Conversely, solvent technology could move towards sterically hindered amines and potassium carbonate-based solvents which have a regeneration temperature below 120°C. Fortunately, improvements in solvent technologies including higher solvent concentrations and enhanced corrosion inhibiting and degradation properties will not significantly affect the steam temperature and pressure needed, e.g. for amines, approximately 134°C and 3 bar (25). Though MEA may remain the most attractive option for at least the near-term, matching the regeneration steam pressure requirements with the extraction steam as closely as possible is essential to minimizing the plant output lost from the power cycle. As the following section discusses, steam turbine modifications for extraction show little flexibility in regeneration pressure, complicating the selection of turbine modifications that appropriately balance flexibility and maximal power output.

3.3 STEAM EXTRACTION LOCATION

The integration between the desorber reboiler and plant steam cycle will require unique modifications to the turbine system based upon the particular base plant's internal process flows. Depending on the turbine configuration, the steam may need to be let-down or sent through a backpressure turbine to enter the reboiler at 3 bar and desuperheated from temperatures greater than 200°C. Some of the waste heat can be recovered by combining the steam with a portion of the reboiler condensate in order to reduce the amount of steam extracted (21). In order to reach the reboiler at sufficient temperature and pressure, steam should be extracted at a minimum of 3.6 bar, though in practice a greater margin may be used or required (27).

The optimal steam extraction location is the crossover pipe between the intermediate pressure (IP) and low pressure (LP) turbines (28). A tee is inserted into the pipe to extract the amount of steam needed for capture, which is expected to be around 50% of the LP cylinder flow (25). Extracting such a large quantity of steam from the crossover pipe will place stress on the nozzles that will carry over to the crossover pipe. Turbine vendors will have to be involved in changes made to alleviate those stresses (24).

The literature generally discusses three different options for steam turbine modifications: using a clutched LP turbine, throttled LP turbine, or floating IP/LP crossover pressure (21)(25)(29). These options are illustrated in Figure 3-2.

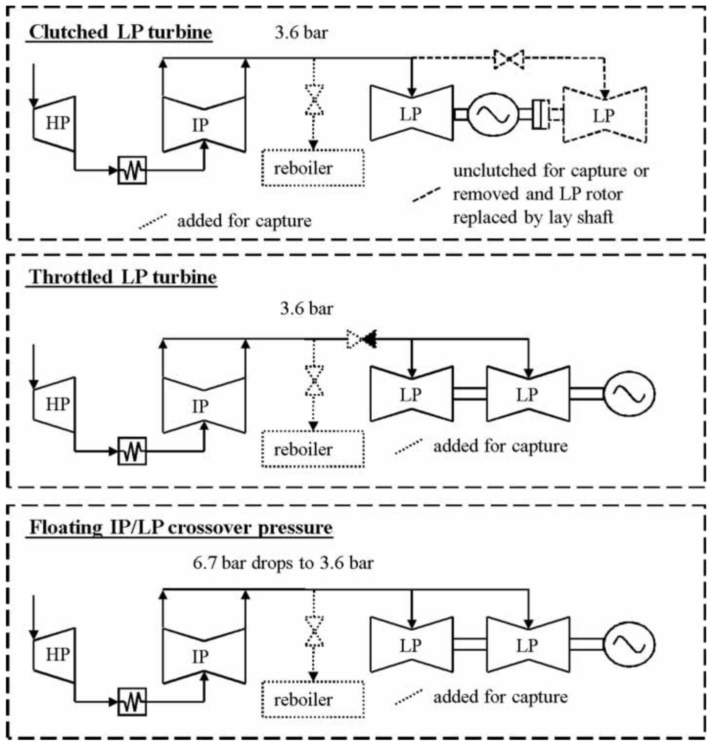

Figure 3-2. **Potential Steam Turbine Modifications for Integrated Retrofits**

3.3.1 Clutched LP Turbine

In this design, steam needed for the reboiler would be withdrawn from an IP/LP crossover pipe at a pressure based upon the specific regeneration system. Space at the crossover pipe for flanges and spool piece that can extract the required amount of steam would have to be available at the site (30). The mass flow of the steam not extracted would match the design mass flow of either one or two of the original LP cylinders to maximize the efficiency of the remaining steam. By matching the designed steam flow of the LP turbines, the steam temperature and pressures in the LP cylinders would not be affected by the extraction of steam. The LP cylinder(s) no longer in use would have its rotor replaced with a lay shaft and would be unclutched and decommissioned for use.

The principal advantage of this approach is that the engineering performance is maximized; the upfront costs, however, are expected to be significantly higher (31). From an operational standpoint, the major problem with this approach is the lack of flexibility in the percentage of steam diverted to the retrofit. Beyond modest fluctuations that can be accounted for using throttling, the extracted steam must be exactly one-third, one-half, or two-thirds of the original plant. Taking into account potential improvements in retrofit technologies discussed earlier, operators and turbine manufacturers would likely have to face the difficulty and costs of additional reengineering at some point in the future in order to keep performance near the optimum level.

Another option to accommodate the particular mass flow needed for CO_2 regeneration would be to design a system using variably-sized LP cylinders. However, even in this scenario, future developments will likely reduce the amount of steam needed for regeneration requiring additional turbine modifications. In addition, the time, potentially years, between turbine modifications and connection to a retrofit plant would be costly to an operator due to lost power generating capacity. This design would be most suitable for a steam cycle using 3 LP cylinders that could handle at minimum 33% and up to 66% of original flow should the steam extraction requirement be reduced (30).

3.3.2 Throttled LP Turbine

Flexibility around the steam mass flow in the LP cylinders could be provided using a throttled LP turbine design, illustrated in Figure 3-2. In this arrangement, the IP/LP crossover pipe would be designed to provide steam at the pressure needed for solvent regeneration. Sufficient space for the steam offtake and the purchase of flanges and spool pieces for the throttling valve would also be required. When capture is implemented, steam would be extracted from the IP/LP crossover pipe at the desired pressure, and the remaining steam would be throttled to maintain crossover pressure.

Throttling losses leading to decreased efficiency constitute the major performance issue of this approach. However, the flexibility in percentage of steam extracted provides a significant benefit in light of the expected improvements in capture technologies. The improvement in performance as steam extraction is reduced follows the trend of lower regeneration duty with better solvents. Additionally, the system can tolerate the absence of CO_2 capture without loss in performance, which may be valuable for operators seeking to make their plant “capture ready” in advance of regulatory pressure. The initial investment for this design would also be lower than the other two options since new purchases would be limited to equipment required for steam offtake.

3.3.3 Floating IP/LP Crossover Pressure

Greater flexibility towards the percentage and pressure of the steam extracted can be obtained using a floating IP/LP crossover design (See Figure 3-2). In this approach, the pressure in the IP/LP crossover pipe is designed to fall to the desired pressure when the specified amount of steam is extracted. The last stages of the IP turbine and initial stages of the LP section would have to be rebuilt in order to handle a range of temperatures and pressures. The IP turbine could be optimized towards either the no capture conditions or decreased flow condition, and when operating on the off-design, a slight loss in efficiency is expected (though within regular fluctuations) (30).

As solvent developments change the optimal pressure of the steam to be used in the reboiler, the floating IP/LP crossover pressure could be adjusted to provide steam at such pressure. In addition, valves could be installed downstream of the extraction offtake or before the LP cylinders to accommodate higher and lower steam flows, respectively. However, as with the clutched LP design, the optimal efficiency is obtained when the turbines are designed for the operational amount of steam needed in the reboiler. In addition to a flange for the steam offtake, the up-front costs for this design not present in the other options include the rebuilding of the last stages of the IP cylinder to handle possible axial thrust changes for single flow units, higher blade bending moments, and flow restrictions.

3.4 COMPARISON AND DISCUSSION OF RETROFIT OPTIONS

As the preceding sections show, the base plant power cycle modifications necessary to provide steam for the capture island are not insignificant. The level of turbine rebuilding necessary for any option and at any level of steam extraction will require major modifications with the associated costs. Section 3.3 discusses three potential steam cycle modification approaches that could be taken: a clutched LP turbine, a throttled LP turbine, and a floating IP/LP crossover pressure. Each approach has varying levels of flexibility, cost, and engineering performance that will result in an economic penalty for a plant operator deciding to retrofit CCS.

The efficiency of each retrofit approach has been compared to a new plant being built with CCS by Lucquiaud and Gibbins and in an IEA Greenhouse Gas R&D Programme study, with similar results (28)(30). No reduction in efficiency relative to a new plant with CCS is seen in the clutched LP turbine retrofit since the steam flow conditions are set to match the turbine's original optimal performance design, though now using fewer LP turbines. The throttled LP turbine design produces the highest efficiency penalty of about 1% relative to a new plant. The floating IP/LP crossover pressure approach has a smaller additional efficiency penalty of 0.3-0.5%. The costs of each approach were estimated based on a plant operator choosing between building a new plant that is carbon capture ready and a new coal plant without consideration to the possibility of retrofitting with CCS. The IEA study estimates that the clutched LP turbine option requires the highest capital investment compared to the costs of the other two options: an additional 3% of the capital of a standard new plant is required to build a clutched LP turbine useable for steam extraction, compared to an additional 1% needed for the other turbine design options. Though building a carbon capture ready plant does not involve the same cost factors as a retrofit, the relative costs of each approach can be understood from this similar analysis.

The performance of the three turbine configurations is summarized in Table 1. As discussed in the previous section, only the floating pressure turbine can tolerate a range of solvent pressures and reduced regeneration energy requirements, i.e. lower steam extraction rates. The clutched LP turbine system does not show flexibility towards the extraction pressure or lower regeneration duties. The problem of inflexibility is compounded when considered with the improvements in capture design expected, though the exact time frame is unknown. The throttled LP turbine option can handle lower regeneration duties, but only from solvents with equivalent or lower regeneration pressures.

Table 1. Assessment of Integration Options.

	Clutched LP turbine	Throttled LP turbine	Floating pressure turbine
Efficiency penalty	Low	High	Medium
Capital investment	High	Medium-low	Medium
Option for solvent change	No	Lower reboiler pressure only	Higher or lower reboiler pressure
Option to have lower steam requirements	No	Yes	Yes

Prior to investment, operators will face the decision of what solvent to choose and weigh the potential for solvent improvements that will alter steam extraction requirements with the current costs of the technologies. Plant operators deciding whether to invest in a post-combustion capture retrofit using integration will face expensive downtime while extensive turbine modifications are being made, additional capital costs, and an additional efficiency loss of up to 1% relative to a new plant with CCS. In addition, the integrated plant will produce potentially 30% less electricity available for sale. The sizeable initial investment for a retrofit combined with the lower electrical output and uncertain technological future of PCC has contributed to the slow progress in constructing full-scale, commercially operating CCS plants.

3.5 POTENTIAL FOR AN AUXILIARY PLANT FOR PCC ENERGY NEEDS

As the principle barrier to new demonstration projects today is the cost of the capture unit, much of the research has been focused on reducing the parasitic energy loss from the large quantities of steam and electricity needed for post-combustion capture. Economic evaluations have found that the operating costs are more important than the capital costs, and that the steam requirement of the reboiler is the largest contributor to the operating costs (32). As discussed in the previous section, perfect integration is not possible with a retrofit since the steam cycle is not designed to provide steam for CO_2 removal. However, the steam cycle of an auxiliary power plant could be designed to produce steam at the required pressure. The generated power would be used for CO_2 compression, with excess power being sold to the grid. The novel idea of using an auxiliary gas turbine for the energetic needs of a capture plant has been introduced in the literature. Romeo *et* *al.* found a 3% increase in efficiency when using a gas turbine for compression energy requirements only (21). Using the same auxiliary gas turbine for compression energy only led to higher CO_2 avoided costs but greater plant output.

The idea of building a gas turbine plant for operation with a steam plant is not new. The history of repowering steam plants with gas turbines in order to improve performance goes back to 1949 (33). Repowering can involve the replacement or addition of electricity generating equipment that can potentially improve a plant's economic performance and increase thermal efficiency while utilizing an existing site and extending the life of a base plant. Cogenerating heat and electricity from an auxiliary plant would better match the energetic needs of the capture unit and potentially reduce the costs of CO_2 capture.

From a plant operator's perspective, several advantages to using an external auxiliary power plant may exist. Building a stand-alone plant for the steam and electricity needed for the capture unit would circumvent the need to make turbine modifications to the base plant power cycle. The re-engineering costs and efficiency penalty on the original base plant could be completely avoided, reducing the technological risk from modifications to the turbine cycle. The plant operator could continue to sell electricity from the base plant while the external plant is being built for the capture unit. The power plant siting difficulty that has plagued new fossil-fuel power plants could be avoided by taking advantage of an existing site with its associated permits and infrastructure to produce more electricity (34). An external auxiliary plant built using natural gas-fired turbines would utilize a more efficient, cleaner technology with which the industry has built a level of familiarity and experience. In addition, less political resistance can be expected towards the construction of a new natural gas plant relative to using a new coal-fired plant to make-up lost power (24). The additional incentive of increased electricity production could be a motivating factor for utilities in areas with growing electricity demand to implement PCC.

Building natural gas-fired plants for an auxiliary purpose would have restrictions in its application however. The existing coal-fired power plant must have space available for a new auxiliary plant. For natural gas-fired auxiliary plants, the site must have access to natural gas supply. The emissions from the natural gas plant may initially not be captured, reducing the amount of CO_2 avoided. The additional CO_2 emissions could make the project undesirable depending on the cost of CO_2 emissions anticipated in the future.

Potentially the most important factor affecting the competitiveness of an external plant relative to the integrated steam cycle approach is the relative price of natural gas to coal. Figure 3-3 shows the variation in average fuel prices for the power industry between 2000 and 2009, and the fuel forecast prices for 2010 and 2011. The natural gas market has shown significant volatility in the past decade due to changing domestic supply and imports. By comparison, the coal price has shown more stability due to an abundance of supply.

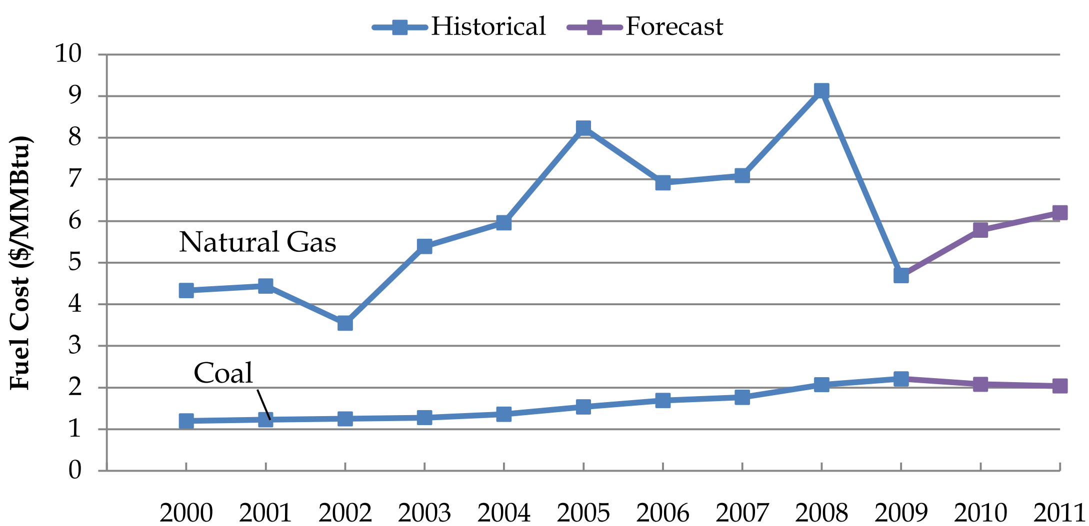

Figure 3-3. Yearly-averaged Price of Fuel for Electric Power Industry (35).

As the relative cost of natural gas to coal increases, the attractiveness of using an external natural gas plant compared to integration will decrease. The higher cost of electricity from the natural gas plant will outweigh the improvement in efficiency relative to using an integrated base plant-capture island system. A closer look at the economics and performance of the external auxiliary is needed in order to ascertain the precise break-even point and sensitivity to this price ratio. The following two chapters describe the specific auxiliary plant technologies considered and the cost estimation approach taken to perform such an analysis. The concluding chapters present the results of the technology simulations and discuss their implications for plant operators choosing among emissions-reducing strategies.

4 Natural Gas Firing Cogeneration Technologies

Instead of derating the base plant for post-combustion capture energy needs, power and steam could be generated in an external auxiliary plant designed specifically for the capture island. After adding a carbon capture unit, both electricity and steam is necessary for the capture island, essentially forcing the coal plant to cogenerate. Problematically, the coal plant was designed to produce electricity as its sole product, but can be made to cogenerate electricity and steam by inserting a tee pipe into the turbine stages for steam extraction. Because the coal plant was not designed for cogeneration, efficiency losses result and add significantly to the cost of implementing CCS. Alternatively, a new auxiliary plant could be used for the power needs of the capture island. The auxiliary plant could be optimally designed to cogenerate the significant amount of steam needed in the capture island in addition to electricity. Figure 4-1 depicts how an auxiliary plant could be used for the capture island energetic needs while the base plant continues to operate as it did prior to capture plant construction.

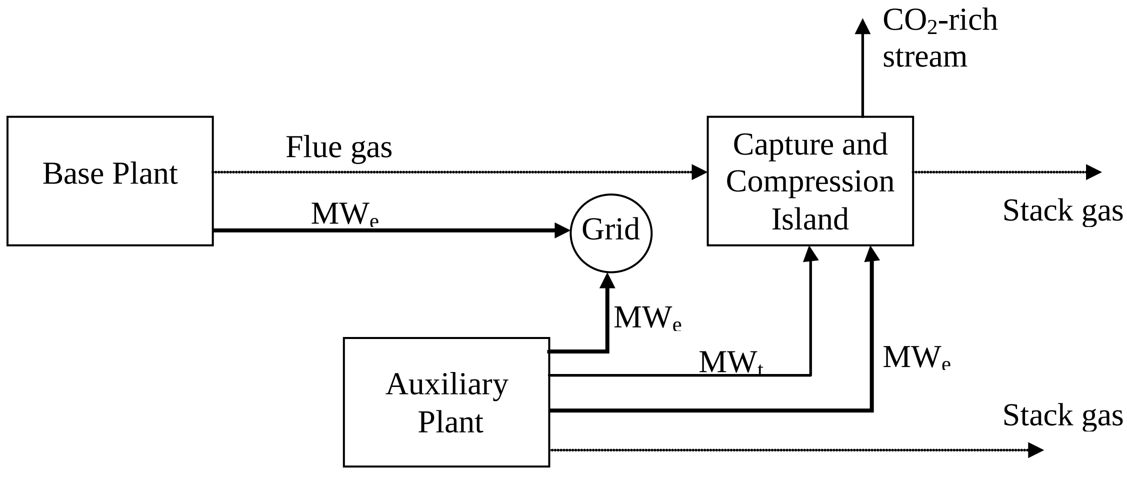

Figure 4-1. Diagram of Auxiliary Plant for Post-Combustion Capture Energy Needs.

Since this auxiliary plant would be a new build, the plant could be designed for the particular heat load of the capture island to minimize efficiency losses. For an MEA capture plant, the thermal energy requirement far exceeds the electrical input, though for other types of solvent plants, this may not be the case (36). The important heat load requirements guiding the design of the auxiliary plant are the required steam flow rate and the maximum steam pressure and temperature allowable in the desorption column reboiler. Due to the high steam flow requirements of the reboiler, a significant amount of excess electricity will be produced beyond what is needed for compression and auxiliary equipment in the capture island. In order to dispatch this excess electricity to the grid, the existing transmission lines and infrastructure around the coal plant may need to be upgraded to handle the extra load (37). If the transmission lines can handle the excess electricity, the profitability of the operation may potentially be enhanced by an increased supply of electricity available for sale.

Natural gas was chosen as the auxiliary plant fuel for a number of reasons. Minimizing the capital investment required was important in order to encourage implementation and make CO_2 emissions mitigation as inexpensive as possible. The ability of a plant operator to get the appropriate permits for new construction was also considered. Finally, the auxiliary plant needed to effectively cogenerate in order to minimize the cost of electricity and make operation profitable. Based on these factors, natural gas was the fuel of choice. Natural gas plants are easier to build relative to coal plants and have lower carbon emissions per electricity unit. Cogeneration of heat and electricity using natural gas could potentially be achieved by one of the following processes:

- Gas turbine only
- Gas turbine with back pressure steam turbine
- Gas boiler with back pressure steam turbine

These three technologies were studied because they cover a range of capital costs and power outputs for a given heat load. The gas turbine only and gas boiler with back pressure steam turbine options would require low to moderate capital investment and have similar power outputs based upon their efficiency. A gas turbine with back pressure steam turbine would maximize electricity production in the auxiliary plant. It would also require a higher capital investment compared to the other two options. An analysis of these three auxiliary plant technologies should be able to reveal the most important parameters affecting the practicality of using auxiliary gas plants for retrofit energy needs.

When using an auxiliary plant for capture energy needs, additional CO_2 is produced that can be dealt with in one of several ways. The auxiliary plant flue gas could be mixed with the coal plant flue gas and then sent to the CO_2 capture plant; the flue gas could be vented into the atmosphere, or it could be sent to its own capture plant for CO_2 removal. The CO_2 concentration in the coal plant flue is significantly higher than in the gas plant flue. Diluting the coal plant flue gas would increase the difficulty and cost of CO_2 removal, as well as require a larger, more expensive capture plant with a greater steam and electricity demand. Diverting the auxiliary plant flue gas to a separate capture plant would require additional space, capital, and energy as well. For the purposes of an initial screening of the auxiliary plant option, this analysis assumes the flue gas from the auxiliary plant is vented to the atmosphere, meaning higher CO_2 emissions than in the integration case. The overall feasibility of using auxiliary gas plants is analyzed in terms of both their economic and environmental performance. The following subsections describe the technological processes used for each auxiliary plant case.

4.1 GAS TURBINE ONLY

Natural gas turbine plants are one of the most common types of cogeneration units. The remaining heat in the combustion gas after turbine expansion is used to generate steam in a heat recovery steam generator. Figure 4-2 depicts the configuration of a stand-alone gas turbine plant cogenerating heat and electricity.

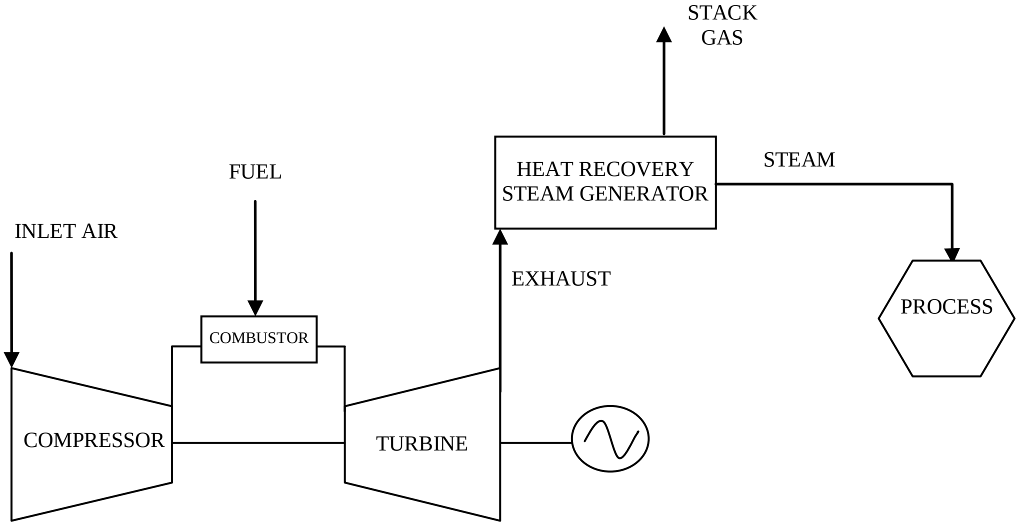

Figure 4-2. Diagram of a Cogenerating Gas Turbine Plant.

Ambient air enters a compressor for pressurization to 10-35 bar, depending upon the type of turbine used. The combustion air is combined with the natural gas fuel on a continuous basis, and the combustion gas is expanded over a turbine to near atmospheric pressure to generate electricity. Large gas turbines are based on a single-shaft connecting the generator, compressor, and turbine and rotating at either 3000 rpm or 3600 rpm (50 Hz or 60 Hz). The exhaust gas enters the heat recovery steam generator at temperatures between 450-650°C for convective heat exchange with water/steam inside pressurized tubes. In most HRSG designs, the unit will have a preheater or economizer, an evaporator, and a superheater. In the economizer, the flue gases transfer heat to the feedwater to heat it to near saturated conditions. The feedwater boils in the evaporator, and the superheater heats and pressurizes the steam to the process conditions. The exhaust gas leaves the HRSG and is sent to the stack for venting while the high pressure steam is transferred for use in an external process (38).

Gas turbines operate on an open Brayton thermodynamic cycle, and the large frame units used in power plants typically have efficiencies in the range of 35-40% (LHV) (38). The total heat utilization from cogeneration in gas turbine plants generally can reach 75% (39). The plant efficiency is highly sensitive to the pressure ratio of the turbine and the peak temperature of the combustion gases. Large gas turbines may have pressure ratios varying from 15:1 to 30:1. The compressors must operate near target levels in order not to affect the turbine performance. In an attempt to prevent any fouling of the equipment, air filters prior to compression are used to remove impurities and increase the efficiency of the plant. Supplementary firing of natural gas in the HRSG can be used to increase heat recovery and is often used to meet higher load swings (39). Modern plant designs tend not to incorporate supplementary firing because it can lead to additional capital cost, an impact on control systems, and a reduction in efficiency.

Because gas turbines utilize high firing temperatures that can lead to unacceptable levels of NO_x emissions, newer gas turbines come with low NO_x combustors that limit emissions to below 10 ppm (39). This is done by ensuring an even firing temperature in each combustor using control instrumentation. Since supplementary firing in the HRSG can also increases the NO_x emissions rate, operators attempt to minimize its use partly to control the overall NO_x emission rate.
An auxiliary plant consisting of a gas turbine operated with a HRSG could theoretically provide the steam and energy needed for carbon capture. The gas turbine plant built next to a CO_2 capture island would be custom-designed to produce enough steam and electricity for the capture plant. Figure 4-3 is a representation of how an auxiliary gas turbine plant could meet the energetic needs of a capture island unit.

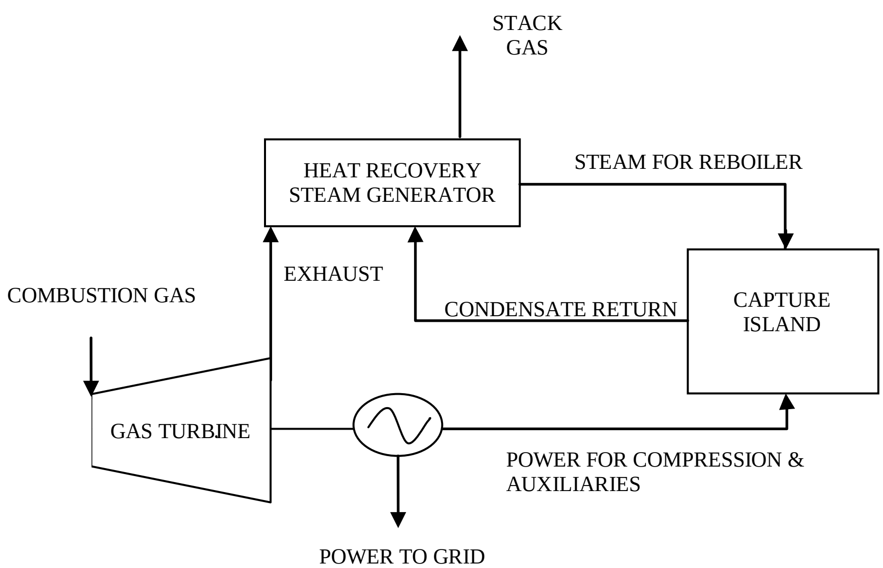

Figure 4-3. Schematic Representation of Auxiliary Gas Turbine Plant and Capture Island.

4.2 GAS TURBINE WITH BACK PRESSURE STEAM TURBINE

Electrical power plants that transfer waste heat from the prime mover, i.e. combustion exhaust, to another fluid for additional electricity generation are referred to as combined cycle plants. Combined cycle gas turbines (CCGT) are the technology currently used in most natural gas-firing plants and as such, are mature technologies.

CCGT plants typically use a gas turbine (Brayton cycle) followed by a steam turbine (Rankine cycle) that uses remaining heat in the exhaust gas to produce electricity. The gas turbine cycle is called the topping cycle as it generates electricity before shedding excess heat to the steam cycle, or bottoming cycle, for further heat utilization. Steam is generally used as the fluid in the bottoming cycle, though theoretically any fluid could be used for heat transfer. The steam turbine in a utility CCGT plant produces roughly 40% of the power of the combined cycle plant, with the other 60% coming from the gas turbine (39).

A diagram of a typical combined cycle gas turbine plant is shown in Figure 4-4. The gas turbine section shown at the top of the figure has a setup similar to that of a stand-alone gas turbine configuration. Steam leaving the boiler (also called HRSG) is expanded over a steam turbine connected to a generator. From the turbine, steam enters a condenser operating at a pressure between 0.13 and 0.033 bar, depending on the cooling water source available. As condenser pressures increase, the plant output is reduced due to less steam expansion in the turbine. The condensate is returned as feedwater to the boiler for pre-heating in the economizer.

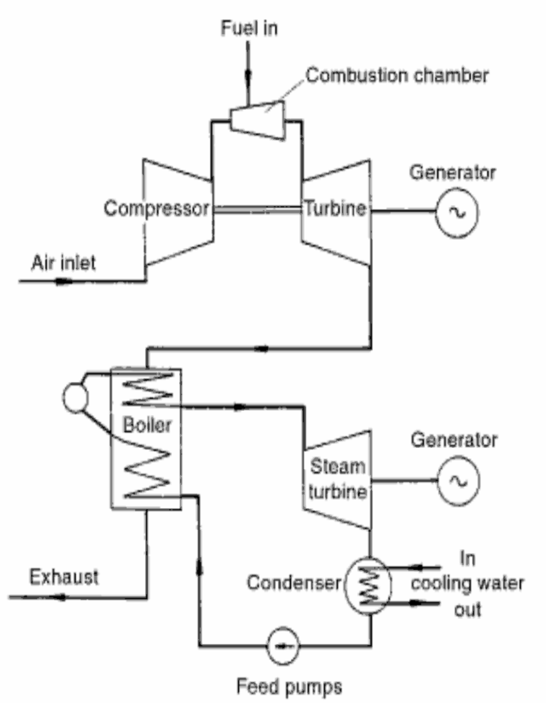

Figure 4-4. Schematic of a Combined Cycle Gas Turbine Plant (40).

In order to use a CCGT plant for cogeneration of heat and electricity, a back pressure steam turbine was used. A back pressure turbine sets the last LP turbine stage pressure based on the desired conditions of the process steam. Figure 4-5 is a schematic of a combined cycle gas turbine (CCGT) plant with a back pressure steam turbine. The system does not need a condenser as the steam is condensed in the process application before being returned to the combined cycle plant.

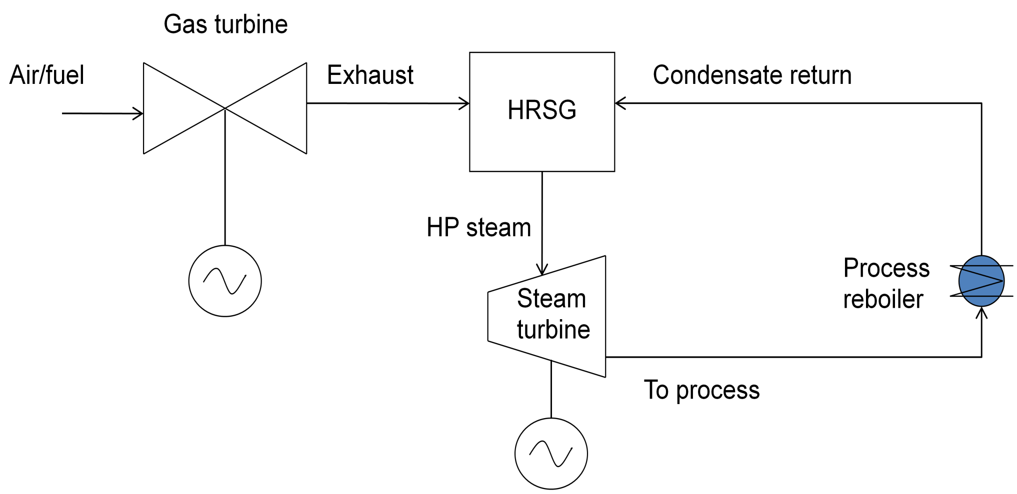

Figure 4-5. Schematic of a Combined Cycle Plant with Back Pressure Turbine Producing Process Steam.

Combined cycle power plants have an efficiency of about 55% (LHV), though with on-the-horizon improvements, this will increase to 60-65% (39). Most combined cycle plants are of the 300-600 MW size in both the 50 Hz and 60 Hz markets. Combined cycle plants have shorter construction times of about 2-3 years compared to 4-5 years for conventional steam-cycle based power plants. CCGT plants can be constructed incrementally, beginning with the gas turbine (1 to 2 years), followed by HRSG and steam turbine installation (additional 6 months to 1 year) (41). The gas turbine can be made to operate independently of the steam turbine in construction and so can produce electricity while the remainder of plant is being commissioned. Combined cycle plants have rapid start-up times and lower initial installed costs compared to coal plants. When compared with gas turbine only plants (no steam turbine), gas turbine only plants will have a lower capital cost due to less equipment needed. The initial cost of a combined cycle plants makes up about 8% of the plant's life cycle cost, however, with 17% of the life cycle cost attributed to maintenance and the remaining 75% derived from the fuel cost (39). Thus the price of natural gas plays a critical role in the economics of new combined cycle plants.

4.3 NATURAL GAS BOILER WITH BACK PRESSURE STEAM TURBINE

Gas–fired utility boilers have been built since at least the 1960s, but since the emergence of combined cycle technology in recent decades, gas boilers have been used less in favor of turbine-based power generation (42). Similar to a conventional coal plant, a natural gas boiler combusts fuel and uses the heat from the gas to produce steam from feedwater. The steam leaving the boiler is used for electricity production in steam turbines. After expansion in the turbine, the steam is sent to a condenser and then pumped back to a boiler with a small amount of makeup water to complete the steam circuit. Steam boilers use the Rankine cycle and typically generate subcritical steam at conditions of 2400-2600 psig, 1000°F (538°C).

Figure 4-6 is a diagram of an El Paso-type natural gas boiler used for utility plants. Burners along the furnace combust the natural gas, and the hot exhaust heats the water or steam flowing along the exhaust path. Fans drive the circulation of the air and stack gas and consume much of the auxiliary power of the boiler. Figure 4-7 shows the water/steam path taken in a typical boiler. Pumps drive the water flow into the boiler where the economizer near the end of the flue gas path uses remaining heat from the flue gas to heat the feedwater up to the evaporation temperature. The steam drum is used for water and steam separation, after which heat exchange with the exhaust gas in the superheat sections increases the steam temperature beyond the saturation point. Utility boilers also typically have a reheat superheater which adds heat to steam between expansion in the high pressure and intermediate pressure sections of the turbine. After expansion in the turbine, the steam is condensed and preheated in feedwater heaters using bleeds from the steam turbine. The number of feedwater heaters used will vary based on the process engineering and economics.

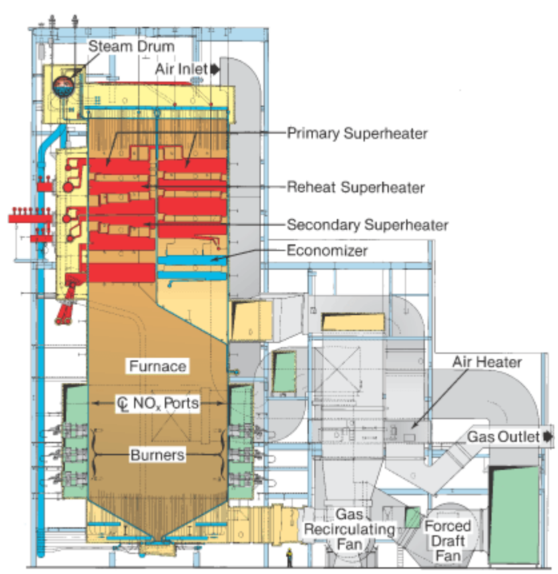

Figure 4-6. Schematic of Natural Gas Boiler - El Paso Type (43).

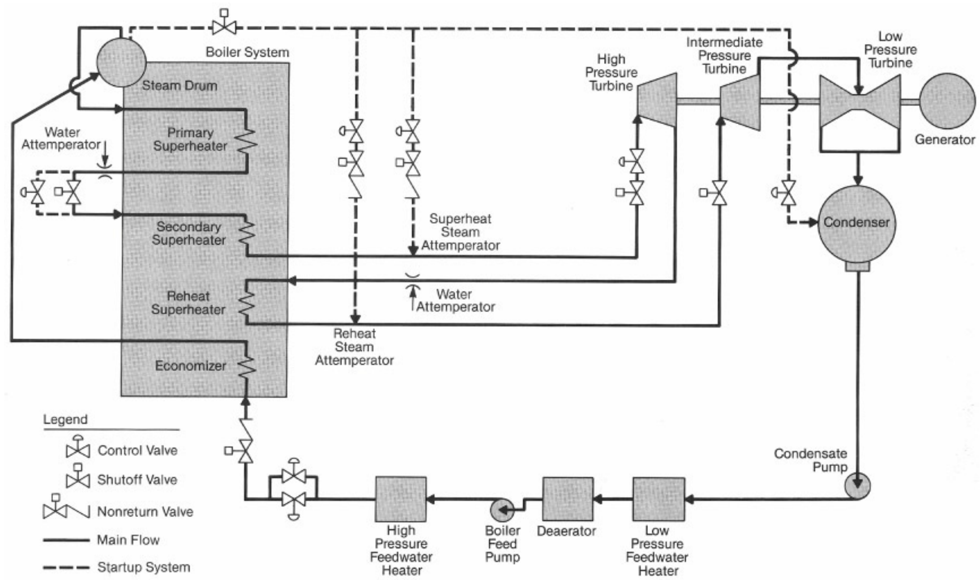

Figure 4-7. Schematic of the Water Circuit of a Drum Boiler (44).

In utility applications, boilers are large, field-erected units that are custom-designed to the fuel, steam pressure, power output, and other design criteria. Natural gas furnaces are smaller than coal-fired furnaces because a shorter residence time is needed for combustion. The difference in fuel combustion characteristics means a more than 50% reduction in furnace size for natural gas furnaces over coal-fired furnaces (45). Utility boilers generating less than 300 MW of electricity are mostly conventional drum-type single reheat boilers using natural or assisted (i.e. pump-based) circulation. Boilers are similar to heat recovery steam generators in that they produce steam for electricity generation, but boilers are larger, also have fuel as an input, and produce steam at pressures exceeding maximum HRSG pressures of approximately 170 bar (42). Using higher steam temperatures and pressures improve the steam cycle efficiency. Supercritical boilers have been constructed that operate at pressures of 4500 psig (310 bar) (44). Where natural gas supply and cost is similar to the economics of coal, the performance of natural gas-fired boilers can be made to match that of coal-fired power plants while providing a slightly better pollutant emissions profile.

In the natural gas boiler auxiliary plant, a back pressure steam turbine is used to supply steam for the capture process. The steam that exits the back pressure steam turbine is sent to the capture island and condensed in the reboiler, and then returned to the feed water heaters of the auxiliary plant. The primary difference with the combined cycle plant is that the gas boiler will have a lower power to heat ratio, resulting in less excess electricity after providing steam and electricity for the capture process. A lower capital investment cost can also be expected for a natural gas boiler with back pressure steam turbine. The following section discusses the specific technological parameters of the auxiliary gas plants based on the coal plant and capture plant designs.

5 PCC Technological and Economical Modeling

In order to assess the feasibility of using an auxiliary plant to provide the electricity and steam needed for a post-combustion capture retrofit plant, a case study for an existing, amortized supercritical pulverized coal plant has been developed. The base plant's coal feed rate, stack gas composition, and net power output were specified using a design found in the literature (6). A post-combustion capture process that captures 90% of the CO_2 in the stack gas was designed, and the associated steam and power needs were calculated. To supply this energy, four different technological processes that could meet the capture unit energy needs were then evaluated. The first case involved integrating the steam cycle of the capture island with that of the base plant. This scenario represents the default option for PCC pursued today. The other three cases use natural gas power plants of various design to provide all of the steam and power needed in the capture island and export excess electricity to the grid. The three combined base plant-capture island-external plant configurations were compared to the integrated process on a number of technological and economic factors. The key economic metrics investigated were the initial capital investment costs, net power output, and cost of electricity per kilowatt-hour. Additionally, an assessment of the efficiency and environmental performance was performed to complete the broad assessment of the four PCC designs.

The base plant model selected was a 500 MW_e supercritical pulverized coal power unit outlined in the 2007 MIT Future of Coal study (6). The plant uses Illinois #6 bituminous coal with 61.2 wt% carbon content and operates at a heat rate of 8870 btu/kWh (38.5% HHV efficiency). The stack gas composition of the supercritical plant would be identical to a subcritical plant's flue gas composition, but produced at a different flow rate. The supercritical plant's stack gas flow rate can be calculated using the ratio of heat rates between a subcritical and supercritical plant, as shown in Equation 1.

$$Flue\ gas\ flow_{SC} = Flue\ gas\ flow_{SubC} \frac{Heat\ Rate_{SC}}{Heat\ Rate_{SubC}} \qquad \text{(Eq. 1)}$$

The flue gas from the supercritical plant has a flowrate of 685 kg/sec, including 115 kg/sec (11%v) of CO_2 .

5.1 CAPTURE PLANT SCENARIOS

As amine based solvents appear to be the dominant choice of solvent for CO_2 capture in the near-term, a significant amount of research has been devoted to reducing the desorption column reboiler duty, in order to reduce the steam flow required. It may be possible in the future to build a CO_2 capture process using a low regeneration pressure solvent such as MEA with lower heat loads than what are typical today, or with a lower heat to power energy need. This study, in the process of comparing alternate PCC retrofit designs, also aims to answer the question of whether the energetic needs profile in the capture island can substantially alter the performance of the retrofit designs. Table 2 presents the energy requirements of the capture plant in the two scenarios considered.

Table 2. Capture Plant Characteristics in Scenarios A and B.

Capture Plant	**Scenario A**	**Scenario B**
Reboiler Pressure	3.0 bar	3.0 bar
Relative Steam to Electricity Requirement	High	Low
Total Power Loss	131 MW	131 MW

5.1.1 Scenario A: MEA Capture Unit Description

Scenario A considers a typical MEA-based CO_2 capture plant that could conceivably be built today. Using an Aspen Plus simulation described in the literature, the MEA scrubbing plant was specified to achieve 90% removal of CO_2 in the base plant flue gas (Figure 5-1) (26). It was assumed that no SO_x and NO_x entered the capture island. Two trains of absorption-regeneration columns were necessary in order to reasonably limit column diameters, with each column handling 342 kg/sec of flue gas each. Each absorber tower was a packed column with a diameter of 15.4 m each and 30 stages of CO_2 absorption. The rich solvent leaving the bottom of the absorption column enters a pump and then a cross heat exchanger for heating. The rich solvent stream exchanges heat with the lean solvent leaving the reboiler of the desorption column, elevating its temperature to 103°C before entering the desorption column. The lean solvent leaving the reboiler, after exchanging heat with the rich solvent, returns to the top stage of the absorber. The gaseous CO_2 stream leaving the desorption column is cooled and flashed to remove most of the water content. The CO_2 stream is then compressed and cooled to reach 99.9% purity and supercritical conditions of 139 bar and 49°C.

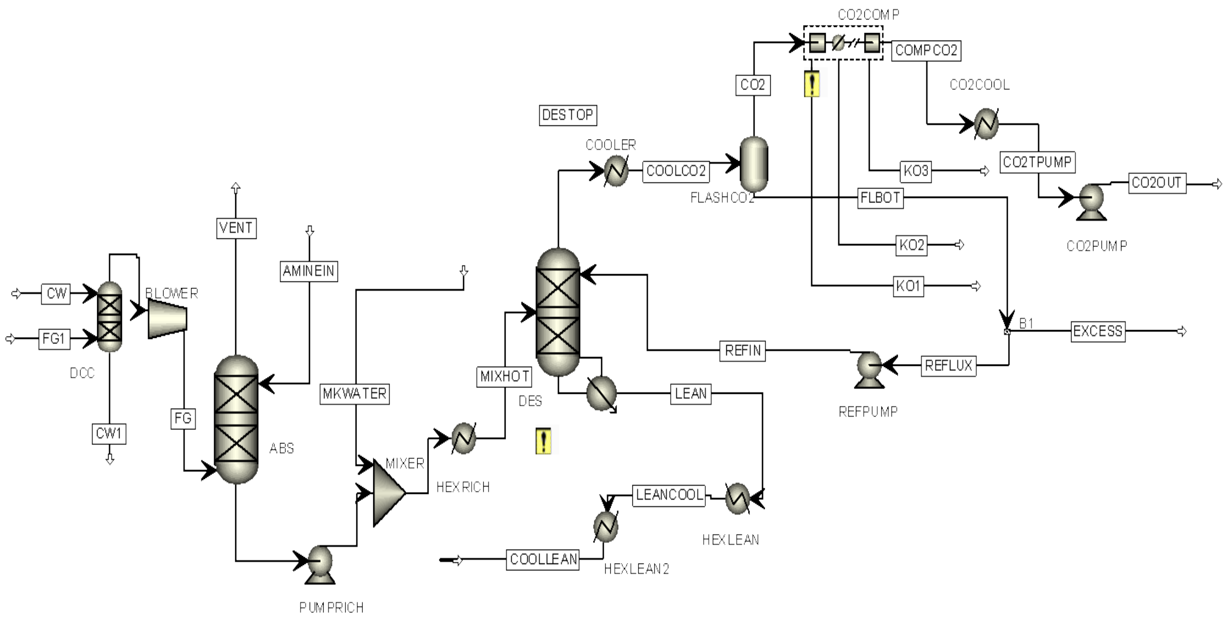

Figure 5-1. Aspen Flowsheet of MEA Capture Unit.

The energy balances from the simulation are used to calculate the power and steam needs for the MEA process and are found to be consistent with other studies (6) (20)(21). The thermal energy needed is assumed to come entirely from the desorption column reboiler and was calculated to be 4.29 GJ_t/t CO_2. The work needed for compression and auxiliary needs is 64 MW or 0.62 GJ_e/t CO_2. The following sub-section describes how the decrease in power output from the base plant is calculated when it provides the steam and power needed under Scenario A.

Integration of Base Plant and Capture Island. In an integrated PCC plant, the thermal and electrical energy diverted from the base plant results in a derating of the base plant's power output. The results of the ASPEN MEA simulation yield a total reboiler duty of 445 MW_t and reboiler temperature of 124°C. For the purposes of this evaluation, the thermal energy needed in the capture island was assumed to be entirely due to the reboiler. Assuming a ten degree pinch difference in the heat exchanger, 206 kg/sec of saturated steam is needed at a temperature of 134°C and 3.0 bar.

In order to calculate the reduction in power from the base plant due to heat consumption, the amount of work that could be generated from expansion of the extracted steam over the LP turbine was estimated. An alpha (•) parameter, defined in Equation 2, is used to express the amount of work lost per megawatt of thermal energy extracted from the steam turbine.

$$\alpha = \frac{Work\ lost\ (MW_e)}{Thermal\ energy\ extracted\ (MW_t)} \qquad \text{(Eq. 2)}$$

The power lost from the steam extraction is calculated based on the amount of work that would have been generated from the expansion of extracted steam to the condenser pressure of 0.1 bar, and is calculated from the difference in availability between the extraction point and condenser conditions. The details of this calculation can be found in Appendix A. Based on the computed • value of 0.15 for steam extraction for MEA solvent regeneration, the reboiler duty causes 67 MW_e of power loss in the base plant. In addition, 64 MW_e of electricity is needed for the compressors and auxiliary equipment. The total loss in power plant output for the 500 MW base plant is then 131 MW, a 26% reduction in power output. The amount of work required for components of the MEA capture process per metric tonne of CO_2 captured is presented in Table 3, and the distribution of work lost in the capture unit is shown in Figure 5-2.

Table 3. Work Consumed in the MEA Capture Plant

Source of energy demand	**Work ($GJ_e/t\ CO_2$)**
Reboiler	0.64
CO_2 compression	0.41
Blowers and auxiliaries	0.20
Total	**1.26**

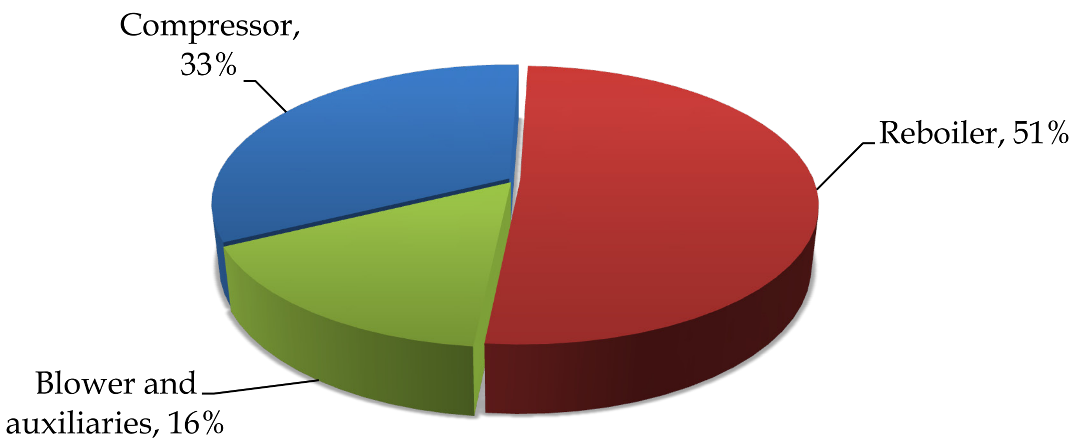

Figure 5-2. Distribution of Energetic Needs in the MEA Simulation.

5.1.2 Scenario B: High Electricity to Steam Solvent

As discussed in Scenario A, the CO_2 capture energy needs was based on 64 MW_e of electrical power needed for compression and auxiliary equipment and 445 MW_t of steam needed for the reboiler. After calculating the work lost from steam extraction, the total power output reduction from the 500 MW coal-fired plant in an integrated design is 131 MW. Under these conditions, the base plant power loss is due in nearly equal proportions to steam required in the reboiler (51%) and electrical energy (49%).

In order to understand the effect of an alternative CO_2 capture island energetic profile, a lower heat to steam energy distribution was assumed while keeping the total base plant derating the same. Specifically, the work lost would shift from a nearly equal distribution between the steam and electrical components to primarily due to electrical energy (85 MW_e, or 65% of 131 MW) and the remaining due to steam extraction (46 MW_e, or 35% of 131 MW). The 65%:35% ratio used here, termed Scenario B, is based on a chilled ammonia process simulation in the literature for 85% CO_2 capture from a coal-fired plant. While chilled ammonia may be able to reduce total energy demands (i.e., the 131 MW), it is kept constant here to isolate the effects of changes in the steam to electricity ratio. In this scenario, the pressure in the regenerator is the same as that for MEA, though future studies may want to vary this value. Consequently, the • parameter or relationship between work lost and steam extracted in Scenario B is the same as in Scenario A since the pressure of the steam needed is unchanged. Based on the heat load of 46 MW_e in Scenario B, using Equation 2 the reboiler duty was calculated to be 305 MW_t in this scenario, 31% lower than the reboiler duty of Scenario A. This reboiler duty can be supplied using 141 kg/s of steam. Table 4 summarizes the integrated plant assumptions and reboiler operating conditions for the different scenarios considered. The total power loss in each scenario is held constant at a 131 MW, and in both cases the maximum solvent temperature in the reboiler is 124°C. The difference in reboiler duties reflect the alternate electricity to heat power distribution assumed in the capture island.

Table 4. Design Scenarios for CO_2 Capture Plant.

		Scenario A: MEA	Scenario B: High Electricity to Heat Solvent
INTEGRATED PLANT			
Total Power Loss	MW_e	131	131
α		0.15	0.15
% Heat		51%	35%
% Electrical		49%	65%
Power Lost - Reboiler	MW_e	67	46
Power Lost - Electrical	MW_e	64	85
REBOILER			
Reboiler Duty	MW_t	445	305
Solvent Temperature	°C	124	124
Steam Temperature	°C	134	134
Steam Sat. Pressure	bar	3.04	3.04
Steam Flow Rate	kg/s	206	141

5.2 DEFINITION OF EXTERNAL AUXILIARY PLANT CASES

To assess the feasibility of using an external plant for capture island steam and electrical energy needs, three different types of power plant technologies were considered, all based on natural gas-firing. The processes were designed using simulations from GTPro and SteamPro software, both part of the Thermoflow 20 engineering suite. GTPro allows users to specify key design criteria and conditions for a gas turbine plant, and the software computes the engineering and equipment performance results. SteamPro is used for the design of conventional steam cycle based boiler plants. For each of the three design configurations analyzed in this study, the auxiliary plant was used to produce exactly the amount of steam needed in the capture island desorption column reboiler. The cases considered for the auxiliary plant are defined as follows:

1. Natural gas turbine with dual pressure heat recovery steam generator. Two types of turbines were assessed:
    - GE 7251FB of the F series (Case 1GE)
    - Siemens SGT6-6000G (Case 1S)
2. Natural gas combined cycle plant with dual pressure heat recovery steam generator and backpressure steam turbine. Two types of gas turbines were assessed:
    - GE7251FB (Case 2GE)
    - SGT6-6000G (Case 2S).
3. Natural gas boiler with backpressure steam turbine (Case 3).

Each auxiliary plant case was designed for each of the two different capture island scenarios:

- A – MEA-Based Capture Plant
- B – High Electricity to Steam Solvent Plant

The five auxiliary plant designs considered for each scenario resulted in a total of 10 different auxiliary plant cases. Table 5 defines and assigns a name to each case using the technology and capture island specification.

Table 5. Definition of Cases by Auxiliary Plant Design and Capture Process Description.

Auxiliary Plant Design: / CO_2 Capture Island	GE7251 FB Gas Turbine	Siemens SGT6-6000G Gas Turbine	GE7251FB Combined Cycle Plant	Siemens SGT6-6000G Combined Cycle Plant	Natural Gas Boiler with Steam Turbine
Scenario A: MEA	Case 1GE-A	Case 1S-A	Case 2GE-A	Case 2S-A	Case 3-A
Scenario B: High Electricity to Steam Solvent	Case 1GE-B	Case 1S-B	Case 2GE-B	Case 2S-B	Case 3-B

The gas turbine only and combined cycle plants were designed using both the GE 7251FB and Siemens SGT6-6000G turbines because they have two of the highest exhaust air flows across all off-the-shelf turbine models. High air flow from the gas turbine is needed to have a sufficient steam flow rate in the HRSG, and two turbine manufacturer models were considered in order to determine the sensitivity to turbine design. In some cases, the maximum amount of steam that could be produced from one turbine without using a substantial amount of duct-firing was less than the steam flow rate required in the reboiler. As the plant technologies are examined for broad performance and economic results, a scaling factor for the number of theoretical turbines necessary to produce a sufficient quantity of steam was used based on the maximum amount of steam that could be produced from one turbine. The scaling factor was calculated for the gas turbine only and combined cycle plant cases (1 & 2) in each scenario using Equation 2. This scaling factor represented the fractional number of turbine plants necessary and was multiplied by the total power output, CO_2 emissions, and cost based on one turbine only design to estimate these parameters for each turbine case. The auxiliary plants using a natural gas boiler (3) did not require a scaling factor as the boilers were redesigned for the unique steam needs of Scenarios A and B.

$$Scaling\ factor = \frac{\frac{kg}{s}\ needed\ in\ capture\ island\ reboiler}{Maximum\ \frac{kg}{s} of\ steam\ produced\ by\ one\ turbine} \qquad \text{(Eq. 3)}$$

The external plants were designed to generate superheated steam at a minimum of 134°C and 5 bar to overcome piping pressure losses during transportation from the external plant to the desorption column reboiler. The condensate from the reboiler was specified to return at a reduced temperature of 32°C due to the requirements of the filtration equipment necessary before the condensate can be returned to the auxiliary plant steam cycle. The cooled and filtered condensate re-entered the auxiliary plant equipment at the preheater in the low temperature section of the HRSG. The capture plant consumes the specified amount of electrical energy from the auxiliary plant, and the excess energy generated in each plant is added to the total power output of the overall coal plant and auxiliary plant system. Ambient air conditions of 59°F and 1 atm were used throughout the study. The natural gas supply was at a temperature of 25°C, 87%v methane gas content, and 0% content of sulfur-containing compounds. Process summaries for each auxiliary plant design are provided in the following subsections.

5.2.1 Case 1GE-A and 1GE-B: GE F Class Gas Turbine with HRSG

This conventional gas power plant design uses a high capacity, GE 7251FB turbine with a dual pressure heat recovery steam generator for steam generation. The operating conditions for the base turbine plant are depicted in Figure 5-3. The steam from each HRSG was extracted evenly between a high pressure and intermediate pressure superheater. The HRSG high pressure section was set to 30 bar in order to limit the size of the HRSG and lower its cost, resulting in some throttling losses. Valves were used to let down the steam leaving the HP and IP sections from roughly 30 bar to 5 bar and saturation temperature of 152°C.

At maximum steam production without supplementary duct-firing, the GE7251 turbine produced slightly more than half of the 205.8 kg/s of steam needed for MEA regeneration in Scenario A. As a result, the process steam needs were distributed over exactly two GE 7251FB gas turbines with their own HRSG and associated equipment. For Scenario B, the steam requirement was 141 kg/s, requiring 1.4 fractional turbines.

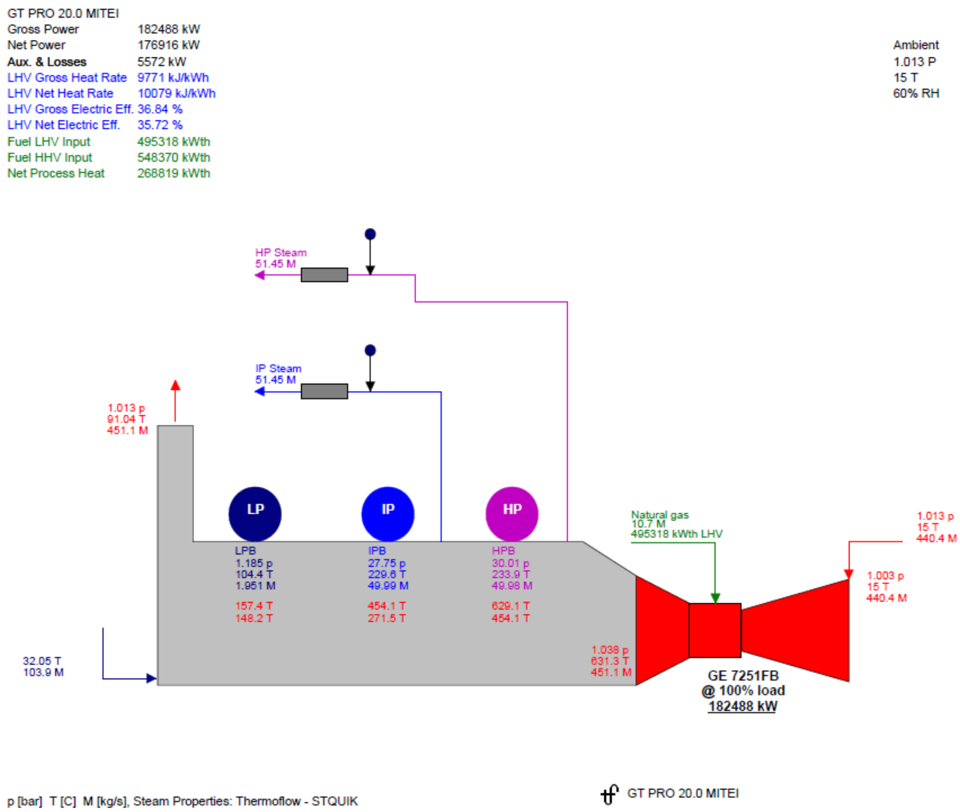

Figure 5-3. Process Summary of Cases 1GE-A and 1GE-B, GE 7251FB Gas Turbine with HRSG.

To produce enough steam for MEA generation, a total fuel input of 21.4 kg/s natural gas was necessary resulting in 354 MW of electricity generation prior to providing the electricity for the capture plant. The turbine efficiency reached 32.3% on a high heating value basis. For the high electricity to steam scenario, 14.7 kg/s of natural gas was used to generate 242 MW of electricity prior to supplying energy for the capture plant. The plant operated at the same efficiency as in Scenario A as only the fractional number of turbine plants was altered for Scenario B while the technical design remained the same.

In order to compare the effectiveness of electricity generation across cases while accounting for the thermal energy withdrawn, an effective heat rate was defined as follows:

$$Effective\ heat\ rate = \frac{Fuel\ energy\ input - Thermal\ energy\ withdrawn}{Net\ auxiliary\ plant\ power\ produced} \qquad \text{(Eq. 4)}$$

The effective heat rate is lower than typical heat rate values because for cogenerating systems, the energy in the steam extracted is subtracted from the fuel energy input in the numerator. An effective heat rate of 5130 btu/KWh was computed for this design, and Table 6 compares this value and other broad operating conditions among all auxiliary plant cases.

Table 6. Performance Summary of Auxiliary Plant Cases.

Auxiliary Plant Cases	Total net power	Efficiency	Effective heat rate	Fuel input	Scaling factor
	(MW)	% (HHV)	btu/kWh	kg/s	
Case 1GE-A	354	32.3	5130	21.4	2.0
Case 1GE-B	242	32.3	5130	14.7	1.4
Case 1S-A	391	33.9	5120	22.5	1.6
Case 1S-B	251	32.8	5130	14.9	1.0
Case 2GE-A	521	40.2	4780	25.2	2.4
Case 2GE-B	356	40.2	4780	17.3	1.6
Case 2S-A	562	41.4	4810	26.5	1.8
Case 2S-B	385	41.4	4810	18.1	1.3
Case 3-A	215	24.3	5340	17.3	1.0
Case 3-B	145	24.0	5360	11.8	1.0

5.2.2 Case 1S-A and 1S-B: Siemens G Class Gas Turbine with HRSG

Case 1S, Siemens SGT6-6000G (abbreviated S6G) gas turbine with dual pressure HRSG, was designed analogously to Case 1GE. The principal variation was the use of a different gas turbine. Figure 5-4 summarizes the operating conditions of the one turbine system. The HRSG is designed to produce steam at 30 bar in the high pressure section in order to control the size of the HRSG. The steam withdrawn equally from the HP and IP superheaters is let down to 5 bar and 152°C using valves. The S6G is slightly larger than the GE7FB, and at maximum steam production using a 10°C pinch in the HRSG, one gas turbine produced 132 kg/s of steam in the HRSG. To meet the 205.8 kg/s steam requirement for amine regeneration (Scenario A), 1.6 theoretical turbines are necessary. As in Case 1GE, all inputs and outputs (e.g., fuel input, CO_2 emissions, cost, etc.) are multiplied by the scaling factor in order to determine the overall cost and performance of the case. For Case 1S-B, the total steam requirement could be met using one gas turbine if a small amount of duct-firing (0.5 kg/s gas) was used, so the process was designed based on using one turbine with 3% of the natural gas being duct-fired (Figure 5-5).

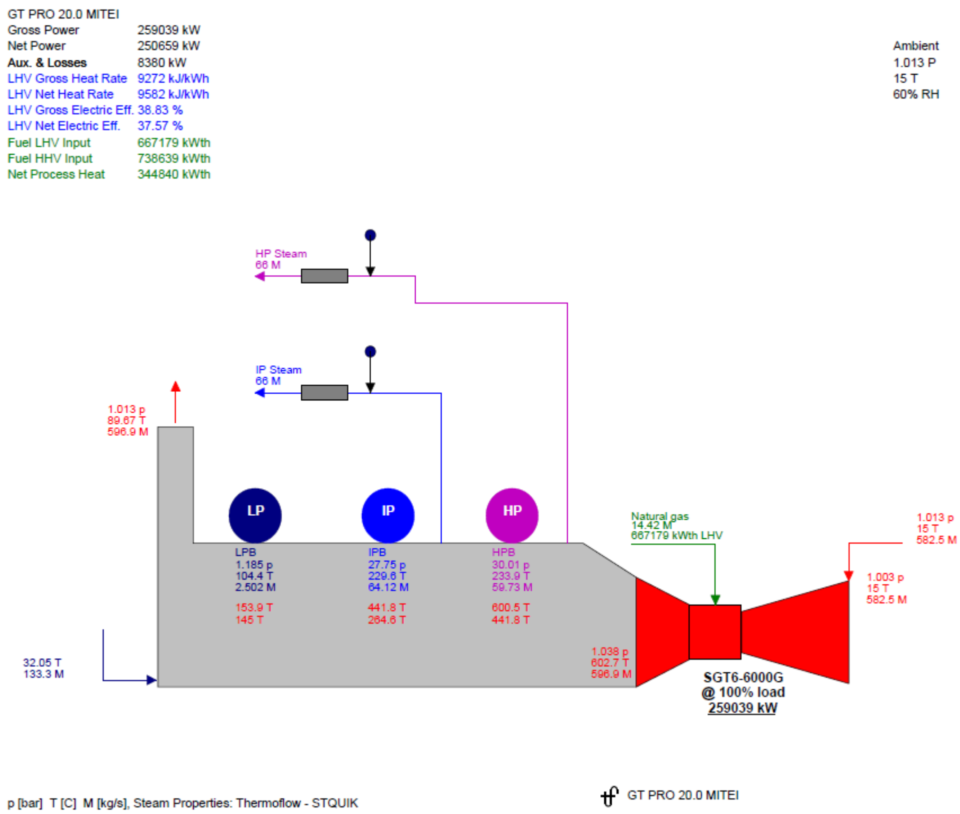

Figure 5-4. Process Summary of Case 1S-A, Siemens SGT6-6000G Turbine with HRSG.

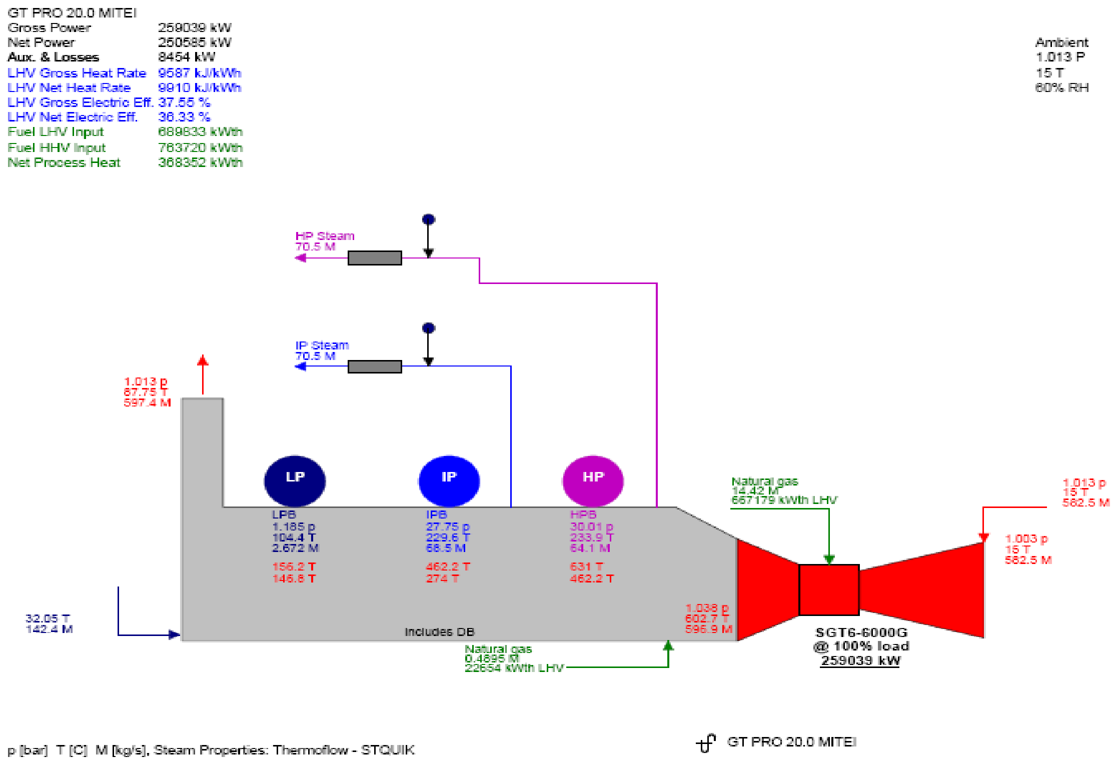

Figure 5-5. Process Summary of Case 1S-B, Siemens SGT6-6000G Turbine with HRSG.

Using 1.6 Siemens gas turbines for an MEA plant, 391 MW of electricity are generated prior to supplying energy for the capture plant. The 1.6 turbines consume 22.5 kg/s of natural gas fuel, and an individual turbine operates at 33.9% HHV efficiency, slightly higher than the GE 7251FB efficiency of 32.3% in Case 1GE-A. The effective heat rates of 5120 btu/kWh for Case 1S-A and 5130 for Case 1S-B are close to, if not equal to the effective heat rate of 5130 btu/KWh in Case 1GE (A & B).

5.2.3 Case 2GE-A and 2GE-B: GE F Class Gas Turbine with HRSG and Back Pressure Steam Turbine

Case 2GE is a dual pressure combined cycle plant with back pressure steam turbine as illustrated in Figure 5-6. A GE 7251FB gas turbine is used as in Case 1GE. Process steam is produced using a back pressure steam turbine set to 5 bar to overcome piping pressure losses before reaching the amine reboiler operating at 3 bar. Since the steam at the end of the LP section of the turbine is superheated, a small amount of desuperheating water is extracted from the intermediate pressure section of the HRSG and injected into the steam turbine outlet stream to produce saturated steam. The steam is at 4.7 bar and 149°C when transported to the regeneration column reboiler.

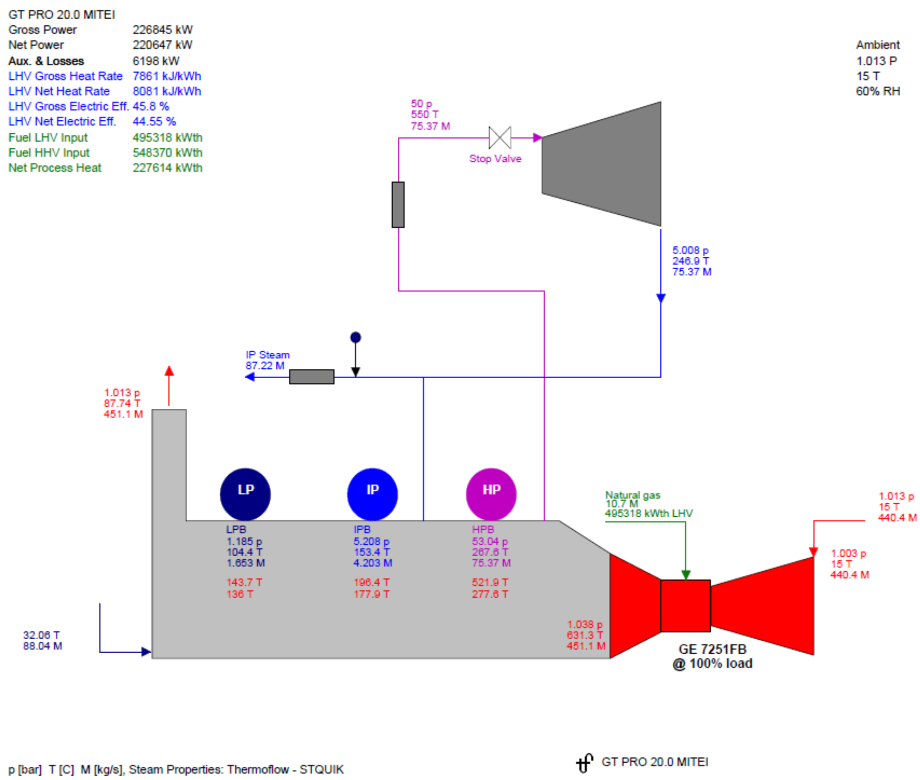

Figure 5-6. Process Summary of Case 2GE-A and 2GE-B, GE 7251FB Combined Cycle Plant.

As in the gas turbine only cases, the combined cycle plant was designed initially using one gas turbine , and a scaling factor was introduced to determine the number of theoretical plants necessary for producing enough steam needed for the regeneration column reboiler. Using a GE 7251FB turbine, 2.4 gas turbines with their associated HRSGs and steam turbines were necessary for Scenario A, and 1.6 turbines were necessary for Scenario B. The total amount of power produced among the 2.4 combined cycle plants is 521 MW of electricity, much higher than the gas turbine only cases due to the use of steam turbines. In Scenario B, 356 MW of electricity was generated prior to diverting 85 MW of electricity to the capture plant. Each combined cycle plant would operate at 40.2% HHV efficiency and the effective heat rate is 4780 btu/kWh. This combined cycle process would have a greater efficiency in the external plant compared to Cases 1GE and 1S but require purchase and maintenance of steam turbines.

5.2.4 Case 2S-A and 2S-B: Siemens 6000G Gas Turbine with HRSG and Back Pressure Steam Turbine

The slightly larger Siemens SGT6-6000G gas turbine was used in the combined cycle plant of Case 2S. The backpressure of the steam turbine was set to 5 bar, and as before, steam was desuperheated to 149°C and 4.7 bar using water from the HRSG IP section (Figure 5-7). Condensate from the reboiler is returned to the external plant at 32°C and fed to the condensate preheater in the HRSG with a small amount of make-up of water. As in Case 2GE, the combined cycle plant was designed to produce as much low pressure steam as possible using a 10°C pinch temperature and no supplementary firing in the HRSG. One gas turbine/HRSG/steam turbine plant produced 112 kg/s of steam, requiring that 1.84 combined cycle plants be used for the MEA plant and 1.3 turbines for the high electricity to steam solvent capture plant.

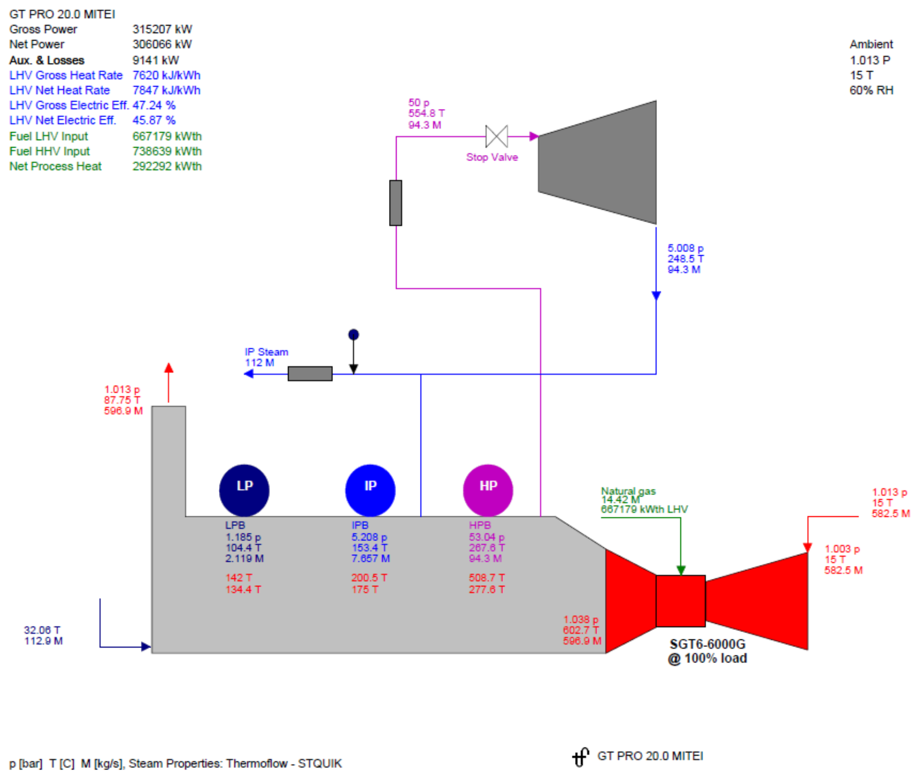

Figure 5-7. Process Summary of Case 2S-A and 2S-B, Siemens SGT6-6000G Combined Cycle Plant.

The large Siemens G Class SG6 turbine allows for fewer turbines to produce the amount of steam needed over smaller turbines. The Siemens gas turbine combined cycle plant has a 1.2 point increase in absolute efficiency over the GE turbine based combined cycle plant, but a similar effective heat (Table 6). Both types of combined cycle plants have higher efficiencies and effective heat rates than the gas turbine only plants due to the additional electricity generated from the steam turbine Rankine cycle. The efficiency improvement will have to be weighed against the additional capital and fuel needed for the combined cycle plant and other factors as discussed in the results section.

5.2.5 Case 3-A and 3-B: Natural Gas Boiler with Back Pressure Steam Turbine

The last type of natural gas cogeneration design considered is a natural gas-firing boiler with back pressure steam turbine as shown below (Figure 5-8 and Figure 5-9). The system was simulated using Themoflow SteamPro software as SteamPro simulates Rankine cycle steam plants in the Thermoflow engineering software suite. The back pressure of the steam turbine was set at 5 bar, but unlike in previous cases, one train of equipment (one boiler and steam turbine) is designed to produce the total amount of steam needed in the capture plants. The steam turbine operates at subcritical conditions of 200 bar and 570°C. Four feedwater heaters are used to heat the reboiler condensate before being returned to the boiler. Three steam turbine bleeds in addition to a portion of the steam turbine outlet stream exchange heat with the feedwater in the four heat exchangers. The rest of the steam turbine outlet stream is sent to the process at saturated conditions of 5 bar and 152°C.

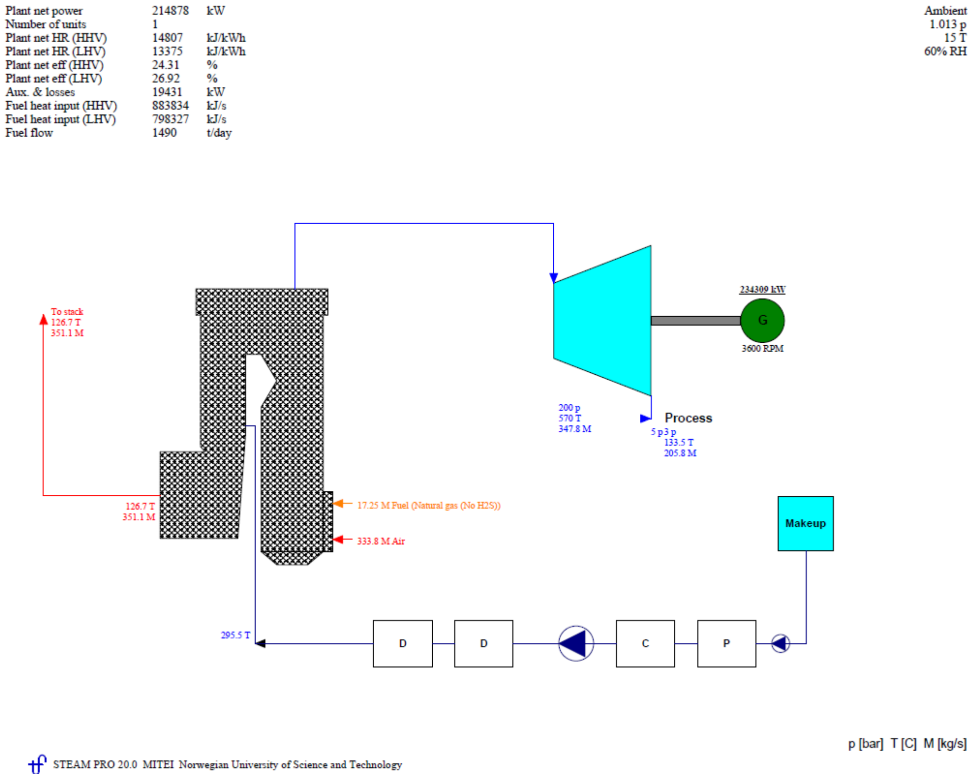

Figure 5-8. Process Summary of Case 3-A, Natural Gas-Fired Boiler with Steam Turbine.

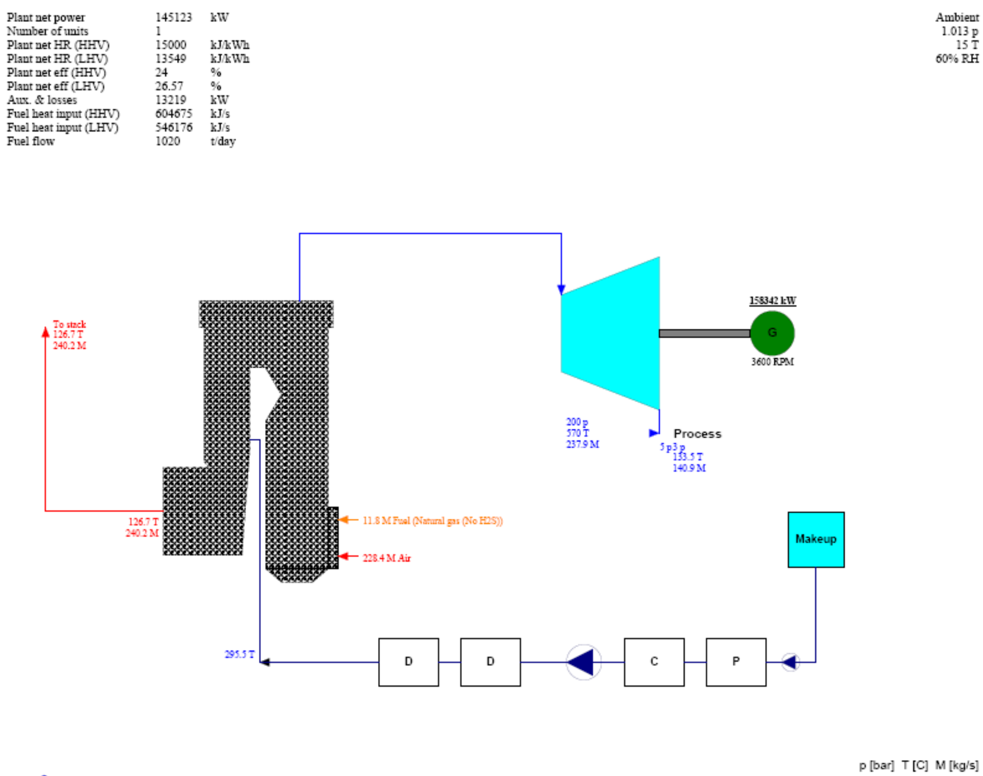

Figure 5-9. Process Summary of Case 3-B, Natural Gas-Fired Boiler with Steam Turbine.

Cases 3-A and 3-B produced 215 and 145 MW of electricity respectively, much lower power outputs than the gas turbine-based cases discussed previously. The required natural gas fuel feed rates are also lower at 17.3 and 11.8 kg/s. Using a natural gas boiler led to net plant efficiencies of 24.3% and 24% on an HHV basis for Cases 3-A and 3-B, respectively. Compared to conventional steam plants, the Case 3 designs have reduced efficiencies due to the large steam production requirements and extraction of steam at 5 bar leading to a loss in power output. The boiler efficiencies are also much lower than the efficiency of the other auxiliary natural gas plants. The effective heat rate of the boilers is 5340 and 5360 Btu/kWh (Case 3-A and 3-B, respectively), higher than in all other cases. The natural gas boiler design leads to a substantially different thermal to electrical energy profile in the cogenerating plant that should serve as an illustrative example of the factors that are most important to auxiliary plant economics.

5.3 COST ESTIMATION METHODOLOGY

In order to compare the five external plant cases with the option of integration for each capture plant scenario, the economics and emissions performance of each case had to be evaluated. The total plant cost (TPC) estimates were generated using Aspen Icarus Process Evaluator and Thermoflow PEACE economic simulator software. TPC estimates were generated for the CO_2 capture island and for the five external plant designs. The base coal plant is assumed to be fully-paid off and thus does not contribute to the utility's cost of electricity.

The MEA-based CO_2 capture island designed in Aspen Plus was transferred to Aspen Icarus for cost estimation. The cost of the MEA capture plant was used across all cases and for both Scenario A and Scenario B. Two complete trains of absorber, desorber, reboiler and auxiliary equipment were needed in the MEA plant to process the flue gas without building unreasonably large towers, heat exchangers, etc. The capital cost estimates were based on the year 2010. For the capture island, this was done in two stages. Within Icarus, the labor and material indices were updated to the fourth quarter of 2008 using the Means and *Chemical Engineering* Plant Cost Index (CEPCI). The Icarus capture island estimate was then scaled from December 2008 to September 2009 using the CEPCI. September 2009 was the most recent time period for which CEPCI data was available and thus approximated as the 2010 index for the capture island.

The capture plant is assumed to be built in the United States Gulf region on land already owned by the utility. The TPC estimate includes major equipment such as towers, pumps, fans, and heat exchangers, in addition to bulk materials, and installation. Certain craft labor and material costs for the Gulf region were specified based on the experience of an industry cost consultant (46). Indirect costs of engineering and home office (18% of project cost before contingency) and overheads were included. Taxes, permits, royalties, and owner's cost were not included in the capital cost estimate. A 25% process contingency factor was applied to the Icarus-generated estimate to account for the inexperience with CO_2 capture plant construction.

For the business-as-usual case of CO_2 capture plant integration with the base coal plant, additional costs are expected to be incurred as a result of purchase of equipment and reengineering of the steam cycle, as outlined in Chapter 3. Because the extent of the additional costs incurred was not specifically computed, the cost of integration is not included in the capital cost estimate for the capture island.

For the external plant cases, TPC estimates were generated using the Thermoflow PEACE 20 module. The PEACE estimates include major equipment, civil, mechanical, electrical wiring, transportation to site, and installation labor. The Texas regional cost factor was applied for all direct and indirect costs. For the external plant, PEACE includes the contractor's soft costs (e.g. profit, contractor's fee, insurance) and owner's soft costs (e.g. permits, licenses, legal fees). Engineering and building costs are also included in the PEACE estimates. A 10% project contingency factor was applied due to the steam cycle integration with the CO_2 capture island. The cost estimates produced by PEACE 20 are based on December 2009 costs and are assumed to be representative of plant construction in 2010 in this analysis.

Operation and maintenance (O&M) and fuel costs were taken from estimates found in the literature. The U.S. EIA annual average projections for 2010 were used for the natural gas and coal fuel costs (47). The existing coal plant's O&M costs were calculated by multiplying the O&M costs for a new supercritical coal plant in 2010 dollars by a factor of 1.5 because maintenance costs are expected to be higher for older plants (48) (49). The O&M costs associated with the CO_2 capture plant was specified using the literature estimate of the O&M

costs for a new SCPC plant with and without CCS (48). The difference in O&M cost between the new plant with and without CCS ($67/kW) was used for the O&M cost for the capture island alone. The Organisation for Economic Co-operation and Development developed estimates for the O&M cost of new gas plants built in 2010 on a per kW_e basis (50). Those values were used for the gas turbine and natural gas combined cycle plants O&M costs. The natural gas boiler O&M cost was calculated using a literature estimate given on a per heat to power ratio (MW_t/MW_e) basis (51). The O&M cost parameter taken from the literature was based on 2002 dollars and was scaled to the reference year 2010 using the U.S. Consumer Price Index.

A levelized cost of electricity (COE) estimate was developed for each scenario using a simplified model of the NETL Power Systems Financial Model developed in the 2007 NETL Cost and Performance Baseline for Fossil Energy Plants Report (17). The cost of electricity is based on a 20 year levelization period and low-risk levelization factors. Capital cost, fuel costs, and O&M costs contribute to the cost of electricity based on 2010 dollars. The COEs computed are used to calculate the cost of CO_2 emissions avoided on a per metric tonne ($/t) basis.

6 RESULTS

6.1 SCENARIO A: MEA CAPTURE PLANT

In this section, the five auxiliary gas plants are compared to thermal integration of an MEA absorption process with the base coal plant for a post-combustion capture retrofit. The capital investment required for the MEA-based CO_2 capture plant was $319,400,000 for the 500 MW plant. In addition to the capital investment of the capture plant, the loss in efficiency, reengineering and downtime, and additional expenditures outlined in Chapter 3 will contribute substantially to the cost of integration. The “integration cost” is difficult to estimate and will vary depending on the characteristics of the coal plant. In order to compare the integration case to the auxiliary plant options, different levels of integration costs are considered. Figure 6-1 plots the cost of electricity versus the cost of integration varied using a scaling factor for the CO_2 capture plant capital cost. This integrated plant cost factor is multiplied by the capture plant capital cost to reflect the cost of the capture plant plus the “integration cost.” The combined cycle plant case 2S-A cost of electricity is also plotted. Equivalent COE’s are achieved when the integrated plant cost factor is 1.49. To compare integration with the auxiliary plant option, three levels of integration costs are studied. Level A uses an integration plant cost factor of 1.25 to reflect a low integration cost estimate. In Level B, the integration plant cost factor is 1.5, approximately the break-even point for electricity costs, and in Level C, the integration plant cost factor is 2 for the scenario where the integration cost is high. These integration cost levels will show how as integration becomes more challenging and costly, the relative desirability of the integration option changes compared to an auxiliary plant.

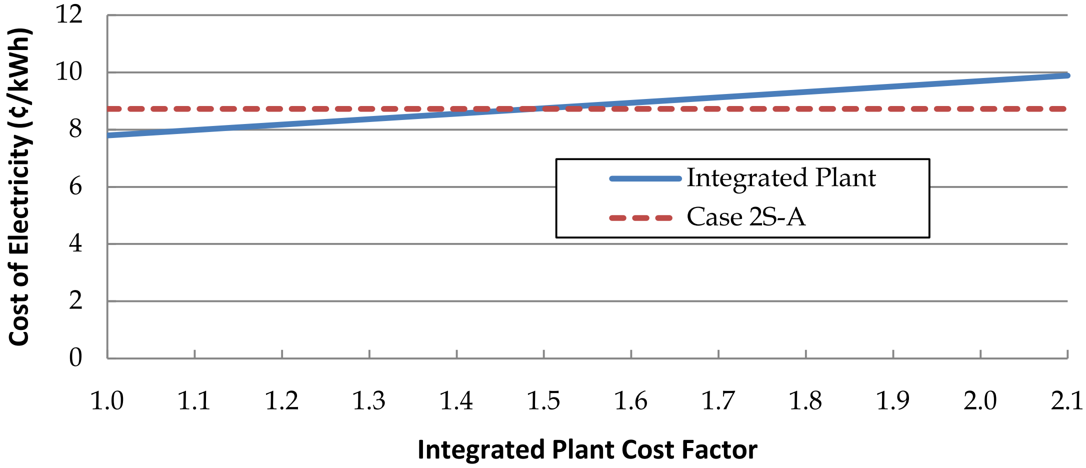

Figure 6-1. Sensitivity of Cost of Electricity to Integrated Plant Cost Factor.

Table 7 presents the effects of integration difficulties on investment required, power output, CO_2 emissions, electricity costs, and mitigation costs. The total costs vary from $399 to $666 MM, though the power output and emissions rate is unchanged in each case. The cost of electricity varies by 1.4 ¢/kWh for the different integration costs, and the cost of CO_2 avoided increases by $20/ton as the integration cost factor increases from 1.25 to 2.0. This suggests that the attractiveness of integration will be highly dependent upon the integration cost faced by a particular plant operator.

Table 7. Summary of Performance for Integration Cases.

	Integration Plant Cost Factor	Capital Cost incl. Capture Plant ($MM)	Net Output (MW)	COE (¢/kWh)	CO_2 Emissions (kg/kWh)	CO_2 Avoided Cost ($/tonne)
Integration Level A (I-A)	1.25	399	369	8.3	0.11	60.3
Integration Level B (I-B)	1.5	479	369	8.7	0.11	66.9
Integration Level C (I-C)	2.0	639	369	9.7	0.11	80.2

The technological and economic performance of the five auxiliary plant options under Scenario A are presented in Table 8. The cost and emissions metrics for the external plant cases summarize the performance of the aggregate base plant - MEA plant - external plant system. In each case, the net power output of the plant increases while the CO_2 emissions rate is higher than the integration option because the auxiliary plant flue gas is vented. The CO_2 avoided cost is presented here for the auxiliary plant cases, but poses problems when compared across the integration and auxiliary plant options. The avoided cost metric, as used in the 2005 Intergovernmental Panel on Climate Change report and 2007 MIT Future of Coal Report, allows for a basis of comparing capture scenarios that have the same electrical output and use one type of fuel. When comparing the auxiliary plant approach to the integration approach, the power outputs differ vastly; the difference can potentially be up to more than 600 MW (See Figure 6-4). The avoided cost metric in the auxiliary plant cases accounts for the cost of make-up power and significant excess power, while it does not in the integrated plant cases. If the integration cases also incorporated the emissions and costs of additional electricity generation from another power source (e.g. natural gas, nuclear, renewable sources), the new avoided cost could be compared to the auxiliary plant case. In the auxiliary plant case, the metric includes not only the cost of make-up power after introducing CCS, but also includes a "fuel switching" component between coal and gas. As a result, a drastically different basis for avoided costs is used in the auxiliary plant and integration cases. When taking into account these differences, using the avoided cost as presented here as a metric to compare the auxiliary plant scenarios to the integration scenarios will be misleading at best. However, when comparing auxiliary plant cases only, the avoided cost reflects similar factors and is an acceptable metric. As a consequence, the auxiliary plant avoided cost is presented here for analysis across auxiliary plant options, but it cannot usefully be compared with the integration cases.

Table 8. Summary of Performance of Auxiliary Plant Cases under Scenario A.

	Capital Cost incl. Capture Plant ($MM)	Ext. Plant Efficiency (HHV)	Net Output (MW)	COE (¢/kWh)	CO_2 Emissions (kg/kWh)	CO_2 Avoided Cost ($/tonne)	Delta Output (MW)
Case 1GE-A	629	32.3	790	9.0	0.30	96.4	290
Case 1S-A	629	33.9	827	8.9	0.30	93.4	327
Case 2GE-A	768	40.2	957	8.8	0.29	90.7	457
Case 2S-A	765	41.4	999	8.7	0.29	88.4	499
Case 3-A	626	24.3	651	10.2	0.31	119.5	151

The total plant costs (TPC) of the external plants varied significantly as shown in Figure 6-2. The gas turbine only and boiler options require a capital investment comparable to the MEA capture plant cost. No significant price difference was seen regardless of whether a Siemens or GE gas turbine was used. The combined cycle auxiliary plants' total plant cost was approximately 50% higher in cost than the gas turbine or boiler plants.

Figure 6-3 shows the differences in efficiencies on a HHV basis among the external plant designs. Because the combined cycle plants have higher efficiencies and therefore more successfully cogenerate than the gas turbines or boiler, they can also be expected to have more power available for sale after meeting the capture island steam and power demands.

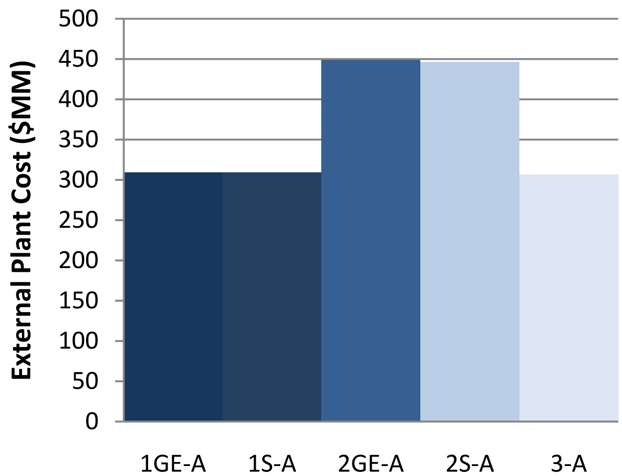

Figure 6-2. External Plant Cost in Reference Year 2010 Dollars.

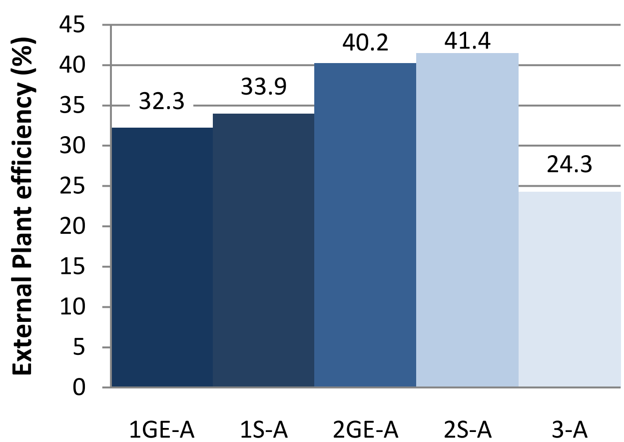

Figure 6-3. External Plant Standalone Efficiency on an HHV Basis (Scenario A).

The aggregate power output from the integration and auxiliary plant cases are presented in the following figure (note that the power output and emissions rate are not affected by the integrated plant cost level). Figure 6-4 presents the aggregate power output available for sale after supplying PCC energy for the auxiliary plant and integration cases. In the integration case, the power output drops to 369 MW due to the energy withdrawn from the coal plant for the capture island. The external plant cases increase the total output of the aggregate system from the base plant size of 500 MW after supplying the energy needed for the capture island. The gas turbine only cases, Cases 1GE-A and 1S-A, increase power output on average by 308 MW. Cases 2GE-A and 2S-A, the combined cycle plants cases, raise power production on average by 478 MW, and the boiler case, Case 3-A, raises the aggregate output by 151 MW.

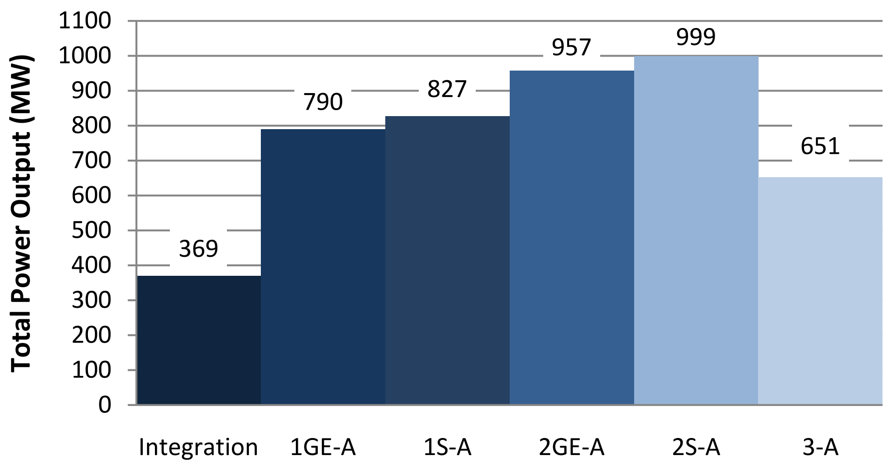

Figure 6-4. Aggregate Power Output Available for Dispatch for Retrofit Cases (Scenario A).

The economic performance of the integration plant case using different cost levels is also compared with the auxiliary plants in terms of capital cost, mitigation cost, and electricity cost. The capital cost per kW of electricity available for sale (including coal plant power output) after supplying energy to the capture plant is shown in Figure 6-5. The integration cases all have significantly higher capital costs per kW of electricity when compared with the auxiliary plant option. The integration case using a Level C cost factor doubles the cost of integration in addition to derating the power plant, resulting in a capital cost per net kW that is more than twice as much as any of the gas turbine options. The gas turbine cases have similar capital costs on a per net KW basis, ranging from $760-803/kW. The natural gas boiler design has the highest capital cost per kW of electricity because of its low power output while requiring a capital investment close in value to the gas turbine only option.

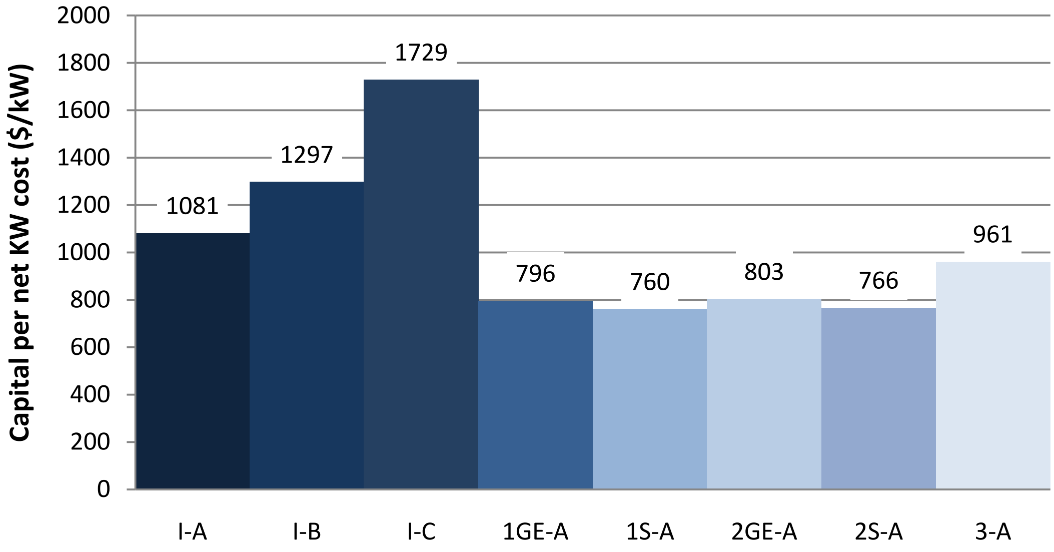

Figure 6-5. Capital Cost on a Net kW Basis after Retrofit for Integration and External Plant Cases.

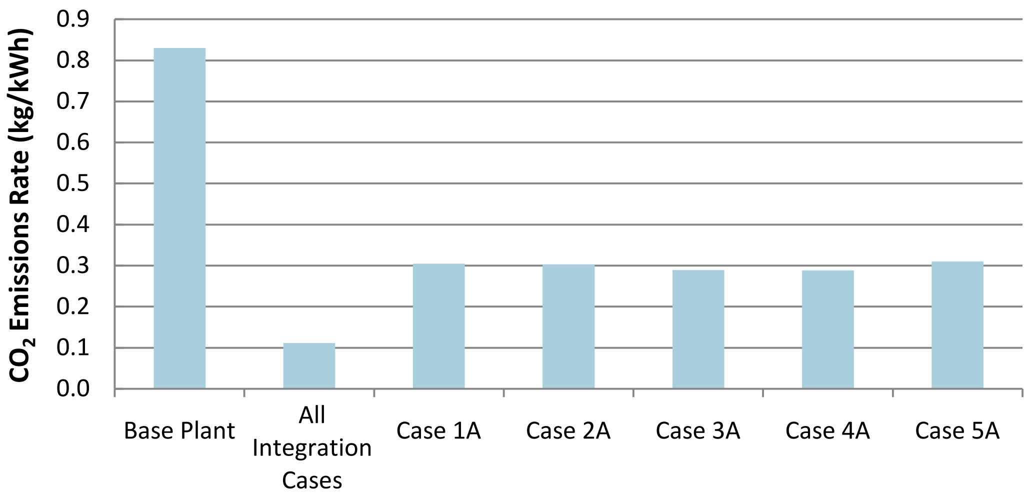

Figure 6-6. CO_2 Emissions Rate per kWh of Electricity

The emissions rate for each plant per kilowatt-hour of electricity is shown in Figure 6-6. The emissions rate using an external plant is about 2.6 times the rate observed when using integration. The auxiliary plant produces more electricity than the coal plant per kg of CO_2 generated, but the CO_2 in the stack gas of the external plant is not captured as discussed in Chapter 5. Taking Case 2S-A as an example, the percentage of carbon dioxide captured from the combined emissions of the base plant and external plant is 56%, a decrease from 90% capture in the integrated plant case. Across natural gas plant cases, no significant difference is seen in the CO_2 emissions rate per kilowatt-hour of electricity.

The cost of electricity for the coal plant, the coal plant integrated with the CO_2 capture island, and the aggregate plant system including the external plant is shown in Figure 6-7. The cost of electricity includes the O&M, fuel (coal and if applicable, natural gas), and capital costs. The base plant COE of 3.9 ¢/kWh increases to 8.3, 8.7 and 9.7 ¢/kWh for the integration cases using cost levels A, B, and C. The COEs for the gas turbine based external plants vary between 8.7 and 9 ¢/kWh. The natural gas boiler's has a 10.2 ¢/kWh COE and is the most expensive option. At the integrated plant cost factor of Level B, the integration and combined cycle gas turbine case of 2S-A have equivalent costs of electricity. The fuel component of the COE increases the fastest between the four gas turbine cases and the integration cases due to the additional natural gas used. The capital component of the COE fluctuates significantly for the integration cases, but does not change substantially across the auxiliary plant cases due to additional capital investment being matched by higher power output. The O&M cost portion increases only slightly in the external plants relative to integration due to lower maintenance costs for gas turbine based plants compared to coal plants and increased power output.

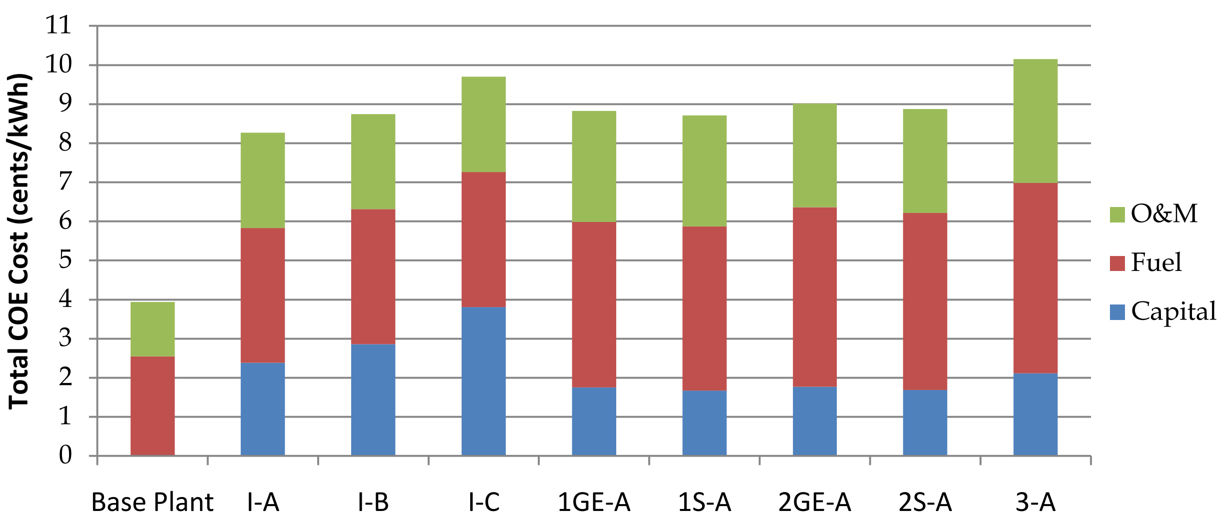

Figure 6-7. Cost of Electricity for Base Plant and Retrofit Cases in Scenario A.

The competitiveness of the external plant option is also influenced strongly by the price of natural gas. The analysis up to this point used a cost of $5.37/MMBtu based on the U.S. Energy

Information Administration's annual average estimate for 2010 (47). The natural gas market has shown significant volatility in recent history (See Figure 3-3), and could be further affected with the expanded use of domestic natural gas reserves. The sensitivity of the cost of electricity of each auxiliary plant option to natural gas prices is examined in Figure 6-8. The natural gas price is scaled from the 2010 value of $5.37 MMBtu (P) by 0.5, 1.5, and 2. The cost of electricity using an external plant changes by about 1.5 ¢/kWh when the natural gas price is scaled by 0.5 or 1.5. This is due to high volumes of natural gas being used in the external plant cases, particularly in the combined cycle plants. The projections for natural gas fuel prices over the lifespan of the external plant will have a strong impact on the favorability of the integration and auxiliary plant retrofit options.

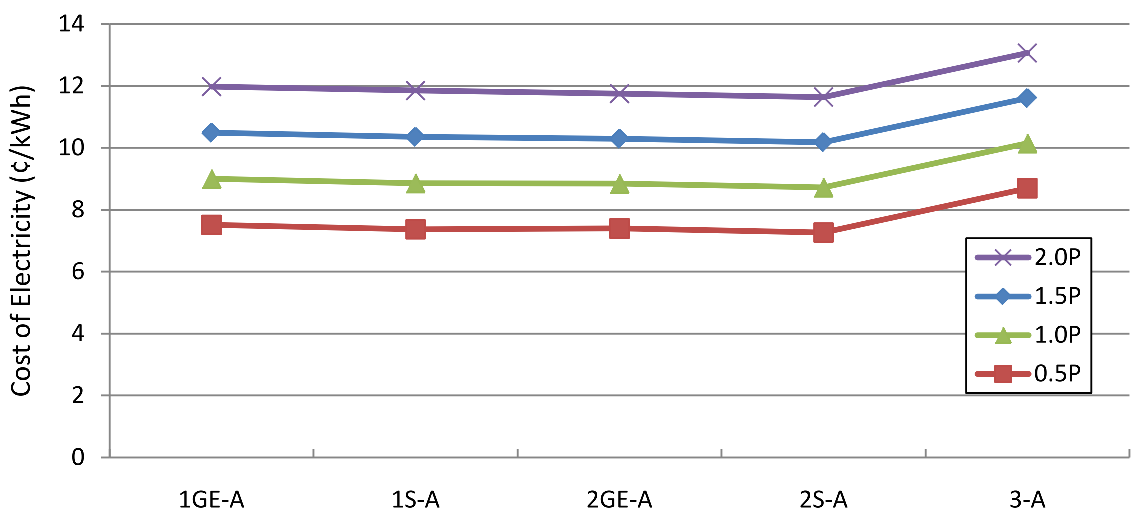

Figure 6-8. Sensitivity of Cost of Electricity to Natural Gas Cost (P=2010 NG Cost).

To understand how changes in natural gas price and integration costs estimates would affect the performance of the two major retrofit approaches, Case 2S-A (Siemens CCGT) economics are examined as a function of both natural gas price and integrated plant cost. The ratio of the cost of electricity of Case 2S-A to the integrated plant is calculated for natural gas prices from 0.5 to 1.5 times today's cost ($5.37/MMBtu) and for integrated plant cost factor ranging from 1.2 to 2. The results for Case 2S-A are plotted in Figure 6-9.

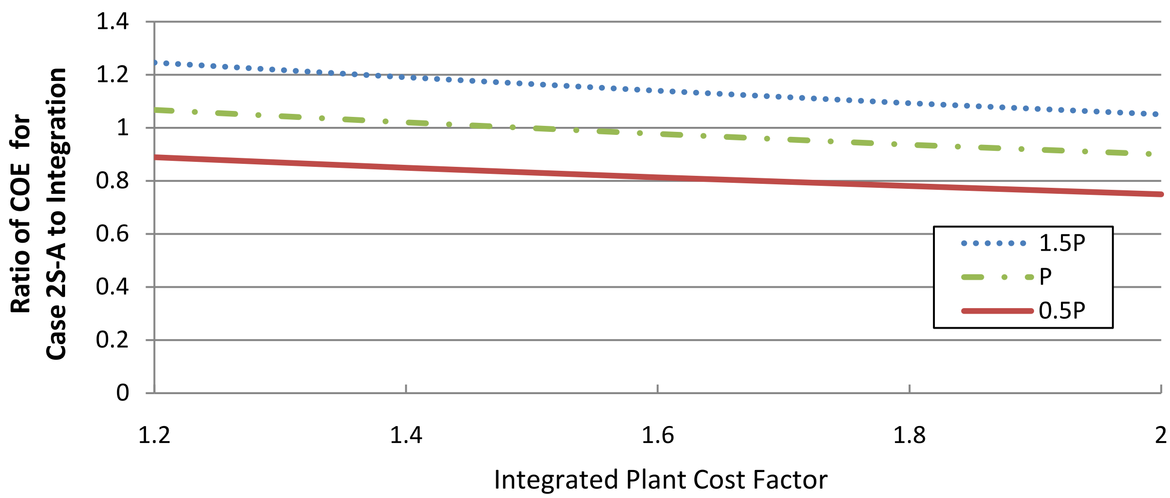

Figure 6-9. Sensitivity of Ratio of COE for Case 2S-A and Integration to Natural Gas Fuel Price and Integrated Plant Cost.

The graph shows that when natural gas fuel prices are at 1.5 times the current price, only at an integrated plant cost factor of around 2 is the COE of Case 2S-A comparable to integration. As mentioned earlier, at today's gas prices, the COE ratio shifts from above 1 to below 1 at a 1.49 integrated plant cost factor. On the other hand, with low natural gas fuel prices of half of today's prices, Case 2S-A has a lower COE than integration regardless of the level of integration difficulty. The integration costs are treated in this analysis as a fixed cost that can be paid for over a 20-year payback period, while the natural gas usage reflects a variable cost in the COE. This graph suggests that the natural gas price will have at least as much of an impact on electricity costs as the integration costs.

The results presented here are for Scenario A, in which the capture plant is based on currently available MEA-based capture technology. The large steam demands in this scenario result in significant excesses of electricity in the auxiliary plants and economics that are highly sensitive to fuel costs. The combined cycle gas turbine option appears to slightly outperform the gas turbine only approach despite its high capital cost because it maximizes the amount of electricity produced per Btu of fuel consumed, i.e. it most effectively cogenerates heat and electricity. The gas turbine only cases gives a similar performance profile to the CCGT option, but at a lower capital cost, reduced natural gas feed rate, and lower total power output. The boiler lags in all performance indicators because it does not effectively cogenerate—it does not produce enough electricity to justify its cost. The high concentration of CO_2 in boiler stack gas leads to the a slightly worse emissions profile per kilowatt-hour of electricity.

The cost of integration and natural gas fuel price has the ability to significantly change the relative performance of the turbine and integration options. As mentioned before, the true cost of integration would include a number of other factors not accounted for here that would drive the cost of electricity upwards. In addition, the natural gas plants' substantial fuel needs imply that changes in the natural gas price from the $5.37/MMBtu estimate used here can alter the competitiveness of the external plant option.

As each auxiliary plant was designed for a specific capture island steam and power requirement profile, the relative performance of these options may be affected by a lower steam to power distribution need (Scenario B). The effect of an alternate steam to electricity demand profile on external plant characteristics and economics is outlined in the following section.

6.2 SCENARIO B: HIGH ELECTRICITY TO STEAM SOLVENT

In Scenario B, the parasitic power load of the capture island was kept constant from Scenario A but the distribution of power needed was changed. In Scenario A, 49% of the 131 MW_e power loss is due to electricity used in the capture island, while 51% of the total power loss is due to the turbine generating less power as a result of steam extraction. In Scenario B, this power distribution is changed to 65% of 131 MW of power loss due to electricity needs and 35% of the total 131 MW_e loss due to a loss of turbine power. Given a lower heat (i.e. steam) requirement in the capture island in Scenario B, the number of theoretical gas turbines necessary to generate the required amount of steam was recalculated for Cases 1 and 2. The gas boiler of Case 3 was redesigned to produce exactly the amount of steam needed. The reboiler of the capture island continued to operate at close to 3 bar, but the amount of steam needed decreased from 206 kg/s in Scenario A to 141 kg/s in Scenario B.

Though the distribution of parasitic energy needed by the capture island is changed in Scenario B, the capture plant cost is assumed to be unchanged from Scenario A. Figure 6-10 varies the integrated plant cost factor to demonstrate the effect on cost of electricity and compares it to the cost using a combined cycle auxiliary plant (Case 2S-B).

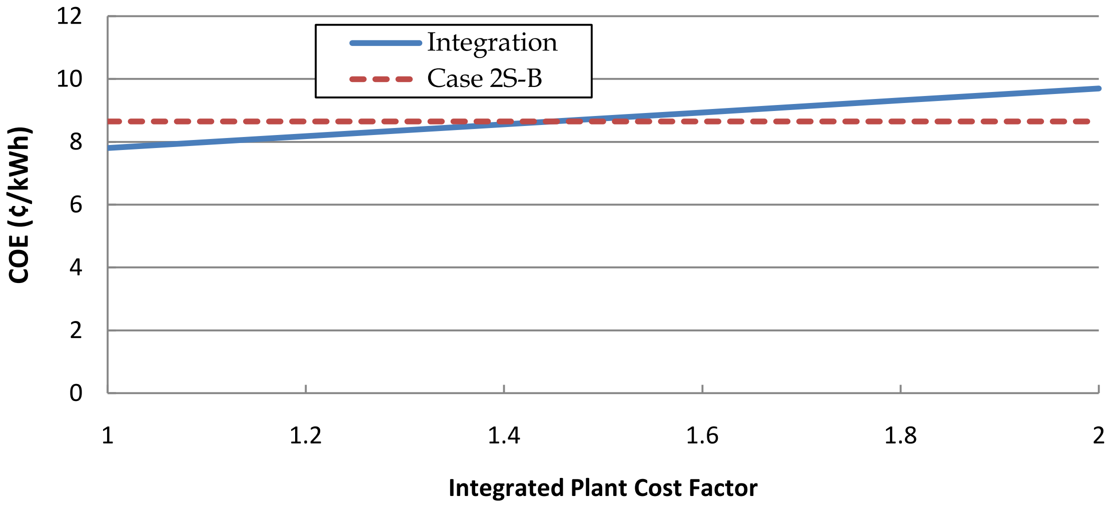

Figure 6-10. Sensitivity of COE to Integrated Plant Cost Factor.

The figure shows that integration and combined cycle auxiliary plant have comparable electricity costs at a cost factor of about 1.45, slightly better than the 1.49 cost factor seen in Scenario A. For the purposes of comparing the auxiliary plant option to integration, the Level B integration cost factor of 1.5 is used for the remainder of the Scenario B integration case analysis.

Table 9. Summary of Performance of Auxiliary Plant Cases under Scenario B.

	Capital Cost incl. Capture Plant ($MM)	Ext. Plant Efficiency (HHV)	Net Output (MW)	COE (¢/kWh)	CO_2 Emissions (kg/kWh)	CO_2 Avoided Cost ($/ton)	Delta Output (MW)
Case 1GE-B	531	32.3	657	8.83	0.27	87.4	157
Case 1S-B	521	32.8	666	8.75	0.27	86.1	166
Case 2GE-B	627	40.2	771	8.75	0.26	84.7	271
Case 2S-B	625	41.4	800	8.65	0.26	83.0	300
Case 3-B	546	24	560	9.91	0.27	107	60

A summary of the results for the auxiliary plant cases in Scenario B is shown in Table 9. A reduced steam load translates to lower initial capital costs relative to Scenario A. The cost of the smaller external plants, shown in Figure 6-11, range from $201 million for Case 3-B to $307 million for Case 2GE-B. Cases 2GE-B and 2S-B require 1.6 and 1.3 theoretical gas and steam turbine systems, respectively. Cases 1GE-B and 1S-B require 1.4 and 1.0 gas turbines with HRSG plants, respectively. The jump in average cost between Case 1 and Case 2 can primarily be attributed to the additional purchase of a steam turbine and ancillary equipment. The boiler and gas turbine only cases require nearly the same capital investment despite the gas turbine only auxiliary plants producing on average 70% more electricity. The low 24% HHV efficiency of the gas boiler case compared to the average efficiency of 32% in the gas turbine only design leads to this gulf in power output (Figure 6-12).

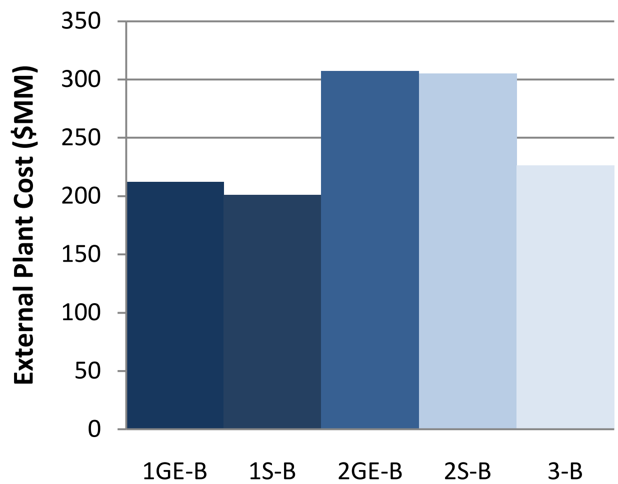

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Figure 6-11. External Plant Cost for Scenario B in Reference Year 2010 Dollars.

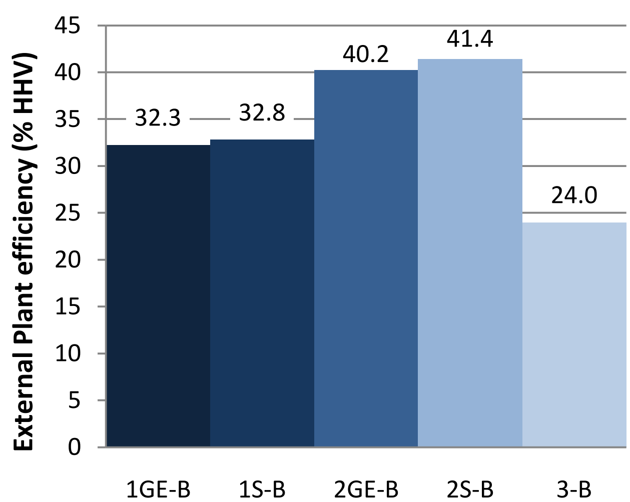

Figure 6-12. External Plant Standalone Efficiency on an HHV Basis (Scenario B).

The net power output after supplying energy to the capture island for each case is shown in Figure 6-13. Auxiliary plants using combined cycle technologies (Case 2) increase power output on average by 57% from the 500 MW of the base plant, the greatest increase in power output among all options. The gas turbine only scenario (Case 1) and boiler case (Case 3) increase power by 32% and 12%, respectively. A decreased steam requirement in the capture island leads to a smaller external plant across all cases relative to Scenario A.

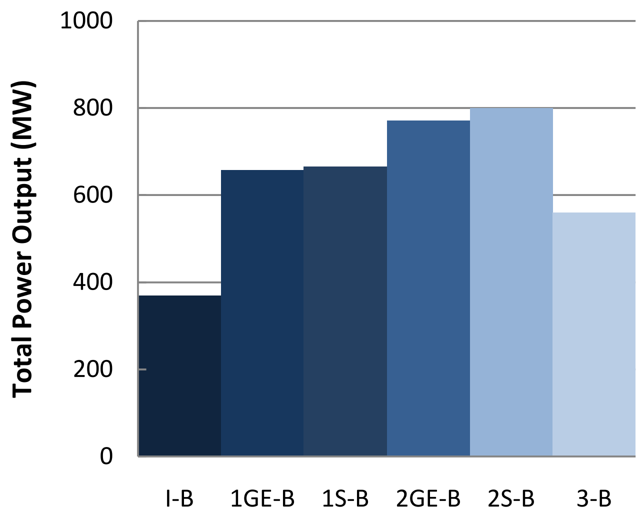

Figure 6-13. Power Available for Sale in Retrofit Cases (Scenario B).

The total capital investment required for the capture island and external plant per kW of electricity available for sale is shown in Figure 6-14. The capital investment per kW of electricity generated is lower for the auxiliary plants compared to the integration case I-B. Because the natural gas boiler case has a much lower efficiency and requires significant capital investment beyond the capture island, Case 3-B has the highest capital per net kW cost.

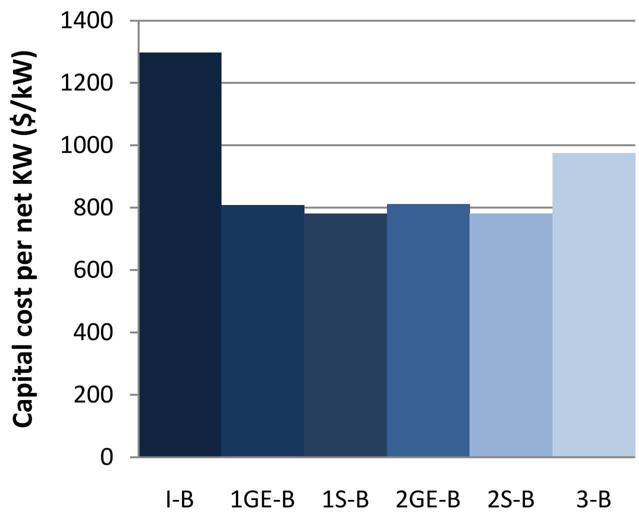

Figure 6-14. Capital Cost on a Net kW Basis for Scenario B.

The emissions rate for each plant per kilowatt-hour of electricity is shown in Figure 6-15. The base plant and integration case emissions rate is unchanged from Scenario A. Using an external plant, CO_2 is released at about 2.4 times the rate of observed when using integration alone. This is lower than the factor of 2.6 observed in Scenario A due to smaller auxiliary plants venting less flue gas. The CO_2 emissions rate does not vary significantly across auxiliary plant technologies.

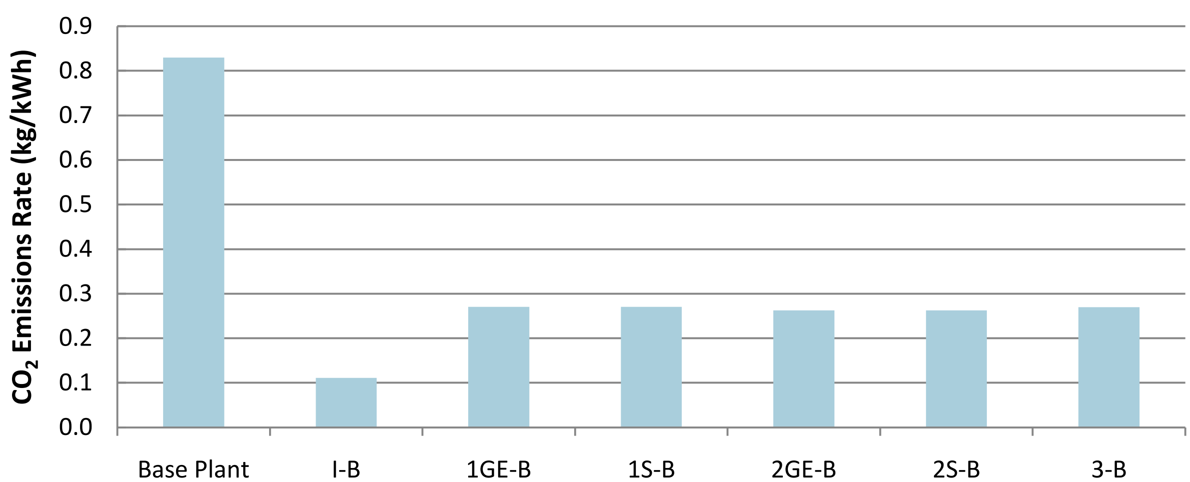

Figure 6-15. CO_2 Emissions Rate per kWh of Electricity.

The costs of electricity for the different cases are shown in Figure 6-16. In Scenario B, Case 2S-B, the combined cycle plant with Siemens gas turbine, again leads to the lowest COE among the external plant options. From the integration COE of 8.27 ¢/kWh, the COE for 2S-B is 8.65 ¢/kWh, an increase of 4.6%. Only a slight increase in the O&M component of COE costs is seen from the integration to the Case 1 and 2 designs, while Case 3 led to a slightly higher O&M component of COE. The fuel component of the cost of electricity for the external plant cases is higher than in the integration case due to the additional natural gas required. The capital portion of the COE is lower for Case 1 and Case 2 relative to integration due to the external plant's electricity production increasing faster than the capital investment compared to an integrated system. The capital contribution to the COE for the natural gas boiler is higher than any other case due to its lower electrical output relative to capital cost required. Compared to Scenario A, each external plants' electricity cost has decreased by 1-2% due primarily to less fuel costs. These results suggest that as the steam requirement from the capture island decreases, the external plant option becomes more competitive with integration in terms of capital costs and CO_2 emissions rate, but not in terms of electricity costs.

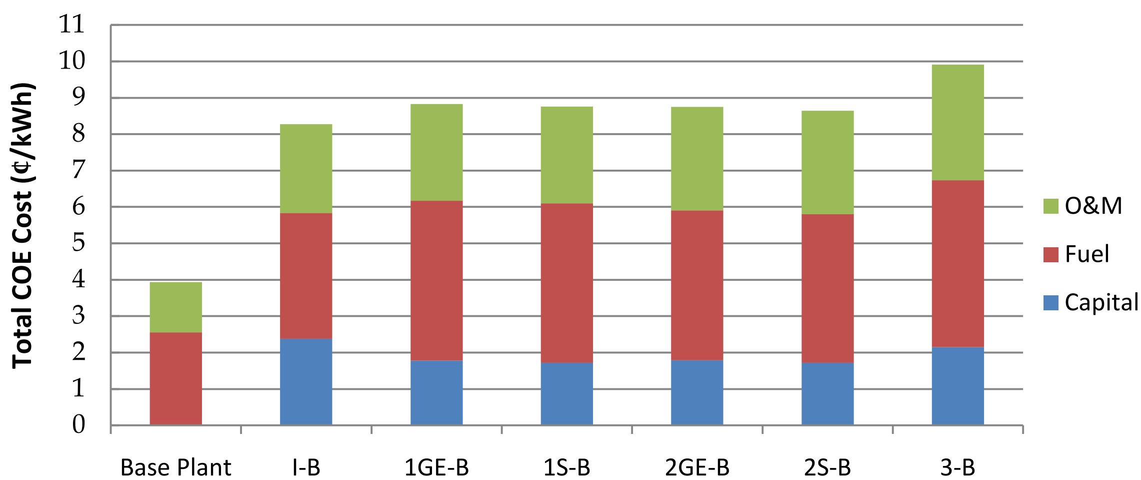

Figure 6-16. Cost of Electricity for Base Plant and Retrofit Cases in Scenario B.

The effect of natural gas price on electricity costs in the auxiliary plants was plotted in Figure 6-17. When the natural gas price is half of the 2010 cost of $5.37/MMBtu, the COE for a gas turbine plant decreases by roughly 1.25 ¢/kWh to between 7.4 and 7.6 ¢/kWh. At 1.5 times the 2010 natural gas cost, the electricity cost using a gas turbine-based external plant reaches about 10 ¢/kWh (compared to 8.27 ¢/kWh in the integration I-B case). As in Scenario A, natural gas price changes have a significant impact on the electricity cost when using a natural gas-firing auxiliary plant.

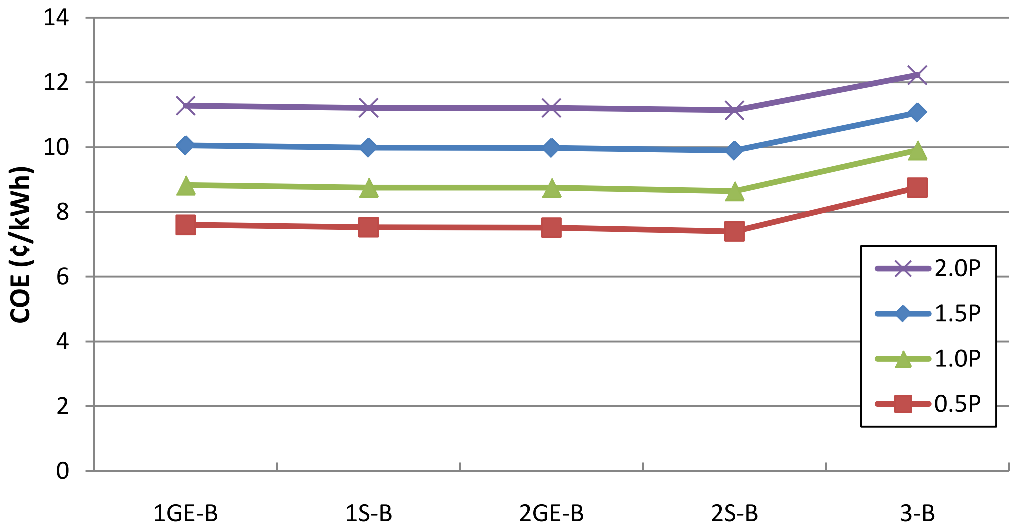

Figure 6-17. Sensitivity of Auxiliary Plant COE to Natural Gas Fuel Price (P=2010 NG Price).

The combined effect of the cost of integration and natural gas price changes on the cost of electricity is explored in Figure 6-18. The y-axis variable is the ratio of the COE of Case 2S-B to the integration case, and the x-axis plots the integrated plant cost factor. At low natural gas prices of half of the 2010 price, the COE ratio is less than one regardless of the integrated plant cost factor used. When natural gas prices remain at their current levels ($5.37/MMBtu), the ratio of COE's is one at the integrated plant cost factors of 1.45. As the natural gas price increases to 1.5 times the 2010 price, the integrated plant cost factor would have to increase to 2 or more before the electricity cost of Case 2S-B is comparable to integration.

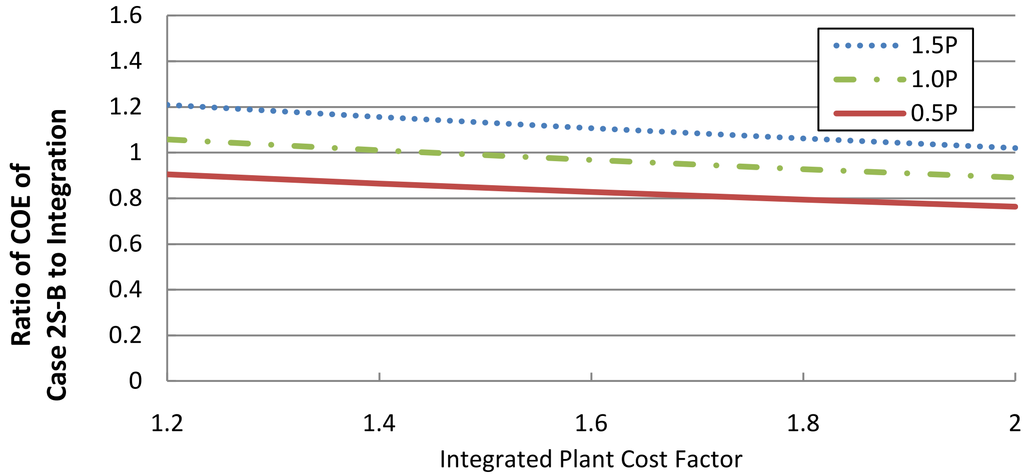

Figure 6-18. Sensitivity of Ratio of COE for Case 2S-B and Integration to Natural Gas Fuel Price and Integrated Plant Cost.

Because the integration cost and natural gas price will vary over time and across units, the economic performance of an external plant relative to integration is difficult to predict. Plant operators faced with the integration constraints discussed in Chapter 3, however, may need to consider a number of different factors when choosing a retrofit option. The likelihood of solvent developments leading to regular changes in steam demand may affect the technical and economic viability of the integration approach. In addition, the future of natural gas prices may become more certain by additional investigations into domestic reserves or new government policies nudging natural gas prices in a particular direction. Thus plant operators face a number of uncertainties and needs when choosing among retrofit options that could potentially alter the attractiveness of the external plant option over the life of the plant.

7 DISCUSSION AND POLICY IMPLICATIONS

The study aims to answer the question of whether using an external plant for energy needed for a post-combustion capture retrofit is a practical alternative to integration. Chapter 6 presents a broad technical and economic outline of how different technologies perform in an auxiliary plant. The two major categories, integrated plants and auxiliary plant retrofits, should be assessed in light of multiple strategic objectives: making CCS retrofits more attractive to undertake and meeting long-term energy goals and carbon reduction targets.

7.1 MAKING CCS RETROFITS MORE ATTRACTIVE TO UNDERTAKE

Due to the number of coal plants already in operation and plans to increase coal-fired electricity production world-wide, making retrofits more practical to implement is a key aspect of accelerating CCS implementation. The auxiliary plant option could provide a number of potential advantages to plant operators over integration in certain scenarios. Whether those conditions are met will depend upon a number of factors, making the auxiliary plant another retrofit option available to plant operators but not necessarily the most attractive one.

Using an auxiliary plant for retrofit will increase the net power produced from the coal plant after installing CCS. This could be a potentially valuable feature of a retrofit if there is sufficient regional demand for electricity, especially in contrast to the 20-30% loss in power output expected from the integrated retrofit option. The most attractive auxiliary plants cogenerate significant excess electricity on the order of hundreds of megawatts of electricity for a 500 MW coal plant, and if the auxiliary plant's variable costs of electricity are low enough to ensure dispatch, the profitability of a retrofit could be improved using an auxiliary plant. Before the excess electricity could be sold, however, improvements to transmission lines and infrastructure around the plant may be necessary to handle an increased load, already a growing national concern (37). Nonetheless, if sufficient demand and infrastructure are in place and its electricity costs are low compared to integration, the increase in power output can make retrofits more affordable to implement.

Auxiliary plants also avoid much of the technical and economic risk associated with modifications to the coal plant's steam turbine system. The technical challenges associated with integration make it difficult to estimate the retrofit cost *a priori*. If the integration costs are expected to be substantial and the loss in power output and efficiency penalty associated with these modifications are expected to be significant, the auxiliary plant option may provide cost savings, making retrofits a more feasible path forward. Many of the practical and technical hurdles of scheduling downtime, turbine modifications and reengineering can also be avoided by building a neighboring auxiliary plant. An auxiliary plant retrofit, while having higher upfront capital costs, would eliminate the risk of a costly integration process that also decreases the plant's power output. The new gas plant would use mature gas turbine technology and could be built from the ground-up to meet the energetic needs of the capture plant. In addition, an integrated base plant requires turbine modifications particularly designed for a specific amount and pressure of extraction steam as discussed in Chapter 3. In contrast, an auxiliary plant designed for steam generation would offer more flexibility for changes in capture plant steam conditions.

The external plant option, while potentially avoiding a costly integration process, also has economic uncertainty associated with it arising from its dependence on natural gas prices. Depending upon the natural gas price, auxiliary plants could make retrofits more (or less) affordable for operators to install relative to integration. Table 10 summarizes the effect of natural gas prices on electricity costs for an MEA plant with total integration costs of 1.25 times the capture plant capital. If natural gas prices drop to about half of today's levels ($2.69/MMBtu), electricity becomes cheaper to produce using an auxiliary plant. If the cost of natural gas increases from today's prices, the auxiliary plant option rapidly becomes more expensive. Natural gas prices will also influence the mitigation costs of the auxiliary plant, though how it will affect the desirability of integration versus an auxiliary plant is unknown. As discussed earlier, the integration case's avoided cost does not consider the replacement power accounted for in the auxiliary plant option. Because of dramatically different power outputs and multiple fuel sources arising from natural gas firing in the auxiliary plant, the comparison of auxiliary plant mitigation costs to integration is unreliable until replacement power is accounted for in the integration cases.

For a capture plant with a high electricity to steam need, the relative costs of the integration and auxiliary plant options are essentially unchanged from the MEA capture plant case. Using a high electricity to steam solvent, the auxiliary plants can be smaller and require roughly 30% less capital than in the MEA plant case. The cost of electricity ratio is not significantly improved when using a high electricity to steam solvent because the lower capital and fuel costs of the auxiliary plant are offset by less electricity produced (Table 11). The auxiliary plant economics still show sensitivity to natural gas prices despite lower natural gas usage. As in the MEA plant case, the electricity costs for an auxiliary plant do not differ significantly from the integrated plant at today's gas prices, but do become more expensive if gas prices increase. The mitigation cost ratios compared to the MEA plant scenario are lower for gas prices at or above today's levels due to less fuel and capital being required when using a high electricity to steam solvent capture plant. Regardless of the energy profile of the capture plant, the auxiliary plant is more expensive than integration unless natural gas prices are at or below today's levels or integration costs are high.

Table 10. Cost Ratios of Combined Cycle 2S-A Plant and Integration Case.

Scenario: MEA Plant, Integrated Plant Cost Factor = 1.25		
Natural Gas Price ($/MMBtu)	COE Ratio (2S-A to Integration)	Cost of CO_2 Avoided Ratio (2S-A to Integration)
$2.69	0.88	1.02
$5.37	1.05	1.47
$8.06	1.23	1.91

Table 11. Cost Ratios of Combined Cycle 2S-B Plant and Integration Case.

Scenario: High Electricity to Steam Solvent, Integrated Plant Cost Factor = 1.25		
Natural Gas Price ($/MMBtu)	COE Ratio (2S-B to Integration)	Cost of CO_2 Avoided Ratio (2S-B to Integration)
$2.69	0.90	1.01
$5.37	1.05	1.38
$8.06	1.20	1.74

The natural gas auxiliary plant option also brings with it specific features or requirements that can make it a more burdensome retrofit option than integration. From the perspective of percentage of total carbon emissions captured, the auxiliary natural gas plant retrofit does lead to a lower total percentage captured, leaving operators susceptible to higher CO_2 prices in the future and essentially "on-the-hook" for the additional CO_2 emissions. Capturing the CO_2 in the auxiliary plant flue gas is possible but would require an additional capture plant or mixing with the coal plant flue gas, leading to additional costs. The auxiliary plant must also have access to natural gas pipelines. If the coal plant location is not within reach of existing natural gas pipelines, new, additional infrastructural investments would be required. Though this could be a neutral factor, natural gas-firing auxiliary plants require more upfront capital than the integration approach. A utility company's unwillingness to invest in capital, especially when faced with an uncertain regulatory scenario, can affect the desirability of the auxiliary plant option relative to the integration option.

For some plants, the auxiliary plant approach will not change the ease of installing a retrofit. If a plant lacks sufficient space for the natural gas plant or capture plant, a retrofit cannot be utilized. Using a natural gas plant will not affect the requirement that upgrades to the SO_x and NO_x emission controls equipment be made in the base plant prior to sending the flue gas to the capture plant. This requirement has important space and cost implications for retrofits that will not change using an auxiliary plant approach. Retrofits are currently least attractive for older plants that have lower efficiencies (i.e., higher CO_2 emissions rates per kWh) and these types of plants will not be affected by an auxiliary plant option. Older plants have shorter remaining life spans making the investment required for a retrofit impractical. Smaller plants also do not warrant the investment in PCC equipment. Inefficient plants produce greater amounts of CO_2 per kWh which drive up capture costs, and the auxiliary plant option will not change this barrier. Practical factors like the proximity to sequestration sites and access to sufficient water supply also remain as deterrents despite which retrofit option is considered.

7.2 SUPPORT FROM LONG-TERM ENERGY SECTOR TRENDS

As utility companies decide how to make expensive modifications to their plants, projections of energy demand growth, stricter emission standards, and increased natural gas supply will likely influence how major investments are made. As the economics of the integration and external plant options are influenced by the ability to gain state and federal government support (both monetary and political), natural gas-based cogeneration might be more attractive in the long-term because of its resilience to the pressures of long-term energy market trends.

Consistent growth in electricity consumption will lead to a greater call for baseload electricity generation over the next two decades. According to the EIA, 259 GW of new capacity will be needed in the next two decades, roughly three-fourth the size of the current coal fleet (1). Between the period of 2009 and 2018, energy demand is projected to increase by 15% (37). However, a CCS retrofit that is integrated with the base plant will decrease the base plant's power output, reducing the region's electricity supply and affecting the operating profit from electricity sale to the grid. An external plant would have precisely the opposite effect, increasing the stability of electricity supply and providing more electricity available for sale. With additional electricity for sale potentially increasing the operating profit for the external plant case, the time to recoup the higher capital costs could also be reduced. A plant operator would have to decide whether lower costs in the short-term using integration will outweigh a larger potential for profit in the long-run once the sunk costs of an external plant are recovered.

The expectation of stricter emission standards also has created a push towards using cleaner fuels, and natural gas has emerged as the preferred fuel until the exact nature of regulatory standards are known (4). Natural gas is responsible for slightly less than one-quarter of US electricity generation today (52). Natural gas plants are attractive for new builds because they are easy to site, have short construction times, and operate with high efficiency. The capital costs associated with natural gas turbine plants meanwhile are lower than what is found with renewable or nuclear energy. Because natural gas plants have a higher efficiency and lower carbon dioxide intensity than traditional fossil-fuel (petroleum or coal) power plants, natural gas use is projected to increase rapidly over the next fifteen years (4). Some plants have already begun to fuel switch from coal to natural gas. For example, in 2009, Progress Energy Carolinas closed three coal plants and announced plans to replace it with one 950 MW combined cycle gas plant. According to the CEO, the company's motivation was partly due to the likelihood of legislation that would reduce carbon emissions, stating "it's in the best interest of our customers to invest in advanced-design, cleaner-burning generation." In addition, the company will diversify its energy portfolio further while taking advantage of low fuel prices. The political response to the Progress Energy's decision was striking. The North Carolina state legislature streamlined the permit process by passing a law that shortens the certification time to 45 days from several months for fuel or technology replacement projects (53). The momentum for natural gas use appears high from a commercial and political perspective. Until the stringency of future emissions regulations are known, plant operators are turning to natural gas plants because of their higher efficiency and lower emissions and favorable perception as a transition technology to a cleaner energy sector.

Lastly, the affordability of the external plant option appears primed to benefit from the recent discovery of additional reserves of natural gas in shale rocks within the United States. The Potential Gas Committee, the authoritative source on national gas supply, estimates that the domestic supply is 35% higher than originally estimated, the largest increase observed in the 44-year history of the committee issuing reports (52). As of April 2010, the Henry Hub Natural Gas Spot Price hovered around $4/MMBtu, more than a $1/MMBtu less than the EIA's projected value for 2010 (35) (54). The EIA projects that natural gas prices will show less volatility in the future due to the increased domestic supply (55). These reserves are also advantageously located near existing natural gas pipelines and large electricity markets, and utilization of these reserves will contribute to the government's goal of greater energy security. These factors have combined to lead to an "overwhelming preference" for natural gas for new capacity according to a report from the organization of U.S. electrical grid operators (37). Concerns over the higher drilling costs, water usage, and grid system reliability issues, however, have tempered the enthusiasm for the new gas supplies (37)(52). In the coming years, as more is known about the accessibility of the natural gas reserves, the long-term forecast for natural gas prices may help improve the economics of the external plant relative to integration.

8 CONCLUSIONS

Three types of auxiliary plant technologies were considered for meeting PCC retrofit energy needs: gas turbine with HRSG, gas turbine with HRSG and steam turbine, and natural gas boiler with steam turbine. The most attractive option was the gas turbine with HRSG and steam turbine plant, followed by the gas turbine with HRSG plant. The least attractive option was the natural gas boiler plant.

- The most important factor affecting performance was the plant efficiency or ability to cogenerate heat and electricity. The excess electricity generated has to be maximized in order to offset the additional capital and fuel costs and make plant operation less expensive.
- Using a steam turbine with the gas turbine required substantial capital and led to nearly 500 MW_e of excess electricity. When using a gas turbine with HRSG only, the power and cost of the auxiliary plant both decreased by about 30%.
- The rate of CO_2 emissions per kWh of electricity was nearly constant across auxiliary plant options.

The auxiliary plant option was also compared to an integrated plant. Based on the cost of electricity, the two approaches are similar when the "integration cost" added an additional 50% to the capital cost of the capture plant.

- A significant difference between the two options was seen in the CO_2 emissions rate. The auxiliary plant option had a CO_2 emissions rate about 2.6 times higher than in the integrated plant because the auxiliary plant flue gas was vented.
- <u>The attractiveness of each option showed significant sensitivity to natural gas prices</u>**.** Low natural gas prices (half of today's levels) made auxiliary plants more attractive than integration from a cost of electricity perspective, even at low integration costs. Similarly, high natural gas prices (50% increase from today's levels) lead to the integrated plant having a lower cost of electricity than in the auxiliary plant case, despite high integration costs.

The effect of using a high electricity to steam solvent in the capture plant was compared to the MEA case. For capture processes with a high electricity to steam solvent, significantly smaller auxiliary plants will be needed.

- For the most economical auxiliary plant design of a gas turbine with steam turbine, the capital cost and power output prior to supplying retrofit energy decreased by 31% when using a high electricity to steam solvent rather than using an MEA-based capture plant.
- CO_2 emission rates per kWh of electricity were also lower when using a high electricity to steam solvent due to smaller plant sizes resulting in less flue gas being vented into the atmosphere.
- The relative electricity costs of the integration and auxiliary plant options are similar to an MEA capture process for the high electricity to steam solvent capture plant. The cost of electricity sensitivity to natural gas price was not affected by whether the capture plant used MEA or a high electricity to steam solvent.

In general, whether an auxiliary plant or integrated plant is preferred is not always clear. High natural gas prices favor the integration option, while high integration costs favor the auxiliary plant option. The existing plant site characteristics and regional needs will play a large role in determining the optimal retrofit approach.

- The mitigation costs of the auxiliary plant and integration cases could not reliably be compared in this analysis as the two cases differed in their net power outputs and fuel components. The mitigation cost of the auxiliary plant accounted for the costs and emissions of make-up power and significant excess electricity, while the integrated plant case did not. Based upon the type of replacement power used, the integration case's electricity and mitigation costs will change to reflects the costs of new power output and, at that point, enable comparison between the two retrofit approaches.

Difficulties in implementing integration leading to substantial costs, when coupled with a high regional electricity demand, may make auxiliary plants more attractive for retrofits when compared to integration.

- Auxiliary plants can more effectively cogenerate electricity than the existing coal plant, resulting in excess electricity that can increase the operating profitability of the retrofit if sufficient regional demand exists.

Integration remains the most attractive option if natural gas prices increase, regional electricity demand does not exist for excess power, or when natural gas plants cannot feasibly be built.

- Because of the high natural gas fuel consumption rates in the auxiliary plants, electricity costs show a strong dependence on the natural gas price. Natural gas auxiliary plants require sufficient space and access to natural gas pipelines for feasible construction.

Auxiliary gas plants do not affect a number of barriers to retrofit that are also present when using integration.

- SO_x and NO_x emissions control upgrades and sufficient space in the vicinity of the coal plant will be required for post-combustion capture retrofits in either option. The economics of older, inefficient coal plants with shorter life spans and higher CO_2 emissions per kWh is unchanged when using an auxiliary plant retrofit.

Auxiliary gas plants are poised to benefit from energy sector trends that could potentially reduce costs in the long-term.

- Auxiliary gas plants increase net output and can be used to meet projected long-term energy demand growth. Significant new investment in base load electricity generation is expected to meet this demand over the next decade. Higher power output from an auxiliary gas plant will improve the operating profit of the retrofit plant and enable utilities to recover some of the costs associated with CCS.
- Natural gas-firing external plants are easier to build relative to new coal plants. Natural gas plants are generally easier to site, have shorter construction times and lower capital costs, and face less political resistance than their coal plant counterparts. Natural gas plants have a higher efficiency and better greenhouse gas emissions profile than other fossil-fuel based plants and provide some security against future emissions regulations relative to coal plants.

- The discovery of new natural gas reserves within the United States has the potential to improve the economics of the auxiliary gas plant option relative to integration. Greater stability in fuel costs will reduce the cost uncertainty associated with CCS and potentially free up access to capital. Lower natural gas prices lead to lower costs of electricity and comparable mitigation costs compared to integration.

8.1 FUTURE WORK

The objective of this work was to do an initial screening of the costs of various retrofit options, and due to the breadth of options explored, many assumptions were utilized to effectively prepare this report. A number of assumptions in the technological and economical modeling analysis are worthy of greater analysis and study. Greater precision around the true costs of integration would improve the cost estimates of the integration case, and increase the confidence in the analysis of the economic performance of the retrofit options. Technical assumptions regarding the decrease in power output from the base plant from steam extraction were based on theoretical calculations rather than actual turbine models. The capital cost estimates are based on economic simulation software and could be improved using industry experience and updated equipment and material costs. The operating and maintenance costs could be refined using cost information from plants actually in operation. The sensitivity of the cost estimates to other factors, including changes in material costs, coal prices, and operating and maintenance costs could provide further insight into the stability of the results reported. This study only looked at the case in which the flue gas from the auxiliary plant was vented into the atmosphere. Future work should also consider capturing CO_2 emissions by either mixing flue gas streams with the coal plant or building an additional CO_2 capture plant.

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Appendix A

Work Lost Calculation for Steam Extracted in Integrated Plant

Isentropic efficiency η	0.88	
Steam flowrate MEA:	205.8	kg/s
MEA Capture Plant	Enthalpy of evaporation, Hvap	
Reboiler	2162.2	kJ/kg
Condenser at 0.1 bar	2584	kJ/kg
External Plant Extraction Point		
Case 2GE	2944	kJ/kg
Case 2S	2958	kJ/kg
Availability (B) loss		
$\Delta B=\Delta H-T\Delta S$		
$\Delta B=\Delta H$ (if isentropic) [kW]		
$W_{lost} = \Delta B = H_{vap,conds}-H_{vap,extraction}$		
Case 2GE	-360	kJ/kg
Case 2S	-374	kJ/kg
Applying isentropic efficiency of 88%		
$\alpha = \eta *W_{lost}/Q$		
Case 2GE	**0.147**	
Case 2S	**0.152**	