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Technical Report

Biomass Power and Conventional Fossil Systems with and without CO_2 Sequestration – Comparing the Energy Balance, Greenhouse Gas Emissions and Economics

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Executive Summary

Power generation emits significant amounts of greenhouse gases (GHGs), mainly carbon dioxide (CO_2). Sequestering CO_2 from the power plant flue gas can significantly reduce the GHGs from the power plant itself, but this is not the total picture. CO_2 capture and sequestration consumes additional energy, thus lowering the plant's fuel-to-electricity efficiency. To compensate for this, more fossil fuel must be procured and consumed to make up for lost capacity. Taking this into consideration, the global warming potential (GWP), which is a combination of CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, and energy balance of the system need to be examined using a life cycle approach. This takes into account the upstream processes which remain constant after CO_2 sequestration as well as the steps required for additional power generation.

This analysis examined power generation for two fossil based technologies, coal-fired power production and natural gas combined-cycle (NGCC), and two biomass technologies, a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop, and a direct-fired biomass power plant using biomass residue as well as a biomass residue/coal cofired system. Each system includes the upstream processes necessary for feedstock procurement (mining coal, extracting natural gas, growing dedicated biomass, collecting residue biomass), transportation, and any construction of equipment and pipelines. For the cases where CO_2 is sequestered, the CO_2 is captured via a monoethanolamine (MEA) system, compressed, transported via pipeline, and sequestered in underground storage such as a gas field, oil field, or aquifer. The power generation capacity of each system examined was kept constant at 600 MW. For the biomass power systems, it was assumed that several small plants are needed to achieve 600 MW of electric capacity. This is because large transportation distances make biomass power uneconomical at large scales. For the systems that sequester CO_2, lost generation capacity was replaced by adding extra capacity from a natural gas combined-cycle system. The following table gives the GWP and energy results for each case and the change in GWP and fossil energy consumption compared to the coal reference case (Case 1).

Summary of GWP and Energy Balance for Fossil and Biomass Power Systems

System	Case	Net GWP (g CO_2-eq./kWh) (a)	Fossil energy consumption (MJ/kWh)	Change from reference coal system (Case 1)	
				change in GWP	change in fossil energy consumption
Coal-fired - reference	1	847	12.5	N/A	N/A
Coal-fired w/CO_2 seq (b)	1a	247	14.6	-71%	16%
NGCC - reference	2	499	8.4	-41%	-33%
NGCC w/CO_2 seq (b)	2a	245	9.7	-71%	-22%
Biomass/coal cofiring - reference	3	681	11.0	-19%	-12%
Biomass/coal cofiring w/CO_2 seq (b)	3a	43	13.1	-95%	4%
Biomass direct-fired - reference	4	-410	0.1	-148%	-99%
Biomass direct-fired w/CO_2 seq (b)	4a	-1,368	2.2	-262%	-82%
Biomass IGCC - reference	5	49	0.2	-94%	-98%
Biomass IGCC w/CO_2 seq (b)	5a	-667	1.6	-179%	-87%

(a) GHG emissions (CO_2, CH_4, and N_2O) expressed as CO_2 equivalence (CO_2-eq.).
(b) These cases include extra capacity from a NGCC system.

On a life cycle basis, because natural gas production and distribution account for a large amount of the system's GHGs, sequestering CO_2 from the NGCC system results in roughly the same GWP as sequestering CO_2 from the coal system. Even with CO_2 sequestration, the amount of GHG emissions per kWh of electricity produced is considerably more for the fossil-based systems (Cases 1a and 2a) than for the power generation systems with 100% biomass feedstock and no sequestration (Cases 4 and 5). There is a significant decrease in fossil energy consumption for all of the biomass power generation systems (Cases 4, 4a, 5, and 5a). Additionally, cofiring with biomass (Case 3) is a near-term option that can be implemented at existing coal-fired power plants to reduce GHG emissions and fossil energy consumption.

When calculating the cost of electricity with CO_2 sequestration, it is important to include the cost to capture, compress, transport, and store the CO_2 as well as the cost to produce additional electricity to make up for lost generating capacity. Currently, the cost to generate electricity from coal is about 2-3¢/kWh (U.S. DOE, 1998). Although the price of natural gas has fluctuated over the past several years, a new natural gas combined-cycle power plant would be expected to generate electricity for about 4-5¢/kWh (U.S. DOE, 2000). Biomass power via direct combustion can be generated for about 8-9¢/kWh (U.S. DOE, 1997), while advanced technologies using gasification combined-cycle are estimated to produce electricity for 5-6¢/kWh (Craig and Mann, 1996; Overend and Bain, 1995). The following table shows the cost of electricity with CO_2 sequestration for coal and natural gas.

Cost of Electricity with CO_2 Sequestration for Coal and Natural Gas Systems

System	Cost of electricity (¢/kWh)				
	Prior to CO_2 sequestration	Cost of CO_2 capture & compression	Cost of CO_2 transport & storage	Cost of replacement power	Total cost
Coal-fired	2.5	2.8	0.9	1.1	7.3
NGCC	4.5	1.7	0.6	0.7	7.5

Biomass power from an advanced combined-cycle system is less than the cost of electricity from a fossil-fueled power generation system with CO_2 sequestration, 5-6¢/kWh compared to roughly 7.4¢/kWh. Additionally, the GWP is lower, 49 g CO_2-eq/kWh compared to about 245 g CO_2-eq/kWh for either the coal or the natural gas system with CO_2 sequestration. Comparing the system GWP, along with the difference in the cost of electricity for the fossil-based systems versus the direct-fired biomass system, gives the credit required for avoided GHG emissions in order for this biomass system to be competitive. Compared to the coal-fired power generation system, an emissions credit of only \$19/tonne of CO_2-equivalent emissions, makes the direct-fired biomass system cost competitive. Relative to NGCC, the credit needs to be \$16/tonne of CO_2-equivalent emissions. However, an additional 1¢/kWh increase in the price of electricity from the fossil-fueled systems with CO_2 sequestration will make the direct-fired biomass system cost-competitive.

To determine if biomass cofiring is economical, a power producer would examine the payback period (i.e., the additional capital cost divided by the savings in operating costs). An acceptable payback period is in the range of 3-4 years. For biomass residues at a cost of \$10/dry tonne and coal at a cost of \$39/tonne, the payback period is 4 years (U.S. DOE, 1997). The payback period increases to 7 years if the coal is cheaper, at a cost of \$28/tonne. However, an emissions credit of only \$5/tonne of CO_2-equivalent emissions is needed to reduce the payback period to 3 years and biomass cofiring is a near-term option that can be utilized at most of the existing coal-fired boilers today.

Overall, producing electricity from biomass instead of fossil fuels with CO_2 sequestration, can be a cost effective solution in helping to reducing GHG emissions as well as reducing fossil energy consumption from electricity generation. This also avoids the concern about the fate of sequestered CO_2 and its long term environmental effects

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Units of Measure

Metric units of measure are used in this report. Therefore, material consumption is reported in units based on the gram (e.g., kilogram or megagram), energy consumption based on the joule (e.g., kilojoule or megajoule), and distance based on the meter (e.g., kilometer). When it can contribute to the understanding of the analysis, the English system equivalent is stated in parenthesis. The metric units used for each parameter are given below, with the corresponding conversion to English units.

Mass:	kilogram (kg) = 2.205 pounds
	megagram (Mg) = metric tonne (T) = 1 x 10^6 g = 1.102 ton (t)
Distance:	kilometer (km) = 1,000 meters (m) = 0.62 mile = 3,281 feet
Volume:	cubic meter (m^3) = 264.17 gallons
Pressure:	megapascals (MPa) = 145 pounds per square inch (psi)
Energy:	kilojoule (kJ) = 1,000 Joules (J) = 0.9488 Btu
gigajoule (GJ)	= 0.9488 MMBtu (million Btu)
	kilowatt-hour (kWh) = 3,414.7 Btu
	gigawatt-hour (GWh) = 3.4 x 10^9 Btu
Power:	megawatt (MW) = 1 x 10^6 J/s
Temperature:	ºC = (ºF - 32)/1.8

Abbreviations and Terms

BIGCC	biomass integrated gasification combined-cycle
BFW	boiler feed water
CO_2-equivalence	Expression of the GWP in terms of CO_2 for the following three components CO_2, CH_4, N_2O, based on Intergovernmental Panel on Climate Change weighting factors
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
GHG	greenhouse gas
GWP	global warming potential
HHV	higher heating value
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle
kWh	kilowatt-hour (denotes energy)
LCA	life cycle assessment
LHV	lower heating value
MEA	monoethanolamine
MW	megawatt (denotes power)
NGCC	natural gas combined-cycle
NREL	National Renewable Energy Laboratory
U.S. DOE	United States Department of Energy
vol%	percentage by volume
wt%	percentage by weight

1.0 Introduction

The burning of fossil fuels is the primary source of anthropogenic CO_2 emissions. The total U.S. anthropogenic carbon dioxide emissions in 1998, expressed as carbon equivalents, were estimated to be 1,496 million tonnes (U.S. DOE, 1999). Of this amount, 37% (550 million tonnes of carbon) was produced from the electric utility sector with 477 million tonnes of carbon resulting from coal-fired power plants (U.S. DOE, 1999). Although CO_2 is the most important greenhouse gas (GHG) and is the largest emission from power generation via fossil fuels, quantifying the total amount of greenhouse gases produced is the key to examining the global warming potential (GWP) of any system. The GWP of the system is considered to be a combination of CO_2, CH_4, and N_2O emissions. The contributions of CH_4 and N_2O to the warming of the atmosphere are 21 and 310 times higher than CO_2, respectively, for a 100-year time frame, according to the Intergovernmental Panel on Climate Change (Houghton, *et al.*, 1996). Thus, the GWP of a system can be normalized to CO_2-equivalence to describe its overall contribution to global climate change.

Because electricity production from fossil-fueled power plants accounts for a significant amount of CO_2 emissions, capturing and sequestering CO_2 from power plants has been proposed as one way that could potentially reduce the GWP of electricity generation by a significant amount. Many analysts have examined CO_2 emissions and the cost of electricity from fossil-fueled power plants with and without CO_2 sequestration (see section 6.0 for a summary of several publications). In order to get a complete environmental picture, the National Renewable Energy Laboratory (NREL) conducted a study to examine the GWP, energy balance, and cost of fossil-fueled power generation, with and without CO_2 capture and sequestration. To understand the overall environmental implications, a life cycle approach, which takes into account the upstream process steps, was taken. This is especially important for those cases where CO_2 is sequestered, because maintaining constant generating capacity required additional feedstock procurement and results in additional upstream emissions and energy consumption. The fossil-based technologies examined are coal-fired power production and a natural gas combined-cycle system. A base case design was developed for each system; then CO_2 sequestration was added. Two biomass power generation systems as well as a biomass/coal cofired system are compared to the fossil systems. The biomass systems are: a direct-fired biomass power plant using biomass residue, and a biomass-fired integrated gasification combined cycle system using a biomass energy crop. CO_2 sequestration was also integrated into these systems.

2.0 Capture Technology and Sequestration Options

Recovering a concentrated CO_2 stream from the power plant flue gas is primarily a matter of CO_2 and N_2 separation. One approach is to scrub the flue gas using chemical absorption (i.e., amines). Alternative approaches include cryogenic distillation, membrane separation, and gas-solid adsorption (i.e., molecular sieves). However, these three options are not competitive with an absorber/stripper system due to the large compression requirements (Blok, 1995; Herzog, 1996; IEA, 1993). Additionally, there has been some discussion about the possibility of removing the N_2 from the air prior to combustion and recycling some of the flue gas back to the combustion zone to control the thermal conditions and prevent overheating of the boiler materials (IEA, 1993). Because chemical absorption is currently the most promising, it was chosen as the capture technology for this study.

There are several types of amines that can be used for chemical absorption. Monoethanolamine (MEA) was used for this analysis because secondary amines, such as diethanolamine (DEA), have lower CO_2 carrying capacities and sterically hindered amines have lower affinities for absorbing CO_2 (IEA, 1993). Additionally, SRI reports that prior to 1987, there were eight power plants worldwide using an MEA system to capture CO_2 from the flue gas. The largest system, which was shut down for economic reasons, could capture 999 tonnes of CO_2/day (SRI International, 1987). A feasibility study done for the Electric Power Research Institute (EPRI) (Smelser and Booras, 1990), indicates that to remove 12,383 tonnes/day of CO_2 from a coal-fired power plant would require four parallel MEA stripper/absorber trains. Although for an existing power plant, some modifications would be required to the current ducting, the concept of recovering CO_2 from power plant flue gas is feasible using the existing MEA technology.

There are several options being proposed for the sequestration of CO_2. One option is the ocean (Fujioka, *et al.*, 1998; Adams, 1994; Herzog and Edmond, 1994). Another option is land disposal into a natural geologic trap such as a gas field, oil field, or aquifer (Hendriks, 1994; Holloway, *et al.*, 1996). For the purpose of this study, it was assumed that suitable land disposal can be found as close as 300 km (187 mi) and as far as 1,800 km (1,120 mi) from the power plant site.

3.0 Coal Plant System Description, Assumptions, and Data Used

The coal-fired power plant design and CO_2 capture technology are the same as those given in Hendriks' thesis, *Carbon Dioxide Removal from Coal-Fired Power Plants* (Hendriks, 1994). The size of the power plant is 600 MW prior to adding CO_2 capture. Table 1 gives the flue gas composition.

Table 1: Power Plant Flue Gas Composition

Component	N_2	CO_2	H_2O	O_2	SO_2 & NO_X
Volume %	72	13	12	3	< 1

It is assumed that 90% of the CO_2 in the flue gas is recovered. Hendriks proposes a base case MEA design and an optimized MEA design. For this study, the optimized design was used. It optimizes the construction of the scrubber based on a more concentrated MEA solvent (50 wt% instead of 30 wt%, which is the base case concentration). However, it should be noted that the results of the optimized case are only slightly different than the base case MEA design. Due to lack of data, the emissions and energy consumption from the production and regeneration or disposal of the MEA itself were not included in this study.

3.1 Transporting CO_2 to Sequestration Site

The most practical way to transport large, continuous quantities of CO_2 is by pipeline (Holloway, *et al.*, 1996). For this analysis, the CO_2 transport distance was varied from 300 km (187 mi) to 1,800 km (1,120 mi) and then the CO_2 is discharged to an underground depth of about 800 m (0.05 mi). This is a plausible depth based on data from the Joule II Project (Holloway, *et al.*, 1996). This is a study initiated by the European Commission in January 1993 to examine the potential for the underground disposal of industrial quantities of CO_2 with the goal of reducing CO_2 emissions to the atmosphere. Compressor stations are used at 300 km (186 mi) intervals to recover a pressure drop of 0.001 MPa/100 m (0.05 psi/100 ft), based on data from Fujioka, *et al.* (1998) and Holloway, *et al.* (1996). The electricity requirement was determined using Aspen Plus®. The electricity for the re-compression step was assumed to be the generation mix of the mid-continental United States, which, according to the National Electric Reliability Council, is composed of 64.7% coal, 5.1% lignite, 18.4% nuclear, 10.3% hydro, 1.4% natural gas, and 0.1% oil. The GHG emissions associated with this mix were taken from a database, known as Data for Environmental Analysis and Management (DEAM), within the life cycle assessment (LCA) software package, Tools for Environmental Analysis and Management (TEAM®), by Ecobalance, Inc. An explanation of the software and its data base can be found in previous NREL LCA reports (Mann and Spath, 1997; Spath and Mann, 1999).

There will be emissions associated with building, drilling, and laying the pipeline. The GHG emissions for building the pipeline were taken from a previous NREL report, which examined the life cycle assessment of a natural gas combined cycle power plant (Spath and Mann, 2000). In this report, the emissions for constructing a natural gas pipeline were determined. These results were used in this analysis because construction of the CO_2 pipeline will be similar to assembling a natural gas pipeline. Due to a lack of data, no additional emissions for digging and laying the pipe were included in the analysis. It should also be note that CO_2 emission leakage rates for transport and for storage were not included in this analysis (i.e., at the moment they are assumed to be zero).

3.2 Energy Requirements for CO_2 Capture and Compression

Capturing the flue gas CO_2 and then compressing it prior to transport consumes energy, thus lowering the power plant's efficiency. First, there is a power loss due to extracting the steam needed for the absorber/stripper system. Low pressure steam is used in the stripper reboiler and must be extracted from the steam cycle. Additional power is consumed in scrubbing the CO_2 due to compressing the flue gas and pumping the solvent. Finally, power is required to compress the recovered CO_2 prior to sequestration. In Hendriks' system design, there is a small amount of power saved because a slipstream from the reboiler replaces some cold boiler feedwater (BFW). One alteration was made in Hendriks' design and that is in the compression of the recovered CO_2. Hendriks' final CO_2 pressure for pipeline transport was lower than other reported literature values (Farla, *et al.*, 1995; Fujioka, *et al.*, 1998; Holloway, *et al.*, 1996), so the pressure was increased from 8 MPa (1,160 psi) to 11 MPa (1,595 psi). Aspen Plus® was used to determine the energy requirement.

Table 2 shows the efficiency loss and the amount of power that is required for each of the steps mentioned in the paragraph above. Steam extraction for the stripper reboiler results in the largest energy loss at 7.4% (108 MW), followed by compression at 2.7% (39 MW). All of the steps combined result in a reduced plant capacity of 457 MW for the optimized MEA case (reference case = 600 MW). The power plant efficiency prior to CO_2 capture and sequestration is listed as 41% (LHV basis) and the new power plant efficiency with CO_2 capture and compression is 31.2%. This design data is also tabulated in section 6.0 with information from studies done by others.

Table 2: Power Losses from Capturing and Compressing CO_2 at the Plant

	From steam extraction	From scrubbing (a)	From compression (b)	From avoiding BFW pre-heating	Total
Plant efficiency loss (percentage points)	7.4	0.4	2.7	-0.7	9.8
Power loss (MW)	108	6	39	-10	143

(a) Compression of flue gas and pumping of solvent.
(b) At 8 MPa, Hendriks' efficiency loss = 2.3% which is a power loss of 34 MW. Therefore, increasing the compression to 11 MPa did not significantly change the power loss compared to Hendriks' design.

3.3 Energy Requirement for Pipeline Re-compression

Table 3 shows the additional electricity requirement for re-compression along the pipeline for a specific distance. Again, this is for removing 90% of the power plant CO_2. This electricity requirement was not subtracted from the power plant capacity because the electricity for this step comes from the grid. However, it should be noted that the electrical requirement for re-compression is accounted for in the overall system; see sections 4.1 through 4.4. The electrical requirement is small even as the distance becomes large; at 1,800 km, the electricity requirement is only 5.7 MW. Most of the power requirement is in the CO_2 capture and compression steps. Section 3.2, above, showed that the coal-fired power plant capacity was reduced from 600 MW to 457 MW with the addition of CO_2 capture and compression.

Table 3: Electricity Requirement for Re-compression

Pipeline distance (km)	Electricity requirement (MW)
300	1.0
600	1.9
900	2.9
1,800	5.7

3.4 Coal Plant and CO_2 Pipeline Greenhouse Gas Emissions

Negligible amounts of CH_4 and N_2O emissions are produced from combusting coal. The carbon is primarily emitted in the form of CO_2 and the nitrogen in the form of nitrogen oxide (NO_x). The CO_2 emissions for the coal-fired power plant reference case is 0.80 kg CO_2/kWh (i.e., prior to CO_2 capture). For comparison, a previous NREL study found that the average coal plant in 1995 emitted 0.97 kg CO_2/kWh and a coal-fired power plant meeting the New Source Performance Standards would emit 0.89 kg CO_2/kWh (Spath and Mann, 1999). For this study, adding the CO_2 capture and compression reduces the power plant CO_2 emissions from 0.80 kg/kWh to 0.10 kg/kWh. Table 4 shows a breakdown of the GWP, expressed as CO_2-equivalence for a 100-year time frame, for the power plant with CO_2 capture and compression and for the CO_2 pipeline. Again, the GWP is a combination of the CO_2, CH_4, and N_2O emissions for which CH_4 and N_2O contribute to the warming of the atmosphere by a factor of 21 and 310, respectively, compared to CO_2. The additional emissions from pipeline construction and re-compression do not add significantly to the overall GWP.

Table 4: GWP for Coal Plant with CO_2 Pipeline Emissions

	With CO_2 capture & compression	Pipeline construction (a)	Re-compression along pipeline (b)	Total
GWP (kg CO_2-equivalent/ kWh of electricity)	0.10	0.0011	300 km distance = 0.0018 600 km distance = 0.0036 900 km distance = 0.0053 1,800 km distance = 0.011	0.1029 0.1047 0.1064 0.1112

(a) Although, the pipeline construction emissions will be emitted in a small block of time, the number reported here is the average over the life of the power plant which is considered to be 30 years. Therefore, the emissions in one year, provided the pipeline were constructed in this time frame, would be 0.04 kg CO_2-equivalent/kWh of electricity.
(b) GHG emissions are based on the grid mix given in section 3.1.

4.0 Systems and Cases Examined

The power generation capacity of each system examined was kept constant at 600 MW. Each system includes the upstream processes necessary for feedstock procurement (mining coal, extracting natural gas, growing dedicated biomass, collecting residue biomass), transportation, and any construction of equipment and pipelines. For the cases where CO_2 is sequestered, the CO_2 is captured via a monoethanolamine system, compressed, transported via pipeline, and sequestered in underground storage such as a gas field, oil field, or aquifer. CO_2 sequestration consumes additional energy; therefore, in order to maintain power generation capacity, additional capacity must come from another source. This study assumes that the electricity required to make up for the lost generating capacity comes from a natural gas combined-cycle system. The NGCC system was chosen because this type of power generation is currently being constructed and future power plants are anticipated to be NGCC. The following table lists the systems and cases examined in this analysis.

Table 5: Systems and Cases Examined

System	Case	
	system prior to CO_2 sequestration	system with CO_2 sequestration and extra capacity from NGCC
Coal-fired	1	1a
NGCC	2	2a
Biomass/coal cofiring	3	3a
Biomass direct-fired	4	4a
Biomass IGCC	5	5a

The following sections discuss the GWP and energy balance for each case shown in Table 5. This is followed by a section which summarizes these results for all of the cases.

4.1 GWP and Energy Balance for Coal-fired Power Production

The reference plant (Case 1) is a 600 MW pulverized coal-fired power plant and the system consists of coal mining, transportation, and power plant operation prior to adding CO_2 sequestration. The data for this system was taken from two sources: Hendriks, 1994 and Spath and Mann, 1997. The power plant and CO_2 pipeline emissions and energy information were discussed earlier in sections 3.0 - 3.4. The pipeline distance is assumed to be 600 km. Figure 1 shows the GWP for the coal reference system to be 847 g CO_2-equivalent/kWh of electricity produced and the energy balance reveals that 12.5 MJ of fossil energy is consumed per kWh of electricity produced.

After adding CO_2 capture and compression, the capacity of the coal-fired power plant is reduced to 457 MW. Including pipeline transport, an additional 145 MW of capacity is required from NGCC power generation in order to maintain 600 MW of capacity. Figure 2 shows the GWP for the coal plant with CO_2 sequestration plus additional capacity from a NGCC system (Case 1a). A previous NREL study (Spath and Mann, 2000 - NGCC LCA) was used to obtain the GHG emissions and energy requirements for the NGCC system. The GWP of the coal system with CO_2 sequestration (Case 1a) is 247 g CO_2-equivalent/kWh of electricity produced, which is a 71% reduction from the reference system shown in Figure 1 (Case 1). To maintain constant capacity, the fossil energy consumption increases 16% from Case 1.

In order to further reduce the GWP of the system, CO_2 could be sequestered from successive power plants. However, the results showed that further sequestering of CO_2 will reduce the system's GWP and increase the fossil energy consumption by negligible amounts. For example, in this case, the CO_2 from the 145 MW NGCC plant could be sequestered in addition to the CO_2 from the coal plant. It was determined that, after adding CO_2 capture and compression, only 110 MW is available from the 145 MW NGCC plant shown in Figure 2. Including pipeline transport, 35 MW of additional NGCC capacity is necessary to still maintain 600 MW of generating capacity. The GWP for this system, with sequestration from the coal and NGCC plant, is reduced by 74% from the reference system (Figure 1) with a 23% increase in fossil energy consumption. This can be compared to Figure 2 (sequestration from the coal plant only) which shows a 71% decrease in GWP and a 16% increase in fossil energy consumption compare to the reference coal system (Case 1). Thus, one sees diminishing returns with additional sequestering of CO_2.

4.2 GWP and Energy Balance for Natural Gas Combined-Cycle

Although, the majority of the electricity generated in the U.S. comes from coal, natural gas is becoming increasingly important in power generation. Natural gas is one of the cleanest burning fossil fuels and NGCC plants have higher conversion efficiencies than coal-fired power plants. The data for the NGCC system in this analysis was taken from Spath and Mann, 2000. Figure 3 shows the NGCC system prior to CO_2 sequestration (Case 2). The GWP is 499 g CO_2-equivalent/kWh of electricity produced and the energy balance shows that 8.4 MJ of fossil energy is consumed per kWh of electricity. Compared to the reference coal plant (Case 1), the GWP and the fossil energy

Figure 1: GWP and Energy Balance for Coal System Prior to CO_2 Sequestration (Case 1)

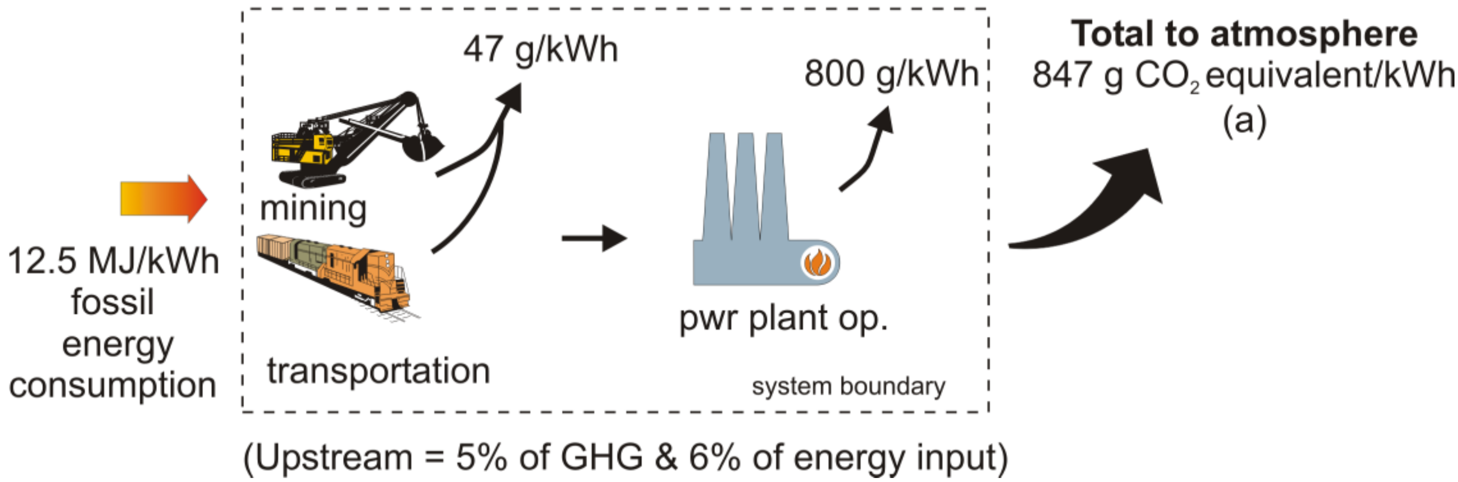
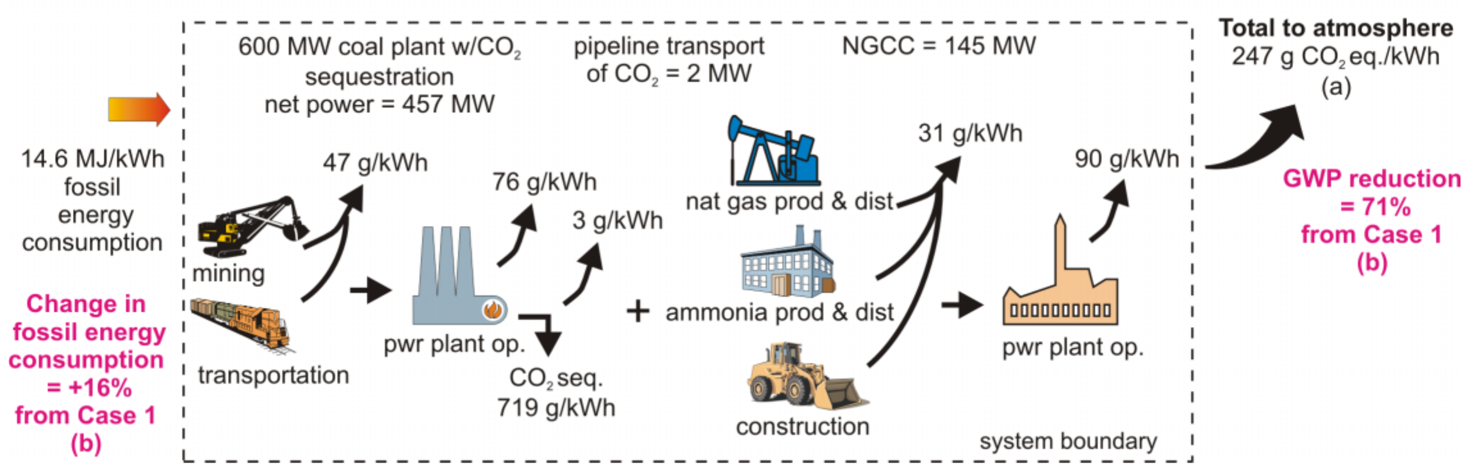


Figure 2: GWP and Energy Balance for Coal System with CO_2 Sequestration at Constant Capacity (Case 1a)



Notes: (a) GHGs (CO_2, CH_4, and N_2O) expressed in grams of CO_2-equivalent/kWh of electricity generated
(b) Change in GWP and change in fossil energy consumption compared to reference coal system (Case1)

consumption are 41% and 33% less, respectively. For the NGCC system, the upstream processes are responsible for a considerable amount of GHG emissions and energy consumption, accounting for 25% of the total GHG emissions and 21% of the total fossil energy consumption. NREL's LCA study of power generation via natural gas (Spath and Mann, 2000) shows that the upstream GHG emissions are primarily a result of the fugitive methane emissions from natural gas production and distribution. This study also determined that of the steps required in natural gas production and distribution (natural gas extraction, separation and dehydration, sweetening, and pipeline transport), the natural gas extraction and transport steps consume the most energy.

Adding CO_2 sequestration and additional capacity from another NGCC source to the system shown in Figure 3, results in a GWP of 245 g CO_2-equivalent/kWh of electricity produced and a fossil energy consumption of 9.7 MJ/kWh of electricity. This can be seen in Figure 4 (Case 2a). Although the fossil energy consumption increases compared to the NGCC system without CO_2 sequestration (Case 2) (a 16% increase compared to Figure 3), it is a 22% decrease compared to the coal reference system (Case 1). It should be noted that because natural gas production and distribution account for a large amount of the system's GHGs, sequestering CO_2 from the NGCC system (Case 2a) results in roughly the same GHG emissions as sequestering CO_2 from the coal system (Case 1a) (roughly 245 g CO_2-equivalent/kWh; compare Figure 2 and Figure 4). If the upstream emissions were not included for both the coal and natural gas systems, then sequestering CO_2 from the natural gas plant would appear to be an improvement of 41% over sequestering CO_2 from the coal plant.

4.3 GWP and Energy Balance for Biomass/Coal Cofired System

Currently, several power plants in the U.S. are testing cofiring of biomass with coal as an inexpensive way to reduce CO_2, sulfur oxide (SO_x), and NO_x stack emissions. The data for this system was taken from Mann and Spath (2001) and applied to the reference coal plant (Case 1) in this analysis. A biomass cofiring rate of 15% by heat input was used. The biomass is assumed to be produced by urban sources and diverted from normal landfilling and mulching operations. Because biomass is diverted from its normal routes of disposal, methane and CO_2 that normally would be produced through decomposition are avoided (see Mann and Spath, 2001 for more details). These avoided emissions are taken as a credit in the GHG emissions inventory for the cofired power generation system. Figure 5 shows the GWP and fossil energy consumption for this system. Although the power plant emissions are higher than the coal only case (Case 1) (845 g CO_2-equivalent/kWh compared to 800 g CO_2-equivalent/kWh), on a life cycle basis, the overall greenhouse gas emissions are reduced by 19% (681 g CO_2-equivalent/kWh compared to 845 g CO_2-equivalent/kWh). The fossil energy consumption is also reduced by 12% compared to the coal system (Case 1).

If CO_2 sequestration is added to this system, the GWP is reduced to 43 g CO_2-equivalent/kWh of electricity produced, which is a 95% reduction from the coal reference case (Case 1). See Figure 6. The fossil energy consumption increases from 11.0 MJ/kWh of electricity produced (shown in Figure 5) to 13.1 MJ/kWh of electricity. This is a 4% increase over the coal reference case (Case 1), resulting from the energy additional electricity production via NGCC to make up for the lost capacity that is consumed for CO_2 sequestration.

Figure 3: GWP and Energy Balance for NGCC System Prior to CO_2 Sequestration (Case 2)

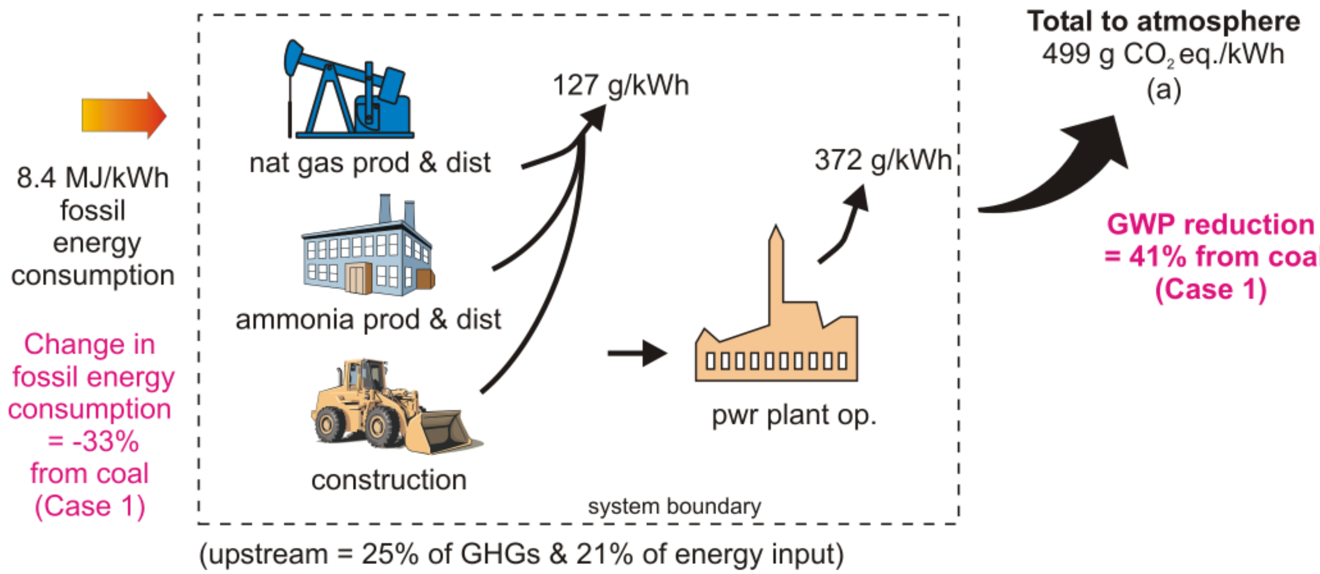
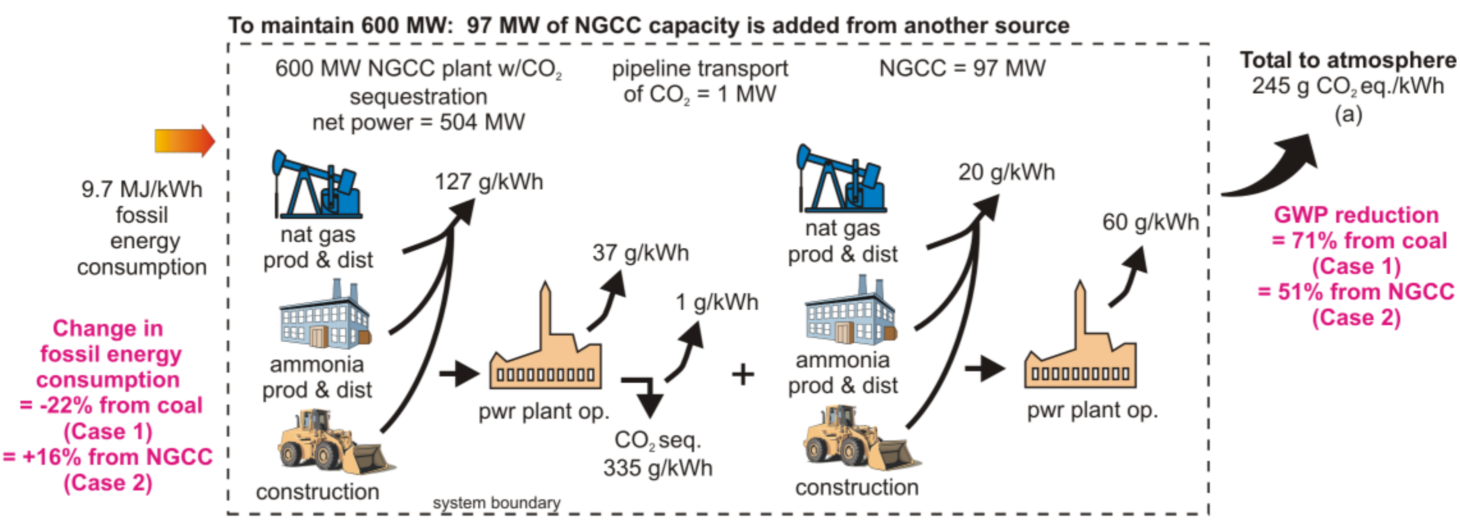


Figure 4: GWP and Energy Balance for NGCC System with CO_2 Sequestration at Constant Capacity (Case 2a)



Note: (a) GHGs (CO_2, CH_4, and N_2O) expressed in grams of CO_2-equivalent/kWh of electricity generated

Figure 5: GWP and Energy Balance for Coal System with Biomass Cofiring Prior to CO_2 Sequestration (Case 3)

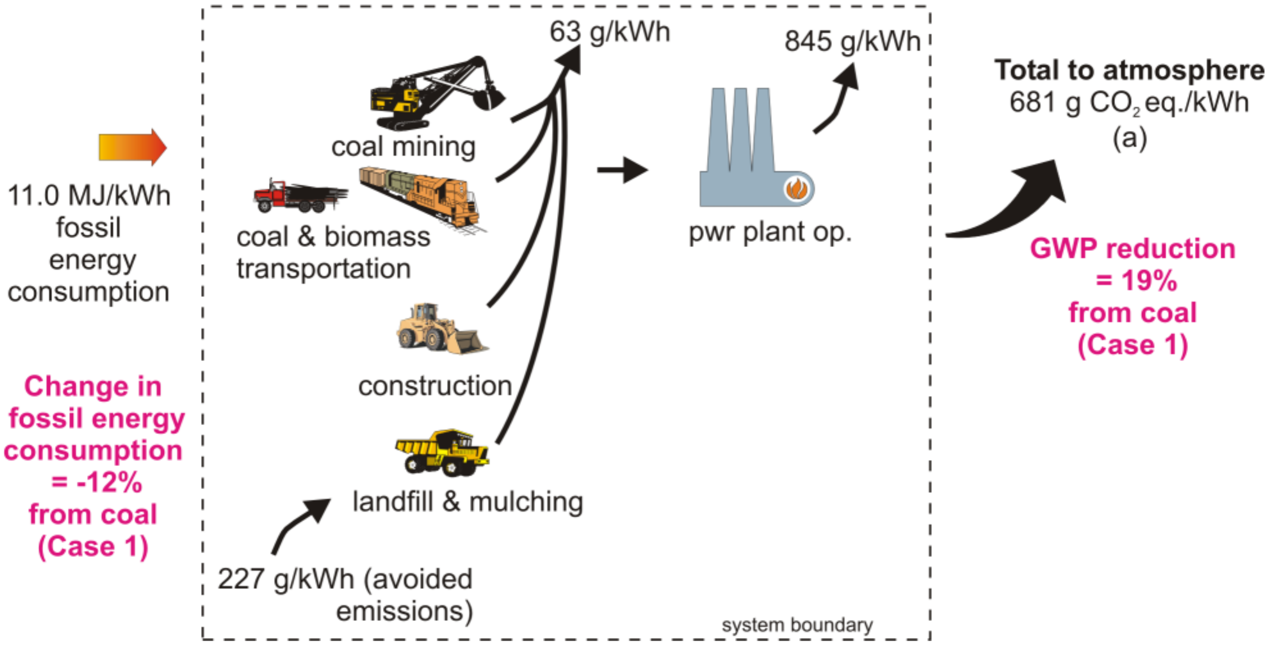
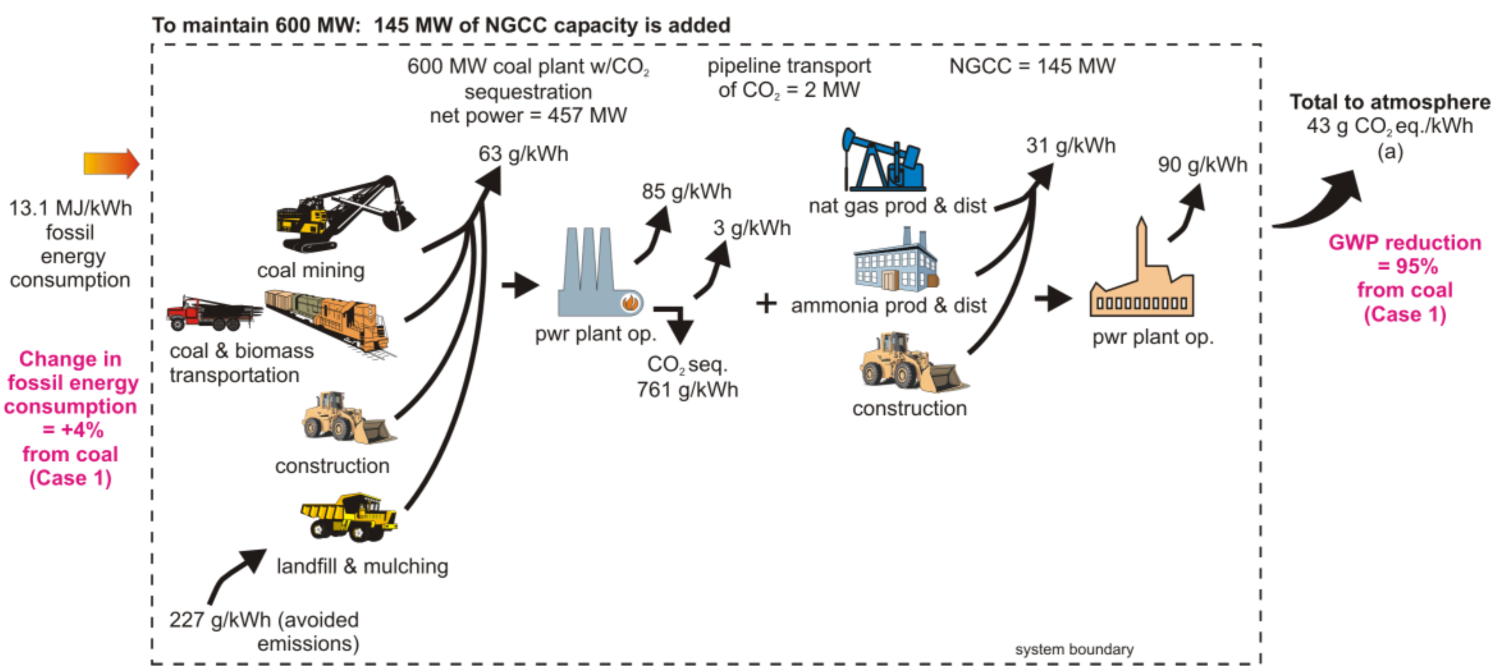


Figure 6: GWP and Energy Balance for Coal System with Biomass Cofiring and CO_2 Sequestration at Constant Capacity (Case 3a)



Note: (a) GHGs (CO_2, CH_4, and N_2O) expressed in grams of CO_2-equivalent/kWh of electricity generated

4.4 GWP and Energy Balance for Direct-fired Biomass

The biomass power system examined in this analysis is representative of today's current technology and employs a direct-fired biomass power plant using biomass residue. The data for this system was also taken from a previous LCA (Mann and Spath, 2000). Because large transportation distances render large scale biomass power plants uneconomical, it is assumed that several small plants are needed to achieve 600 MW of electric capacity. Just like the cofired system, the biomass is assumed to be produced by urban sources and diverted from normal landfilling and mulching operations. Therefore, avoided methane and CO_2 emissions are credited in this system also. Because of this, the system (Case 4) results in a negative GWP of -410 g CO_2-equivalent/kWh of electricity produced and the fossil energy consumption is 0.1 MJ/kWh of electricity produced, as shown in Figure 7. The GWP is a 148% reduction from the coal reference system (Case 1) and the fossil energy consumption is reduced by 99%.

Although the GHG emissions for the direct-fired biomass system are already negative, applying CO_2 sequestration to this system will decrease the net GWP even more. Figure 8 shows the GWP and energy balance for the direct-fired biomass system with CO_2 sequestration at constant power generation capacity (Case 4a). The GWP is reduced to -1,368 g CO_2-equivalent/kWh of electricity produced which is 262% lower than the coal reference system (Case 1). The fossil energy consumption is now 2.2 MJ/kWh of electricity produced, which is still lower than the coal reference system (Case 1) by 82%.

4.5 GWP and Energy Balance for Biomass-fired Integrated Gasification Combined-Cycle

The advanced technology biomass power production system examined in this analysis implements a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop. Again, the data for this system came from a previous LCA (Mann and Spath, 1997) and it was assumed that several small plants would be needed to produce 600 MW of electricity. Figure 9 shows the GWP and fossil energy consumption for this system to be 49 g CO_2-equivalent/kWh of electricity produced and 0.2 MJ/kWh of electricity produced, respectively. Because CO_2 emitted from the power plant is recycled back to the biomass as it grows, the net GHG emissions from this system are only 6% of those from the reference coal system (Case 1). Additionally, because of the renewable feedstock source, the fossil energy consumption is 98% less than the coal reference system (Case 1).

If CO_2 sequestration is incorporated into this biomass power generation system, then the net GWP will be negative. As can be seen in Figure 10 (Case 5a), the GWP is reduced to -667 g CO_2-equivalent/kWh of electricity produced, which is a 179% reduction from the coal reference system (Case 1). Additionally, the fossil energy consumption is still considerably less than the coal reference system at 1.6 MJ/kWh of electricity produced (an 87% decrease from Case 1).

Figure 7: GWP and Energy Balance for Biomass Residue Direct-fired System Prior to CO_2 Sequestration (Case 4)

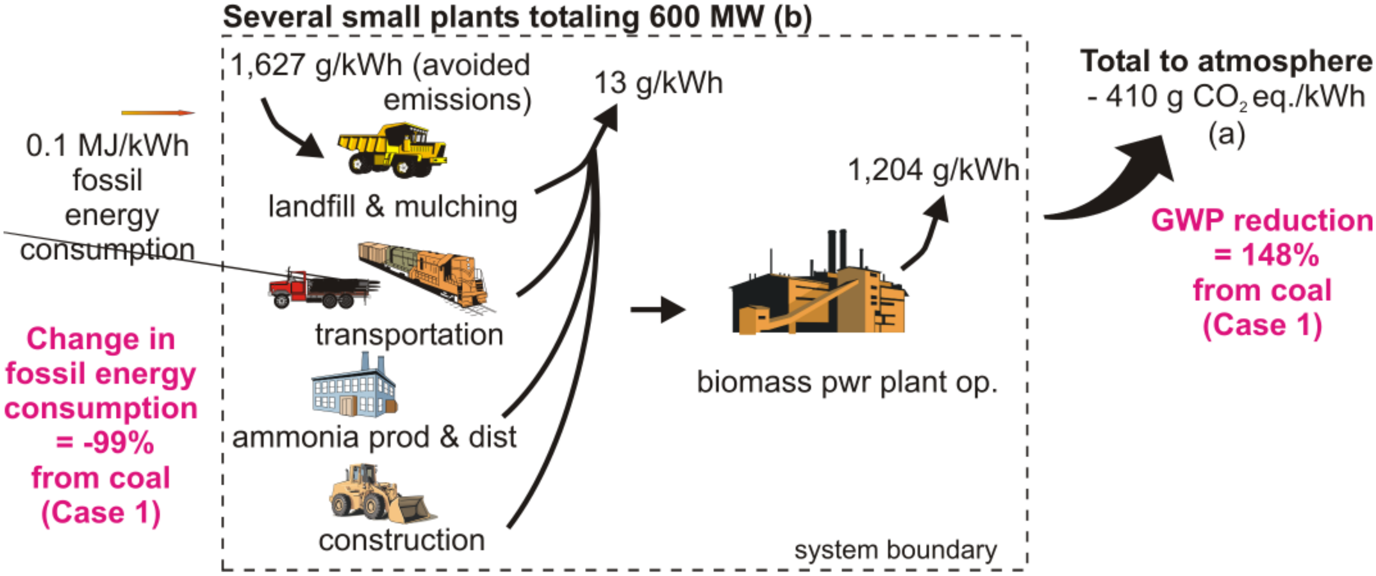
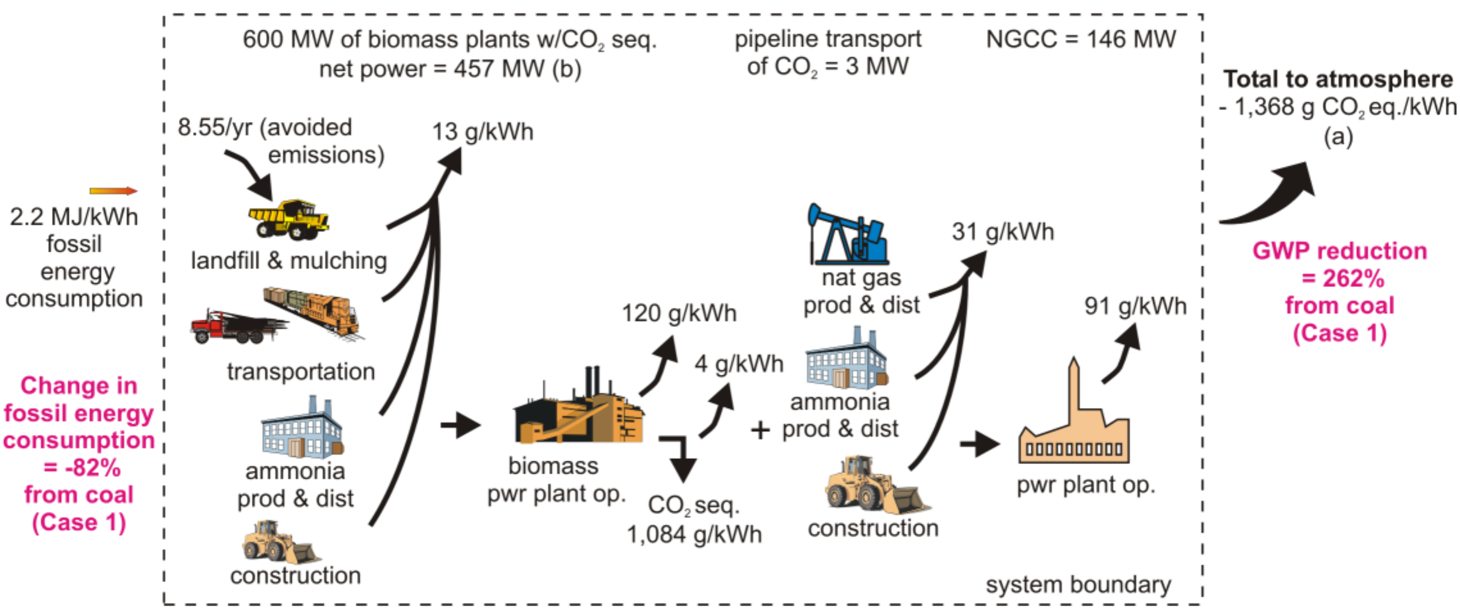


Figure 8: GWP and Energy Balance for Biomass Residue Direct-fired System with CO_2 Sequestration at Constant Capacity (Case 4a)



Notes: (a) GHGs (CO_2, CH_4, and N_2O) expressed in grams of CO_2-equivalent/kWh of electricity generated
(b) Several small biomass plants are required to economically produce 600 MW

Figure 9: GWP and Energy Balance for Biomass Dedicated Feedstock IGCC System Prior to CO_2 Sequestration (Case 5)

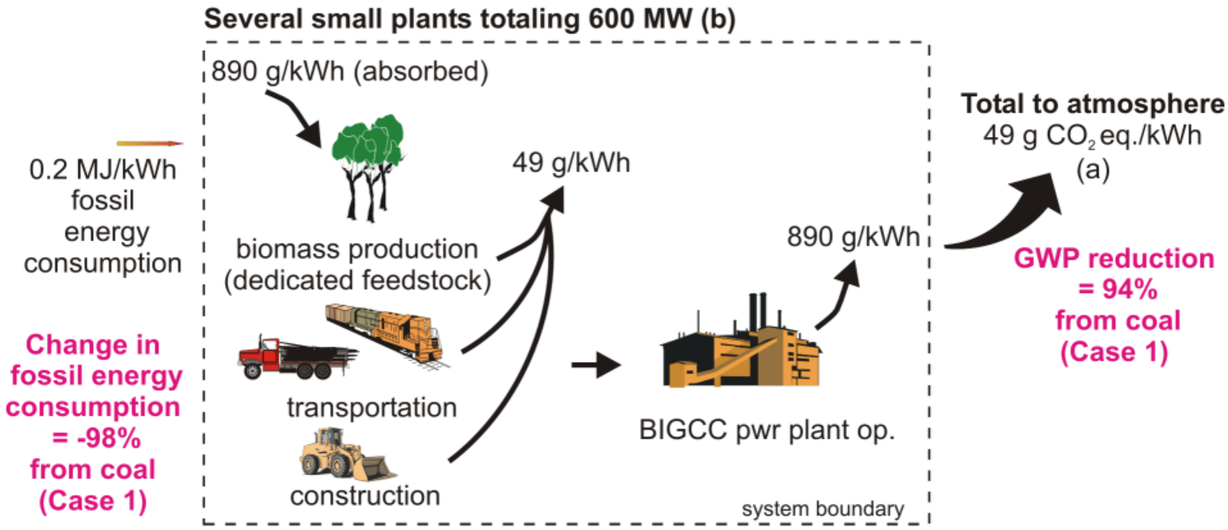
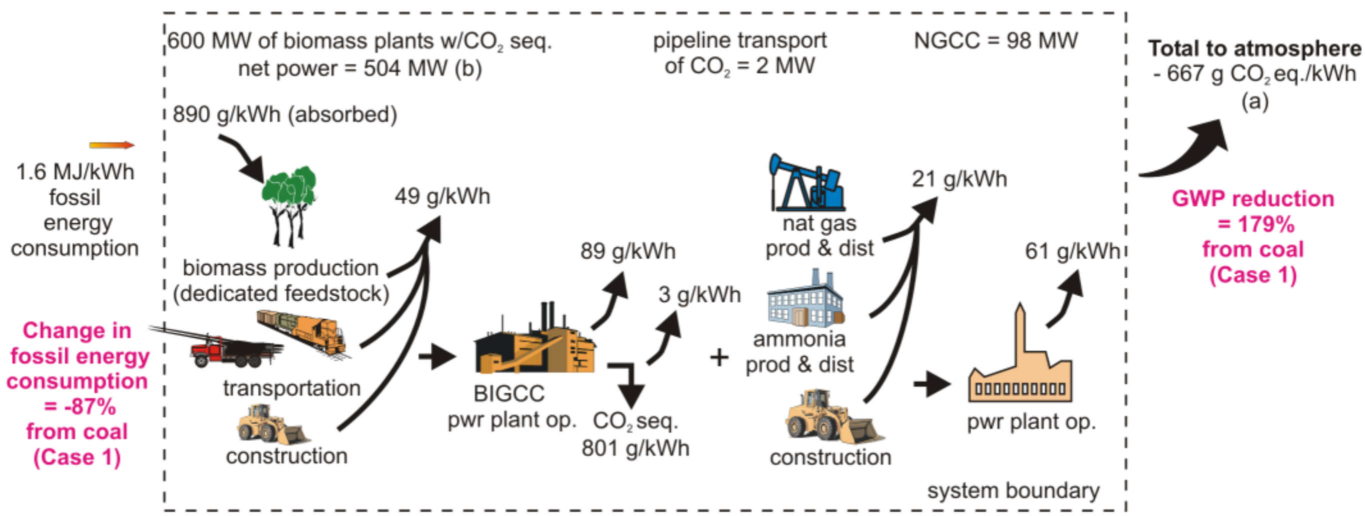


Figure 10: GWP and Energy Balance for Biomass Dedicated Feedstock IGCC System with CO_2 Sequestration at Constant Capacity (Case 5a)



Notes: (a) GHGs (CO_2, CH_4, and N_2O) expressed in grams of CO_2-equivalent/kWh of electricity generated
(b) Several small biomass plants are required to economically produce 600 MW

4.6 Summary of GWP and Energy Balance for Fossil and Biomass Systems

Table 6 summarizes the GWP and energy balance for the fossil and biomass systems discussed in the previous sections. Additionally, the table gives the change in the GWP and energy balance compared to the coal reference system (Case 1). The GWP numbers (column 3) and fossil energy consumption (column 4) are also shown graphically in Figure 11 and 12, respectively. Even with CO_2 sequestration, the amount of GHG emissions per the same amount of electricity production is higher for the fossil based systems (Cases 1a and 2a) than for the biomass power generation systems (Cases 4 and 5). Cofiring with biomass is a near-term option that can be implemented at existing coal-fired power plants to reduce GHG emissions and fossil energy consumption.

Table 6: Summary of GWP and Energy Balance for Fossil and Biomass Power Systems

System	Case	Net GWP (g CO_2-equivalent/kWh) (a)	Fossil energy consumption (MJ/kWh)	Change from reference coal system (Case 1)	
				change in GWP	change in fossil energy consumption
Coal-fired	1	847	12.5	N/A	N/A
	1a (b)	247	14.6	-71%	16%
NGCC	2	499	8.4	-41%	-33%
	2a (b)	245	9.7	-71%	-22%
Biomass/ coal cofiring	3	681	11.0	-19%	-12%
	3a (b)	43	13.1	-95%	4%
Biomass direct-fired	4	-410	0.1	-148%	-99%
	4a (b)	-1,368	2.2	-262%	-82%
Biomass IGCC	5	49	0.2	-94%	-98%
	5a (b)	-667	1.6	-179%	-87%

(a) GHG emissions (CO_2, CH_4, and N_2O) expressed as CO_2 equivalence.

(b) These cases include CO_2 sequestration and extra capacity from a NGCC system.

5.0 Cost of Electricity without CO_2 Sequestration

The cost of electricity generation is determined by several factors including, the power generation technology (e.g., coal-fired boiler, natural gas combined-cycle, direct-fired biomass, etc.), the power plant size, and the feedstock cost. Currently, the cost to generate electricity from coal is about 2-3¢/kWh (U.S. DOE, 1998). Although the price of natural gas has fluctuated over the past several years, a new natural gas combined-cycle power plant is expected to generate electricity for about 4-5¢/kWh (U.S. DOE, 2000). Biomass power via direct combustion can be generated for about 8-9¢/kWh (U.S. DOE, 1997), while advanced technologies using gasification combined-cycle are estimated to produce electricity for 5-6¢/kWh (Craig and Mann, 1996; Overend and Bain, 1995).

Figure 11: Comparison of Global Warming Potential - All Cases

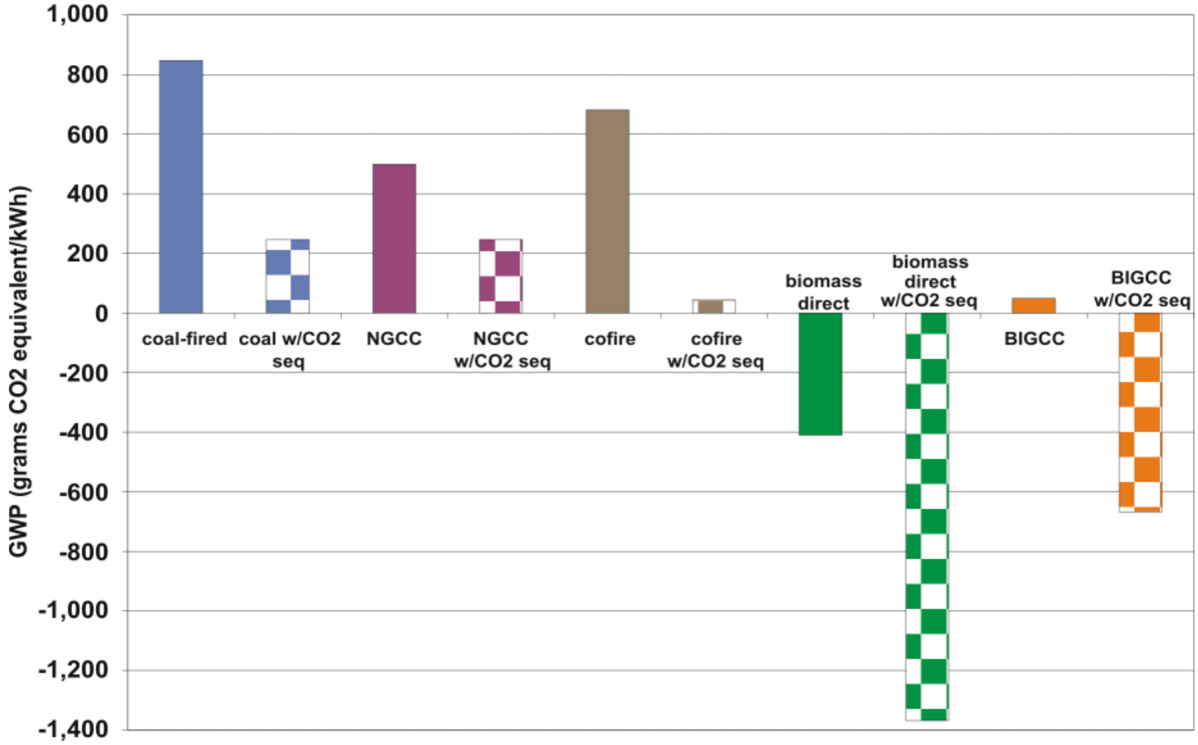
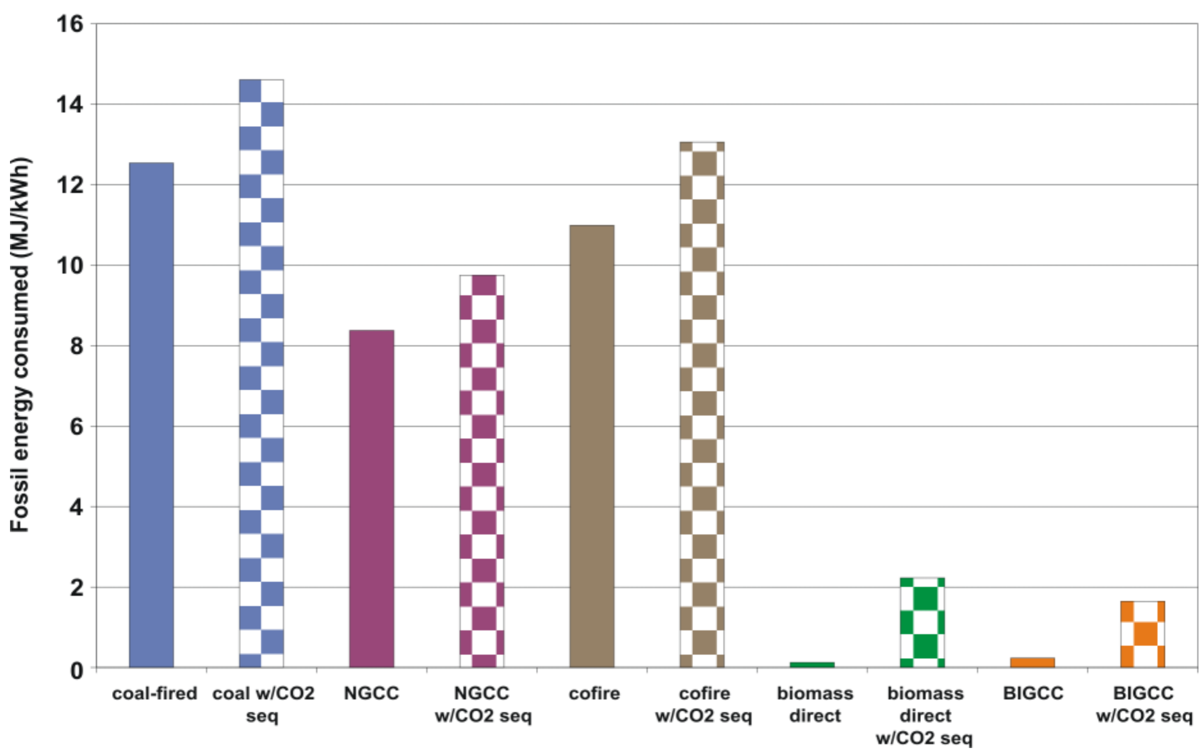


Figure 12: Comparison of Fossil Energy Consumption - All Cases



6.0 Costs Associated with CO_2 Sequestration

The cost of CO_2 sequestration consists of the cost to capture, compress, transport, and store the CO_2 from the power plant flue gas as well as the cost to produce additional electricity to make up for the lost generating capacity. Several studies by others have examined the cost of electricity from a fossil-fueled power plant with CO_2 sequestration. Tables 7 and 8 summarize the information from these studies. Table 7 contains data for coal-fired power production with CO_2 sequestration and Table 8 has the same information for NGCC systems with CO_2 sequestration. However, almost all of these studies have included only the cost to capture and compress the CO_2. Only, Dave (2000), Hendriks, *et al.*, (2000), and Smelser and Booras (1990/1991) have incorporated CO_2 transport and storage costs into their analysis. However, a few of the studies have discussed the cost associated with transport and storage of CO_2, concluding that this will be low compared to the cost of capture and compression. Additionally, Smelser and Booras (1990/1991) is the only reference that even discusses the need to include the cost of replacement power to make up for the lost generating capacity.

Tables 7 and 8 show that the cost of electricity from a coal-fired power plant with CO_2 sequestration is expected to increase by about 2.8¢/kWh (This is the average of the data in Table 7 excluding the cost given by Johnson, *et al.*, 1992.) and about 1.7¢/kWh for a NGCC plant with CO_2 sequestration (average of the numbers in Table 8). However, these numbers do not include the cost for storage and transport of the CO_2 and the cost of replacement power. These studies also show a wide range for the cost of CO_2 avoided; roughly \$30-\$65/tonne of CO_2 avoided. Note that the cost per tonne of CO_2 avoided is not the same as the cost per tonne of CO_2 captured. Depending on the efficiency of the plant, for a coal-fired power plant, the amount of CO_2 captured in terms of kg/kWh will be roughly 1.4 times the amount of CO_2 avoided. The kg of CO_2 avoided/kWh of electricity produced is lower because there is a large energy penalty associated with capture and compression of the CO_2. The CO_2 avoided is the difference in the kg of CO_2 emitted/kWh of electricity produced for the reference plant compared to the plant with CO_2 sequestration.

7.0 CO_2 Transport and Storage Costs

Several factors will affect the transport and storage cost of CO_2, including the amount of CO_2 transported, the transport distance, the storage option (land or ocean), the storage medium (gas field, oil field, or aquifer), and the depth of storage. The transport cost will be significantly cheaper for larger pipe diameters and thus larger volumes of CO_2. In the U.S., many of the power plant sources are predominantly in the upper and southeast regions, while most of the potential land disposal reservoirs are concentrated in the south-central U.S. at a distance of 804-2,414 km (500-1,500 miles) away (Bergman, *et al.*, 1997). Therefore, to minimize costs, smaller pipelines from individual power plants would need to be connected to larger common pipelines.

Information in Kirk-Othmer (1993), indicates that about 75% of the pipeline cost generally comes from the costs for material and labor. Many studies (Johnson, *et al.*, 1992; Herzog, 2000; IEA 2001) have stated that for CO_2 sequestration, the cost of CO_2 transport and storage will add 20%-25% to the cost of electricity while capture and compression accounts for the majority of the additional cost

Table 7: Coal-fired Power Production with CO_2 Sequestration - Cases in the Literature

Reference	Net power (MW)		Power loss (MW)	Net efficiency (%) (LHV unless specified)		Percentage point change in efficiency	Electricity cost (¢/kWh)		Increase in electricity cost from base case		($/tonne of avoided CO_2) (a)
	base	with CO_2 seq		base	with CO_2 seq		base	with CO_2 seq	¢/kWh	%	
Audus (2000)	---	---	---	46	33	-13	3.7¢	6.4¢	2.7¢	73%	$47
Bergman *et al* (1997)	---	---	---	---	---	---	---	---	---	---	$58 (b)
Dave (2000)	500	323	177(c)	36.8 (HHV)	29.9 (HHV) 23.3 (c)	-6.9 -13.5 (c)	4.2¢ (d)	---	3.1¢ - 3.6¢ (d)	74% - 86% (d)	$50 (b, d)
Hendriks (1994)	600	462	138	41	31.5	-9.5	3.7¢	6.1¢	2.4¢	65%	$34
Herzog (2000)	500	400	100	40.3	33.2	-7.1	4.3¢	6.9¢	2.6¢	60%	$40
Holt and Booras (2000)	462	329	133	---	---	---	5.2¢	8.7¢	3.5¢	70%	---
IEA (1993)	500	333	167	39.9	26.6	-13.3	---	---	---	---	---
IEA (2000a)	500	367	137	40	29	-11	4.9¢	7.4¢	2.5¢	51%	$37
IEA (2000b)	501	362	139	45.6	33.0	-12.6	3.7¢	6.4¢	2.7¢	73%	$50
Mathieu (2001)	---	---	---	---	---	-13	---	---	---	60%	$31-35 (e) $55-64 (f)
Johnson *et al* (1992)	513	338	175	34.8 (HHV)	23.0 (HHV)	-11.8	4.9¢	10.8¢	5.9¢	120%	$76 (g)
Simbeck (1999)	400	310	90	44.6	34.6	-10.0	4.2¢	7.0¢	2.8¢	67%	---
Smelser and Booras (1990/1991)	513	336	177	34.8 (HHV)	22.8 (HHV)	-12.0	---	---	---	---	---

(a) Based on CO_2 difference from base case coal-fired plant. This is equal to (the increase in the cost of electricity) / (the amount of CO_2 avoided).
(b) Converted from $/ton of CO_2 disposed. (c) Including transport & storage. (d) Cost including transport & storage and converted from Australian dollar.
(e) Based on plant efficiency of 40%. (f) Based on plant efficiency of 33%. (g) Calculated from data in reference.

Table 8: NGCC with CO_2 Sequestration - Cases in the Literature

Reference	Net power (MW)		Power loss (MW)	Net efficiency (%) (LHV unless specified)		Percentage point change in efficiency	Electricity cost (¢/kWh)		Increase in electricity cost from base case		($/tonne of avoided CO_2) (a)
	base	with CO_2 seq		base	with CO_2 seq		base	with CO_2 seq	¢/kWh	%	
Audus (2000)	---	---	---	56	47	-9	2.2¢	3.2¢	1.0¢	---	$32
Bergman *et al* (1997)	---	---	---	---	---	---	---	---	---	---	$86 (b)
Hendriks *et al* (2000)	1000	---	---	60.0	52.8	-7.2	---	---	---	---	$44 - $55 (c)
Herzog (2000)	500	433	67	54.1	46.8	-7.3	3.3¢	5.2¢	1.9¢	58%	$40
Holt and Booras (2000)	384	311	73	---	---	---	3.1¢	4.9¢	1.8¢	59%	---
IEA (1993)	465	396	69	52.0	44.3	-7.7	---	---	---	---	---
IEA (2000a)	500	404	96	52	42	-10	3.5¢	5.3¢	1.8¢	51%	$55
IEA (2000b)	790	663	127	56.2	47.2	-9	2.2¢	3.2¢	1.0¢	45%	$35
Mathieu (2001)	---	---	---	56	47	-9	---	---	---	50%	$34
Schütz *et al* (1992)	---	---	---	---	---	---	---	---	2.5¢	---	---
Simbeck (1999)	400	347	53	60	52	-8	3.1¢	4.9¢	1.8¢	58%	$60

(a) Based on CO_2 difference from base case NGCC plant. This is equal to (the increase in the cost of electricity) / (the amount of CO_2 avoided).
(b) Converted from $/ton of CO_2 disposed.
(c) Costs converted from dollars Euro. Cost of recovery, compression & transport, and storage. Costs are given for a fuel price range of $1.5/GJ - $3.1/GJ.

at 75%-80%. Again, it should be pointed out that the cost of replacement power needs to be considered too. Information on the cost to transport and store CO_2 was gathered from various literature sources and the information is given in Table 9. As can be seen from the data in this table, the cost differs significantly ($1-$35/tonne of CO_2 avoided) depending on the size of the pipe, the transport distance, and the storage medium.

Table 9: Cost of CO_2 Transport and Storage

Reference	Information from source	Calculated Cost ($/tonne of CO_2 avoided)
Bergman, *et al* (1997)	Pipeline costs = $0.02/mile/ton	$6
Blok, *et al* (1997)	transport = $3-15/100km/tonne of avoided C underground storage = $2-20/tonne of avoided C	$5 - 35
David and Herzog (2000)	CO_2 transport & injection adds $10/ton of CO_2 avoided.	$10
Herzog (2000)	$5-15/Mg CO_2 avoided	$5 - 15
IEA (1999)	0.5 m (20 in) dia pipeline @ 500 km (310 mi) with capacity of 18,000 tonne/day = $12/tonne of CO_2. Significant advantage to larger pipe: 1 m (40 in) dia pipeline would carry 4 times as much CO_2 for less than 4 times the cost.	$17
IEA (2001)	storage = $1-3/tonne of CO_2 transport for 100 km = $1-3/tonne of CO_2	$3 - 8
Johnson, *et al* (1992)	$0.54/100 scf of CO_2 for 100 mi	$14
Kirk-Othmer (1993)	14 inch pipe = $310,000/km 24 inch = $530,000/km 42 inch = $1,802,000/km	$11 (24 in.)
Skovholt (1993)	for 250 km: 16 inch pipe = $7/tonne of CO_2 30 inch = $2.1/tonne of CO_2 64 inch = $1/tonne of CO_2	$10 $3 $1
Smelser and Booras, (1990)	pipeline and disposal cost: PC plant = $649/kW IGCC plant = $1,226/kW	$4 - 7
Stevens, *et al* (1999)	capital & operating cost of injection wells for coalbed methane recovery: capital = $25 million; operating = $ 2,400/month	$5
Wildenborg (2000)	transport: Close proximity, costs would be solely compression: $7/tonne of CO_2 @ annual volume of 1 million tonnes. At 200 km (124 mi) distance: $11/tonne of CO_2 @ annual volume of 1 million tonnes and $18/tonne of CO_2 @ annual volume of 4 million tonnes. storage: $3/avoided tonne of CO_2 if 1 trap is need and $6-7 for 3 traps $2 if 1 depleted gas field is needed to $5 for 3 depleted gas fields	$12 - 32

8.0 Cost of Electricity with CO_2 Sequestration

To get a true picture of the increase in the cost of electricity with CO_2 sequestration, data was taken from the studies listed in Tables 7 - 9 and a total cost of electricity was calculated. The results are shown in Table 10. The cost of electricity from coal increases by 191% from 2.5¢/kWh to 7.3¢/kWh while the cost from natural gas increases by 67% from 4.5¢/kWh to 7.5¢/kWh when CO_2 sequestration is added.

Table 10: Cost of Electricity for Coal and Natural Gas with CO_2 Sequestration

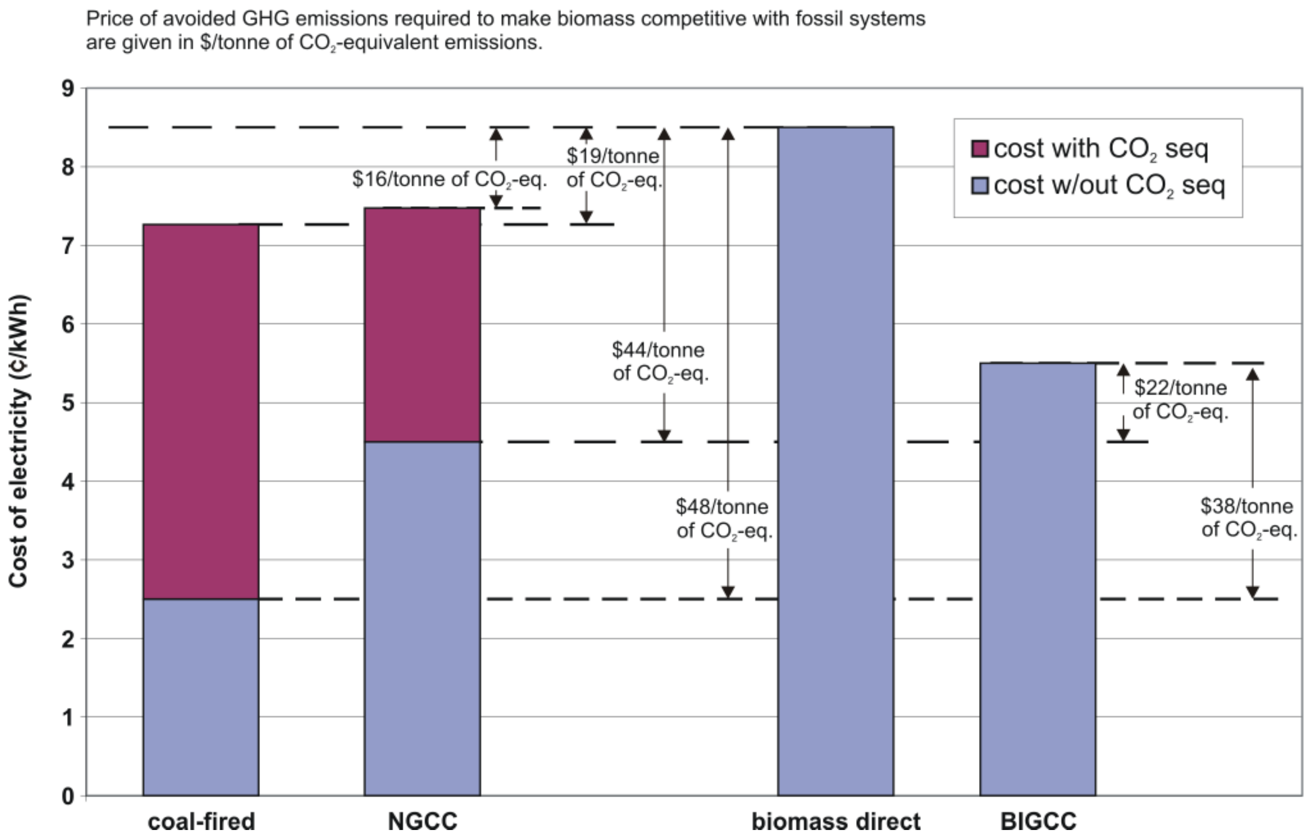
System	Cost of electricity (¢/kWh)				
	Prior to CO_2 sequestration	Cost of CO_2 capture & compression	Cost of CO_2 transport & storage	Cost of replacement power	Total cost
Coal-fired	2.5	2.8	0.9	1.1	7.3
NGCC	4.5	1.7	0.6	0.7	7.5

Biomass power using an advanced gasification combined-cycle technology, BIGCC, is cheaper than either fossil system with CO_2 sequestration, about 5.5¢/kWh compared to roughly 7.4¢/kWh; in addition, the BIGCC system uses a dedicated feedstock, resulting in a nearly carbon neutral system (see section 4.5). The cost of electricity from a direct-fired biomass system is slightly higher than either fossil system with CO_2 sequestration, about 8.5¢/kWh compared to roughly 7.4¢/kWh. However, an additional 1¢/kWh increase in the price of electricity from the fossil-fueled systems with CO_2 sequestration will make the direct-fired biomass system cost competitive.

9.0 Cost of Avoided Greenhouse Gas Emissions for the Biomass Systems

The electricity costs in Table 10 are shown in Figure 13, along with the price of avoided GHG emissions required to make the biomass systems competitive with the fossil systems, with and without CO_2 sequestration. For example, the difference in the electricity price for the direct-fired biomass system (Case 4) compared to the coal-fired system (Case 1) is 6.0¢/kWh. When comparing the GHG emissions from these two systems along with the difference in the cost of electricity, a \$48/tonne of CO_2-equivalent emissions credit will make the biomass direct system competitive with the coal system. However, when comparing the direct-fired biomass system to coal with CO_2 sequestration (Case 1a), this number drops to \$19/tonne of CO_2-equivalent emissions. The BIGCC system is already cheaper than both fossil systems with CO_2 sequestration (Cases 1a and 2a) and the greenhouse gas emissions are lower (49 g CO_2-eq/kWh compared to about 245 g CO_2-eq/kWh for coal or natural gas with CO_2 sequestration. See section 4.6.). Comparing the electricity costs and GHG emissions for BIGCC to coal and natural gas without CO_2 sequestration (Cases 1 and 2) shows that an emissions credit of \$22 and \$38 per tonne of CO_2-equivalent emissions, respectively, are required to make the biomass system cost-competitive. Even though the difference in the cost of electricity is less between the BIGCC system and the fossil systems without CO_2 sequestration than between the direct-fired biomass system and the fossil systems without CO_2 sequestration, fewer GHGs are emitted from the direct-fired biomass system. This is due to the avoided emissions from using biomass residue (see section 4.4).

Figure 13: Cost of Electricity and Greenhouse Gas Emissions Credit Required to make Biomass Power Competitive to Fossil



Because biomass cofiring would be practiced at an existing power plant, evaluating the economic feasibility would normally be done in terms of payback period. The additional capital cost for biomass cofiring is expected to range from \$50 to \$250 per kW of biomass power capacity (U.S. DOE, 1997). The cost depends on factors such as the type of boiler, the rate of cofiring, the amount and nature of the biomass feedstock, etc. To be economical, the payback period needs to be in the range of 3-4 years (Stermole, 1984). At a capital cost of \$250/kW and a cofiring rate of 15% by heat input, a payback period of 4 years is obtained if the biomass residue cost is about \$10/dry tonne (\$0.5/MMBTU) and the coal cost is around \$39/tonne (\$1.4/MMBTU) (U.S. DOE, 1997). The payback period is defined as the total capital investment for cofiring divided by the annual savings in operating costs. If the coal cost were as low as \$28/tonne (\$1/MMBTU) then the payback period would increase to 7 years (U.S. DOE, 1997). In order for cofiring to be economical at the low coal cost, a greenhouse gas emissions credit is necessary. Using the difference in the greenhouse gases reported in this study between the coal and cofiring systems (i.e., difference in life cycle GHG emissions between the coal system (Case 1) and the cofiring system (Case 3)), a credit of only \$5/tonne of CO_2-equivalent emissions is necessary to achieve a payback period of 3 years for the low cost coal case. Thus, cofiring with biomass residue is an inexpensive option that is applicable to most existing coal-fired boilers and can be practiced today to help reduce GHG emissions and fossil energy consumption.

10.0 Conclusions

This analysis shows how important it is to take a life cycle approach and include the upstream process steps in order to get the true environmental picture of electricity generation and the effect of CO_2 sequestration. This is evident when comparing the emissions from coal with CO_2 sequestration to that from natural gas with CO_2 sequestration. Because natural gas production and distribution account for a large amount of the system's GHGs, sequestering CO_2 from the NGCC system results in roughly the same GWP as sequestering CO_2 from the coal system. Overall, compared to fossil fuel-generated electricity, producing electricity with biomass feedstocks will substantially reduce the GWP and the fossil energy consumption per kWh of electricity generated. Even with CO_2 sequestration, the amount of GHG emissions per kWh of electricity produced is more for the fossil-based systems than for the biomass power generation systems. Furthermore, when examining the cost of electricity with CO_2 sequestration, it is important to include the cost to capture, compress, transport, and store the CO_2, as well as the cost to produce additional electricity to make up for lost generating capacity. In doing so, biomass power from an advanced combined-cycle system is less than the cost of electricity from a fossil-fueled power generation system with CO_2 sequestration, and biomass power from a direct-fired system requires only a small GHG credit to make the system cost competitive. Additionally, cofiring with biomass residues is a near-term option that is cost competitive in today's electricity market. Therefore, the use of biomass for power production can be a cost-effective solution in helping to reduce GHG emissions and fossil energy consumption from electricity generation. This also avoids the concern about the fate of sequestered CO_2 and its long term environmental effects.

11.0 Possible Future Work

Although this study examined capturing CO_2 from existing coal-fired boilers without the option of costly retrofitting, it is possible that coal boilers could be retrofitted to IGCC designs. Additionally, future new coal plants will most likely be IGCC systems. Table 11 gives data from other studies for new coal IGCC plants incorporating CO_2 sequestration including power plant efficiency loss, increase in base electricity cost, and cost in dollars per tonne of avoided CO_2. Due to the efficiency and design of these plants, the sequestration cost in dollars per tonne of avoided CO_2 is about half that for a plant using a coal-fired boiler (see Table 7). Future work could be done to incorporate this type of information into the results of this study.

Table 11: Coal IGCC Power Production with CO_2 Sequestration - Cases in the Literature

Reference	Net power (MW)		Power loss (MW)	Net efficiency (%) (LHV unless specified)		Percentage point change in efficiency	Electricity cost (¢/kWh)		Increase in electricity cost from base case		(\$/tonne of avoided CO_2) (a)
	base	with CO_2 seq		base	with CO_2 seq		base	with CO_2 seq	¢/kWh	%	
Bergman *et al* (1997)	---	---	---	---	---	---	---	---	---	---	\$19-\$32 (b)
Doctor *et al* (1993)	469.6	328.5	141.1	---	---	---	---	---	---	---	---
Hendriks (1994)	600	500	100	43.6	36.3	-7.3	3.8¢	5.1¢	1.3¢	33%	\$17
Herzog (2000)	500	421.4	78.6	42.0	35.4	-6.6	4.6¢	6.0¢	1.4¢	30%	\$21
Holt and Booras (2000) (c)	425	404	21	---	---	---	5.24¢	6.57¢	1.33¢	25%	---
IEA (1993)	503	417	86	41.7	34.6	-7.1	---	---	---	---	---
IEA (2000a)	500	429	71	42	36	-6	5.3¢	6.3¢	1.0¢	19%	\$23
Johnson et al (1992)	432	388	44	35.4 (HHV)	28.5 (HHV)	-6.9	6.2¢	8.7¢	2.5¢	40%	\$32 (d)
Schütz *et al* (1992)	300	257	43	45	38.6	-6.4	---	---	---	---	---
Simbeck (1999)	400	355	45	47.6	38.7	-8.9	3.9¢	5.1¢	1.2¢	31%	---
Smelser and Booras (1990/1991)	431.65	378.94	52.71	35.4 (HHV)	28.5 (HHV)	-6.9	12.2¢	15.2¢	3.0¢	25%	---
Shell (1990)	750	667	83	43	33	-10	---	---	1-1.6¢	---	\$12-18 (f)
Van der Burgt (1992)	750	537	213	43	33	-10	---	---	---	40%	---

(a) Based on CO_2 difference from base case coal-fired plant. This is equal to (the increase in the cost of electricity) / (the amount of CO_2 avoided).
(b) Converted from \$/ton of CO_2 disposed.
(c) DeLallo et al (2000) is another reference by same authors containing the same numbers.
(d) Calculated.
(e) Converted from their Dutch currency numbers.

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