Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant

Appendix:
Process Modeling Data Assumptions and GaBi Modeling Inputs

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A.1 Life Cycle Stage Process Modeling Data Assumptions and GaBi Modeling Inputs

Appendix A details the process modeling data assumptions and GaBi modeling inputs for each of the life cycle (LC) stages considered in this study. For more details on the system boundary and other aspects of this study, please see the main final report. GaBi output data will be shown for air emissions. Results associated with land and all economic modeling assumptions and results are included in the main text.

All stages will be the same for both cases except for Stage #3, which has different assumptions and therefore will be described separately for each case. For each stage, the construction assumptions will be discussed separately from the operations as they often come from different reference sources. When applicable, the commissioning, installation, and decommissioning will also be discussed. For clarity, the following are general descriptions of each term as they are used in this study:

- **Construction**: materials used in the construction of a process (steel used to build a power plant).
- **Commissioning/Installation**: energy used and emissions created to prepare the land and install the processing facility. This is also when land use change occurs. Commissioning and installation are used interchangeably because commissioning is the word typically used in the literature while installation is used in GaBi.
- **Decommissioning**: energy use and emissions associated with removing the processing facility (and returning the land to grassland). Typically a fraction of the assumptions made for commissioning.
- **Operations**: energy use and subsequent emissions due to the operation of a process (electricity and diesel during coal mining, natural gas for the auxiliary boiler during power plant operations).

All assumptions and data limitations will be noted. All references are listed at the conclusion of the appendix.

Figure A-1 and **Figure A-2** show the main GaBi plans for this study. **Figure A-1** represents the plan for the existing pulverized coal (EXPC) plant without carbon capture and sequestration (CCS), and **Figure A-2** represents the plan for the EXPC plant that is retrofitted with a CCS system. Plans are used in GaBi to assemble unit processes or sub-plans (nested plans) within an LC study. Essentially, plans are the process maps which visually depict a stage or sub-stage in a system. There are several levels of plans: main, second level, third level, etc. The main plan represents the highest level LC in which all other plans are embedded; from the main plan one could click onto a secondary plan (i.e., LC Stage #1 coal acquisition), and from there onto a third level plan (i.e., coal mine construction). The input and output values shown on this plan are based on the reference flow of one megawatt hour (MWh) (3,600 megajoule [MJ] = 1 MWh). In the case of the EXPC plant that is retrofitted with CCS, 69.9 percent of delivered MWh is from the EXPC plant and the remaining 31.1 percent is from replacement power, which is used to make up for the reduced output of the EXPC plant when a CCS system is installed. The Southeast Electric Reliability Council's (SERC) electricity grid is used to represent the sources of replacement power. Also included in the main plans are the adjustable parameters considered during the life cycle inventory (LCI) sensitivity analysis for this study (see

main report text for results). Specific details on why these parameters are adjustable are included within the following data assumption text.

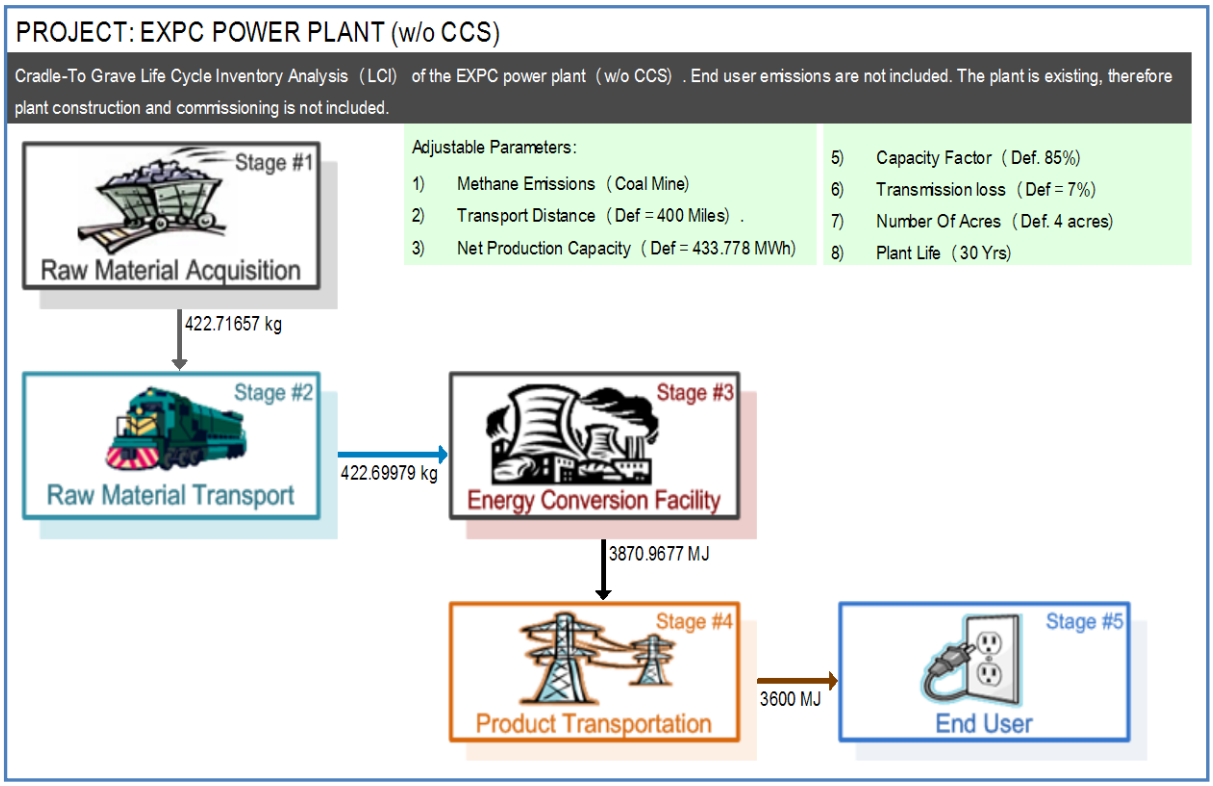

Figure A-1: Main GaBi Plan for the EXPC Case without CCS

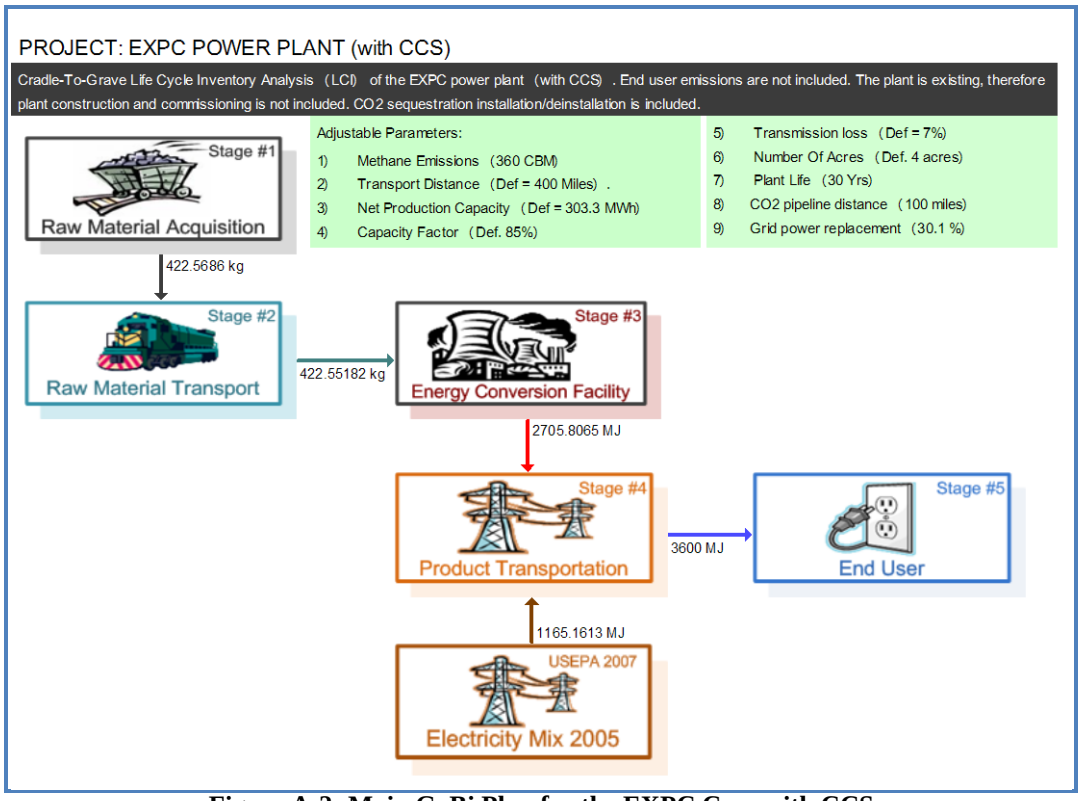

Figure A-2: Main GaBi Plan for the EXPC Case with CCS

A.1.1 Life Cycle Stage #1: Raw Material Acquisition – Coal Mining and Processing

A.1.1.1 GaBi Plan

Figure A-3 is the second level GaBi plan for the Stage #1 coal mining process. For this stage, methane (CH_4) emissions are the only adjustable parameter, meaning that sensitivity analysis can be performed on this parameter within the GaBi modeling framework. The reference flow of this stage is 1 kg of coal produced from the mine. Coal mine construction is not included within the boundaries of this analysis; the coal mine exists regardless of whether the EXPC plant is retrofitted with a CCS system. Coal mine operation and decommissioning are included in this analysis and are discussed in the following sections. Water use and emissions are not captured in the GaBi plans; they only show input data that is tracked within the GaBi modeling system. Emissions are considered outputs and therefore are not included. Water use, although an input, is not tracked in the model as no GaBi profiles exist for water use in the model to date. For now, water is inventoried for each stage, when applicable.

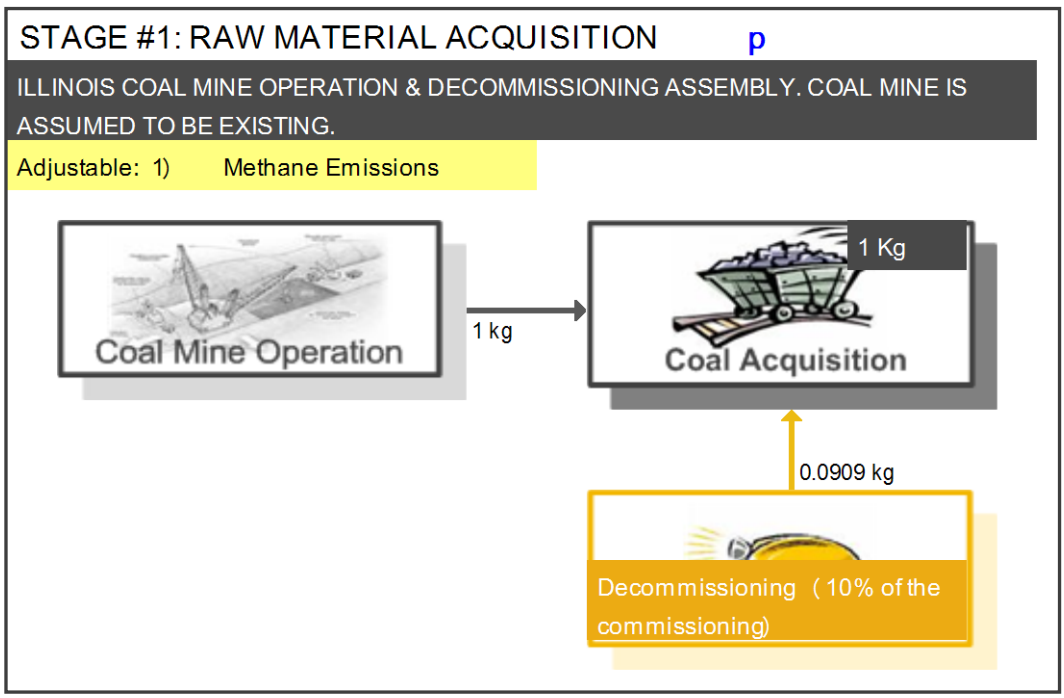

Figure A-3: GaBi Plan for LC Stage #1: Coal Acquisition

A.1.1.2 Commissioning, Installation, and Decommissioning Assumptions

This analysis calculates decommissioning by assuming it represents 10 percent of commissioning burdens. Thus, in order to model decommissioning, commissioning must first be determined.

No data were available for the commissioning or decommissioning of the Galatia Mine, so fuel consumption and emissions data were obtained from a draft Environment Impact Statement (EIS) for the Red Cliff Mine in Colorado (DOI, 2009). The Red Cliff Mine is an underground mine expected to have an annual output of 8 million tons, and have a productive lifetime of 20 to 30 years. The EIS provided data for the onsite machinery fuel use and tailpipe emissions (greenhouse gas [GHG] and criteria air pollutants) in Appendix H, Air Quality Analysis Modeling Report (DOI, 2009). Tons of pollutants emitted per year were converted into tons per commissioning by multiplying by 1.5, the length of time expected to complete the commissioning (DOI, 2009). These values were then converted into kilograms and divided by the total expected output of the mine over 30 years (217,724,337,600 kg) to determine the amount of emissions on a per kg of coal produced basis. Equipment fuel use data, for both gasoline and diesel, were taken from the same data source and calculated on a per kg of coal produced basis in the same fashion.

The particulate matter (PM) emissions were taken from a different location in the same source (DOI, 2009). It was assumed that the value given for $PM_{2.5}$ emissions would encompass all PM greater than 2.5 microns, including PM_{10} emissions; therefore, the total value for $PM_{2.5}$ was assumed for all PM $\leq$10 microns. It was also assumed that the total PM values given included consumption and fugitive dust emissions. The given values were in tons/yr, and were also converted to kg PM/kg coal produced.

The emissions for ammonia (NH_3) and mercury (Hg) were calculated using data from two other sources (Battye, Battye et al., 1994; Conaway, Mason et al., 2005). The emission factors for both fuels was given, NH_3 in kg/1,000 L of gas (or diesel) (Conaway et al. 2005) and Hg in ng/g of gas (or diesel) (Battye et al. 1994). Each emission factor was multiplied by the amount of each fuel used during commissioning to get a final value per kg of coal produced.

The values of each fuel and emission for commissioning was then multiplied by 10 percent to account for decommissioning emissions and fuel consumption, a common assumption in the literature (Hill, O"Keefe et al., 1995; Odeh and Cockerill, 2008; Gorokhov, Manfredo et al., 2002). Reliable data for water use during coal mine commissioning and decommissioning was unable to be located and was thus considered a minor data limitation. Water would be used to suppress particulate emissions during construction and decommissioning activities.

Based on the given data assumptions, **Figure A-4** represents the fuel inputs to produce 1 kg of output coal during the commissioning/decommissioning process.

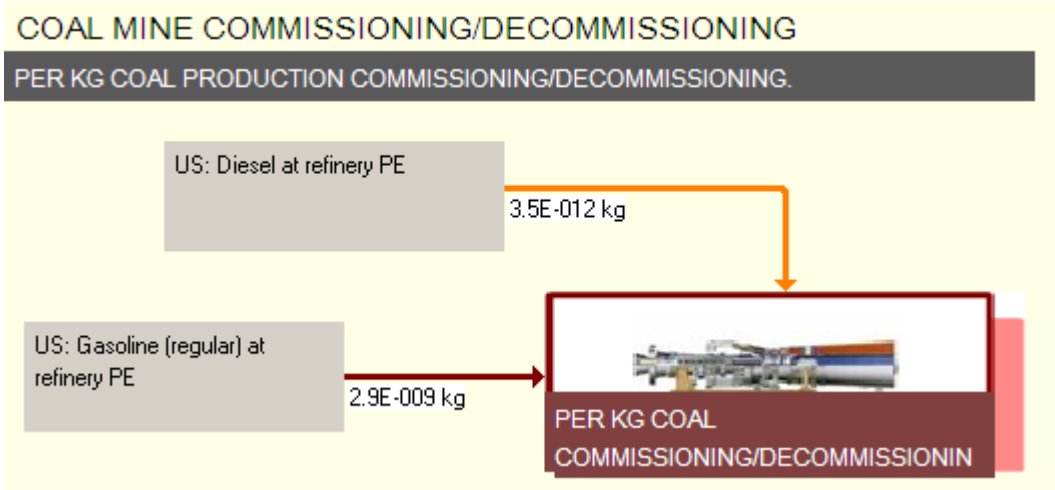

Figure A-4: Fuel Inputs into the Coal Mine Commissioning/Decommissioning Third Level GaBi Plan

Table A-1: GaBi Air Emission Outputs for Coal Mine C/D, kg/kg Coal Ready for Transport

	Total	Coal Mine Commissioning/ Decommissioning	Diesel at Refinery	Gasoline (regular) at Refinery
Lead	7.1801E-17	0	6.51451E-20	7.17359E-17
Mercury	3.94104E-16	3.86463E-16	5.5211E-21	7.63503E-18
Ammonia	3.1827E-10	3.18252E-10	9.6348E-18	1.82055E-14
Carbon Dioxide	1.26609E-05	1.2659E-05	1.44081E-12	1.87168E-09
Carbon Monoxide	3.30227E-08	3.30206E-08	2.10394E-15	2.11068E-12
Nitrogen Oxides	1.01032E-07	1.01028E-07	4.47432E-15	4.22177E-12
Nitrous Oxide (laughing gas)	2.33776E-10	2.3375E-10	2.46789E-17	2.60517E-14
Sulfur Dioxide	8.8559E-11	8.25E-11	5.78282E-15	6.0532E-12
Sulfur Hexafluoride	5.33777E-21	0	5.49034E-24	5.33228E-21
Methane	3.90742E-10	3.78125E-10	1.49838E-14	1.26025E-11
Methane (biotic)	0	0	0	0
VOC (unspecified)	4.55813E-09	4.55813E-09	6.24103E-18	5.28924E-15
Particulate Matter, unspecified	3.40588E-07	3.40588E-07	0	0
Dust (unspecified)	7.60644E-14	0	8.52581E-17	7.59791E-14

A.1.1.3 Operation Assumptions

This process covers the energy needs and emissions associated with the production of coal during operation of the coal mine, from resource extraction through the boundary for LC Stage #2; again, all data inputs for this stage were based on the reference flow of 1 kg of fully processed (output) coal over the 30-year study lifetime. Considered are the consumption of electricity, consumption of diesel, emissions of CH_4 associated with off-gassing from the coal/coal mine, PM emissions associated with fugitive coal dust, water input flows required for mining and cleaning operations, wastewater flows, and emissions of criteria air pollutants, as well as emissions of Hg and NH_3.

Operations of the coal mine were based on operations of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, CH_4 emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations, and use for this model was estimated based on previous estimates made by the Environmental Protection Agency (EPA) for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008d). The LC profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems; the current version of eGRID was updated in January 2009 and is based on 2005 data (EPA, 2009). Although no data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary onsite operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Department of Commerce, 2004).

Emissions of criteria pollutants were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004). Diesel is assumed to be ultra-low sulfur diesel (ULSD) (15 parts per million [ppm] sulfur). Emissions of Hg and NH_3 from diesel combustion were estimated from other sources and calculated in the same fashion as diesel used during commissioning (Battye, Battye et al., 1994; Conaway, Mason et al., 2005).

In addition to combustion, other sources of PM and CH_4 existed during coal mine operations. PM emission inventory includes those due to the combustion of diesel, as well as fugitive coal dust from the mining process. Total coal dust emissions from the Galatia Mine were used based on EPA (2005) data for the mine, and were normalized to the reference flow (EPA, 2005b). Coal mining accounts for approximately 30 percent of CH_4 emissions in the United States, with underground mines contributing the largest share (EPA, 2008e). During coal acquisition, CH_4 is released during both the underground coal extraction and the post-mining coal preparation activities. From the EPA inventory of GHG emissions from 1990 through 2006, 90 percent of CH_4 emitted from underground mining was a result of coal extraction, while the remaining 10 percent was emitted during post-mining activities (EPA, 2008e). An average of CH_4 emission

estimates for the Galatia Mine (EPA, 2008d) were added to CH_4 combustion emissions for this process. Due to the uncertainty in CH_4 emission estimates, the large global warming potential (GWP) of CH_4, and the ability to capture and use or sell CH_4 for onsite energy, the amount of CH_4 released is included as an adjustable parameter in this process. Sensitivity analysis results are included and discussed in the main report text.

Water use was estimated by Galatia Mine staff (Personal Communication 2009), and wastewater data were taken from available National Pollutant Discharge Elimination System permit reporting documentation for Galatia Mine from 2005 to 2008 (EPA, 2008c). **Figure A-5** shows the third level GaBi plan view for energy inputs during coal mine operations; water used in coal mining is assumed to be resource (ground or surface water). It is not specifically tracked in GaBi and therefore is not included in the plan. **Table A-2** shows the total GaBi emission outputs for coal mine operation and the additional LC emissions associated with electricity and diesel production.

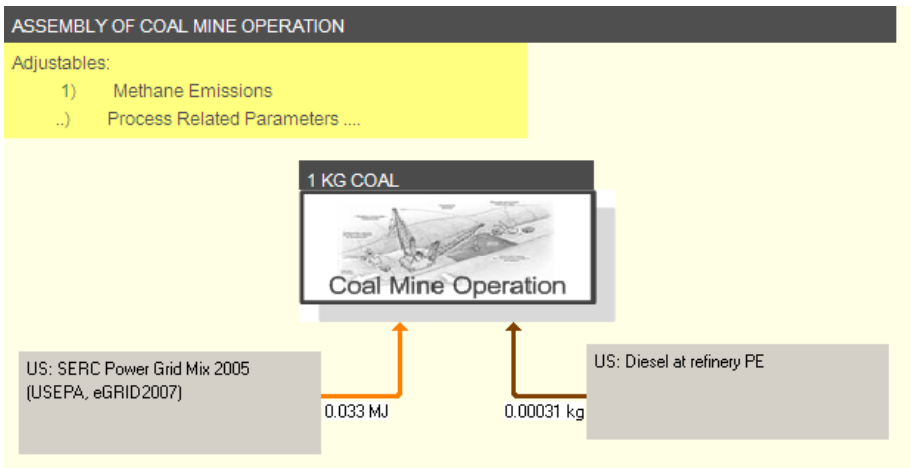

Figure A-5: Coal Mine Operations Fuel Inputs

Table A-2: GaBi Air Emissions for Coal Mine Operations, Electricity, and Diesel Use, kg/kg Coal Ready for Transport

Emissions (kg/kg coal ready to transport)	Total	SERC Power Grid Mix 2005 (USEPA, eGRID2007)	Coal Mining Operation (Illinios No, 6)	Diesel at Refinery PE
Lead	3.30E-10	3.24E-10	0.00E+00	5.80E-12
Mercury	9.19E-11	9.14E-11	4.08E-14	4.90E-13
Ammonia	6.61E-08	3.12E-08	3.41E-08	8.50E-10
Carbon Dioxide	7.47E-03	6.51E-03	8.30E-04	1.30E-04
Carbon Monoxide	7.32E-06	2.69E-06	4.44E-06	1.90E-07
Nitrogen Oxides	1.35E-05	1.26E-05	5.10E-07	4.00E-07
Nitrous Oxide (laughing gas)	1.10E-07	8.62E-08	2.13E-08	2.20E-09
Sulfur Dioxide	3.74E-05	3.69E-05	0.00E+00	5.10E-07
Sulfur Hexafluoride	4.49E-14	4.44E-14	0.00E+00	4.90E-16
Methane	7.57E-03	7.14E-06	7.56E-03	1.30E-06
Methane (biotic)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC (unspecified)	2.40E-07	9.08E-10	2.38E-07	5.50E-10
Particulate Matter, unspecified	1.27E-06	0.00E+00	1.27E-06	0.00E+00
Dust (unspecified)	7.08E-07	7.01E-07	0.00E+00	7.50E-09

A.1.2 Life Cycle Stage #2: Raw Material Transport – Coal Transport

In Stage #2 it was assumed that the mined coal was transported by rail from the coal mine in southern Illinois to the energy conversions facility located in southeastern Illinois, an assumed distance of 205 miles. For this study, a unit train is defined as one locomotive pulling 100 railcars loaded with coal; the locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 91-tonne (100-ton) coal capacity (NETL, 2007a).

A.1.2.1 GaBi Plan

Figure A-6 shows the second level plan for this stage. Construction and commissioning/decommissioning are not included in this stage; it is assumed that the train and associated infrastructure are in use regardless of whether an EXPC plant is retrofitted with a CCS system. The reference flow of this stage is 1 kg of coal transported a roundtrip distance of 400 miles. The transport distance is an adjustable parameter and is the subject of sensitivity analysis.

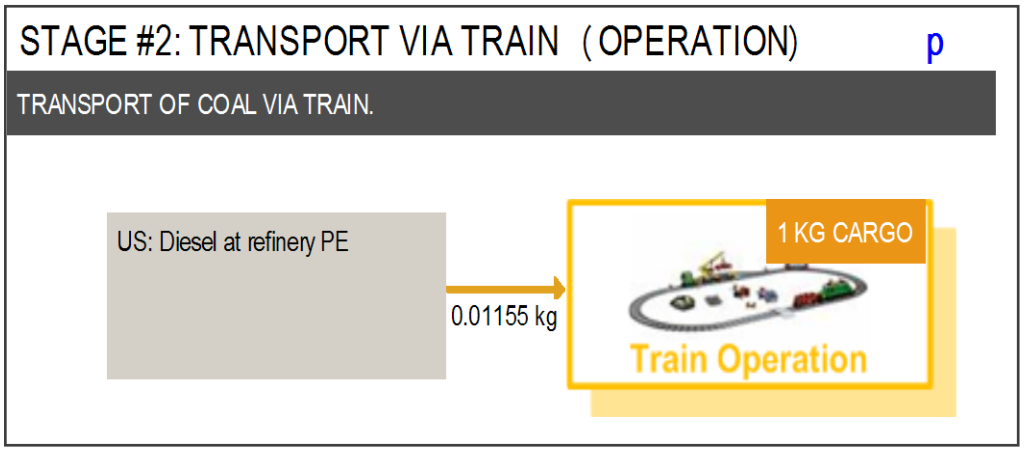

Figure A-6: Second Level GaBi Plan: Stage #2 Train Transport

A.1.2.2 Operation Assumptions

The scope of this process covers rail transport of coal in the United States and estimates criteria pollutant emissions, CO_2 emissions, and fugitive dust emissions on the basis of 1 kg of coal being transported along a user-defined distance (200 miles for the EXPC cases). The calculation assumes that backhaul and front haul have the same energy intensity and emission profile. The diesel locomotive, which would operate from 2010 to 2040, is assumed to meet the emission standards of EPA's Tier 4 emissions criteria for the duration of the 30-year period. Note that the Tier 4 emissions standards are set to become effective in 2015. Accordingly, diesel consumed by the train is assumed to be ULSD, with a sulfur content of 15 ppm.

The energy requirement/diesel consumption factor used for the diesel locomotive was taken from the U.S. Bureau of Transportation statistics for 2008, which includes energy intensity data for railroad freight service (DOT, 2008). Emission factors were taken from EPA's Tier 4 standard for diesel locomotive engines for nitrogen oxide (NO_X), PM, volatile organic chemicals (VOCs), and carbon monoxide (CO) (EPA, 2008b). Emission factors for CO_2, CH_4, and nitrous oxide (N_2O) were taken from the national emissions inventory (EPA, 2005b). Sulfur dioxide (SO_2) emissions are calculated based on the sulfur content of ULSD and assuming complete stiochiometric conversion from sulfur to SO_2 during diesel combustion.

Fugitive coal dust emissions are based on a study of Australian coal mine transport in Queensland, Australia (Cornnell Hatch, 2008). Therein, fugitive coal dust emissions were quantified on a per metric tonne basis over distances ranging from approximately 125 km to 500 km. Fugitive coal dust emissions were then normalized to a basis of kg coal dust emissions per kg-km of coal transport, and incorporated into the model calculations.

The amount of Hg released as a result of the combustion of diesel was based on information from a study examining gasoline and diesel fuel combustion in the San Francisco Bay area of California (Conaway, Mason et al., 2005). An emission factor for NH_3 from the combustion of diesel from mobile sources was obtained from a report that developed emission factors for various sources of NH_3 (Battye, Battye et al., 1994). The GaBi plan for train transport operation

is located in **Figure A-6,** with 1 kg representing 1 kg of processed coal from the mine. **Table A-3** shows the GaBi air emission outputs due to Stage #2 operations.

Table A-3: GaBi Air Emission Outputs and Profiles for Stage #2 Operations, kg/kg Coal Delivered to the Plant with a Round Trip of 400 Miles

Emissions (kg/kg coal delivered)	Total	Diesel at Refinery	Transport of Coal Via Train
Lead	2.14923E-10	2.14923E-10	0
Mercury	1.97373E-11	1.82149E-11	1.52242E-12
Ammonia	1.3019E-06	3.17865E-08	1.27012E-06
Carbon Dioxide	0.035704076	0.004753434	0.030950642
Carbon Monoxide	0.00010211	6.94118E-06	9.51683E-05
Nitrogen Oxides	9.72406E-05	1.47614E-05	8.24792E-05
Nitrous Oxide (laughing gas)	8.74489E-07	8.14192E-08	7.9307E-07
Sulfur Dioxide	1.93701E-05	1.90783E-05	2.91755E-07
Sulfur Hexafluoride	1.81134E-14	1.81134E-14	0
Methane	5.1874E-05	4.94338E-05	2.44021E-06
Methane (biotic)	0	0	0
VOC (unspecified)	8.90297E-06	2.059E-08	8.88238E-06
Particulate Matter, unspecified	0.000118033	0	0.000118033
Dust (unspecified)	2.81278E-07	2.81278E-07	0

A.1.3 Life Cycle Stage #3: EXPC Energy Conversion Facility without CCS

Case 1 includes the operation and decommissioning of a 433-megawatt electric (MWe) net output EXPC plant without CCS.

Decommissioning data was developed from an application for a power plant in California, which included equipment specifications that allowed the calculation of fuel use and air emissions associated with commissioning and decommissioning activities. Operations data came from several sources. Plant capacity and CO_2 emissions are based on a National Energy Technology Laboratory (NETL) study of a subcritical pulverized coal (SCPC) energy conversion facility in Conesville, Ohio (NETL 2007a). EPA emissions inventories (EPA 2009 and EPA 2007) were used to estimate other types of air emissions (including criteria air pollutants, NH_3, and Hg) from the Conesville facility. Water use was estimated from the Power Plant Water Usage and Loss Study (NETL 2007c), which includes data for SCPC boilers. Finally, sulfur hexafluoride (SF_6) emissions from circuit breakers were estimated from loss rates cited by a manufacturer of power systems (HVB 2003).

Details on the development of data used to characterize the operations and decommissioning of an EXPC facility without CCS are provided below.

A.1.3.1 GaBi Plan

Figure A-7 defines the second level GaBi plan for the EXPC case without CCS. This plan is based on a reference flow of 1 MWh of electricity output over the 30-year study lifetime.

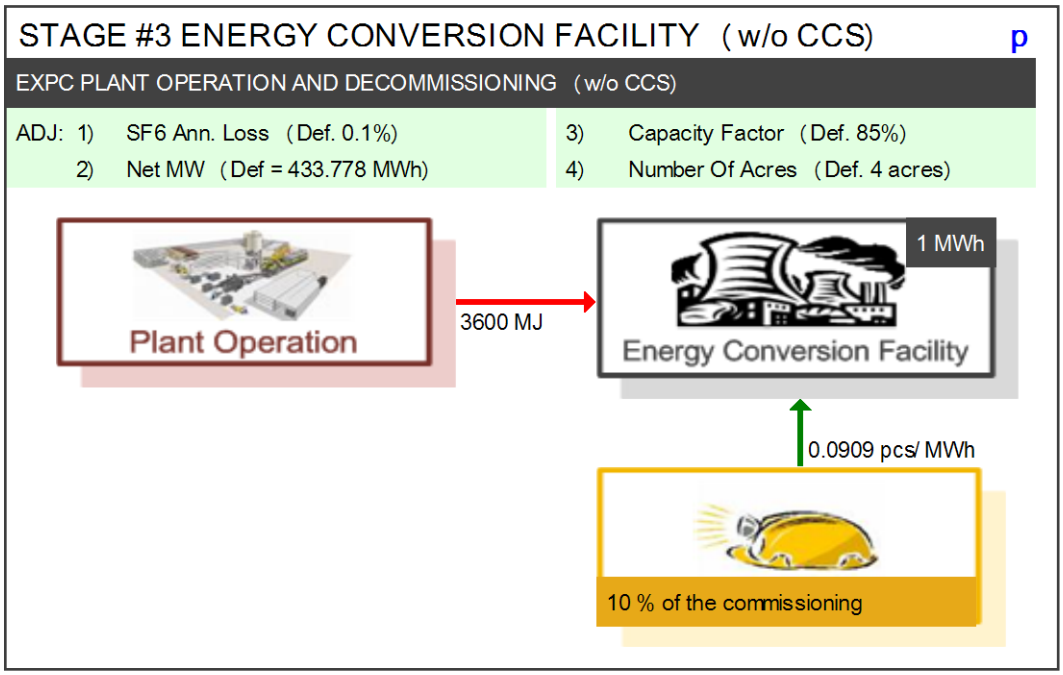

Figure A-7: GaBi Plan for EXPC Case without CCS

A.1.3.2 Commissioning, Installation, and Decommissioning Assumptions

The energy and water used and emissions associated with the installation and deinstallation of a power plant are dominated by the use of diesel fuel to power construction equipment. Data for the installation of a power plant came from the Russell City Energy Center Application for Certification to the California Energy Commission (Calpine/Bechtel, 2001). The application was for the proposed Russell Energy Center, a 14.7-acre, 600-MW natural gas combined cycle (NGCC) plant with equipment needs (two gas turbines with heat recovery steam generators and one steam turbine) similar to those in the Baseline Report (NETL, 2007a).

The application included data on diesel fuel use, water use, and criteria air pollutants associated with a 21-month installation period. The data were calculated assuming many emission control measures were implemented, including water spray for dust suppression, low sulfur fuels, preventative maintenance on construction equipment, and limited idling time (Calpine/Bechtel, 2001). It is noted as a minor data limitation that emissions are based on a plant in California, while our model is considering a plant in Illinois. Some differences are expected due to varying landscapes and regulatory requirements.

Although it was assumed that water suppression was used to control PM emissions, no data were given on the specific amount of water used during installation. This amount was calculated

using a given application rate of water, and took into account several assumptions. The application stated that most of the plant fugitive dust emissions occurred in the first month or two and thus, water usage was only calculated for the first two months (Calpine/Bechtel, 2001). The application also stated that the construction process would occur from 6 a.m. to 6 p.m., Monday through Saturday, for a total of 288 hours of construction per month of activity (Calpine/Bechtel, 2001). Finally, it was assumed that the application rate of 0.25 hours per application (or four applications per hour) was incorrectly reported in the source (Calpine/Bechtel, 2001); applying that amount of water would result in approximately one inch of water per day being used over the entire installation area. Research and Development Solutions, LLC (RDS) felt that, although dust would be suppressed, such an amount of water would cause additional problems with standing water and mud. Therefore, an adjusted application rate of 0.25 applications per hour was assumed, which correlated to one application every four hours. This application rate seemed more practical, and an inverse of units as written in the original report is a realistic error.

Diesel use during installation was obtained from the Russell City Energy Center Application for Certification (Calpine/Bechtel, 2001). In Appendix 8.1-E, Table 8.1E-8 lists the total diesel use, in gallons per year, of each piece of construction equipment. These amounts were summed for a total of 122,817.7 gal/yr. This value was multiplied by the length of the construction period, 21 months (or ~1.75 years), for the volume over the entire construction period. This value was then multiplied by the density of diesel (7.1 lb/gal) and converted to kilograms (American Petroleum Institute, 2004).

The amount of CO_2 released during installation of the power plant was calculated by first determining how much carbon was present in the amount of diesel used. There are 2,778 grams of carbon in one gallon of diesel (EPA, 2005a). The amount of carbon in the diesel (568,645.9 kg) was converted to CO_2 by following EPA and Intergovernmental Panel on Climate Change (IPCC) guidelines, which state that 99 percent of carbon in a fuel is oxidized and emitted as CO_2, and the mass of CO_2 was determined multiplying by the ratio of the molecular weights of CO_2 (44 moles/gram) and carbon (12 moles/gram) (EPA, 2005a). The total calculated mass of CO_2 released during construction was divided by the number of acres of construction that the study was based on (14.7, Calpine/Bechtel, 2001) to determine kg/acre of CO_2.

Table 8.1E-3 of the Russell City application lists the emissions, in tons/year, for five pollutants – NO_X, CO, VOC, sulfur oxide (SO_X), and PM (Calpine/Bechtel, 2001). The values for each, 22.95 tons/yr for NO_X, 63.82 tons/year for CO, 6.09 tons/year for VOC, 0.58 tons/year for SO_X, and 3.1 tons/year for PM, were multiplied by the number of years of construction (1.75) and then converted into kilograms. Finally, these values were divided by the total area of the construction site to get the amount of each emission per acre.

The emissions of four other pollutants were calculated using different sources – CH_4, N_2O, NH_3, and Hg. The emissions factors for CH_4 and N_2O were pulled from Appendix H of a U.S. Department of Energy (DOE) report, which references the EPA GHG inventory (EPA, 2008e). It was assumed that the diesel-powered construction equipment would be representative of the equipment used at the power plant. These emission factors were 0.58 g/gallon of diesel for CH_4 and 0.26 g/gallon for N_2O (EPA, 2008e). The NH_3 emission factor was obtained from a report published by the EPA documenting the development and selection of emission factors for NH_3. The emission factor for the combustion of diesel from mobile sources was given as 0.11 kg/1,000 L of diesel (Battye, Battye et al., 1994). The emission factor of the final pollutant, Hg,

was determined by dividing the average concentration of Hg in diesel from various studies by the number of samples to get 0.1564 ng/g diesel (Conaway, Mason et al., 2005).

Each of the pollutants was converted from their emission factor units into kg/acre to correspond with the other emissions. Both the CH_4 and N_2O emissions were calculated by converting first to kg/gallon of diesel, and then by multiplying by the previously determined gallons of diesel used per acre of development. The NH_3 was also converted to kg/gallon and multiplied by the gallons of diesel used, but there was an intermediate conversion from 1,000 L to gallons. Finally, the Hg was converted by changing g diesel to kg diesel, multiplying by the diesel use per acre (in kg/acre), and dividing by 10^{12} (ng/kg). These calculations gave total emissions, per acre of development, of 8.48 kg CH_4, 3.80 kg N_2O, 6.09 kg NH_3, and 7.36×10^{-06} kg Hg.

The total amount of water and diesel used and the emissions released includes decommissioning of the power plant site. It was assumed that the decommissioning use and emissions were 10 percent of the total commissioning use and emissions (Odeh and Cockerill, 2008). The diesel use, water use, and emissions were all multiplied by 10 percent, and this value was added onto the total values previously calculated on a per acre of installation basis.

Table A-4 gives the GaBi emission outputs and profiles associated with this process.

Table A-4: GaBi Air Emission Outputs and Profiles for Power Plant Installation/Deinstallation, kg/MWh Plant Output

	Total	Diesel at Refinery	Power Plant Installation/Deinstallation
Lead	3.6E-12	3.6E-12	0
Mercury	3.4E-13	3.1E-13	3.0E-14
Ammonia	2.6E-08	5.4E-10	2.5E-08
Carbon Dioxide	6.9E-04	8.0E-05	6.1E-04
Carbon Monoxide	2.9E-05	1.2E-07	2.8E-05
Nitrogen Oxides	1.0E-05	2.5E-07	1.0E-05
Nitrous Oxide (laughing gas)	1.7E-08	1.4E-09	1.6E-08
Sulfur Dioxide	5.8E-07	3.2E-07	2.6E-07
Sulfur Hexafluoride	3.0E-16	3.0E-16	0.0E+00
Methane	8.7E-07	8.3E-07	3.5E-08
Methane (biotic)	0	0	0
VOC (unspecified)	2.7E-06	3.5E-10	2.7E-06
Particulate Matter, unspecified	1.4E-06	0.0E+00	1.4E-06
Dust (unspecified)	4.7E-09	4.7E-09	0.0E+00

A.1.3.3 Construction Assumptions

The unmodified EXPC scenario does not require new construction. No environmental burdens are modeled for the unmodified EXPC scenario.

A.1.3.4 Operation Assumptions

All primary operations of the EXPC plant without CCS are included in this unit process, using inputs of coal, air, and process water to produce electricity. Emissions output from operation of the plant also include the leakage of SF_6 from circuit breakers at the 345-kilovolt (kV) switchyards at either end of the trunkline. Error! Reference source not found. shows the GaBi plan for unmodified EXPC operations.

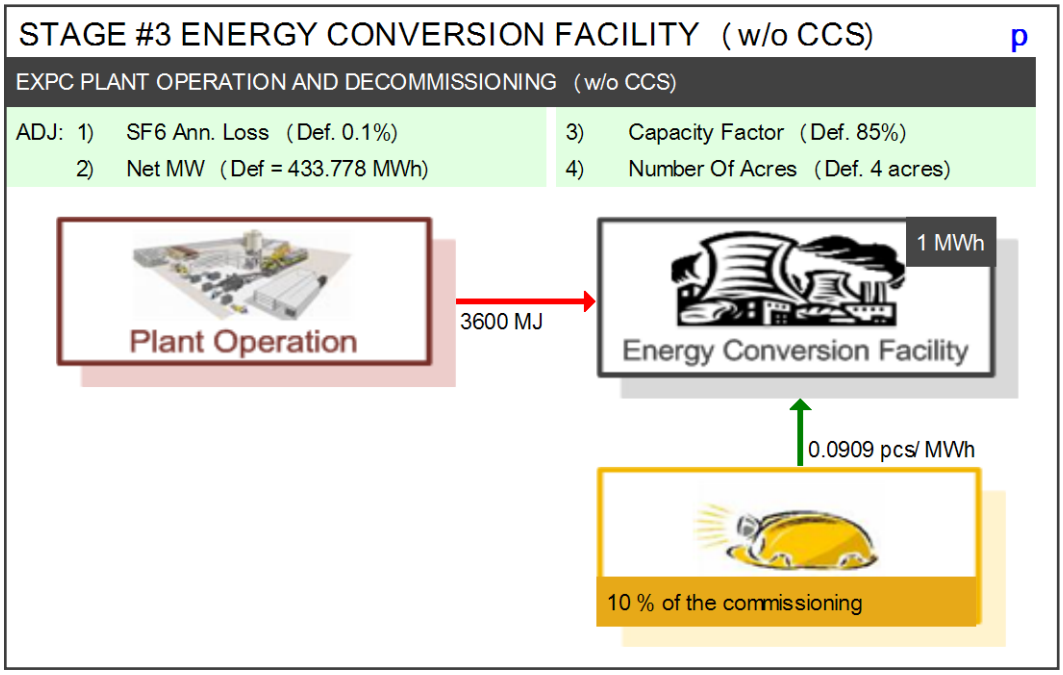

Figure A-8: GaBi Plan for EXPC Power Plant Operation and Decommissioning without CCS

This process is modeled as a facility with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. Reference data from a CO_2 capture study (NETL 2007a) for Conesville Unit #5, a nominal 450-MW SCPC plant with a capacity factor of 85 percent located in Ohio, is utilized for the modeling as is EPA emissions data (EPA 2009 and EPA 2007). The actual generation for Unit #5 during 2005 was 2,427,313 MWh at a capacity factor of 62 percent (EPA 2009). The difference in capacity factor between the CO_2 capture study (NETL 2007a) and the actual emissions data (EPA 2009) is considered a data limitation.

Boiler heat recovery equipment includes an economizer and regenerative air heater. The flue gas emissions control equipment includes an electrostatic precipitator (ESP) and a lime-based flue gas desulfurization (FGD) system. Water that is discharged from the EXPC plant is discharged into a municipal sewer system (NETL 2007a).

Air Emissions

Emissions data for the Conesville plant were obtained from the eGRID2007 (EPA 2009) and national emissions inventory (NEI) (EPA 2007) databases.

Water Usage

Water usage for the EXPC plant was estimated from the Power Plant Water Usage and Loss Study (NETL 2007c), henceforth referred to as the water report. For Subcritical PC Boiler Raw Water Usage, the water report lists a value of 663.8 gallons/MWh (2.51 m^3/MWh) which is used for the plant water input value. This input is only for water withdrawn from a municipal or other source and does not include moisture in the coal or humidity in the combustion air. Water that is discharged from the plant as a waste is listed under SCPC Boiler Water Loss by Function as cooling tower blowdown in the water report at a rate of 149.5 gallons/MWh (0.57 m^3/MWh), which is used for the plant water output value.

Circuit Breaker SF_6 Leakage

Once electricity is produced in the EXPC plant, circuit breakers are used for safety during electricity transmission. It was assumed that two circuit breakers would be needed to operate the EXPC plant; one at the output of the generator and one at the end of the trunkline. It is common practice to use SF_6 gas in the breakers, which is a GHG with a high GWP. The amount of SF_6 used in each circuit breaker is given in the literature as 690 lbs; therefore, the EXPC plant requires 626 kg of SF_6 (HVB 2003). Although estimates vary, the national electrical manufacturers association states that the management guidelines for leakage of SF_6 from circuit breakers are 0.1 percent/year (Blackman). This calculates to a leakage rate of 2.58 × 10-7 kg/MWh net output.

Auxiliary Boiler Operation

An auxiliary boiler is not identified in the Conesville report (NETL 2007a), nor are emissions from an auxiliary boiler at the Conesville plant identified in either of the emissions sources used for modeling (EPA 2007, and EPA 2009). While it is likely that one exists, it is the modeler's opinion that an auxiliary boiler would not be operated for a significant period of time as the EXPC plant is modeled after Conesville Unit #5, which is one of four coal-fired steam units listed as active at the site. Therefore, rather than risk the introduction of additional emissions which may be double counted, a decision was made that emissions from an auxiliary boiler would not be modeled.

Table A-5: Air Emission Outputs for Unmodified EXPC, kg/MWh Plant Output

	EXPC Power Plant Operation (w/o CCS)
Lead	5.9E-06
Mercury	4.8E-05
Ammonia	2.0E-04
Carbon Dioxide	941
Carbon Monoxide	1.0E-01
Nitrogen Oxides	1.9
Nitrous Oxide (laughing gas)	1.6E-02
Sulfur Dioxide	2.2
Sulfur Hexafluoride	2.6E-07
Methane	1.1E-02
Methane (biotic)	0
VOC (unspecified)	1.2E-02
Particulate Matter, unspecified	6.3E-01
Dust (unspecified)	0

A.1.4 Life Cycle Stage #3, Case 2: EXPC Energy Conversion Facility with CCS

Case 2 includes the operation and decommissioning of a 303-MWe net output EXPC plant that is retrofitted with a new CCS system.

Decommissioning data was developed from an application for a power plant in California which included equipment specifications that allowed the calculation of fuel use and air emissions associated with commissioning and decommissioning activities. Operations data for these scenarios came from several sources. Plant capacity and CO_2 emissions are based on an NETL study of an SCPC coal energy conversion facility in Conesville, Ohio (NETL 2007a). EPA emissions inventories (EPA 2009 and EPA 2007) were used to estimate other types of air emissions (including criteria air pollutants, NH_3, and Hg) from the Conesville facility. Water use was estimated from the Power Plant Water Usage and Loss Study (NETL 2007c), which includes data for SCPC boilers. Finally, SF_6 emissions from circuit breakers were estimated from loss rates cited by a manufacturer of power systems (HVB 2003). Construction data, which is applicable only to the retrofitted EXPC case, is based on a European life cycle assessment (LCA) that lists the steel, concrete, and other material requirements of a CCS system.

Details on the development of data used to characterize the CCS construction, operations, and decommissioning of an EXPC facility with CCS are provided below.

A.1.4.1 GaBi Plan

Figure A-9: GaBi Plan for Stage #3, Case 2: EXPC with CCS

defines the second level GaBi plan for the EXPC case retrofitted with CCS. This plan is based on a reference flow of 1 MWh of electricity output. The addition of a CO_2 pipeline and the incorporation of replacement power (due to the EXPC power loss due to the addition of a CCS system) are the main differences between two scenarios modeled in Stage #3. Assumptions on the commissioning/decommissioning, construction, and operation of the pipeline are included in the following sections.

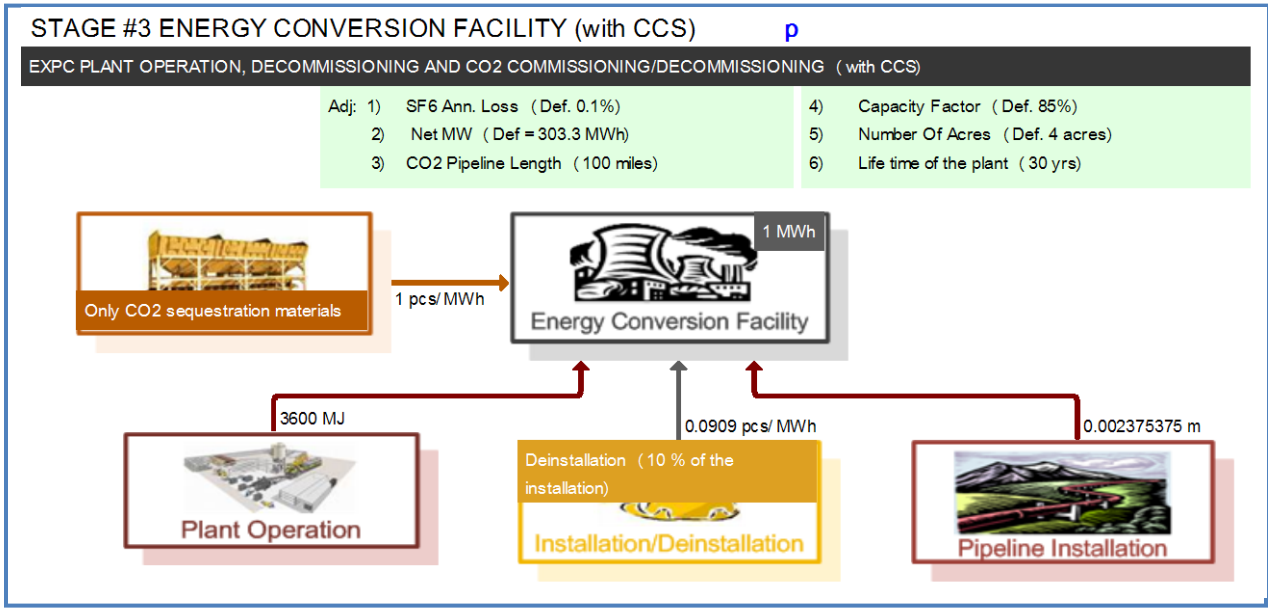

Figure A-9: GaBi Plan for Stage #3, Case 2: EXPC with CCS

A.1.4.2 Commissioning, Installation, and Decommissioning Assumptions

There are no case-specific power plant commissioning/decommissioning parameters within this study; **Section A.1.3.2** represents both cases, so the discussion on plant commissioning and decommissioning is not repeated here. However, the retrofitted EXPC case does require the commissioning of a CO_2 pipeline, which is discussed below.

Emissions consistent with underground pipeline laying/construction include heavy construction equipment exhaust emissions, emissions from transport of pipes and associated materials (200 miles round-trip), and fugitive dust. PM, NO_X, SO_X, CO, and VOC emissions were estimated for pipeline installation based on the installation of a natural gas pipeline (SMUD, 2001). Emissions were placed on a per-mile-installed basis. Diesel consumption was also estimated from the aforementioned report.

The emissions of four other pollutants (CH_4, N_2O, NH_3, and Hg) were calculated using different sources in conjunction with the estimated diesel consumption (SMUD 2001). The emissions factors for CH_4 and N_2O were pulled from Appendix H of a report from DOE that cited the EPA GHG emission inventory (EPA, 2008e). It was assumed that the construction equipment would

be diesel-powered. These emission factors were 0.58 g/gallon of diesel for CH_4 and 0.26 g/gallon for N_2O. The NH_3 emission factor was obtained from a report published by EPA documenting the development and selection of emission factors for NH_3. The emission factor for the combustion of diesel from mobile sources was given as 0.11 kg/1,000 L of diesel (Battye, Battye et al., 1994). The emission factor of the final pollutant, Hg, was determined by dividing the average concentration of Hg in diesel from various studies by the number of samples to get 0.1564 ng/g diesel (Conaway, Mason et al., 2005).

Water usage for hydrotesting pipeline is ignored because water is assumed returned to source after use. Deinstallation emissions are assumed to be 10 percent of installation emissions, as consistent with the rest of the study assumptions for decommissioning. **Figure A-10** represents the GaBi plan for pipeline installation. It is important to note that the values in **Figure A-10** and the air emissions presented in **Table A-6** are on a per mile basis.

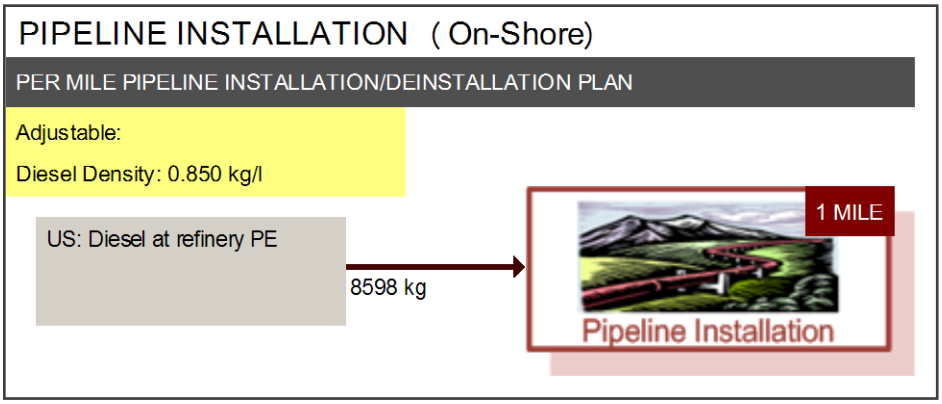

Figure A-10: GaBi Plan for Pipeline Installation/Deinstallation

Table A-6: Air Emissions for On-Shore Pipeline Installation/Deinstallation, kg/mile pipeline

Emissions (kg/mile pipeline)	US: Diesel at Refinery PE	Pipeline Installation/Deinstallation	Total
Lead	1.60E-04	0.00E+00	1.60E-04
Mercury	1.36E-05	1.35E-06	1.49E-05
Ammonia	2.37E-02	1.11E+00	1.14E+00
Carbon Dioxide	3.54E+03	3.43E+04	3.79E+04
Carbon Monoxide	5.17E+00	1.22E+02	1.27E+02
Nitrogen Oxides	1.10E+01	3.51E+02	3.62E+02
Nitrous Oxide (laughing gas)	6.06E-02	6.95E-01	7.55E-01
Sulfur Dioxide	1.42E+01	0.00E+00	1.42E+01
Sulfur Hexafluoride	1.35E-08	0.00E+00	1.35E-08
Methane	3.68E+01	1.55E+00	3.84E+01
Methane (biotic)	0.00E+00	0.00E+00	0.00E+00
VOC (unspecified)	1.53E-02	2.58E+01	2.58E+01
Particulate Matter, unspecified	0.00E+00	6.95E+01	6.95E+01

Dust (unspecified)	2.09E-01	0.00E+00	2.09E-01

A.1.4.3 Construction Assumptions

The boundaries of the retrofitted EXPC scenario include the construction of the CCS system. Data for the construction of the CCS retrofit was taken from one study which listed the amounts of concrete, steel, and stainless steel (Koornneef 2008). The amount of each construction material for carbon capture infrastructure given in the study was adjusted for the EXPC plant CO_2 flow (NETL 2007a).

The amount of pipeline for CO_2 transport and sequestration was determined as follows. The internal diameter of the pipe was calculated as described in Section 2.4.1 of Heddle et al. (2003) and was based on the flow rate of CO_2 to be sequestered (NETL 2007a). Pipe weight was calculated using data from the Engineering Toolbox (2005). The weight included the entire pipeline from the plant to the sequestration site and from the ground surface at the site to the injection well depth from NETL's Baseline Report (2007b). An assumption was made to account for the extra weight (10 percent) associated with pipeline valves, fittings, and sections of heavy walled pipe (for sections buried below roads, railroad tracks, river beds, etc.).

The concrete casing for the sequestration pipeline is poured in layers that get larger as the pipeline gets closer to ground surface. The 'production' casing surrounds the pipeline over its entire length. The 'surface' casing surrounds the pipeline from ground surface to a depth of approximately 750 feet and encompasses the production casing as well as the pipeline. The 'conductor' casing surrounds the pipeline from ground surface to a depth of approximately 40 feet and encompasses the production and surface casings as well as the pipeline (Brown 2008). The depth of the injection well is stated in the NETL Baseline Report as 4,055 feet (NETL 2007b). The volume of concrete required for all three casing levels was summed and converted to a mass.

Finally, the construction materials for each plant site component (carbon capture infrastructure, CO_2 pipeline, and injection well) were divided by the total MWe produced during the lifetime of the plant. This put each major component on a kg/MWh produced basis. Lastly, materials present in more than one of the plant site components were added together to give a total for the process.

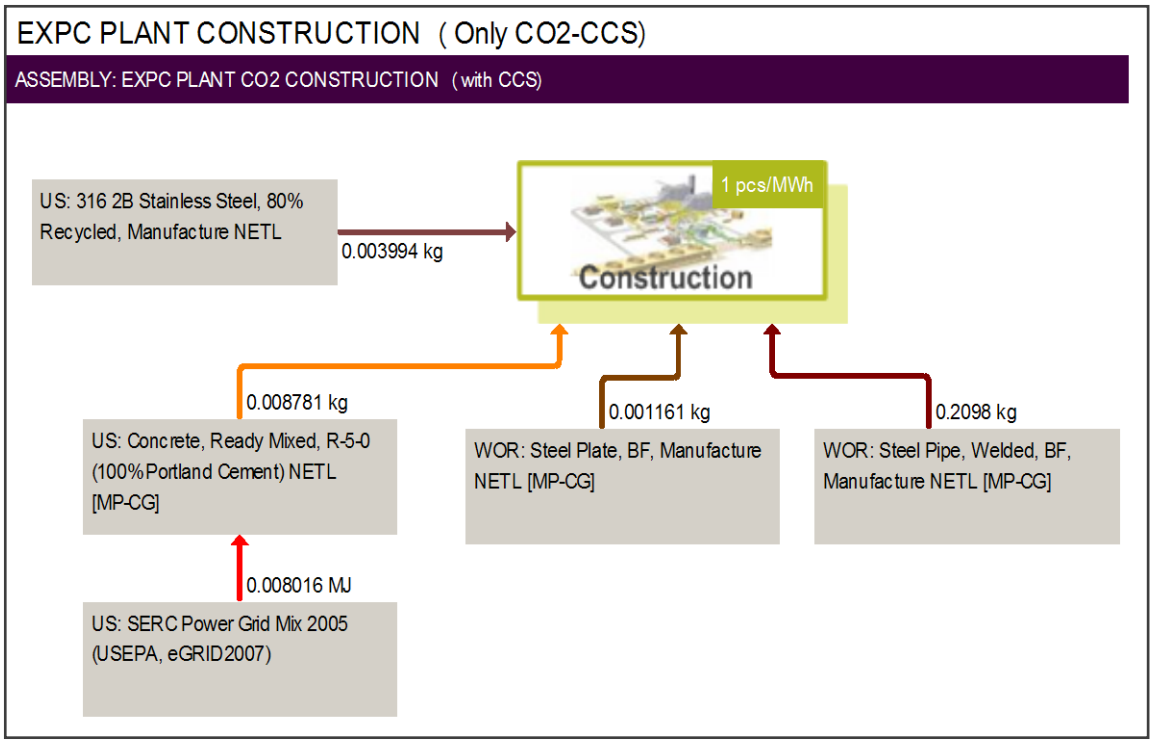

Figure A-11: GaBi Plan for EXPC Power Plant Construction with CCS

Table A-7: Air Emissions CCS Retrofit Construction, kg/MWh Plant Output

	Total	SERC Power Grid Mix 2005	316 2B Stainless Steel, 80% Recycled, Manufacture	Concrete, Ready Mixed, R-5-0 (100% Portland Cement)	Steel Pipe, Welded, BF, Manufacture	Steel Plate, BF, Manufacture
Lead	7.04E-07	7.86E-11	0	0	7.02E-07	2.66E-09
Mercury	1.88E-08	2.22E-11	0	0	1.86E-08	1.67E-10
Ammonia	7.57E-09	7.57E-09	0	0	0	0
Carbon Dioxide	2.56E-01	1.58E-03	2.17E-02	1.22E-03	2.30E-01	1.34E-03
Carbon Monoxide	1.76E-03	6.52E-07	3.88E-05	1.57E-06	1.70E-03	1.13E-05
Nitrogen Oxides	4.34E-04	3.06E-06	4.92E-05	3.71E-06	3.76E-04	2.25E-06
Nitrous Oxide	1.29E-05	2.09E-08	0	0	1.29E-05	6.99E-08
Sulfur Dioxide	6.69E-04	8.95E-06	0	2.83E-06	6.54E-04	3.06E-06
Sulfur Hexafluoride	1.08E-14	1.08E-14	0	0	0	0
Methane	2.47E-04	1.73E-06	0	0	2.44E-04	1.02E-06
Methane (biotic)	5.55E-08	0	0	5.55E-08	0	0
VOC (unspecified)	3.14E-05	2.20E-10	0	1.37E-07	3.11E-05	2.00E-07
Particulate Matter, unspecified	2.85E-05	0	2.85E-05	0	0	0
Dust (unspecified)	2.75E-04	1.70E-07	0	3.62E-06	2.70E-04	3.22E-07

A.1.4.4 Operation Assumptions

The primary operations of the EXPC plant with CCS include the coal consumption, water consumption, and air emissions associated with the production of one MWh of electricity. **Figure A-12** shows the GaBi plan for CCS-retrofitted EXPC operations.

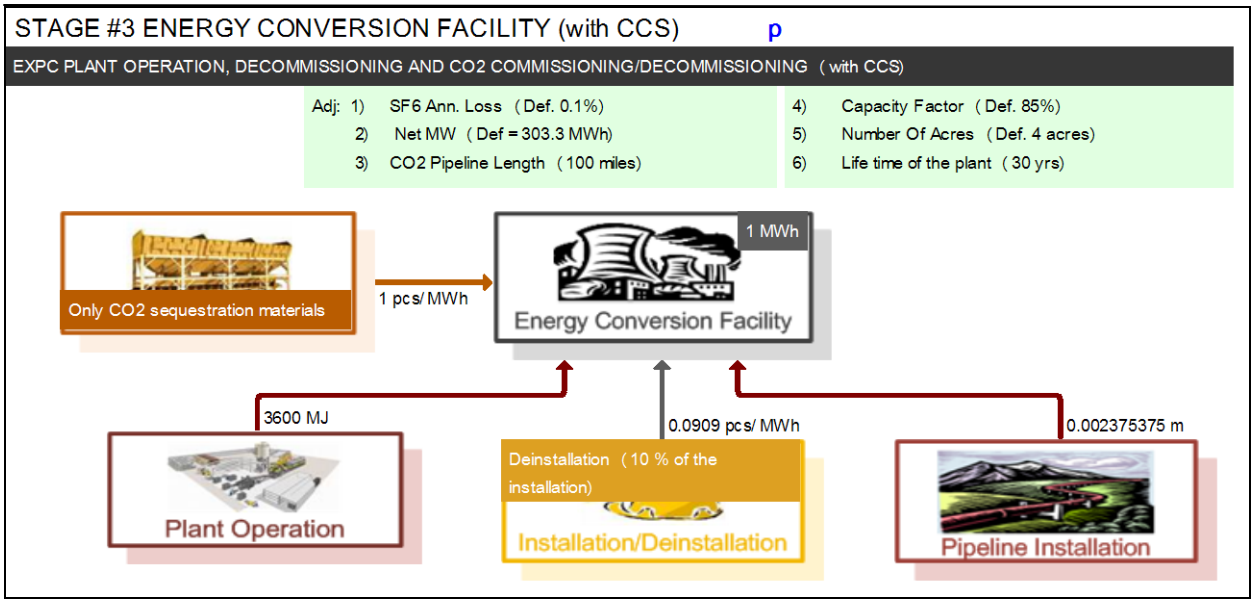

Figure A-12: GaBi Plan for EXPC Power Plant Operation without CCS

This process is modeled as a facility with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, has been retrofitted with CCS capability and is located in southern Illinois. Reference data from a CO_2 capture study (NETL 2007a) for Conesville Unit #5, a nominal 450-MW SCPC plant without CCS with a capacity factor of 85 percent located in Ohio, is utilized for the modeling as is EPA emissions data (EPA 2009 and EPA 2007). The actual generation for Unit #5 during 2005 was 2,427,313 MWh at a capacity factor of 62 percent (EPA 2009). The difference in capacity factor between the CO_2 capture study (NETL 2007a) and the actual emissions data (EPA 2009) is considered a data limitation.

Boiler heat recovery equipment includes an economizer and regenerative air heater. The flue gas emissions control equipment includes an ESP and a lime-based FGD system. Water that is discharged from the EXPC plant is discharged into a municipal sewer system (NETL 2007a).

Air Emissions

Emissions data for the Conesville plant were obtained from the eGRID2007 (EPA 2009) and NEI (EPA 2007) databases. The CO_2 capture study (NETL 2007a) indicates that the net plant output rating for the 90 percent capture case decreases from 443,778 kW to 303,317 kW. The decrease is due to an increased consumption of power for the CCS portion of the plant. The emissions rates were modified from the without CCS values to reflect the lower plant output by a

multiplier of 1.43, which is the ratio of the original capacity (non-CCS) to that of the new (with CCS). The CO_2 emission rate assumes a 90 percent capture rate.

Water Usage

Water usage for the EXPC plant was estimated from the Power Plant Water Usage and Loss Study (NETL 2007c), henceforth referred to as the water report. For SCPC Boiler Raw Water Usage, the water report lists a value of 663.8 gallons/MWh, which is used for the plant water input value. Additionally, the CO_2 capture study (NETL 2007a) lists additional CCS requirements of 84.5 gal/MWh for makeup to the amine plant and 413.6 gal/MWh for cooling tower makeup for a total of 1,161.9 gal/MWh or 4.39 m^3/MWh. This input is only for water withdrawn from a municipal or other source and does not include moisture in the coal or humidity in the combustion air. Water that is discharged from the plant as wastewater is listed under SCPC Boiler Water Loss by Function as cooling tower blowdown in the water report at a rate of 149.5 gallons/MWh or 0.57 m^3/MWh.

Circuit Breaker SF_6 Leakage

Once electricity is produced in the EXPC plant, circuit breakers are used for safety during electricity transmission. It was assumed that two circuit breakers would be needed to operate the EXPC plant; one at the output of the generator and one at the end of the trunkline. It is common practice to use SF_6 gas in the breakers, which is a GHG with a high GWP. The amount of SF_6 used in each circuit breaker is given in the literature as 690 lbs; therefore, the EXPC plant requires 626 kg of SF_6 (HVB 2003). Although estimates vary, the national electrical manufacturers association states that the management guidelines for leakage of SF_6 from circuit breakers are 0.1 percent/year (Blackman). This calculates to a leakage rate of 3.69 × 10-7 kg/MWh net output. The emissions rate was modified from the without CCS value to reflect the lower plant output by a multiplier of 1.43, which is the ratio of the original capacity (non-CCS) to that of the new (with CCS).

Auxiliary Boiler Operation

An auxiliary boiler is not identified in the Conesville report (NETL 2007a), nor are emissions from an auxiliary boiler at the Conesville plant identified in either of the emissions sources used for modeling (EPA 2007, and EPA 2009). While it is likely that one exists, it is the modeler's opinion that an auxiliary boiler would not be operated for a significant period of time as the EXPC plant is modeled after Conesville Unit #5, which is one of four coal-fired steam units listed as active at the site. Therefore, rather than risk the introduction of additional emissions which may be double counted, a decision was made that emissions from an auxiliary boiler would not be modeled.

CCS System CO_2 Leakage

The captured CO_2 from this system is dried and pressurized to a supercritical state before being placed into a pipeline for transport to the saline sequestration site. Carbon dioxide becomes denser when in its supercritical phase, making transport easier. Once in the pipeline it can be assumed that some leakage might occur, but because CO_2 pipelines are a relatively new infrastructure, little data is available on leak rates. Personal email communication with Marco

Roncal of Kinder Morgan (Roncal 2009) suggested that maintenance activities could result in an annual leakage rate of 0.0165 percent.

Very little in the way of operations of the saline sequestration site is included in this study. No energy or emissions associated with the day-to-day operation of the site are modeled, but a leak rate is assumed for the loss of CO_2 over the lifetime of the system. Again, this is not an established infrastructure and very little is known about sequestration potential over an extended period of time. Therefore, the arbitrary value of one percent is applied as a leak rate parameter for the sequestration site. It is the belief of NETL that a saline site, which may leak more than one percent, would not be a candidate for CO_2 sequestration in the first place.

The operation-related air emissions per 1 MWh of output from an EXPC plant retrofitted with a CCS system are shown in
Table A-8 below.

Table A-8: Air Emission Outputs for CCS-Retrofitted EXPC, kg/MWh Plant Output

	EXPC Power Plant Operation (w/o CCS)
Lead	8.4E-06
Mercury	6.9E-05
Ammonia	2.9E-04
Carbon Dioxide	147
Carbon Monoxide	1.4E-01
Nitrogen Oxides	2.7
Nitrous Oxide (laughing gas)	2.3E-02
Sulfur Dioxide	3.2
Sulfur Hexafluoride	2.6E-07
Methane	1.5E-02
VOC (unspecified)	1.7E-02
Particulate Matter, unspecified	9.0E-01

Replacement Power

The LC model includes replacement power for the retrofitted EXPC scenario. When a CCS system is retrofitted to an existing power plant, the net power output of the facility is decreased. In the scenarios of this study, the CCS system reduces the net power from 433 MW to 303 MW. For every 0.699 MWh of electricity delivered by the retrofitted EXPC plant, 0.301 MWh of electricity is assumed to be “replaced” by the SERC electricity grid.

The relationship between replacement power and other LC Stage #3 processes is not shown in the secondary plan for the retrofitted EXPC facility as shown in

Figure A-9: GaBi Plan for Stage #3, Case 2: EXPC with CCS

; rather, since replacement power is modeled parallel to the energy conversion facility, the relationship between replacement power and the energy conversion facility is shown in the primary GaBi plan for the retrofitted EXPC scenario (**Figure A-2**). The GaBi plan for the SERC electric grid is shown in **Figure A-13**. The air emissions profile of the SERC electric grid is shown in **Table A-9**.

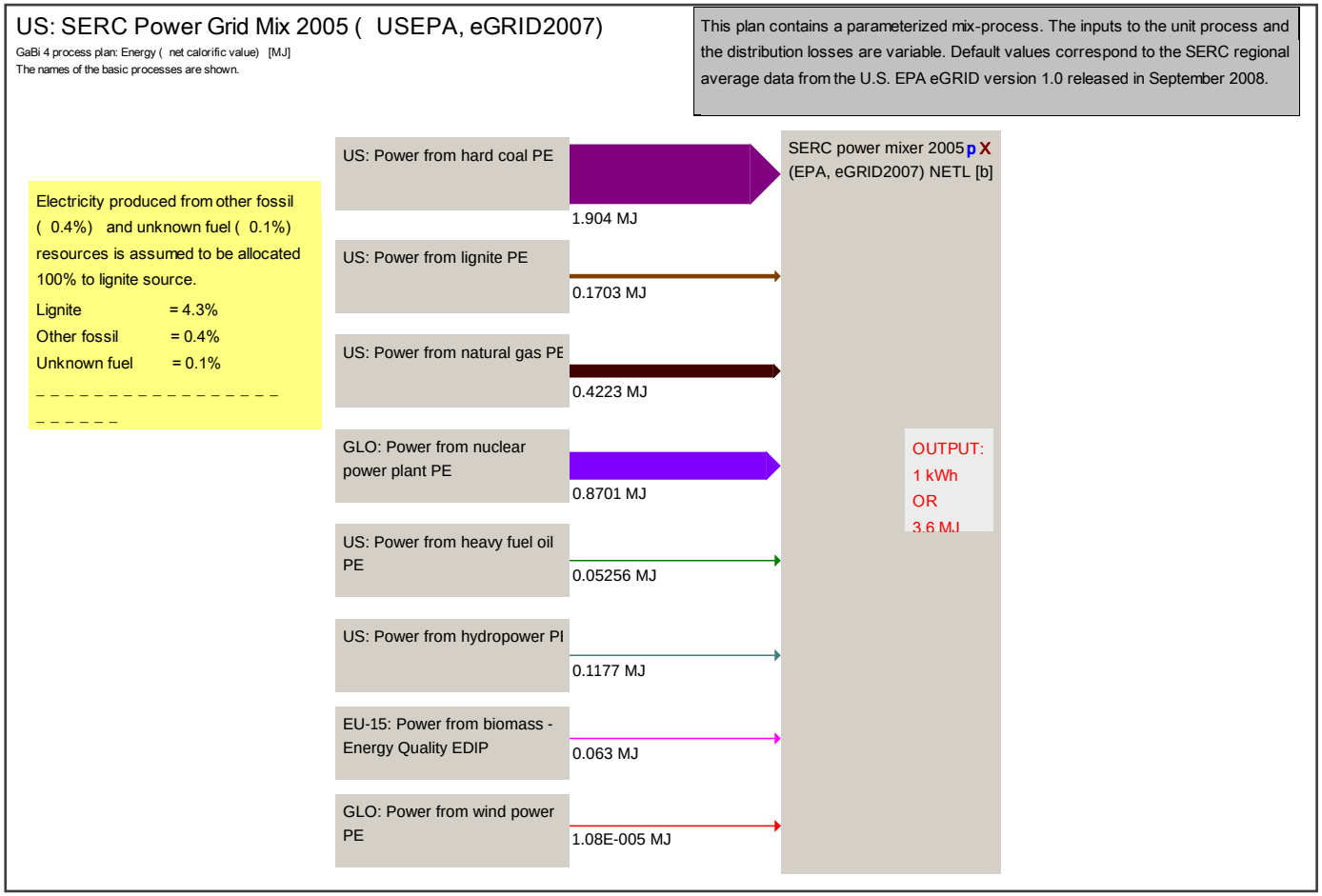

Figure A-13: GaBi Plan for SERC Electric Grid

Table A-9: Air Emission Profile of the SERC Electric Grid

	Total	EU-15: Power from Biomass - Energy Quality EDIP	GLO: Power from Nuclear Power Plant PE	GLO: Power from Wind Power PE	US: Power from Hard Coal PE	US: Power from Heavy Fuel Oil PE	US: Power from Hydropower PE	US: Power from Lignite PE	US: Power from Natural Gas PE
Lead	3.5E-08	0	1.4E-09	6.5E-14	2.5E-08	2.4E-09	1.8E-10	5.5E-09	9.9E-10
Mercury	9.9E-09	1.0E-11	7.8E-11	3.7E-16	6.2E-09	1.1E-11	3.5E-12	3.6E-09	7.8E-11
Ammonia	3.4E-06	8.8E-10	8.2E-08	5.3E-14	3.1E-06	8.5E-08	2.0E-10	8.5E-09	1.7E-07
Carbon Dioxide	7.1E-01	3.2E-04	7.0E-03	1.8E-08	5.5E-01	1.5E-02	7.7E-04	5.5E-02	8.1E-02
Carbon Monoxide	2.9E-04	3.8E-05	2.9E-06	5.4E-11	2.2E-04	5.4E-06	2.0E-07	6.7E-06	2.0E-05
Nitrogen Oxides	1.4E-03	1.4E-05	1.2E-05	3.6E-11	1.1E-03	1.7E-05	2.6E-07	1.2E-04	1.1E-04
Nitrous Oxide (laughing gas)	9.4E-06	1.1E-08	1.2E-07	1.1E-12	7.3E-06	1.3E-07	7.1E-10	7.9E-07	1.0E-06
Sulfur Dioxide	4.0E-03	1.3E-05	2.9E-05	5.1E-11	3.6E-03	6.2E-05	6.5E-08	2.3E-04	4.7E-05
Sulfur Hexafluoride	4.8E-12	0	1.1E-13	0	2.8E-14	6.3E-15	4.6E-12	2.4E-14	9.4E-14
Methane	7.8E-04	0	9.3E-06	3.9E-11	5.9E-04	1.5E-05	9.6E-08	3.3E-05	1.3E-04
VOC (unspecified)	9.9E-08	2.3E-09	1.1E-09	6.1E-13	1.8E-09	6.1E-09	4.7E-11	5.3E-10	8.7E-08
Dust (unspecified)	7.6E-05	0.0E+00	2.1E-06	9.9E-12	6.9E-05	2.7E-07	3.5E-08	4.3E-06	9.6E-07

A.1.5 Life Cycle Stage #4: Product Transportation – Electrical Grid

Once the electricity is produced and sent through the switchyard and trunkline system it is ready for transmission, via the grid, to the user. A seven percent loss in electricity during transmissions was assumed for all the NETL Power LCA studies (Bergerson, 2005; EIA, 2007). This loss only impacts the cost parameters as no environmental inventories are associated with transmission loss. **Table A-10** shows how this loss is captured in the GaBi modeling framework. The transmission line was considered existing infrastructure, therefore the construction of the line, along with the associated costs, emissions, and land use changes, was not included within the system boundaries for this study.

Table A-10: Stage #4 Transmission Loss

Parameter	Formula	Value	Comments
Elec_loss		7%	Transmission line loss (EIA 2005)
Pow_loss	100/(100-Elec_loss)	1.0753	[%] Electricity input to the transmission line.

Sulfur hexafluoride leakage rates from the U.S. transmission and distribution grid are estimated using information collected and compiled from the EPA's "SF_6 Emission Reduction Partnership for Electric Power Systems" (EPA, 2007). Data is collected and compiled from various members of the partnership, which in 2006 represented 42 percent of the U.S. grid in terms of U.S. transmission mileage.

EPA utilizes the aforementioned data to develop the "Inventory of US Greenhouse Gas Emissions and Sinks" (EPA, 2008e). In preparing the national SF_6 leakage estimate, EPA assumes that "partners commit to reducing SF_6 emissions through technically and economically feasible means. However, non-partners were assumed not to have implemented any changes that would have reduced emissions over time."

It was noted that in 2007 and 2008, the partnership continued to grow but there was no quantification of the percent representation of the U.S. power grid. Therefore, it has been assumed that in 2007, the partnership represented 42 percent of the U.S. grid (conservative estimate which will result in slightly higher SF_6 emissions estimate). For this analysis, it is assumed that the SF_6 leak rate for non-partners (remaining 58 percent of the U.S. grid transmission mileage) will be twice that of non-partners. This value could be entered as a parameter and could be varied in a sensitivity analysis. Note that SF_6 emissions calculated in this manner exceed EPA's estimates by five percent (EPA, 2008e).

A.1.6 Life Cycle Stage #5: End User – Electricity Consumption

Finally, the electricity is delivered to the end user in LC Stage #5. All NETL power generation LCA studies assume electricity is used by a non-specific, 100 percent efficient process. This assumption avoids the need to define a unique user profile and allows all power generation studies to be compared on equal footing. Therefore, no environmental inventories were collected for Stage #5.

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