IECM Technical Documentation: Ammonia-Based Post-Combustion CO_2 Capture

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The Integrated Environmental Control Model

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Abstract

In this work a performance model of an ammonia-based CO_2 capture system was developed in Aspen Plus® V7.2, and costs for the system were estimated. This work was undertaken because public performance and cost information on ammonia-based CO_2 capture is limited. The model was simulated under a variety of process conditions in Aspen Plus®, and the results were used to develop an ammonia-based CO_2 capture module in the Integrated Environmental Control Model (IECM). This allowed for a systematic evaluation of ammonia-based CO_2 capture systems on hypothetical plants with various financial assumptions and technology and fuel configurations. Following the integration of the model into the IECM, the model was used to do an analysis of plants with ammonia-based CO_2 capture over a range of conditions and on different types of power plants.

Introduction

The Motivation for Carbon Capture and Sequestration

One approach to large CO_2 emission reductions is carbon capture and sequestration (CCS), which targets CO_2 emissions released during the combustion of fossil fuels from stationary sources. CCS involves two steps: 1) capturing the CO_2 normally emitted during combustion, and 2) transporting and sequestering the CO_2 into an appropriate geologic formation. The potential for CCS to reduce CO_2 emissions in the U.S. is significant because of the broad use of fossil fuels in electric power generation. In 2008, coal-fired electric power generation released 35% of U.S. CO_2 emissions from fossil fuel combustion, while natural gas-based electric power generation released an additional 6% (EPA, 2010). Many organizations acknowledge the potential of CCS, recognizing it as a necessary component in lowering CO_2 emissions if fossil fuels are going to continue to be used in power generation (DOE/NETL, 2010).

Post-Combustion CO_2 Capture

A variety of CCS process designs are being considered for power plants, including post-combustion, oxy-combustion, and integrated coal gasification combined cycle (IGCC) CO_2 capture, each of which has advantages and disadvantages. Post-combustion capture is likely to be cost competitive as a retrofit option for existing pulverized coal power plants (Rochelle 2009). This is important because under scenarios of relatively low growth rates in electricity demand, much of the CO_2 emission reductions may occur at existing power plants making this technology most able to reduce CO_2 emissions in the power sector in the short term (ITFCCS 2010). In addition, industrial sources account for approximately a quarter of U.S. CO_2 emissions, and post-combustion capture can also be applied to many of these sources including at oil and gas refineries, chemical plants, pulp and paper plants, and iron and steel plants (van Straelen 2010, ITFCCS 2010).

While many processes are being pursued for post-combustion CO_2 mitigation, at present only two technologies have emerged that are being incorporated into the designs of planned large-scale demonstration plants: amine and ammonia-based post-combustion CO_2 capture technologies (ITFCCS 2010, Rubin et al. 2010). Amine-based CO_2 capture processes are currently used for natural gas scrubbing and are the most understood post-combustion CO_2 capture technology (Rochelle, 2009). Ammonia-based systems are more complicated, but they are attractive because ammonia is inexpensive, and an ammonia-based process potentially could operate with a lower energy penalty compared to an amine-based process (Hilton, 2009).

Ammonia-Based Post-Combustion CO_2 Capture

Performance and cost estimates for power plants and industries using CCS technologies are valuable to a variety of groups including engineers, researchers, and policy makers as they inform potential policies regarding CO_2 mitigation. Unfortunately performance and cost estimates can also be difficult to find or expensive and time consuming to produce, and existing estimates can be challenging to modify if different financial, technological, or environmental conditions are assumed. For example, in 2007 the U.S. National Energy Technology Laboratory estimated that on a new supercritical coal-fired power plant with amine-based CO_2 capture and long term storage, CCS would lower the plant efficiency by 11.9 percentage points and would increase the cost of electricity by $52/MWh compared to a plant without CCS (Woods et al., 2007). This is a valuable baseline but it is also dependent on a large number of particular financial, technological and site specific assumptions, and it can be difficult to extend these results to alternate scenarios. The development of accessible analytical tools grounded in strong scientific principles that can provide flexible estimates, such as the Integrated Environmental Control Model (IECM), are important resources and can help put the development of other technologies into context.

This document outlines work done to integrate ammonia-based post-combustion CO_2 capture into the IECM with updated modules for this technology. The resulting updated version of the IECM is intended as a starting point for others to do their own preliminary performance and cost analysis for pulverized or natural gas power plants using this leading post-combustion CO_2 capture technology. The model is technical but every effort will be made to keep the model accessible to as wide an audience as possible.

Chilled Ammonia Process Description

The description of the ammonia-based CO_2 capture process is as follows: power plant flue gasses are initially cooled using circulating water and a direct contact cooler, and most of the water in the gases are condensed out. The flue gases are further cooled in a cross flow heat exchanger using chilled water from a vapor compressor. The chilled flue gasses feed into a CO_2 absorption column, where the gases are contacted with a lean solvent mixture. The lean solvent contains ammonia, carbon dioxide, and water, at a specified lean loading NH_3/CO_2 ratio. Higher ratios result in increased ammonia slip over the absorber and therefore increased flue gas cleaning demands, while lower ratios require additional solvent flow or higher ammonia concentrations to capture 90% CO_2 (Versteeg an Rubin, 2011). The CO_2 rich stream leaves the bottom of the absorber and is compressed to 3.0 MPa by a high pressure pump. The rich solution then flows through a cross flow heat exchanger where it is heated by the hot lean solution coming off the reboiler, and if any solids remain in the stream a heater is used to dissolve them. Steam is used in the CO_2 stripper to regenerate the CO_2 at 2.8 MPa, and the regenerated solvent is then returned to the absorber. The absorber gasses are cleaned of ammonia in a water wash and are then heated in a second direct contact cooler, before being released through the stack. Finally, distillate from the second stripper containing ammonia, carbon dioxide, and water is fed back to the CO_2 absorber. The system diagram is shown in Figure 1.

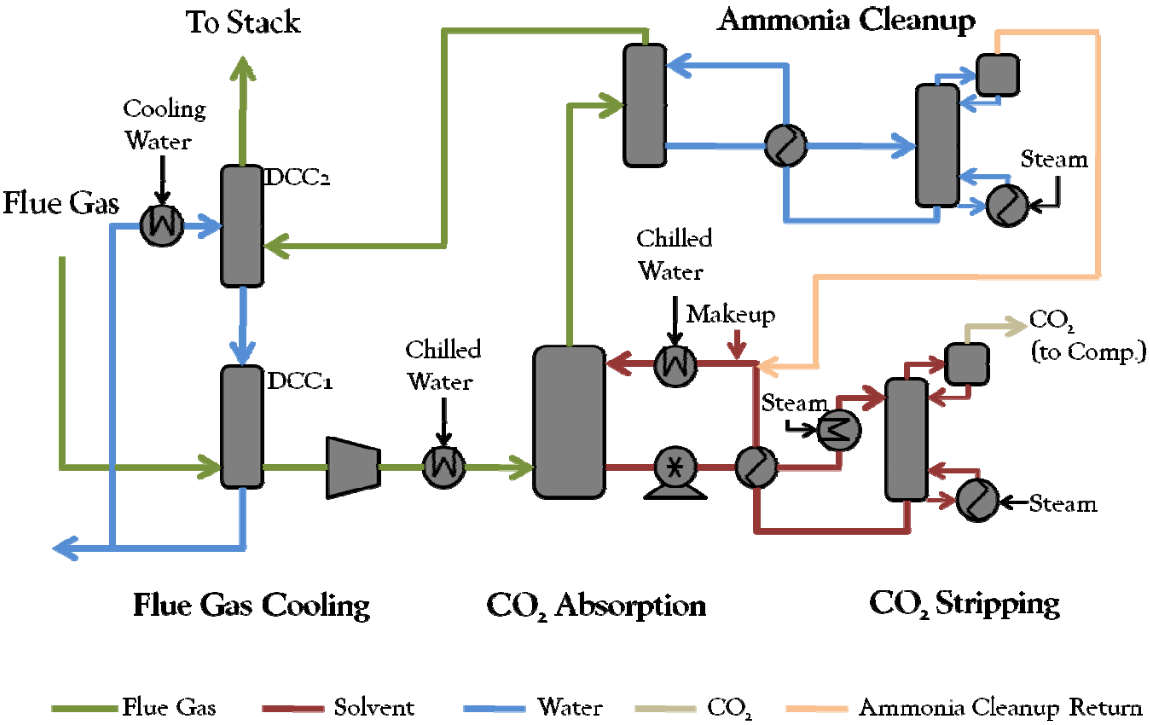

Figure 1: Primary Ammonia System Flows

Developing an Ammonia-Based CO_2 Capture Module in the IECM

The performance and cost model used to develop the ammonia-based CO_2 capture module in the IECM is outlined in detail elsewhere (Versteeg and Rubin, 2011). The performance and cost results for the ammonia system are dependent on a number of factors (cooling water temperature, absorber temperature, NH_3/CO_2 lean solvent loading ratio, solvent NH_3 concentration, solvent flowrate, percent CO_2 capture etc.). An understanding of the impact of all of these factors is critical in the development of an ammonia-based CO_2 capture module for the IECM, but the impact of these factors has not yet been fully explored on coal-fired power plant or on natural gas combined cycle power plant configurations. This section will explain how these factors were systematically explored. The steps taken to complete this process were as follows:

1) Runs for the ammonia-based CO_2 capture model in Aspen Plus® V7.2, shown in Figure 2, were done over a range of conditions and for variations in the important system variables since many input variables can impact the performance and cost of this system.

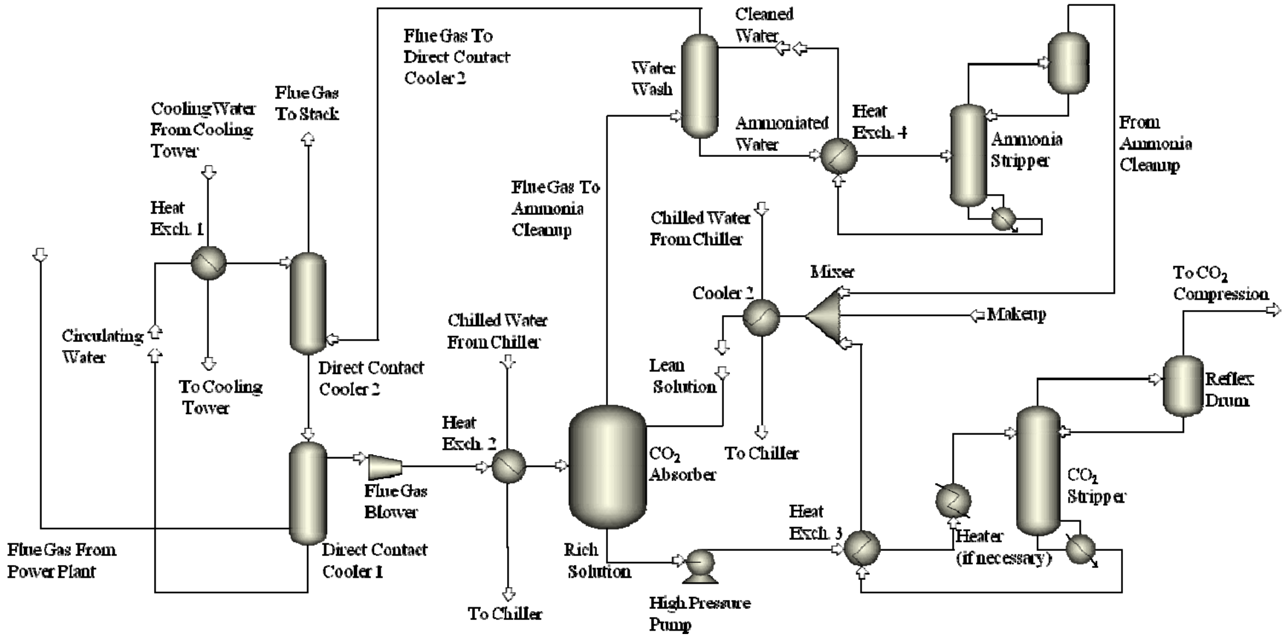

Figure 2: The ammonia-based CO_2 capture performance model as built in Aspen Plus® V7.2

2) Exploring the model space in a full factorial design (varying each of the input variables systematically to evenly cover the model space) proved challenging because a large number of model runs were required for this approach and many of these runs experienced time consuming convergence difficulties in Aspen Plus®.

3) To cover the full model space in an efficient way, the input variables were changed systematically in a fractional factorial design to lower the model runs needed. A fractional factorial design takes advantage of the fact that most systems are dominated by lower order effects. For example, for the key input variables in Table 1, the number of model runs can be reduced from a full factorial design exploring all the variables at both the upper and lower bounds in the range (2^9 = 512 runs) to a much more compact design by using the generators: A, B, C, D, E, F, G, ABCDEFG, BCDEFG (2^7 = 128 runs, see variable labels in Table 1). A portion of the structure of this design is shown in Table 2.

Table 1: Varied Parameters in the Model

Label	Parameter	Type	Units	Lower Bound (-)	Upper Bound (+)
A	Input Flue Gas Temperature	Input	°F	100	150
B	Input Flue Gas CO_2 Content	Input	mole/sec	2,800	4,200
C	Input Flue Gas N_2 Content	Input	mole/sec	16,000	24,000
D	Input Flue Gas H_2O Content	Input	mole/sec	4,000	6,000
E	DCC Cooling Water Temperature	Input	°F	65	85
F	DCC Circulating Water Flow Rate	Input	mole/sec	65,000	95,000
G	Absorber Lean in NH_3 Mol Flow*	Input	mol/sec	4,000	7,000
H	Absorber Lean in H_2O Mol Flow	Input	mol/sec	13,000	19,000
I	Water Wash Water Flow Rate	Input	mol/sec	1,000	10,000

*In this analysis the Absorber Lean CO_2 Molar Flow Rate (mol/sec) was fixed at 0.4*the Absorber Lean NH_3 Molar Flow Rate (mol/sec) to keep the NH_3/CO_2 Ratio at 2.5, according to the published baseline runs (Versteeg and Rubin, 2011).

Table 2: Partial Structure of the Fractional Factorial Design.

A	B	C	D	E	F	G	H = ABCDEFG	I = BCDEFG
-	-	-	-	-	-	-	-	+
-	-	-	-	-	-	+	+	-
-	-	-	-	-	+	-	+	-
-	-	-	-	-	+	+	-	+
-	-	-	-	+	-	-	+	-
…	…	…	…	…	…	…	…	…
+	+	+	+	+	+	+	+	+

*Negative (-) represents the lower bound, positive (+) represents the upper bound of the variable

4) The variable ranges in Table 1 aim to cover large variations around flue gas flows and concentrations that may be found in power plants. A set of additional model runs were also done in regions of interest in the model space, specifically for the CO_2 concentrations of flue gasses found at coal and natural gas-fired power plants in the literature (Woods et al., 2007) and for lean solvent flow rates and ammonia concentrations that led to 90% CO_2 capture in the absorber, to ensure appropriate coverage. These additional model runs were only completed on a section of the model consisting of the direct contact coolers, absorber, and water wash owing to convergence difficulties related to the loops around the CO_2 and NH_3 strippers.

5) The combination of exploring the model space using a fractional factorial design as well as targeted runs aimed at capturing the details of the model near regions of particular interest led to adequate coverage of the model space. The resulting data for each successful model run was merged as a complete dataset.

6) Several other model variables were calculated by Aspen Plus® as a consequence of the varied input parameters in the model. For example, the flue gas flow, gas concentration, lean solvent flow rate, and ammonia concentration in the lean solvent together determines the amount of cooling the absorber requires, the high pressure pump power requirements, and the amount of CO_2 that must be regenerated in the CO_2 stripper to complete the material balance in the model. This in turn helps determine chiller power requirements, and CO_2 heater stripper steam requirements, and eventually costs.

7) Multivariate linear regression equations were created based on the dataset and these equations were incorporated as a module in the IECM. The minimum dataset sample size required for any regression was calculated according to a multivariate sample size calculator (Soper, 2010), and each regression met this minimum requirement. For example, if all 9 predictors in Table 1 were used at least 113 data points would be required for statistical significance at the 0.05 probability level for an anticipated effect size of 0.15 and a statistical power level of 0.8 according to the statistics calculator.

8) The response variables for the model are shown in Table 3. These response variables from the performance model are required to estimate the performance and costs of the components in the ammonia-based CO_2 capture system.

Table 3: Response Variables in the Model

Parameter	Type	Units
Aspen Flue Flow Rate into DCC1	Response	cum/sec
Aspen Flue Flow Rate into DCC2	Response	cum/sec
Circulating Water Flow Rate into HeatX1	Response	kg/sec
Gas Flow Rate Into Absorber	Response	cum/sec
Lean Solvent Flow Rate	Response	kg/sec
Rich Solvent Flow	Response	kg/sec
Absorber Ammonia Slip	Response	Ppm
Water Wash Water Flow Rate	Response	kg/sec
Solids Fraction in the Rich Solution	Response	%
Nitrogen (N_2) to Stack	Response	cum/sec
Oxygen (O_2) to Stack	Response	cum/sec
Carbon Dioxide (CO_2) to Stack	Response	cum/sec
Carbon Monoxide (CO) to Stack	Response	cum/sec
Hydrochloric Acid (HCl) to Stack	Response	cum/sec
Sulfur Dioxide (SO_2) to Stack	Response	cum/sec
Sulfuric Acid (equivalent SO_3) to Stack	Response	cum/sec
Nitric Oxide (NO) to Stack	Response	cum/sec

Nitrogen Dioxide (NO_2) to Stack	Response	cum/sec
Ammonia (NH_3) to Stack	Response	cum/sec
Argon (Ar) to Stack	Response	cum/sec
Particulate (Flyash) to Stack	Response	kg/sec
Water Vapor (H_2O) to Stack	Response	cum/sec
HTX2 Chilling Water Flow	Response	kg/sec
Absorber Chilling Water Flow Rate	Response	kg/sec
Lean Solution Cooler Chilling Water Flow	Response	kg/sec
CO_2 Capture System Cooling Water Required	Response	kg/sec
CO_2 Compressor Cooling Water Flow	Response	kg/sec
Water Bleed	Response	mol/sec
Cooler Chilling Load	Response	Btu/hr
Absorber Chilling Load	Response	Btu/hr
HeatX2 Chilling Load	Response	Btu/hr
Steam Flow to CO_2 Stripper & Heater	Response	Btu/hr
Steam Flow to NH_3 Stripper	Response	Btu/hr
High Pressure Pump Power Usage	Response	MWe
Aspen Heat Exchanger 1 Surface Area	Response	sqm
Aspen Heat Exchanger 2 Surface Area	Response	sqm
Aspen Heat Exchanger 1 Liquid Flow Rate	Response	kg/sec
Aspen Heat Exchanger 2 Liquid Flow Rate	Response	kg/sec
Aspen Heat Exchanger 3 Surface Area	Response	sqm
Solution Cooler Surface Area	Response	sqm
CO_2 to Compressor	Response	mol/sec
Reclaimer Waste	Response	kg/sec
Ammonia Makeup	Response	mol/sec
Water Makeup	Response	mol/sec

The Response Models

This section introduces the key response equations that comprise the response model used by the ammonia-based CO_2 capture system. The response model is built in stages and the resulting performance and cost estimates were tested against the Aspen Plus® model runs and existing cost calculations. Since in some cases the ability to calculate later equations depends on earlier equations, these calculations are completed sequentially by the IECM. The predictors for each independent variable were chosen using a manual approach. Multiple predictors were initially selected for each independent variable based on the author’s knowledge of the process. These were variables that were likely impact the independent variable. For example, it was expected by the author’s that the most important variables impacting the lean solvent flow rate needed into the absorber would be the flue gas flow rate and composition, the CO_2 capture required by the user, and the NH_3 concentration of the lean solution. Plots of the dependent versus independent variables were created and each regression was fit with the dependent variables where significant dependencies were seen.

Response Model Calculation Order

Several of the equations in the overall response model are dependent on one another, and so they are calculated in a particular order that generally follows the process flow of the system. For example, the rich solvent flow is dependent on the lean in solvent flow rate calculated in the regression before it. The order of the overall calculation is outlined below.

1) Direct Contact Cooler (DCC) Flow Rates
    a. Aspen Flue Flow Rate into DCC1
    b. Aspen Flue Flow Rate into DCC2
    c. Circulating Water Flow Rate into HeatX1

2) CO_2 Capture and Ammonia Cleanup Variables
    a. Gas Flow Rate Into Absorber
    b. Lean Solvent Flow Rate
        i. For <91% CO_2 Capture
        ii. For => 91% CO_2 Capture
    c. Rich Solvent Flow
    d. Absorber Ammonia Slip
    e. Water Wash Water Flow Rate
    f. Solids Fraction in the Rich Solution

3) Flue Gas to Stack Variables
    a. Nitrogen (N_2)
    b. Oxygen (O_2)
    c. Carbon Dioxide (CO_2)
    d. Carbon Monoxide (CO)
    e. Hydrochloric Acid (HCl)
    f. Sulfur Dioxide (SO_2)
    g. Sulfuric Acid (equivalent SO_3)
    h. Nitric Oxide (NO)
    i. Nitrogen Dioxide (NO_2)
    j. Ammonia (NH_3)
    k. Argon (Ar)
    l. Particulate (Flyash)
    m. Water Vapor (H_2O)
    n. Stack Temperature

4) Water Balance Variables
    a. Chilled Water
        i. HTX2 Chilling Water Flow
        ii. Absorber Chilling Water Flow Rate
        iii. Lean Solution Cooler Chilling Water Flow

    b. Cooling Water
        i. CO_2 Capture System Cooling Water Required
        ii. CO_2 Compressor Cooling Water Flow
    c. Waste Water
        i. Water Bleed

5) Refrigeration Loads
    a. Cooler Chilling Load
    b. Absorber Chilling Load
    c. HeatX2 Chilling Load

6) Steam Flow Requirements
    a. Steam Flow to CO_2 Stripper & Heater
    b. Steam Flow to NH_3 Stripper

7) Aspen Calculated Power Usage
    a. High Pressure Pump Power Usage

8) Heat Exchanger Variables
    a. Aspen Heat Exchanger 1 Surface Area
    b. Aspen Heat Exchanger 2 Surface Area
    c. Aspen Heat Exchanger 1 Liquid Flow Rate
    d. Aspen Heat Exchanger 2 Liquid Flow Rate
    e. Aspen Heat Exchanger 3 Surface Area
    f. Solution Cooler Surface Area

9) CO_2 to Compressor

10) Reclaimer Waste

11) Makeup
    a. Ammonia Makeup
    b. Water Makeup

The Response Model Equations

The individual response model equations are outlined below in the same order as above. Given initial values of the independent variables, a user should be able to calculate the dependent variable in each case by hand if necessary. In a number of cases the response model equations are nonlinear to take into account the extensive nonlinearities inherent in some parts of the process. In other cases, it was found that the data was modeled more accurately as two individual regressions separated by a particular boundary. Each of the response model equations should be read from left to right on sequential lines in the tables below.

1) Direct Contact Cooler (DCC) Flow Rates

a. Aspen Flue Flow Rate into DCC1 ($R^2 = 0.98$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Aspen Flue Flow Rate in DCC1			cum/sec	=
	-282.8621			+
	0.025923	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.030188	N_2 in the Incoming Flue Gas	mol/sec	+
	0.012649	H_2O in the Incoming Flue Gas	mol/sec	+
	2.210346	Flue Gas Temperature	°F	

b. Aspen Flue Flow Rate into DCC2 ($R^2 = 0.99$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Aspen Flue Flow Rate in DCC2			cum/sec	=
	82.63099			+
	-0.7653	CO_2 Capture	%	+
	0.0076455	CO_2 in the Incoming Flue Gas	mol/sec	+
	0. 0236881	N_2 in the Incoming Flue Gas	mol/sec	+
	0.0001557	H_2O in the Incoming Flue Gas	mol/sec	+
	0.0866089	Water Wash Flow Rate	kg/sec	+
	-0.1246694	Cooling Water Temperature	°F	

c. Circulating Water Flow Rate into HeatX1

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Circulating Water Flow Rate			kg.sec	=
	1.783			*
		Aspen Flue Flow Rate in DCC1	cum/sec	

2) CO_2 Capture and Ammonia Cleanup Variables

a. Gas Flow Rate Into Absorber ($R^2 = 0.99$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Gas Flow Rate Into Absorber			cum/sec	=
	-0.418934			+
	0.0263549	CO_2 Capture	%	+
	0.0202873	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.0201861	N_2 in the Incoming Flue Gas	mol/sec	+
	0.0017601	H_2O in the Incoming Flue Gas	mol/sec	+
	-0.0165	Circulating Water Flow Rate	kg/sec	+
	0.0143333	Water Wash Flow Rate	kg/sec	+
	0.1143204	Flue Gas Temperature	°F	+
	0.1018737	Cooling Water Temperature	°F	

b. The Lean Solvent Flow Rate regression is composed of two regressions separated by a boundary at 91% CO_2 capture. It was found that two regressions more accurately described the dataset than one alone. In the below regressions, a jump discontinuity is avoided at the 91% boundary by defining the regressions as equal at the boundary.

i. Lean Solvent Flow Rate ($R^2 = 0.98$) for <=91% CO_2 Capture

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
ln(Lean Sorbent Flow)				=
	7.401809			+
	0.020091	CO_2 Capture	%	+
	-1.27139	ln(NH_3 Wt%)	%	+
	0.000227	CO_2 in the Incoming Flue Gas	mol/sec	+
	6.06E-06	N_2 in the Incoming Flue Gas	mol/sec	+
	1.30E-06	H_2O in the Incoming Flue Gas	mol/sec	+
Lean Sorbent Flow			kg/sec	=
		exp(ln(Lean Sorbent Flow))		

ii. Lean Solvent Flow Rate ($R^2 = 0.84$) for >91% CO_2 Capture

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
ln(Lean Sorbent Flow)				=
	7.401809			+
	0.020091*91			+
	0.05474001	(CO_2 Capture-91)	%	+
	-1.27139	ln(NH_3 Wt%)	%	+
	0.000227	CO_2 in the Incoming Flue Gas	mol/sec	+
	6.06E-06	N_2 in the Incoming Flue Gas	mol/sec	+
	1.30E-06	H_2O in the Incoming Flue Gas	mol/sec	+
Lean Sorbent Flow			kg/sec	=
		exp(ln(Lean Sorbent Flow))		

The equivalent molar flow rates of individual components (NH_3, CO_2, H_2O) of the lean solvent determine the lean solvent flow rate, the NH_3/CO_2 mole ratio, and the NH_3 Wt%. These relationships are described below and were used in Aspen Plus® but are not available in detail on the IECM user screens. However, a user could calculate these details by using data in the IECM and solving for the three unknowns in the three equations below.

1. Lean In Flow (kg/sec) = 17/1000 * Equivalent Lean In NH_3 Flow Rate (mol/sec) + 40/1000 * Equivalent Lean In CO_2 Flow Rate (mol/sec) + 18/1000 * Equivalent Lean In H_2O Flow Rate (mol/sec)
2. NH_3/CO_2 Mole Ratio = Equivalent NH_3 Flow Rate (mol/sec)/ Equivalent CO_2 Flow Rate (mol/sec)

3. NH_3 Wt% = (17 * Equivalent NH_3 Flow Rate (mol/sec))/(17 * Equivalent NH_3 Flow Rate (mol/sec) + 40 * Equivalent CO_2 Flow Rate (mol/sec) + 18* Equivalent H_2O Flow Rate (mol/sec))

c. Rich Solvent Flow ($R^2 = 0.99$)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
Rich Solvent Flow			kg/sec	=
	-117.4991			+
	1.715576	CO_2 Capture	%	+
	-.6278055	NH_3 Wt%	%	+
	0.9850088	Lean in Solvent Flow Rate	kg/sec	+
	0.0316657	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.0010072	N_2 in the Incoming Flue Gas	mol/sec	+
	0.0013217	H_2O in the Incoming Flue Gas	mol/sec	

d. Absorber Ammonia Slip ($R^2 = 0.98$)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
ln(Absorber NH_3 Slip)				=
	6.254814			+
	2.71e-08	CO_2 Capture^4	%	+
	0.007752	NH_3 Wt%	%	+
	0.0837074	ln(Lean in Solvent Flow Rate)	kg/sec	+
	-1.029565	ln(CO_2 in the Incoming Flue Gas)	mol/sec	+
	0.7730576	ln(N_2 in the Incoming Flue Gas)	mol/sec	+
	0.0075508	ln(H_2O in the Incoming Flue Gas)	mol/sec	+
Absorber NH_3 Slip			ppm	=
		exp(ln(Absorber NH_3 Slip)		

e. Water Wash Water Flow Rate ($R^2 = 0.99$)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
ln(Water Wash Flow Rate)				=
	-3.459428			+
	-4.122067	ln(CO_2 Capture)	%	+
	2.949985	ln(NH_3 Wt%)	%	+
	1.976051	ln(Lean in Solvent Flow Rate)	kg/sec	+

	1.225447	ln(Absorber Ammonia Slip)	ppm	+
	-0.0570676	ln(Water Wash Ammonia Slip)	ppm	+
	-1.316468	ln(CO_2 in the Incoming Flue Gas)	mol/sec	+
	0.5253992	ln(N_2 in the Incoming Flue Gas)	mol/sec	+
	-0.0312865	ln(H_2O in the Incoming Flue Gas)	mol/sec	+
Water Wash Flow Rate			kg/sec	=
		exp(ln(Water Wash Flow Rate))		

f. Solids Fraction in the Rich Solution ($R^2 = 0.96$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Solids Fraction			wt%	=
	-11.05579			+
	-0.1659079	CO_2 Capture	%	+
	3.806864	NH_3 Wt%	%	+
	0.0028427	CO_2 in the Incoming Flue Gas	mol/sec	+
	-0.0002865	N_2 in the Incoming Flue Gas	mol/sec	+
	-0.0001919	H_2O in the Incoming Flue Gas	mol/sec	

3) Flue Gas to Stack Variables

a. Nitrogen (N_2)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Nitrogen (N_2) To Stack			mol/sec	=
		Nitrogen (N_2) Into Model	mol/sec	

b. Oxygen (O_2)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Oxygen (O_2) To Stack			mol/sec	=
		Oxygen (O_2) Into Model	mol/sec	

c. Carbon Dioxide (CO_2)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
CO_2 To Stack			mol/sec	=
		CO_2 Into Model	mol/sec	-
		CO_2 Capture	mol/sec	*
		CO_2 Into Model	mol/sec	

d. Carbon Monoxide (CO)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
CO To Stack			mol/sec	=

		CO Into Model	mol/sec	-
		CO Removal Efficiency in IECM	mol/sec	*
		CO Into Model	mol/sec	

e. Hydrochloric Acid (HCl)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
HCl To Stack			mol/sec	=
		HCl Into Model	mol/sec	-
		HCl Removal Efficiency in IECM	mol/sec	*
		HCl Into Model	mol/sec	

f. Sulfur Dioxide (SO_2)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
SO_2 To Stack			mol/sec	=
		SO_2 Into Model	mol/sec	-
		SO_2 Removal Efficiency in IECM	mol/sec	*
		SO_2 Into Model	mol/sec	

g. Sulfuric Acid (equivalent SO_3)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
SO_3 To Stack			mol/sec	=
		SO_3 Into Model	mol/sec	-
		SO_3 Removal Efficiency in IECM	mol/sec	*
		SO_3 Into Model	mol/sec	

h. Nitric Oxide (NO)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
NO To Stack			mol/sec	=
		NO Into Model	mol/sec	-
		NO Removal Efficiency in IECM	mol/sec	*
		NO Into Model	mol/sec	

i. Nitrogen Dioxide (NO_2)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
NO_2 To Stack			mol/sec	=
		NO_2 Into Model	mol/sec	-
		NO_2 Removal Efficiency in IECM	mol/sec	*
		NO_2 Into Model	mol/sec	

j. Ammonia (NH_3)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
NH_3 to Stack			mol/sec	=
		[Nitrogen (N_2) to stack	mol/sec	+

		Oxygen (O_2) to stack	mol/sec	+
		Water Vapor (H_2O) to stack	mol/sec	+
		Carbon Dioxide (CO_2) to stack	mol/sec	+
		Carbon Monoxide (CO) to stack	mol/sec	+
		Hydrochloric Acid (HCl) to stack	mol/sec	+
		Sulfur Dioxide (SO_2) to stack	mol/sec	+
		Sulfuric Acid to stack	mol/sec	+
		Nitric Oxide (NO) to stack	mol/sec	+
		Nitrogen Dioxide (NO_2) to stack	mol/sec	+
		Argon (Ar) to stack]	mol/sec	*
		Ammonia Slip Above Water Wash	ppm	/
		1E6		+
		Ammonia (NH_3) Into Model	mol/sec	

Since the user specifies the ammonia slip above the water wash, the ammonia to stack is calculated based on this slip and the flow rates of the other gases to the stack, as well as the ammonia coming into the capture system from the upstream environmental controls. The circulating water may remove some ammonia from the flue gas, but since this water goes to waste water treatment the ammonia removed by the circulating water is assumed to reach the environment eventually, and the model treats the ammonia above the water wash as ammonia that leaves out the stack. This quantity for mass balance purposes is calculated as:

1. $\text{NH3 Flow Out the Stack } \left[\frac{\text{mol}}{\text{sec}}\right] = \frac{\text{Ammonia Slip Above Water Wash [ppm]} * \sum \text{Mol Flowrates of All Gasses To Stack } [\frac{\text{mol}}{\text{sec}}]}{\text{1E6[ppm]}}$

k. Argon (Ar)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Argon (Ar) To Stack			Mole/sec	=
		Argon (Ar) Into Model	Mole/sec	

l. Particulate (Flyash)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Particulate (Flyash)To Stack			mol/sec	=
		Particulate Into Model	mol/sec	-
		Removal Efficiency in IECM	mol/sec	*
		Particulate Into Model	mol/sec	

Note: Particulate is a separate mass flow within the flue gas in the IECM framework. It is not counted as any of the above flue gas species.

m. Water Vapor (H_2O) ($R^2 = 0.99$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Water Vapor To Stack			mol/sec	=
	-2388.283			+
	-1.518133	CO_2 Capture	%	+
	-1.822638	NH_3 Wt%	%	+
	0.0178865	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.048015	N_2 in the Incoming Flue Gas	mol/sec	+
	0.0004356	H_2O in the Incoming Flue Gas	mol/sec	+
	32.39481	Cooling Water Temperature	°F	

n. Stack Temperature

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Stack Temperature			°F	=
		Cooling Water Temperature	°F	+
		10	°F	

Note: The temperature approach on Heat Exchanger 1 is 10°F, and therefore the stack temperature is calculated as 10°F more than the cooling water temperature.

4) Water Balance Variables
  a. Chilled Water
    i. HTX2 Chilling Water Flow

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
HTX2 Chilled Water Flow			kg/sec	=
				+
	1000		kg/sec	

Note: The HTX2 Chilled Water flow is fixed at 1000 kg/sec in this version. For changes in system and power plant size, the HTX2 surface area and therefore the cost of the heat exchanger changes with larger or smaller flue gas flow rates to maintain a constant flue gas temperature entering the absorber of 42°F. Alternative options to lower the flue gas temperature to 42°F would have included changing the chilled water flow rate, changing the temperature of the chilled water, changing the temperature approach of the heat exchanger, or doing a combination of these options. Changing the heat exchanger surface area and fixing everything else as constant was the option that lead to the most straightforward cost calculations.

    ii. Absorber Chilling Water Flow Rate ($R^2 = 0.96$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Absorber Chilling Water Flow Rate			kg/sec	=
	-9112.466			+
	72.1217	CO_2 Capture	%	+
	175.0502	NH_3 Wt%	%	+
	2.1176	CO_2 in the Incoming Flue Gas	mol/sec	+

	0.0711	N_2 in the Incoming Flue Gas	mol/sec	+
	0.2883	H_2O in the Incoming Flue Gas	mol/sec	

iii. Lean Solution Cooler Chilling Water Flow

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Lean Solution Cooler Chilling Water Flow			kg/sec	=
	18		kg/sec	

Note: In this version, the Lean Solution Cooler Chilling Water Flow is fixed at 18 kg/sec. For changes in power plant size, the cooler surface area changes for larger or smaller lean solvent flow rates, for similar reasons as above.

b. Cooling Water

i. CO_2 Capture System Cooling Water Required ($R^2 = 0.81$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
CO_2 Capture System Cooling Water Required			kg/sec	=
	7637.364			+
	4.7476	CO_2 Capture	%	+
	-32.3213	NH_3 Wt%	%	+
	-0.3061	CO_2 in the Incoming Flue Gas	mol/sec	+
	-0.0549	N_2 in the Incoming Flue Gas	mol/sec	+
	-0.1733	H_2O in the Incoming Flue Gas	mol/sec	+
	10.9584	Water Wash Flow Rate	kg/sec	+
	3.9532	Rich Solvent Flow	kg/sec	

Note: Cooling water within the CO_2 capture system consists of cooling water for HTX1, for the CO_2 Stripper Condenser, for the NH_3 Stripper Condenser.

ii. CO_2 Compressor Cooling Water Flow

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
CO_2 Compressor Cooling Water Flow			[kg/sec]	=
	2.07		tonne H_2O/tonne CO_2 to compression	

Power consumption for the CO_2 compressor from 1 to 152.7 bar in the IECM equals 0.099 kWh/kg CO_2, while water consumption equals 3123 [tonne H_2O]/461.1 [tonne CO_2] = 6.77 [tonne H_2O/tonne CO_2]. The ammonia-based CO_2 capture system regenerates CO_2 at 27.5 bar, and therefore only requires 0.0304 [kWh/kg CO_2] to compress to 152.7 bar. Therefore, the CO_2 compression cooling water required for the ammonia system is estimated as 6.77 [tonne H_2O]/[tonne CO_2] *(0.0304 [kwh/kg CO_2]/0.099[kwh/kg CO_2]) = 2.07 [tonne H_2O]/[tonne CO_2 to compression].

c. Waste Water

i. Water Bleed ($R^2 = 0.97$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Water Bleed			mol/sec	=
	5377.593			+
	-0.2095	CO_2 in the Incoming Flue Gas	mol/sec	+
	-0.0859	N_2 in the Incoming Flue Gas	mol/sec	+
	0.7305	H_2O in the Incoming Flue Gas	mol/sec	+
	0.6079	Circulating Water Flow Rate	kg/sec	+
	-0.8363	Flue Gas Temperature	°F	+
	-40.0557	Cooling Water Temperature	°F	

5) Refrigeration Loads (an energy measurement, with units in either Btu/hr or tons refrigeration/hr)

a. Cooler Chilling Load ($R^2 = 0.82$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Cooler Chilling Load			tons refrigeration /hr	=
	-4291.751			+
	199.5634	CO_2 Capture	%	+
	-675.2407	NH_3 Wt%	%	+
	0.8383	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.2256	N_2 in the Incoming Flue Gas	mol/sec	

b. Absorber Chilling Load ($R^2 = 0.92$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Absorber Chilling Load			Tons refrigeration /hr	=
	-85704.43			+
	899.0939	CO_2 Capture	%	+
	1208.371	NH_3 Wt%	%	+
	17.28144	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.5816745	N_2 in the Incoming Flue Gas	mol/sec	+
	0.9546541	H_2O in the Incoming Flue Gas	mol/sec	

c. HeatX2 Chilling Load ($R^2 = 0.86$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
HeatX2 Chilling Load			tons refrigeration/hr	=
	-7863.238			+
	0.6541	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.4418	N_2 in the Incoming Flue Gas	mol/sec	+

	1.0217	H_2O in the Incoming Flue Gas	mol/sec	+
	-2.7794	Circulating Water Flow Rate	kg/sec	+
	29.6179	Flue Gas Temperature	°F	+
	21.4856	Cooling Water Temperature	°F	

6) Steam Flow Requirements
   a. Steam Flow to CO_2 Stripper & Heater ($R^2 = 0.98$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Steam Flow to CO_2 Stripper			Btu/hr	=
	-7.19e+08			+
	5065583	CO_2 Capture	%	+
	2.48e+07	NH_3 Wt%	%	+
	184594.8	CO_2 in the Incoming Flue Gas	mol/sec	+
	368130.9	Rich Solvent Flow	kg/sec	

   b. Steam Flow to NH_3 Stripper ($R^2 = 0.83$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Steam Flow to NH_3 Stripper			Btu/hr	=
	3.82E7			+
	-619	N_2 in the Incoming Flue Gas	mol/sec	+
	389857	Water Wash Flow Rate	kg/sec	+
	7287	Absorber NH3 Slip	ppm	

7) Aspen Calculated Power Usage. These regression equations estimate the power consumption of components calculated by Aspen Plus®. The pump power usage is a simple function of the rich solvent flow rate, as indicated in the table below.

   a. High Pressure Pump Power Usage (also called CO_2 Capture System Circulation Pumps or Solvent Circulation Pump) ($R^2 = 0.98$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
High Pressure Pump Power Usage			MW	=
	0.0081			+
	0.0031	Rich Solvent Flow	kg/sec	

8) Heat Exchanger Variables (these are used primarily for calculating the surface area of the key heat exchangers).

a. Aspen Heat Exchanger 1($R^2 = 0.99$)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
Aspen Heat Exchanger 1			sqm	=
	10663.24			+
	10.7825	Circulating Water Flow Rate	kg/sec	+
	-152.1726	Cooling Water Temperature	°F	

b. Aspen Heat Exchanger 2 ($R^2 = 0.96$)

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
Aspen Heat Exchanger 2			sqm	=
	-379.8505			+
	0.1773122	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.1413364	N_2 in the Incoming Flue Gas	mol/sec	+
	0.0490353	H_2O in the Incoming Flue Gas	mol/sec	+
	-0.4017035	Circulating Water Flow Rate	kg/sec	+
	2.05628	Flue Gas Temperature	°F	

c. Aspen Heat Exchanger 1 Liquid Flow Rate

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
Aspen Heat Exchanger 1 Liquid Flow Rate			kg/sec	=
	5000			+

Note: The Aspen Heat Exchanger 1 Liquid Flow Rate (the cooling water from the cooling tower) is fixed in this version of the model. As outlined for other major heat exchangers above, there are other options for determining the specifications of this heat exchanger for changes in plant size and flue gas flow rate, but fixing this liquid flow rate was done for reasons of simplicity.

d. Aspen Heat Exchanger 2 Liquid Flow Rate

Dependent Variable	**Coeff.**	**Independent Variable**	**Unit**	**Calc.**
Aspen Heat Exchanger 2 Liquid Flow Rate			kg/sec	=
	1000			+

The Aspen Heat Exchanger 2 Liquid Flow Rate (the chilled water from the chillers) is fixed in this version of the model. As outlined for other major heat exchangers above, there are other options for determining the specifications of this heat exchanger for changes in plant size and flue gas flow rate, but fixing this liquid flow rate was done for reasons of simplicity.

e. Aspen Heat Exchanger 3 ($R^2 = 0.95$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Aspen Heat Exchanger 3			sqm	=
	29882.73			+
	-377.6261	CO_2 Capture	%	+
	-138.8811	NH_3 Wt%	%	+
	-9.4264	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.8638	H_2O in the Incoming Flue Gas	mol/sec	+
	68.0621	Rich Solvent Flow	kg/sec	

f. Solution Cooler Surface Area ($R^2 = 0.88$)

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Solution Cooler Surface Area			sqm	=
	-428.6294			+
	19.7596	CO_2 Capture	%	+
	-2.0463	CO_2 in the Incoming Flue Gas	mol/sec	+
	0.2135	N_2 in the Incoming Flue Gas	mol/sec	+
	0.3976	H_2O in the Incoming Flue Gas	mol/sec	+
	15.4230	Rich Solvent Flow	kg/sec	

9) CO_2 to Compressor

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
CO_2 To Compressor			mol/sec	=
		CO_2 Into Model	mol/sec	*
		CO_2 Capture	mol/sec	

10) Reclaimer Waste/CO_2 Product

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Reclaimer Waste/CO_2 Product			kg/tonne CO_2	=
	6.0		kg/tonne CO_2	

Note: The reclaimer waste for the ammonia-based CO_2 capture system is estimated based on the amine system in the IECM. The reclaimer waste in the amine system is 3020 [kg/hr] for a CO_2 product flow rate of 500.7 [tonne/hr], meaning the reclaimer waste is 6.0 [kg/tonne CO_2]. This is the same value used for the ammonia system.

11) Makeup

a. Ammonia Makeup

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Ammonia Makeup			kg/hr	=
	0.5	Reclaimer Waste	kg/hr	+
	1	NH_3 to Stack	mol/sec	*
	3600		sec/hr	*
	17		g NH_3/mol	*
	0.001		kg/g	

Note: Ammonia losses are assumed to constitute 50% of the reclaimer waste, plus ammonia lost out the stack and with the CO_2 product. In this analysis, the ammonia loss with the CO_2 product is assumed to be negligible.

a. Water Makeup

Dependent Variable	Coeff.	Independent Variable	Unit	Calc.
Water Makup			tonne/hr	=
	0		tonne/hr	

There is actually a small requirement to purge water in the system to prevent a buildup of water. Depending on the system configuration, this could be large (~100-150 tonnes per hour), but is typically much less (~10-20 tonnes/hr). It is assumed that the sorbent reclaimer handles this purge, and therefore no makeup is required.

Baseline Equipment Performance and Cost Calculations

The following performance and cost calculations are programmed into the IECM and completed for each model run. Some of these calculations are related directly to the ammonia-based CO_2 capture system while others are required to calculate the overall performance or cost of the power plant.

Performance Based Calculations Overview

Table 4 below shows an overview and set of results of performance calculations for a plant with an ammonia-based CO_2 capture system, called the ammonia system reference model based on published work in the literature (Versteeg and Rubin, 2011). The power consumption of major components of the ammonia-based CO_2 capture system are listed, as well as the overall power consumption from other major plant systems (base plant, environmental controls for removing NO_x, SO_2, particulate matter etc.). Calculations for the overall net plant power and plant efficiency are also included. The calculation methods and associated equations for each of these performance based calculations are provided in the following sections.

Table 4: The Ammonia System Reference Model Performance Calculations

	Notes	Example Result (MWe)
Potential Power	Based on Coal Flow Rate	827.6
Auxiliary Steam Load		
CO_2 Stripper & Heater		108.5
NH_3 Stripper		3.5
Steam Turbine Power	Based on Aux. Steam Load	715.6
Auxiliary Electrical Load		
Flue Gas Blower		18.9
Heat Exchanger 1 Pumps		2.2
Heat Exchanger 2 Pumps		0.4
Gas Cooling Water Pumps		0.6
Chiller for Heat Exch 2		5.7
Chiller for Absorber Cooling		48.2
Chiller for Solvent Cooling		6.0
Absorber Cooling Pumps		5.1
Solvent Circulation Pumps (See Regression No.7)		3.5
CO_2 Compression		16.9
Balance of Plant	Based on Other IECM Models	49.0
Plant Net Power	Based on All IECM Models	558.7
Plant Efficiency (% HHV)	Based on All IECM Models	27.9%

The reference equipment and associated performance estimates are taken from the literature, Aspen Plus®, and in many cases, results from the IECM which was set up to simulate a plant with amine-based CO_2 capture in the literature (Woods et al., 2007). This amine model and the equipment performance in this model is called the Amine Reference Model in the following sections.

Details of Performance Based Calculations

Below are the details of each of the performance calculations. The overall structure follows that of Table 4. Generally, the performance requirements for each piece of equipment is dependent on the user specifications and configurations in the IECM, the response model regression equations, data from the literature, and assumptions made in the original modeling effort.

Potential Power (Equivalent Plant Size without CCS)

The potential power available as calculated in Table 4 is a parameter used for comparing plants, and is based on the coal flow rate of a baseline supercritical coal-fired power plant without CCS (Case 12, Woods et al., 2007). This is a simplified calculation, and is not used by the IECM (which relies on a large number parameters, material, and energy balances solved in an iterative manner). The calculation is, however, illustratively useful for comparing two similar power plants, one with and one without CO_2 capture.

$$\text{Potential Power [MW]} = \left[\frac{\text{Coal Flow Rate With CCS [lb/hr]}}{\left[\frac{\text{Coal Flow Rate w/o CCS [lb/hr]}}{\text{Gross Plant Size w/o CCS[MW]}}\right]}\right]$$

Auxiliary Steam Loads (MWe Equivalent)

The auxiliary steam load calculates the MWe Equivalent steam use of the CO_2 stripper & solution heater and the NH_3 stripper. This value is calculated because as steam is diverted for each of these pieces of equipment less steam is available to generate power in the steam turbine and the lost power is counted against that equipment. The electrical equivalent loss (MWe) due to the steam requirements of this equipment is calculated in several steps. First, the steam flow rate required is calculated directly, and then this value is used along with the Heat-to-Electricity Conversion Efficiency to calculate the electrical equivalent loss. The full calculation steps are as follows:

The steam mass flow rate required for each component is calculated as:

$$\dot{M}_{\text{Steam Flow}}[\text{lb/hr}] = \frac{\text{Heat Energy [Btu/hr]}}{\text{Enthalpy}_{\text{Steam Inlet}}\left[\frac{\text{Btu}}{\text{lb Steam}}\right] - \text{Enthalpy}_{\text{Steam Condensate}}\left[\frac{\text{Btu}}{\text{lb Steam}}\right]}$$

Where:

(1) Heat Energy is estimated by Heat Energy Regressions (Steam Flow to CO_2 Stripper & Heater, Steam Flow to NH_3 Stripper).
(2) $\text{Enthalpy}_{\text{Steam Inlet}}$ = 1397.7 [Btu/lb] (Woods et al. 2007)
(3) $\text{Enthalpy}_{\text{Steam Condensate}}$ = 319.5 [Btu/lb] (Woods et al. 2007)

Then, the equivalent electrical loss (MWe Equivalent) due to steam drawn off by these system components is calculated as:

$$\text{MW}_{\text{Eq.}} = (\text{Heat} - \text{to} - \text{Electricity Efficiency}) * \dot{M}_{\text{Steam Flow}} * \text{Enthalpy}_{\text{Steam Inlet}} * 2.97\text{E}^{-7}$$

Where:

(1) The $\text{Heat} - \text{to} - \text{Electricity Efficiency}$ represents the energy conversion efficiency of the plant for converting steam to electricity, and is dimensionless. The default value for the $\text{Heat} - \text{to} - \text{Electricity Efficiency}$ is 0.22 but it can be defined by the user in the IECM for specific applications.

(2) $2.97\text{E}^{-7} = \text{A Conversion Factor for Btu to MW } [\text{MW}/[\text{Btu/hr}]]$

The overall equations for calculating the MWe Equivalent auxiliary steam loads are as follows:

$$
\begin{aligned}
&\text{CO2 Stripper \& }\textit{Heater}\text{ Steam Use [MWeq]} \\
&\quad = [\text{Heat} - \text{to} - \text{Electricity Efficiency}] * \left[\frac{\text{Steam Flow to CO2 Stripper \& Heater } \left[\frac{\text{Btu}}{\text{hr}}\right]}{\text{Enthalpy}_{\text{Steam Inlet}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right] - \text{Enthalpy}_{\text{Steam Condensate}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right]}\right] \\
&\quad * \left[\text{Enthalpy}_{\text{Steam Inlet}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right] * 2.97\text{E}^{-7}\right]
\end{aligned}
$$

$$
\begin{aligned}
&\text{NH3 Stripper Steam Use [MWeq]} \\
&\quad = [\text{Heat} - \text{to} - \text{Electricity Efficiency}] * \left[\frac{\text{Steam Flow to NH3 Stripper } \left[\frac{\text{Btu}}{\text{hr}}\right]}{\text{Enthalpy}_{\text{Steam Inlet}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right] - \text{Enthalpy}_{\text{Steam Condensate}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right]}\right] \\
&\quad * \left[\text{Enthalpy}_{\text{Steam Inlet}} \left[\frac{\text{Btu}}{\text{lb Steam}}\right] * 2.97\text{E}^{-7}\right]
\end{aligned}
$$

Steam Turbine Power

The steam turbine power is calculated as the Potential Power [MW] minus the Auxiliary Steam Loads of the CO_2 stripper & heater, and the NH_3 stripper in MWe equivalent.

Auxiliary Electrical Load - Flue Gas Blower

The auxiliary electrical load required by the Flue Gas Blower is calculated according to the equation:

$$
\begin{aligned}
&\text{Flue Gas Blower [MWe]} \\
&\quad = \text{Flue Gas Blower}_{\text{Ref}} \text{ [MWe]} * \left(\frac{\Delta\text{P Across DCC1, CO2 Absorber, Water Wash, \& DCC2 [psi]}}{\Delta\text{P Across Refrence System [psi]}}\right. \\
&\quad \left. * \frac{\text{Aspen Flue Flow Rate in DCC1 [cum/sec]}}{\text{IECM Reference Flue Flow Rate [cum/sec]}}\right)
\end{aligned}
$$

Where:

(1) $\text{Flue Gas Blower}_{\text{Ref}}$ [MWe] is from the reference amine system in the IECM = 6.3 MWe

(2) $\Delta\text{P Across DCC1, CO2 Absorber, Water Wash, \& DCC2 [psi]}$ is the gas phase pressure drop through these pieces of equipment. The default value for ΔP is 3 psi but

this value can be defined in the user interface screen in the IECM for specific applications.

(3) $\Delta\text{P Across Refrence System [psi]}$ is from the reference amine system in the IECM and equals 1 psi.

(4) $\text{Aspen Flue Flow Rate in DCC1 [cum/sec]}$ is calculated as a function of the flue gas molecular flow rates as well as the temperature of the flue gas flowing into DCC1. This variable is estimated from the $\text{Aspen Flue Flow Rate in DCC1}$ Regression Equation

(5) $\text{IECM Reference Flue Flow Rate [cum/sec]}$ is calculated in the IECM Amine Reference Model and is equal to 884.50 [cum/sec]

In the model, the default blower efficiency is assumed to be 75%, but this can be changed by the user and the power requirements will change as well accordingly.

Auxiliary Electrical Load - Heat Exchanger 1 Pumps

The auxiliary electrical load required by the Heat Exchanger 1 Pumps is calculated according to the equation:

$$\text{Heat Exchanger 1 Pumps [MWe]} = \text{Pumps Usage}_{\text{Ref}}\ \text{[MWe]} * \left(\frac{\text{Liquid Flow Rate [tonne/hr]}}{\text{Liquid Flow Rate in Refrence System [tonne/hr]}}\right)$$

Where:

(1) $\text{Pump Usage}_{\text{Ref}}$ [MWe] is the pump power usage used to circulate solvent in the reference amine system in the IECM = 1.046 MWe

(2) $\text{Liquid Flow Rate [tonne/hr]}$ is cooling water from the cooling tower at a temperature of 80F and a flow rate of 18000 tonnes/hr.

(3) $\text{Liquid Flow Rate in Refrence System [tonne/hr]}$ is the solvent circulation rate from the reference amine system in the IECM = 8660 tonne/hr

In the model, the default pump efficiency is assumed to be 75%, but this number can be changed by the user.

Auxiliary Electrical Load - Heat Exchanger 2 Pumps

The auxiliary electrical load required by the Heat Exchanger 2 Pumps is calculated according to the equation:

$$\text{Heat Exchanger 2 Pumps [MWe]} = \text{Pumps Usage}_{\text{Ref}}\ \text{[MWe]} * \left(\frac{\text{Liquid Flow Rate [tonne/hr]}}{\text{Liquid Flow Rate in Refrence System [tonne/hr]}}\right)$$

Where:

(1) $\text{Pump Usage}_{\text{Ref}}$ [MWe] is the pump power usage used to circulate solvent in the reference amine system in the IECM = 1.046 MWe

(2) $\text{Liquid Flow Rate [tonne/hr]}$ is chilling water from the chillers at a temperature of 37F and a flow rate of 3600 tonnes/hr.

(3) $\text{Liquid Flow Rate in Refrence System [tonne/hr]}$ is the solvent circulation rate from the reference amine system in the IECM = 8660 tonne/hr

In the model, the default pump efficiency is assumed to be 75%, but this number can be changed by the user.

Auxiliary Electrical Load - Gas Cooling Water Pumps

The auxiliary electrical load required by the Gas Cooling Water Pumps is calculated according to the equation:

$$\text{Gas Cooling Water Pumps [MWe]} = \text{Pumps Usage}_{\text{Ref}}\ \text{[MWe]} * \left(\frac{\text{Liquid Flow Rate [tonne/hr]}}{\text{Liquid Flow Rate in Refrence System [tonne/hr]}}\right)$$

Where:

(4) $\text{Pump Usage}_{\text{Ref}}$ [MWe] is the pump power usage used to circulate solvent in the reference amine system in the IECM = 1.046 MWe

(5) $\text{Liquid Flow Rate [tonne/hr]}$ is from the Circulating Water Flow Rate from the IECM ammonia user interface screen.

(6) $\text{Liquid Flow Rate in Refrence System [tonne/hr]}$ is the solvent circulation rate from the reference amine system in the IECM = 8660 tonne/hr

In the model, the default pump efficiency is assumed to be 75%, but this number can be changed by the user.

Auxiliary Electrical Load - Chiller for Heat Exch 2

The Chiller for Heat Exch 2 supplies chilled water in order to cool the flue gas before it enters the absorber system. The chilling load required is dependent on the temperature of the chilled water, which is fixed here at 37°F, and the cooling duty of the heat exchanger. The auxiliary electrical load required by the Chiller for Heat Exch 2 is calculated according to the equation:

$$\text{Chiller for Heat Exch 2 [MWe]} = \text{Chilling Electrical Usage} \left[\frac{\text{kWe}}{\text{Ton Cooling}}\right] * \frac{1}{1000}\left[\frac{\text{MWe}}{\text{kWe}}\right] * \left[\frac{\text{Chiller for Heat Exch 2 Chilling Load } \left[\frac{\text{Btu}}{\text{hr}}\right]}{12000\ \left[\frac{\text{BTU}}{\text{Ton Cooling}}\right]}\right]$$

Where:

(1) $\text{Chilling Electrical Usage}\left[\frac{\text{kWe}}{\text{Ton Cooling}}\right]$ is the power usage required to cool water from 80°F to 37 °F, and equals 0.55 (Platts, 2004).

(2) $\text{Chiller for Heat Exch 2 Chilling Load [Btu/hr]}$ is from the Chiller for Heat Exch 2 Chilling Load Regression Equation.

Auxiliary Electrical Load - Chiller for Absorber Cooling

The Chiller for Absorber Cooling supplies chilled water in order to cool the flue gas before it enters the absorber system. The chilling load required is dependent on the temperature of the chilled water, which is fixed here at 37°F, and the cooling duty of the heat exchanger within the absorber. The auxiliary electrical load required by the Chiller for Absorber Cooling is calculated according to the equation:

$$\text{Chiller for Absorber Cooling [MWe]} = \text{Chilling Electrical Usage}\left[\frac{\text{kWe}}{\text{Ton Cooling}}\right] * \frac{1}{1000}\left[\frac{\text{MWe}}{\text{kWe}}\right] * \left[\frac{\text{Chiller for Absorber Cooling Chilling Load}\left[\frac{\text{Btu}}{\text{hr}}\right]}{12000\left[\frac{\text{BTU}}{\text{Ton Cooling}}\right]}\right]$$

Where:

(1) Chilling Electrical Usage $\left[\frac{\text{kWe}}{\text{Ton Cooling}}\right]$ is the power usage required to cool water from 80°F to 37°F, and equals 0.55 (Platts, 2004).

(2) Chiller for Absorber Cooling Chilling Load $[\text{Btu/hr}]$ is from the Chiller for Absorber Cooling Chilling Load Regression Equation

Auxiliary Electrical Load - Chiller for Solvent Cooling

The Chiller for Solvent Cooling supplies chilled water in order to cool the solvent before it enters the absorber. The chilling load required is dependent on the temperature of the chilled water which is fixed here at 37°F, the temperature of the solvent, the flow rate of the solvent, the composition of the solvent, and the temperature approach of the heat exchanger cooling the solvent. The auxiliary electrical load required by the Chiller for Solvent Cooling is calculated according to the equation:

$$\text{Chiller for Solvent Cooling [MWe]} = \text{Chilling Electrical Usage}\left[\frac{\text{kWe}}{\text{Ton Cooling}}\right] * \frac{1}{1000}\left[\frac{\text{MWe}}{\text{kWe}}\right] * \left[\frac{\text{Chiller for Solvent Cooling Chilling Load}\left[\frac{\text{Btu}}{\text{hr}}\right]}{12000\left[\frac{\text{BTU}}{\text{Ton Cooling}}\right]}\right]$$

Where:

(1) Chilling Electrical Usage $\left[\frac{\text{kWe}}{\text{Ton Cooling}}\right]$ is the power usage required to cool water from 80°F to 37°F, and equals 0.55 (Platts, 2004).

(2) Chiller for Solvent Cooling Chilling Load $[\text{Btu/hr}]$ is from the Chiller for Solvent Cooling Chilling Load Regression Equation

Auxiliary Electrical Load – Absorber Cooling Pumps

The auxiliary electrical load required by the Absorber Cooling Pumps is calculated according to the equation:

$$\text{Absorber Cooling Pumps [MWe]} = \text{Pumps Usage}_{\text{Ref}}\ \text{[MWe]} * \left(\frac{\text{Absorber Cooling Water Flow Rate [tonne/hr]}}{\text{Liquid Flow Rate in Refrence System [tonne/hr]}}\right)$$

Where:

(1) Pump Usage $_{\text{Ref}}$ [MWe] is the pump power usage used to circulate Absorber in the reference amine system in the IECM = 1.046 MWe

(2) Liquid Flow Rate $[\text{tonne/hr}]$ is a utility measurement from the Aspen Plus® Model, and is from the Absorber Cooling Water Flow Rate Regression Equation

(3) Liquid Flow Rate in Refrence System $[\text{tonne/hr}]$ is the Absorber circulation rate from the reference amine system in the IECM = 8660 tonne/hr

In the model, the default pump efficiency is assumed to be 75%, but this number can be changed by the user.

Auxiliary Electrical Load – Solvent Circulation Pumps

The solvent circulation pump energy consists of the energy required from the high pressure pump. The high pressure pump pressurizes the solvent slurry coming off the bottom of the absorber from 1 atm to 32 atm. The auxiliary electrical load required by the Solvent Circulation Pumps is calculated according to the equation:

$$\text{Solvent Circulation Pumps [MWe]} = \text{High Pressure Pump Power Usage [MWe]}$$

Where:

(1) $\text{High Pressure Pump Power Usage [MWe]}$ is a utility measurement from the Aspen Plus® Model, and is from the High Pressure Pump Power Usage Regression Equation

Auxiliary Electrical Load – NH_3 Cleanup Pumps

The auxiliary electrical load required by the NH_3 Cleanup Pumps is calculated according to the equation:

$$\text{NH3 Cleanup Pumps [MWe]} = \text{Pumps Usage}_{\text{Ref}}\ \text{[MWe]} * \left(\frac{\text{NH3 Cleanup Water Flow Rate [kg/sec]}}{\text{Liquid Flow Rate in Refrence System [tonne/hr]}}\right)$$

Where:

(1) $\text{Pump Usage}_{\text{Ref}}\ \text{[MWe]}$ is the pump power usage used to circulate Absorber in the reference amine system in the IECM = 1.046 MW

(2) $\text{NH3 Cleanup Water Flow Flow Rate [kg/sec]}$ is from the NH_3 Cleanup Water Flow Rate Regression Equation

(3) $\text{Liquid Flow Rate in Refrence System [kg/sec]}$ is the Absorber circulation rate from the reference amine system in the IECM = 2405.5 kg/sec

In the model, the default pump efficiency is assumed to be 75%, but this number can be changed by the user. The value of the NH_3 Cleanup Pumps is small relative to the power usage of the other system components. Typically, it will be on the order of ~ 0.01 MWe, and so while it is calculated by the IECM, is not listed as one of the main auxiliary electrical consumers in the output screens.

Auxiliary Electrical Load – CO_2 Compression

The total compression work and associated electrical use required is dependent on the amount of CO_2 that goes to the compressor, as well as the initial and final CO_2 stream pressures. The auxiliary electrical load required by the CO_2 Compressors is calculated according to the equation:

$$\begin{aligned}\text{CO2 Compressor [MWe]} &\\ &= \text{CO2 Flow Rate to Compressor} \left[\frac{\text{kg}}{\text{hr}}\right] \\ &* \text{Energy Required to Compress from 28 bar to final pressure in bar} \left[\frac{\text{kWh}}{\text{kg CO2}}\right]\end{aligned}$$

Where:

(1) $\text{CO2 Flow Rate to Compressor} \left[\frac{\text{kg}}{\text{hr}}\right]$ is calculated in the model as the CO_2 To Compressor.

(2) Energy Required to Compress from 28 bar to final pressure in bar $[\frac{\text{kWh}}{\text{kg CO2}}]$ is derived from the CO_2 compression model within the IECM. For compression between 28 bar and 152 bar, this value equals 0.03.

Auxiliary Electrical Load – Additional Cooling Tower Pump Requirements

The large cooling demands from the ammonia-based CO_2 capture system affect the water requirements in the plant and change the water flow to the cooling tower, which affects pumping requirements. The cooling tower pumping requirements for the IECM are detailed in the Wet Cooling Tower documentation for the IECM.

Cost Based Calculations Overview

Table 5 below shows an overview w and set of results of cost calculations for a plant with an ammonia-based CO_2 capture system, called the ammonia system reference model based on published work in the literature (Versteeg and Rubin, 2011). The cost of major components of the ammonia-based CO_2 capture system are listed, as well as the overall costs from other major plant systems (base plant, environmental controls for removing NO_x, SO_2, particulate matter etc.). Calculations for the overall plant levelized cost are also included. The calculation methods and associated equations for each of these cost calculations are provided in the following sections. Typically, where costs in the IECM or the literature were not available, cost estimates for equipment were determined through the equipment sizing and costing functions of Aspen Icarus®. The costs in Aspen Icarus® were given in first quarter 2008 dollars and are scaled in the IECM to the appropriate dollar year as specified by the user using the Marshal & Swift Index or a similar index. These costs as well as the parameters used to determine these costs are shown below. Not all cost details are directly available in the IECM results screens in the interest of clarity, and space, and costs for some pieces of equipment are aggregated and presented as costs for functional areas (for example, all the heat exchanger costs below have been aggregated as one total heat exchanger cost on the IECM result screen). However, using the regression equations, the data supplied by the IECM, and the equations below, a user should be able to reproduce the costs for individual pieces of equipment.

Table 5: The Ammonia System Reference Model Cost Calculations

	Notes	Example Result ($2007)
CO2 Capture Process Area Costs		
DCC #1		30.9
DCC #2		23.3
Flue Gas Blower		6.3
Heat Exch. 1		6.7
Heat Exch. 2		2.9
Heat Exch. 1 Pumps		1.4
Heat Exch. 2 Pumps		0.5
Cooling Water Circulation Pumps		0.7
Chiller System		54.6
Absorber		105.1
Absorber Pumps		2.4
Heat Exch. 3		41.6
Solvent Circulation Pumps		7.9
Solvent Heater 1		2.2
Solvent Cooler		2.2
CO_2 Stripper		35.1
CO_2 Stripper Reboiler		13.4
Water Wash		2.2
Heat Exch. 4		0.1
NH3 Stripper		1.5
NH3 Cleanup Pumps		0.8
Steam Extractor		3.3
Sorbent Reclaimer		1.1
Sorbent Processing		1.1
Drying and Compress Unit		18.6
General Facilities Capital	Based on IECM Data	5.7
Eng. & Home Office Fees	Based on IECM Data	34.3
Project Contingency Cost	Based on IECM Data	59.9
Process Contingency Cost	Based on IECM Data	17.1
CO2 System (TCR)	Based on Area Costs	483.0
Base Plant (TCR)	Based on IECM Data	884.1
Cooling Tower (TCR)	Based on IECM Data	62.7
NO_x Control (TCR)	Based on IECM Data	33.7
TSP Control (TCR)	Based on IECM Data	49.8
SO_2 Control (TCR)	Based on IECM Data	138.7
CO2 Transport & Storage O&M	Based on IECM Data	22.3
Balance of Plant O&M	Based on IECM Data	128.9

Plant Total Capital Requirement	Based on TCR Costs	1652.0
Total O&M Costs	Total O&M	151.3
Capital Required ($/kW-net)	Based on Performance	2956.8
Revenue Required ($/MWh)	Equation 2	105.4

The scaling of most equipment is non-linear because the value to be scaled is assumed to benefit from economies of scale as the size of the equipment increases. The form of the equation for much of the cost scaling is similar to the one below.

$$\mathrm{X} = \mathrm{X}_{\mathrm{Ref}} * \left(\frac{\mathrm{Y}}{\mathrm{Y}_{\mathrm{Ref}}}\right)^{0.6}$$

Where

(1) X = the cost of the piece of equipment as estimated by the IECM.
(2) $\mathrm{X}_{\mathrm{Ref}}$ = a reference cost of a similar piece of reference equipment that may be larger or smaller, or may process more or less of a key component of the system.
(3) Y = A process parameter of the piece of equipment in which costs are to be estimated (material flow, energy requirements).
(4) $\mathrm{Y}_{\mathrm{Ref}}$ = a reference process parameter of the reference equipment.

The reference equipment and associated costs are taken from the literature, Aspen Icarus®, and in many cases, results from the IECM which was set up to simulate a plant with amine-based CO_2 capture in the literature (Woods et al., 2007). This amine model and the equipment costs in this model is called the Amine Reference Model in the following sections. The ammonia system reference model

Cost Calculations – DCC1

The total cost for DCC1 is based on the volumetric flow rate through the direct contact cooler and is calculated according to the equation:

$$\text{DCC1 Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Aspen Flue Flow Rate in DCC1 [cum/sec]}}{\text{IECM Reference Flue Flow Rate [cum/sec]}}\right]^{0.6}$$

Where:

(1) Refrence System Cost [$] is calculated in the IECM Amine Reference Model and is equal to 32.48 [$M]
(2) Aspen Flue Flow Rate in DCC1 [cum/sec] is calculated as a function of the flue gas molecular flow rates as well as the temperature of the flue gas flowing into DCC1. This variable is estimated from the Aspen Flue Flow Rate in DCC1 Regression Equation
(3) IECM Reference Flue Flow Rate [cum/sec] calculated in the IECM Amine Reference Model and is equal to 884.50 [cum/sec]

Cost Calculations – DCC2

The total cost for DCC2 is based on the volumetric flowrate through the direct contact cooler and is calculated according to the equation:

$$\text{DCC2 Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Aspen Flue Flow Rate in DCC2 [cum/sec]}}{\text{IECM Reference Flue Flow Rate [cum/sec]}}\right]^{0.6}$$

Where:

1. Refrence System Cost [$] is calculated in the IECM Amine Reference Model and is equal to 32.48 [$M]
2. Aspen Flue Flow Rate in DCC2 [cum/sec] is calculated is a function of the flue gas molecular flow rates as well as the temperature of the flue gas flowing into DCC2. This variable is estimated from the Aspen Flue Flow Rate in DCC2 Regression Equation
3. IECM Reference Flue Flow Rate [cum/sec] calculated in the IECM Amine Reference Model and is equal to 884.50 [cum/sec]

Cost Calculations – Flue Gas Blower

The total cost for the Flue Gas Blower is based on the volumetric flow rate through DCC1 (and therefore also the Flue Gas Blower) and is calculated according to the equation:

$$\text{Flue Gas Blower Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Aspen Flue Flow Rate in DCC1 [cum/sec]}}{\text{IECM Reference Flue Flow Rate [cum/sec]}}\right]^{0.6}$$

Where:

1. Refrence System Cost [$] is calculated in the IECM Amine Reference Model and is equal to 6.639 [$M]
2. Aspen Flue Flow Rate in DCC` [cum/sec] is calculated is a function of the flue gas molecular flow rates as well as the temperature of the flue gas flowing into DCC1. This variable is estimated from the Aspen Flue Flow Rate in DCC1 Regression Equation
3. IECM Reference Flue Flow Rate [cum/sec] calculated in the IECM Amine Reference Model and is equal to 884.50 [cum/sec]

The default blower efficiency is assumed to be 75%, but this value can be changed by the user in the model.

Cost Calculations – Heat Exchanger 1

The total cost for Heat Exchanger 1 is based on the heat exchanger surface area and is calculated according to the equation:

$$\text{Heat Exchanger 1 Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Heat Exchanger 1 Surface Area [sqm]}}{\text{Reference Heat Exchanger Surface Area [sqm]}}\right]^{0.6}$$

Where:

1. Refrence System Cost [$] is calculated by the Ammonia System Aspen Icarus® Reference Model and is equal to 6.671 [$M].
2. Reference Heat Exchanger Surface Area [sqm] is calculated by the Ammonia System Aspen Plus® Reference Model and is equal to 14155.3 [sqm].

(3) Heat Exchanger 1 Surface Area [sqm] is calculated as a function of the temperature approach of the heat exchange (default 10°F between the cold side inlet and the hot side outlet), the flow rates, flow compositions, flow rate heat capacity, chemical reactions, and the temperature of the flows into and out of the heat exchanger. This variable is estimated from the Aspen Heat Exchanger 1 Regression Equation.

Cost Calculations – Heat Exchanger 2

The total cost for Heat Exchanger 2 is based on the heat exchanger surface area and is calculated according to the equation:

$$\text{Heat Exchanger 2 Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Heat Exchanger 2 Surface Area [sqm]}}{\text{Reference Heat Exchanger Surface Area [sqm]}}\right]^{0.6}$$

Where:

(1) Refrence System Cost [\$] is calculated by the Ammonia System Aspen Icarus® Reference Model and is equal to 2.871 [\$M].

(2) Reference Heat Exchanger Surface Area [sqm] is calculated by the Ammonia System Aspen Plus® Reference Model and is equal to 3102.62 [sqm].

(3) Heat Exchanger 2 Surface Area [sqm] is calculated as a function of the temperature approach of the heat exchange (default 10°F between the cold side inlet and the hot side outlet), the flow rates, flow compositions, flow rate heat capacity, chemical reactions, and the temperature of the flows into and out of the heat exchanger. This variable is estimated from the Aspen Heat Exchanger 2 Regression Equation.

Cost Calculations – Heat Exchanger 1 Pumps

The total cost for Heat Exchanger 1 Pumps is calculated according to the equation:

$$\begin{aligned}&\text{Heat Exchanger 1 Pumps Installed Cost [\$]}\\&\quad = \text{Refrence System Cost [\$]} * \left[\frac{\text{Heat Exchanger 1 Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}\end{aligned}$$

Where:

(1) Refrence System Cost [\$] is based on the circulating water pumps cost in an NETL Reference Study and equals 2.065 [\$M] (Woods et al., 2007).

(2) Reference Liquid Flow Rate [tonne/hr] is based on the circulating water pumps flow rate in an NETL Reference Study and equals 32706 [tonne/hr] (Woods et al., 2007).

(3) Heat Exchanger 1 Liquid Flow Rate [tonne/hr]is estimated from the Aspen Heat Exchanger 1 Liquid Flow Rate Regression Equation.

Cost Calculations – Heat Exchanger 2 Pumps

The total cost for Heat Exchanger 2 Pumps is calculated according to the equation:

$$\text{Heat Exchanger 2 Pumps Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Heat Exchanger 2 Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}$$

Where:

(1) Refrence System Cost [\$] is based on the circulating water pumps cost in an NETL Reference Study and equals 2.065 [\$M] (Woods et al., 2007).
(2) Reference Liquid Flow Rate [tonne/hr] is based on the circulating water pumps flow rate in an NETL Reference Study and equals 32706 [tonne/hr] (Woods et al., 2007).
(3) Heat Exchanger 2 Liquid Flow Rate [tonne/hr] is estimated from the Aspen Heat Exchanger 2 Liquid Flow Rate Regression Equation.

Cost Calculations – Cooling Water Circulation Pumps

The total cost for Cooling Water Circulation Pumps is calculated according to the equation:

$$\text{Cooling Water Circulation Pumps Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Cooling Water Circulation Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}$$

Where:

(1) Refrence System Cost [\$] is based on the circulating water pumps cost in an NETL Reference Study and equals 2.065 [\$M] (Woods et al., 2007).
(2) Reference Liquid Flow Rate [tonne/hr] is based on the circulating water pumps flow rate in an NETL Reference Study and equals 32706 [tonne/hr] (Woods et al., 2007).
(3) Cooling Water Circulation Liquid Flow Rate [tonne/hr]is estimated from the Circulating Water Flow Rate IECM Interface Screen.

Cost Calculations – Chiller System

The total cost for Chiller System is based on the chilling loads required by the ammonia-based CO_2 capture system. The total cost is calculated according to the equation:

$$\text{Chiller Installed Cost [\$]} = \text{Chilling System Installed Cost } \left[\frac{\$}{\text{ton chilling}}\right] * \frac{[\text{DCC2 Chilling Load [Btu]} + \text{Absorber Chilling Load [Btu]} + \text{Lean Solution Chilling Load [Btu]}]}{12000\ [\frac{\text{Btu}}{\text{ton chilling}}]}$$

Where:

(1) Chilling System Installed Cost $\left[\frac{\$}{\text{ton chilling}}\right]$ is equal to \$441.245 in \$2007, scaled from \$350 in \$2000, from a reference in the literature (RDC, 2003) using the Marshal & Swift Index.
(2) DCC2 Chilling Load [Btu], Absorber Chilling Load [Btu], and Lean Solution Chilling Load [Btu] are estimated from the regression equations associated with each of these variables.

Cost Calculations – Absorber

Currently, the most appropriate absorber design for the ammonia-based CO_2 capture system is a spray tower absorber designed to handle a significant amount of solids precipitation. Spray tower absorber equipment is typically used in wet flue gas desulfurization (FGD) processes, and is considerably different than the traditional packed or trayed columns found in amine scrubbers, and therefore the base costs for the ammonia-based CO_2 capture system absorber are taken from the wet FGD model rather than the existing amine system model in the IECM. The total cost of the spray tower absorber and associated equipment is calculated according to the equation:

$$\text{Absorber Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Gas Flow Rate into Absorber [cum/sec]}}{\text{Reference Gas Flow Rate [cum/sec]}}\right]^{0.6}$$

Where:

(1) $\text{Refernce Installed Cost [\$]}$ is equal to 105.1 (\$M) in \$2007, based on the wet FGD system cost in the IECM reference amine model. It is appropriate to use the cost of the wet FGD system of a plant with an amine system, because the wet FGD system will have to process approximately the same amount of flue gas as the absorber in the CO_2 capture system. A plant without a CO_2 capture system that produces the same amount of net electricity will have to process considerably less flue gas all other things being equal.

(2) $\text{Gas Flow Rate into Absorber [cum/sec]}$ is from the Gas Flow Rate Into Absorber regression equation.

(3) Reference Gas Flow Rate [cum/sec] is based on the gas flow rate in the Aspen Plus® Reference Study and equals 497.3 [cum/sec].

Cost Calculations – Absorber Pumps

The total cost for Absorber Pumps is calculated according to the equation:

$$\text{Absorber Pumps Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Absorber Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}$$

Where:

(1) $\text{Refrence System Cost [\$]}$ is based on the circulating water pumps cost in an NETL Reference Study and equals 2.065 [\$M] (Woods et al., 2007).

(2) $\text{Reference Liquid Flow Rate [tonne/hr]}$ is based on the circulating water pumps flow rate in an NETL Reference Study and equals 32706 [tonne/hr] (Woods et al., 2007).

(3) $\text{Absorber Liquid Flow Rate [tonne/hr]}$is estimated from the $\text{Absorber Cooling Water Flow Rate Regression Equation.}$

Cost Calculations – Heat Exchanger 3 (The Rich/Lean Heat Exchanger)

The total cost for Heat Exchanger 3 is based on the heat exchanger surface area and is calculated according to the equation:

$$\text{Heat Exchanger 2 Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Heat Exchanger 3 Surface Area [sqm]}}{\text{Reference Heat Exchanger Surface Area [sqm]}}\right]^{0.6}$$

Where:

1. Refrence System Cost [\$] is calculated by the Ammonia System Aspen Icarus® Reference Model and is equal to 19.343 [\$M].
2. Reference Heat Exchanger Surface Area [sqm] is calculated by the Ammonia System Aspen Plus Reference Model and is equal to 10078.5 [sqm].
3. Heat Exchanger 3 Surface Area [sqm] is calculated as a function of the temperature approach of the heat exchange (default 10°F between the cold side inlet and the hot side outlet), the flow rates, flow compositions, flow rate heat capacity, chemical reactions, and the temperature of the flows into and out of the heat exchanger. This variable is estimated from the Aspen Heat Exchanger 3 Regression Equation.

Cost Calculations – Solvent Circulation Pumps (The High Pressure Pump)

The total cost for Solvent Circulation Pump is calculated according to the equation:

$$\begin{aligned}&\text{Solvent Circulation Pumps Installed Cost [\$]}\\&\quad = \text{Refrence System Cost [\$]} * \left[\frac{\text{Solvent Circulation Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}\end{aligned}$$

Where:

1. Refrence System Cost [\$] is based on the circulating water pumps cost in the IECM amine reference model and is equal to 13.38 [\$M].
2. Reference Liquid Flow Rate [tonne/hr] is based on the circulating water pumps flow rate in the IECM amine reference model and is equal to 2405.5 [kg/sec].
3. Solvent Circulation Liquid Flow Rate [tonne/hr] is estimated from Rich Solvent Flow Regression Equation.

Cost Calculations – Solution Heater 1

The total cost for Solution Heater is calculated according to both the solvent flow rate through the heater as well as the heat transferred, according to the equation:

$$\begin{aligned}&\text{Solution Heater Installed Cost [\$]}\\&\quad = \text{Refrence System Cost [\$]} * \left[\frac{\text{Solution Heater Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}} * \frac{\text{Steam Flow to Heater [Btu/hr]}}{\text{Reference Steam Use [Btu/hr]}}\right]^{0.6}\end{aligned}$$

Where:

1. Refrence System Cost [\$] is based on Aspen Icarus® costing in the ammonia system reference model and is equal to 26.38 [\$M].

(2) Reference Liquid Flow Rate [tonne/hr] is the Absorber circulation rate from the reference amine system in the IECM and is equal to 8660 tonne/hr.
(3) Solvent Circulation Liquid Flow Rate [tonne/hr] is estimated from Rich Solvent Flow Regression Equation.
(4) Reference Steam Use [Btu/hr] is from the steam use in the CO_2 stripper reboiler in the IECM amine reference model, and is equal to 1.88E9 Btu/hr.
(5) Steam Flow to Heater [Btu/hr] is from the Steam Flow to Heater Regression Equation.

Cost Calculations – Solution Cooler

The total cost for the Solution Cooler is based on the heat exchanger surface area and is calculated according to the equation:

$$\text{Solution Cooler Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{Solution Cooler Surface Area [sqm]}}{\text{Reference Heat Exchanger Surface Area [sqm]}}\right]^{0.6}$$

Where:

(1) Refrence System Cost [\$] is calculated by the Ammonia System Aspen Icarus® Reference Model and is equal to 2.315 [\$M].
(2) Reference Heat Exchanger Surface Area [sqm] is calculated by the Ammonia System Aspen Plus® Reference Model and is equal to 17138.89 [sqm].
(3) Solution Cooler Surface Area [sqm] is calculated as a function of the temperature approach of the heat exchange (default 10°F between the cold side inlet and the hot side outlet), the flow rates, flow compositions, flow rate heat capacity, chemical reactions, and the temperature of the flows into and out of the heat exchanger. This variable is estimated from the Solution Cooler Surface Area Regression Equation.

Cost Calculations – CO_2 Stripper

The total cost for Solvent Circulation Pump is calculated according to the equation:

$$\text{CO2 Stripper Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{CO2 Stipper Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}$$

Where:

(1) Reference System Cost [\$] is based on the CO_2 Stripper cost in the IECM amine reference model and is equal to 54.07 [\$M].
(2) Reference Liquid Flow Rate [tonne/hr] is the Absorber circulation rate from the reference amine system in the IECM and is equal to tonne/hr.
(3) Solvent Circulation Liquid Flow Rate [tonne/hr] is estimated from the Rich Solvent Flow Regression Equation.

Cost Calculations – CO_2 Stripper Reboiler

The total cost for the CO_2 Stripper Reboiler is calculated according to both the solvent flow rate through the reboiler as well as the heat transferred, according to the equation:

$$\text{CO2 Stripper Reboiler Installed Cost [\$]} \\ = \text{Refrence System Cost [\$]} \\ * \left[\frac{\text{CO2 Stripper Reboiler Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}} * \frac{\text{Steam Flow to Reboiler [Btu/hr]}}{\text{Reference Steam Use [Btu/hr]}}\right]^{0.6}$$

Where:

1. Reference System Cost [\$] is based on the cost of the reboiler in the IECM amine system reference model and is equal to 26.38 [\$M].
2. Reference Liquid Flow Rate [tonne/hr] is the Absorber circulation rate from the reference amine system in the IECM and is equal 8660 tonne/hr
3. Solvent Circulation Liquid Flow Rate [tonne/hr] is estimated from the Rich Solvent Flow Regression Equation.
4. Reference Steam Use [Btu/hr] is from the steam use in the CO_2 stripper reboiler in the IECM amine reference model, and is equal to 1.88E9 Btu/hr.
5. Steam Flow to Reboiler [Btu/hr] is from the Steam Flow to Reboiler Regression Equation.

Cost Calculations – Water Wash Absorber

The total cost for CO_2 water wash absorber was sized according to Aspen Icarus®, and is assumed to be constant and equal to 2.2 [\$M] in \$2007.

Cost Calculations – Heat Exch. 4

The total cost for Heat Exch. 4 was sized according to Aspen Icarus®, and is assumed to be constant and equal to 0.1 [\$M] in \$2007. The calculated cost is of this heat exchanger is considerably lower than the other heat exchangers in the ammonia-based CO_2 capture system primarily both because the liquid flow rates are typically much smaller, and because the hot and cold streams are already closer in temperature than elsewhere in the process. These two factors significantly reduce the heat transfer requirement and therefore the surface area and corresponding cost. Due to the small cost of this heat exchanger relative to the other equipment in the process, the cost of this exchanger is held constant in the model through all power plant sizes and model conditions by default. For significantly different applications, the user can adjust the total cost of the heat exchangers in the IECM by adjusting the appropriate retrofit parameters in the user screen.

Cost Calculations – NH_3 Stripper

The total cost for the NH_3 Stripper was sized according to Aspen Icarus®, and is assumed to be constant and equal to 1.51 [\$M] in \$2007. The calculated cost of this stripper is considerably lower than most of the other components in the ammonia-based CO_2 capture system primarily because it is smaller and has a lower liquid flow rate and heat transfer surface area in the reboiler. Due to the small cost of the NH_3 stripper relative to the other equipment in the process, the cost of this exchanger is held constant in the model through all power plant sizes and model conditions by default. For significantly different applications, the user can adjust the total cost of the overall water wash system in the IECM by adjusting the appropriate retrofit parameters in the user screen.

Cost Calculations – NH_3 Cleanup Pumps

The total cost for NH_3 Cleanup Pump (the water wash pumps) is calculated according to the equation:

$$\text{NH3 Cleanup Pumps Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \left[\frac{\text{NH3 Cleanup Liquid Flow Rate [tonne/hr]}}{\text{Reference Liquid Flow Rate [tonne/hr]}}\right]^{0.6}$$

Where:

1. Reference System Cost [\$] is based on the circulating water pumps cost in the IECM amine reference model and is equal to 13.38 [\$M].
2. Reference Liquid Flow Rate [tonne/hr] is based on the circulating water pumps flow rate in the IECM amine reference model and is equal to 2405.5 [kg/sec].
3. Solvent Circulation Liquid Flow Rate [tonne/hr] is estimated from the Water Wash Flow Rate Regression Equation.

Cost Calculations – Steam Extractor

The total cost for the Steam Extractor is taken from the IECM amine system reference model, and is assumed to be constant and equal to 3.3 [\$M] in \$2007. This value is assumed constant regardless of the size of the plant. For specific applications, the user can adjust the total cost of the steam extractor in the IECM by adjusting the appropriate retrofit parameters in the user screen.

Cost Calculations – Sorbent Reclaimer

The total cost for the Sorbent Reclaimer is taken from the IECM amine system reference model, and is assumed to be constant and equal to 1.12 [\$M] in \$2007. This value is assumed constant regardless of the size of the plant. For specific applications, the user can adjust the total cost of the steam extractor in the IECM by adjusting the appropriate retrofit parameters in the user screen.

Cost Calculations – Sorbent Processing

The total cost for Sorbent Processing is taken from the IECM amine system reference model, and is assumed to be constant and equal to 1.13 [\$M] in \$2007. This value is assumed constant regardless of the size of the plant. For specific applications, the user can adjust the total cost of the steam extractor in the IECM by adjusting the appropriate retrofit parameters in the user screen.

Cost Calculations – Drying and Compression Unit

The total compression work and therefore electrical use required is dependent on the amount of CO_2 that goes to the compressor, as well as the initial and final stream pressures. The costs of the compressors are assumed to be proportional to the MWe usage required. Therefore, the total cost for the Drying and Compression Unit is calculated according to the equation:

$$\text{Drying and Compression Unit Installed Cost [\$]} = \text{Refrence System Cost [\$]} * \frac{\text{Auxiliary Electrical Load for CO2 Compressor [MWe]}}{\text{Reference Electrical Use for CO2 Compressor [MWe]}}$$

Where:

(1) Refrence System Cost [$] is based on the Drying and Compression Unit cost in the IECM amine reference model and is equal to 57.3 [$M].

(2) Reference Electrical Use for CO_2 Compressor is based on the IECM amine reference model and is equal to 52.89 [MWe].

(3) The Auxiliary Electrical Load for CO_2 Compressor [MWe] is calculated in the auxiliary electrical load section above.

Selection of System Defaults

Selection of Default Parameters

There are many adjustable parameters in the ammonia-based CO_2 capture module, and a set of default values were selected for these parameters, primarily based on the baseline model values in the corresponding publication (Versteeg and Rubin, 2011). These parameters represent the best currently available information on this technology and may be updated in future versions of the IECM as new information comes out or as specific applications of the technology are developed.

Ammonia System Train Size and Spares

The default maximum train size for the ammonia-based CO_2 capture module is set at 1000 tons CO_2/hr (907.2 tonnes CO_2/hr). This is significantly larger than public designs for amine-based CO_2 capture systems, but train sizes have been increasing through the years. In addition, the absorber in the ammonia-based CO_2 capture system is envisioned as a spray tower, and spray towers for wet FGD systems have been designed at large scales. For example, a 62 foot diameter General Electric Environmental Services Inc. designed absorber that is part of a forced oxidation limestone FGD system processes flue gas from a 700 MWe boiler at a power plant (Kohl, 1997). The train size influences costs in a significant way, especially because each train in an ammonia system is very capital intensive. The user has the option of setting the maximum train size for the ammonia-based CO_2 capture module on the user input screen.

When an additional train is added not all process components related to the CO_2 capture system necessarily need to be duplicated as some equipment can be sized to handle the requirements of multiple trains. Table 6 below describes which process components are duplicated when an additional train needs to be added. Due to the limited operating experience of this type of process at scale, the selection components that are duplicated when additional trains are added may not represent designs that are actually implemented. For specific applications, the user can adjust the train size and then also adjust the individual cost for specific components as needed in the retrofit screen for the ammonia-based CO_2 capture system.

Table 6: Duplication of Components with the Addition of a Train

Process Area	Multiple Trains
DCC	Share among trains
Flue Gas Blower	Split into trains if necessary
Chiller System	Share among trains
CO_2 Absorber Vessel	Split into trains if necessary
Heat Exchangers	Split into trains if necessary
Circulation Pumps	Split into trains if necessary
Sorbent Regeneration	Split into trains if necessary
Ammonia Water Wash	Split into trains if necessary
Steam Extractor	Share among trains
Sorbent Processing and Reclaimer	Share among trains
Drying and Compression Unit	Split into trains if necessary
NH_3 Stripping	Split into trains if necessary
Auxiliary Natural Gas Boiler	Share among trains
Auxiliary Steam Turbine	Share among trains

When more than one train is required, the cost of components that are duplicated (split into trains) is adjusted according to the following equation:

$$\text{Total Installed Cost [\$]} = \text{Calculated Installed Cost For One Train [\$]} * \frac{(\text{No of Trains Required} + \text{No. of Spares Required})}{\text{No. Of Trains Required}^{0.6}}$$

For example, consider the costs of the CO_2 absorber vessel portion of the ammonia-based CO_2 capture system. Ignoring the impact of multiple trains and spares, the cost of the absorber is calculated as in the previous section:

$$\text{Absorber Installed Cost [\$]} = \text{Reference System Cost [\$]} * \left[\frac{\text{Gas Flow Rate into Absorber [cum/sec]}}{\text{Reference Gas Flow Rate [cum/sec]}}\right]^{0.6}$$

If three trains and one spare absorber are required, however, the total gas flow rate is processed by three absorbers, the spare absorber is unused during regular operation, and each operating absorber processes one third of the flue gas. The total cost of the three absorbers and the spare is calculated as:

$$\text{Total Absorber Installed Cost [\$]} = (3 + \text{No. of Spares}) * \text{Reference System Cost [\$]} * \left[\frac{\frac{1}{3}\text{Total Gas Flow Rate into Absorbers [cum/sec]}}{\text{Reference Gas Flow Rate [cum/sec]}}\right]^{0.6}$$

which equals:

$$\text{Total Absorber Installed Cost [\$]} = \text{Reference System Cost [\$]} * \left[\frac{\text{Total Gas Flow Rate into Absorbers } \left[\frac{\text{cum}}{\text{sec}}\right]}{\text{Reference Gas Flow Rate } \left[\frac{\text{cum}}{\text{sec}}\right]}\right]^{0.6} * \frac{(3 + \text{No. of Spares})}{3^{0.6}}$$

which equals:

$$\text{Total Absorber Installed Cost [\$]} = \text{Calculated Installed Cost For One Train [\$]} * \frac{(\text{No of Trains Required} + \text{No. of Spares Required})}{\text{No. Of Trains Required}^{0.6}}$$

Design of the CO_2 Capture Screens for the Ammonia-Based System in the IECM

Introduction

The capture screens in the IECM have been designed to provide the user with options for specifying the parameters of the ammonia-based CO_2 capture system, and the outputs provide a concise summary of the performance and costs of the components in the system. The following sections describe the inputs required from the IECM to run the model, the inputs required from the user (though there are default values preset for all the key inputs), and the resulting output screens after the IECM has calculated all the values in the performance and costs response model.

When the Ammonia System is selected from the CO_2 Capture Menu in the Configure Plant > Overall Plant> Diagram Screen, the ammonia model is used as the CO_2 capture system. When the ammonia-based CO_2 capture system is selected, the ammonia model requires data from the IECM, including data from the IECM input screens that are described in the next sections.

Inputs from the IECM Performance Model

Key inputs from the IECM Performance Model for the ammonia based CO_2 capture system are listed in Table 7 below.

Table 7: Inputs Required from the Performance Model in the IECM

Parameter	Type	Units
Nitrogen (N_2) Into Model	IECM Module Output	mole/sec
Oxygen (O_2) Into Model	IECM Module Output	mole/sec
Water Vapor (H_2O) Into Model	IECM Module Output	mole/sec
Carbon Dioxide (CO_2) Into Model	IECM Module Output	mole/sec
Carbon Monoxide (CO) Into Model	IECM Module Output	mole/sec
Hydrochloric Acid (HCl) Into Model	IECM Module Output	mole/sec
Sulfur Dioxide (SO_2) Into Model	IECM Module Output	mole/sec
Sulfuric Acid (equivalent SO_3) Into Model	IECM Module Output	mole/sec
Nitric Oxide (NO) Into Model	IECM Module Output	mole/sec
Nitrogen Dioxide (NO_2) Into Model	IECM Module Output	mole/sec
Ammonia (NH_3) Into Model	IECM Module Output	mole/sec
Argon (Ar) Into Model	IECM Module Output	mole/sec
Flue Gas Volumetric Flow Into Model	IECM Module Output	cum/sec
Flue Gas Temperature Into Model	IECM Module Output	°F

Available Cooling Water Temperature	IECM Module Output	°F
Particulate Into Model	IECM Module Output	kg/sec

Inputs from the User on the Set Parameters > CO_2 Capture>Config Screen

Key inputs from the user on this screen are listed in the Table 8 below. Enabling Bypass on this menu leads to additional line items appearing, as shown in Table 9.

Table 8: Inputs Required from the IECM User

Parameter	Type	Units
Sorbent Used	IECM Interface Screen	N/A
Auxiliary Natural Gas Boiler?	IECM Interface Screen	N/A
CO_2 Product Compressor Used?	IECM Interface Screen	N/A
Flue Gas Bypass Control	IECM Interface Screen	N/A

Table 9: Additional Inputs Required from the IECM User when Bypass is Enabled

Parameter	Type	Units
Maximum CO_2 Removal Efficiency	IECM Interface Screen	%
Overall CO_2 Removal Efficiency	IECM Interface Screen	%
Absorber CO_2 Removal Efficiency	IECM Interface Screen	%
Minimum Bypass	IECM Interface Screen	%
Allowable Bypass	IECM Interface Screen	%
Actual Bypass	IECM Interface Screen	%

Inputs from the User on the Set Parameters > CO_2 Capture>Performance

Key inputs from the user on this screen are listed in Table 10 below.

Table 10: Inputs Required from the IECM User

Parameter	Type	Units
Maximum CO_2 Removal Efficiency	IECM Interface Screen	%
Scrubber CO_2 Removal Efficiency	IECM Interface Screen	%
SO_2 Removal Efficiency	IECM Interface Screen	%
SO_3 Removal Efficiency	IECM Interface Screen	%
NO_2 Removal Efficiency	IECM Interface Screen	%
HCl Removal Efficiency	IECM Interface Screen	%
Particulate Removal Efficiency	IECM Interface Screen	%
Mercury Removal from CO_2 Absorber	IECM Interface Screen	

Maximum Train CO_2 Capacity	IECM Interface Screen	tons/hr
Number of Operating Absorbers	IECM Interface Screen	integer
Number of Spare Absorbers	IECM Interface Screen	integer
Max CO_2 Compressor Capacity	IECM Interface Screen	tons/hr
No. of Operating CO_2 Compressors	IECM Interface Screen	integer
No. of Spare CO_2 Compressors	IECM Interface Screen	integer
NH_3 Scrubber Power Requirement	IECM Interface Screen	% MWg

Inputs from the User on the Set Parameters > CO_2 Capture>Capture Screen

Key inputs from the user on this screen are listed in Table 11 below.

Table 11: Inputs Required from the IECM User

Parameter	Type	Units
Ammonia Concentration	IECM Interface Screen	wt %
Overall Ammonia Slip	IECM Interface Screen	ppmv
Absorber NH3 Slip	IECM Interface Screen	ppmv
Circulating Water Flow Rate	IECM Interface Screen	lb/sec
Gas Phase Pressure Drop	IECM Interface Screen	psia
ID Fan Efficiency	IECM Interface Screen	%
Capture System Cooling Duty	IECM Interface Screen	t H_2O/t CO_2
Percent Cooling Supply by Chillers	IECM Interface Screen	%
Power Requirement by Chillers	IECM Interface Screen	kW/ton refrig.
Regen. Heat Requirement	IECM Interface Screen	Btu/lb CO_2
Regen. Steam Heat Content	IECM Interface Screen	Btu/lb steam
Heat-to-Electricity Efficiency	IECM Interface Screen	%
Pump Efficiency	IECM Interface Screen	%
Percent Solids in Reclaimer Waste	IECM Interface Screen	%

Inputs from the User on the Set Parameters > CO_2 Capture>CO_2 Storage Screen

Key inputs from the user on this screen are listed in Table 12 below.

Table 12: Inputs Required from the IECM User

Parameter	Type	Units
CO_2 Product Pressure	IECM Interface Screen	psig
Captured CO_2 Purity	IECM Interface Screen	vol %
H_2O Content	IECM Interface Screen	vol %
Other Content	IECM Interface Screen	vol %

CO_2 Compressor Efficiency	IECM Interface Screen	%
CO_2 Unit Compression Energy	IECM Interface Screen	kWh/ton CO_2
CO_2 Storage Method:	IECM Interface Screen	

Inputs from the User on the Set Parameters > CO_2 Capture>Retrofit Cost

Key inputs from the user on this screen are listed in the Table 13 below.

Table 13: Inputs Required from the IECM User

Parameter	Type	Units
Direct Contact Coolers	IECM Interface Screen	
Flue Gas Blower	IECM Interface Screen	retro $/new $
Chiller System	IECM Interface Screen	retro $/new $
CO_2 Absorber Vessel	IECM Interface Screen	retro $/new $
Heat Exchangers	IECM Interface Screen	retro $/new $
Circulation Pumps	IECM Interface Screen	retro $/new $
Sorbent Regeneration	IECM Interface Screen	retro $/new $
Ammonia Water Wash	IECM Interface Screen	retro $/new $
Steam Extractor	IECM Interface Screen	retro $/new $
Sorbent Processing and Reclaimer	IECM Interface Screen	retro $/new $
CO_2 Drying and Compression Unit	IECM Interface Screen	retro $/new $
NH_3 Stripping	IECM Interface Screen	retro $/new $
Auxiliary Natural Gas Boiler	IECM Interface Screen	retro $/new $
Auxiliary Steam Turbine	IECM Interface Screen	retro $/new $

Inputs from the User on the Set Parameters > CO_2 Capture>Capital Cost Screen

Key inputs from the user on this screen are listed in the Table 14 below.

Table 14: Inputs Required from the IECM User

Parameter	Type	Units
Construction Time	IECM User Input	Years
General Facilities Capital	IECM User Input	%PFC
Engineering & Home Office Fees	IECM User Input	%PFC
Project Contingency Cost	IECM User Input	%PFC
Process Contingency Cost	IECM User Input	%PFC
Royalty Fees	IECM User Input	%PFC
Months of Fixed O&M	IECM User Input	Months
Months of Variable O&M	IECM User Input	Months
Misc. Capital Cost	IECM User Input	%TPI
Inventory Capital	IECM User Input	%TPC

TCR Recovery Factor	IECM User Input	%

Inputs from the User on the Set Parameters > CO_2 Capture>O&M Cost Screen

Key inputs from the user on this screen are listed in the Table 15 below.

Table 15: Inputs Required from the IECM User

Parameter	Type	Units
Ammonia Cost	IECM User Input	$/ton
Water Cost	IECM User Input	$/kgal
Auxiliary CCS Cooling Cost	IECM User Input	$/ton cool H_2O
Reclaimer Waste Disposal Cost	IECM User Input	$/ton
Electricity Price (Base Plant)	IECM User Input	$/MWh
Number of Operating Jobs	IECM User Input	jobs/shift
Number of Operating Shifts	IECM User Input	shifts/day
Operating Labor Rate	IECM User Input	$/hr
Total Maintenance Cost	IECM User Input	%TPC
Maint. Cost Allocated to Labor	IECM User Input	% total
Administrative & Support Cost	IECM User Input	% total labor
CO_2 Transportation Cost	IECM User Input	$/ton
CO_2 Storage Cost	IECM User Input	$/ton

Outputs Expected from the Ammonia Model

Mass Balance Outputs from the Ammonia Model

The mass balance outputs from the ammonia model are described below in Table 16.

Table 16: Mass Balance Outputs Required from the Performance Model in the IECM

Parameter	Type	Units
Nitrogen (N_2) To Stack	Ammonia Module Output	mole/sec
Oxygen (O_2) To Stack	Ammonia Module Output	mole/sec
Water Vapor (H_2O) To Stack	Ammonia Module Output	mole/sec
Carbon Dioxide (CO_2) To Stack	Ammonia Module Output	mole/sec
Carbon Monoxide (CO) To Stack	Ammonia Module Output	mole/sec
Hydrochloric Acid (HCl) To Stack	Ammonia Module Output	mole/sec
Sulfur Dioxide (SO_2) To Stack	Ammonia Module Output	mole/sec
Sulfuric Acid (equivalent SO_3) To	Ammonia Module Output	mole/sec

Stack		
Nitric Oxide (NO) To Stack	Ammonia Module Output	mole/sec
Nitrogen Dioxide (NO_2) To Stack	Ammonia Module Output	mole/sec
Ammonia (NH_3) To Stack	Ammonia Module Output	mole/sec
Argon (Ar) To Stack	Ammonia Module Output	mole/sec
Particulate To Stack	Ammonia Module Output	ton/hr
Water Bleed from Flue Gas Cooling System	Ammonia Module Output	kg/sec
CO_2 Flow to Compressor	Ammonia Module Output	mole/sec
Cooling Water Flow	Ammonia Module Output	kg/sec
Chilled Water Flow	Ammonia Module Output	kg/sec
Steam Flow to Heater (if necessary)	Ammonia Module Output	kg/sec
Steam Flow to NH_3 Cleanup System	Ammonia Module Output	kg/sec
Steam Flow to CO_2 Regeneration System	Ammonia Module Output	kg/sec

Note: Nitrogen (N_2), Oxygen (O_2), and Argon (Ar) pass through the CO_2 capture system unchanged in this version of the model.

Energy Usages of the Ammonia System Equipment

The energy balance outputs from the ammonia model are described below in Table 17. The IECM interface calculates all these parameters, though in some cases the user sees an aggregate of several values.

Table 17: Energy Usages of the Ammonia System Equipment

Parameter	Type	Units
Flue Gas Blower	NH3 Module Output	MWe
DCC1 Pumps	NH3 Module Output	MWe
DCC2 Pumps	NH3 Module Output	MWe
Flue Gas Cooler Water Circulation Pumps	NH3 Module Output	MWe
Absorber Cooling Pumps	NH3 Module Output	MWe
Ammonia Cleanup Pumps	NH3 Module Output	MWe
Drying and Compress Unit	NH3 Module Output	MWe
High Pressure Pump	NH3 Module Output	MWe
Abs Cooling (water)	NH3 Module Output	Btu/hr
Lean Solution Cooling (water)	NH3 Module Output	Btu/hr
DCC2 Chilling Load (water)	NH3 Module Output	Btu/hr
CO_2 Flash Cooling (water)	NH3 Module Output	Btu/hr
Heater (steam)	NH3 Module Output	Btu/hr
CO_2 Stripper (steam)	NH3 Module Output	Btu/hr
NH3 Stripper (steam)	NH3 Module Output	Btu/hr

Capital Costs of the Ammonia System Equipment

The resulting capital cost outputs from the ammonia model are described below in Table 18. The IECM interface calculates all these parameters, though in some cases the user sees an aggregate of several values, for example all the heat exchanger costs are combined on the IECM Results screen.

Table 18: Capital Costs of the Ammonia System Equipment

Parameter	Type	Units
Direct Contact Cooler 1	NH3 Module Output	$
Flue Gas Blower	NH3 Module Output	$
Heat Exchanger 1	NH3 Module Output	$
Heat Exchanger 2	NH3 Module Output	$
Direct Contact Cooler 2 Equipment	NH3 Module Output	$
DCC1 Pumps (Also Called Heat X1)	NH3 Module Output	$
DCC2 Pumps (Also Called Heat X2)	NH3 Module Output	$
Flue Gas Cooler Water Circulation Pumps	NH3 Module Output	$
Flue Gas Cooling - Chiller System	NH3 Module Output	$
CO_2 Spray Tower Absorber Vessel	NH3 Module Output	$
Absorber Cooling Pumps	NH3 Module Output	$
Rich/Lean Heat Exchanger	NH3 Module Output	$
Solution Heater 1	NH3 Module Output	$
Solution Cooler	NH3 Module Output	$
High Pressure Pump	NH3 Module Output	$
CO_2 Capture Packed Bed Stripper	NH3 Module Output	$
Reboiler	NH3 Module Output	$
Ammonia Cleanup Water Wash Unit	NH3 Module Output	$
Ammonia Cleanup Heat Exchanger	NH3 Module Output	$
Ammonia Cleanup Stripper	NH3 Module Output	$
Ammonia Cleanup Pumps	NH3 Module Output	$
Steam Extractor	NH3 Module Output	$
Sorbent Reclaimer	NH3 Module Output	$
Sorbent Processing	NH3 Module Output	$
Drying and Compress Unit	NH3 Module Output	$

O&M Costs of the Ammonia System Equipment

The resulting O&M cost outputs from the ammonia model are described below in Table 19. Fixed costs are also calculated as a fraction of other costs, as specified by the user.

Table 19: Operating and Maintenance Costs of the Ammonia System Equipment

Parameter	Type	Units
Ammonia	Ammonia Module Output	$/Year
Natural Gas	Ammonia Module Output	$/Year
Reclaimer Waste Disposal	Ammonia Module Output	$/Year
Electricity	Ammonia Module Output	$/Year
Auxiliary Power Credit	Ammonia Module Output	$/Year
Water	Ammonia Module Output	$/Year
CO_2 Transport	Ammonia Module Output	$/Year
CO_2 Storage	Ammonia Module Output	$/Year

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