A Feasibility Study of Carbon Dioxide Removal and Sequestration from a 500 MW Power Plant

Background

The production of carbon dioxide from the combustion of fossil fuels is believed to be the major contributing factor to the increase of atmospheric CO_2, which in turn is believed to be responsible for the "Greenhouse" effect suspected of causing global warming. The level of carbon dioxide in the atmosphere has increased from 315 ppm in 1958 to a value of 362 ppm in 1996 [1]. Over this same period the total amount of carbon equivalent released from fossil energy sources was estimated to be 180×10^9 tonnes. This rapid rate of increase in CO_2 production, coupled with the rapid global population growth and the associated increase in energy needs suggests that if global warming is not a problem now it will almost certainly be a problem in the future. The intent of this study is to provide an estimate for the cost of building a new 500 MW coal burning power plant. In this plant, the carbon dioxide produced in the combustion process is to be removed from the stack gas prior to emission to the atmosphere via an absorption technique. The proposed process uses a chemical solvent (monoethanolamine or MEA). However, other chemical or physical solvents could be used, e.g., hot potassium carbonate or Selexol. The removed CO_2 will then be stored in an aquifer located at a depth up to 700 meters and a distance of 10 miles from the plant. Alternative storage techniques such as ocean storage could also be considered. This project should also consider the environmental impact of building such a plant at the location specified in the assignment.

Process Description

The overall block flow diagram (BFD) for the process to remove and sequester CO_2 from a 500 MW power plant is shown in Figure 1 [2]. The power plant selected for this process is a

2^{nd} generation pressurized fluidized bed (PFB) plant and will be referred to as Unit 100. Unit 100 consists of: Coal and Dolomite Preparation, Handling and Storage, the PCFB Boiler, the Carbonizer Island, the Steam Turbine Island, Flue Gas Filtration, the Gas Turbine, Ash Handling and Storage, and the Heat Recovery Unit (HRU). Coal (43.8% volatiles) and dolomite are fed to Unit 100 to produce electricity and control SO_x emissions, respectively [2]. The cost of electricity for the unit is approximately 3.40¢/kWh. This cost signifies the cost of electricity if 100% of the CO_2 emitted from Unit 100 were discharged into the atmosphere, or the base cost of electricity for the entire process.

The flue gas from Unit 100 is sent to Unit 200 for carbon dioxide removal. In this unit, approximately 26% of the CO_2 is removed in an absorber via a 20% by weight monoethanolamine (MEA) solution. Carbon dioxide is then stripped from the rich amine solution to recover 99.4% by weight CO_2 prior to being sent to Unit 300.

Unit 300 is the compression and storage section for the CO_2. In this section, carbon dioxide is compressed with inter-cooling, liquefied, pumped and then transported through a pipe for a distance of 10 miles to a saline aquifer for permanent storage.

Unit 100

As mentioned previously, Unit 100 is a 2^{nd} generation PFB power plant. The unit utilizes Foster Wheeler's Advanced Gas Turbine System technology to produce power and is expected to be feasible within the next 5 years. In Figure 2, coal (43.8% volatiles) and dolomite are sent to the carbonizer, Z-101, where the coal is separated into its volatile and char components [2]. The volatile components are sent to a quench unit, Q-101, and then filtered in F-101. The cleaned syngas is then sent to the topping combustor, TC-101. The remaining char is sent to the 2^{nd} generation PFB, B-101, for combustion.

Figure 3 shows the char and a small amount of pure coal being sent to B-101 where combustion occurs. The heat given off from the combustion is used to generate steam for the steam turbines [2]. The CO_2 leaves the top of B-101 as a part of the flue gas at 28.8 bar. This flue gas then passes through filters, F-102, to remove the fly ash, which is then sent to a landfill.

After leaving the filters, the clean flue gas is sent to the topping combustor, as shown in Figure 4 [2]. TC-101 takes the syngas, flue gas, and natural gas and combusts it isothermally at 1510°C. Boiler feed water is utilized to maintain the temperature of TC-101 at 1510°C and is vaporized to produce low-pressure steam for Unit 200. The natural gas is added in the topping combustor for two reasons: the first reason is that it is the start-up fuel to begin the process; the second reason is to combust the remaining oxygen in the flue gas so that the concentration of O_2 is below 100 ppm for Unit 200. At O_2 concentrations higher than 100 ppm, oxygen in the flue gas stream tends to speed up the amine degradation, which increases the corrosion rate of the process equipment [4,5]. Corrosion inhibitors are commercially available that allow the concentration of the MEA to be increased, but such compounds are made of heavy metals, such as $AsCl_3$. (Since these chemicals are environmentally unfriendly, it has been decided to avoid the use of such compounds in the developed removal process.)

The topping combustor exhausts the flue gas at 28.8 bar pressure and then expands it in a gas turbine, C-105, to 1.36 bar. This gas turbine drives a generator to produce electricity and also works to compress the air that is needed in the boiler.

The flue gas is still at high temperature when it exhausts from the turbine and is utilized in the heat recovery unit (HRU) to preheat steam and feedwater for the steam turbine unit (C-102, C-103, and C-104) as shown in Figure 5 [2]. The steam turbine unit operates in three separate stages. The first stage operates at an inlet condition of 165.4 bar and expands the steam to 38.4 bar. The intermediate stage takes steam at 35.9 bar and expands it to 5.5 bar. The final stage takes steam at 5.5 bar and expands it to 0.08 bar. The steam condenses at 0.08 bar and 42°C using cooling water obtained at 25°C and returned at 35°C [2]. The condensate and low-pressure steam leaving the turbines are condensed in E-106, and return to the cycle to be recompressed and vaporized.

This plant will have acceptable emissions of all currently regulated pollutants. It has already been mentioned that adding dolomite to the coal during combustion controls SOx removal. Dolomite has been proven to be an effective control for the emission of sulfur [2]. NO_x formation is expected to be at or below current expectations for power plants [2]. This is a result of operating all combustion centers in Unit 100 (the carbonizer, the PFBC, and the topping combustor) below the temperature at which NO_x formation occurs, 1600°C.

Table 1 shows the power summary for the process excluding Units 200 and 300. The stream table for Unit 100 is given in Table 2.

Table 1: Net Power summary for Unit 100

Equipment	Power Output (MW)
Power Generated:	
Gas Turbine	456.0
Steam Turbine	308.0
Power Consumed:	
Air Compressor	222.0
Other Equipment	17.0
Net Power	525.0

Table 2: Stream Tables for Unit 100							
Stream #	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Temperature [ºC]	19.00	19.00	19.00	93.00	93.00	16.00	967.00
Pressure [Bar]	1.00	1.00	1.00	1.00	1.00	34.20	32.90
Total Flowrate [kg/h]	123,019	30,182	15,547	10,145	30,391	27,163	66,400
Weight %							
C	70.62		70.62				53.54
H	4.67		4.67	0.57	0.57		0.33
S	2.83		2.83				1.22
N	1.45		1.45				1.10
O	4.40		4.40				0.52
Ash	9.38		9.38				17.38
Water	6.65	1.00	6.65	32.07	32.07	100.00	
Calcium Carbonate		54.00					
Magnesium Carbonate		43.00		11.33	11.33		
Inerts		2.00					0.91
Calcium Sulfide				1.49	1.49		8.58
Calcium Sulfate							
Magnesium Oxide				39.24	39.24		9.34
Calcium Oxide				15.30	15.30		7.08

Table 2 (continued). Stream Tables for Unit 100													
Stream #	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Temperature [ºC]	745.00	196.00	316.00	968.00	862.00	286.00	154.00	19.00	NA	16.00	43.00	282.00	336.00
Pressure [Bar]	32.80	34.30	31.00	33.20	29.60	5.30	5.10	1.00	0.00	1.00	30.90	198.60	196.90
Total Flowrate [kg/h]	408,851	294,887	654,077	381,687	710,935	2,035	2,035	1,509,755	0	1,509,755	294,887	807,596	807,596
Weight %													
Water	9.00	0.67	0.67	9.00	4.49	100.00	100.00	0.67	100.00	0.67	0.67	100.00	100.00
Carbon Dioxide	9.15	0.05	0.05	9.15	23.62			0.05		0.05	0.05		
Nitrogen	52.81	75.01	75.01	52.81	68.85			75.01		75.01	75.01		
Oxygen		22.98	22.98		1.83			22.98		22.98	22.98		
Argon	0.90	1.28	1.28	0.90	1.17			1.28		1.28	1.28		
Sulfur Dioxide					0.02								
Nitrogen Oxide	14.22			14.22	0.01								
Hydrogen	0.13			0.13									
Methane	13.15			13.15									
Carbon Monoxide	0.03			0.03									
Hydrogen Sulfide	0.61			0.61									

Table 2 (continued). Stream Tables for Unit 100													
Stream #	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**
Temperature [ºC]	1510.00	716.00	396.00	455.00	210.00	361.00	16.00	25.00	37.00	538.00	325.00	538.00	448.00
Pressure [Bar]	28.80	1.36	1.33	184.50	200.30	188.00	1.00	2.40	2.40	165.40	38.40	35.90	19.00
Total Flowrate [kg/h]	1,686,500	1,686,500	1,686,500	815,984	807,627	799,523	8,180	30,920,903	30,920,903	812,471	812,471	812,471	38,153
Weight %													
Water	8.47	8.47	8.47	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Carbon Dioxide	23.35	23.35	23.35										
Nitrogen	66.98	66.98	66.98										
Oxygen	0.01	0.01	0.01										
Argon	1.14	1.14	1.14										
Sulfur Dioxide	0.02	0.02	0.02										
Nitrogen Oxide	0.02	0.02	0.02										

Table 2 (continued). Stream Tables for Unit 100													
Stream #	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**
Temperature [ºC]	371.00	286.00	74.00	42.00	42.00	42.00	48.00	70.00	135.00	154.00	158.00	164.00	158.00
Pressure [Bar]	10.90	5.50	0.40	0.10	0.08	11.90	0.40	11.40	9.90	5.30	215.70	10.60	203.80
Total Flowrate [kg/h]	31,900	28,007	36,397	683,632	728,170	728,170	36,397	728,170	728,170	824,087	824,087	70,022	16,460
Weight %													
Water	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Stream #	**47**	**48**	**49**	**50**	**51**
Temperature [ºC]	183.00	188.00	408.00	160.00	159.00
Pressure [Bar]	202.10	18.60	28.80	6.00	6.00
Total Flowrate [kg/h]	807,626	38,153	534	444,368	444,368
Weight %					
Water	100.00	100.00		100.00	100.00
Methane			100.00		

Unit 200

The CO_2 produced in the power plant is removed in Unit 200 using the MEA removal process. MEA is a chemical absorbent that reacts with the carbon dioxide to remove it from the flue gas. The primary reactions associated with CO_2 removal by reaction with MEA are as follows [3]:

Ionization of Water:

$$H_2O \Leftrightarrow H^+ + OH^- \qquad (1)$$

Hydrolysis and Ionization of Dissolved CO_2:

$$CO_2 + H_2O \Leftrightarrow HCO_3^- + H^+ \qquad (2)$$

Protonation of MEA:

$$CH_3CH_2OHNH_2 + H^+ \Leftrightarrow CH_3CH_2OHNH_3^+ \qquad (3)$$

Carbamate Formation:

$$CH_3CH_2OHNH_2 + CO_2 \Leftrightarrow CH_3CH_2OHNHCOO^- + H^+ \qquad (4)$$

The primary route for carbon dioxide removal is via Reaction 4. In order to regenerate the amine, heat must be added to shift the equilibrium back toward the reactants. Therefore, after the CO_2 is absorbed it is sent to a stripper, where the MEA solution is regenerated and recycled to the absorber. The CO_2 is then dehydrated and sent to Unit 300 for storage.

Figure 6 is a process flow diagram (PFD) for Unit 200. Table 3 shows a summary of the stream conditions in this process. In Unit 200, the flue gas enters in Stream 1 and is partial

Table 3: Stream Tables for Unit 200

	1	2	3	4	5	6
Temperature (°C)	395.65	113.00	35.00	35.00	35.00	66.70
Pressure (bar)	1.33	1.18	1.03	1.03	1.03	1.36
Vapor mole Fraction	1.00	1.00	0.91	1.00	0.00	1.00
Total (kg/h)	1,686,547	1,686,547	1,686,547	1,595,712	90,834	1,595,712
Total (kmol/h)	57,710.17	57,710.17	57,710.17	52,668.70	5,041.50	52,668.70
Mole Fraction						
Sulfur Dioxide	0.0001	0.0001	0.0001	0.0001	0.0000	0.0001
Nitric Oxide	0.0002	0.0002	0.0002	0.0002	0.0000	0.0002
Argon	0.0084	0.0084	0.0084	0.0092	0.0000	0.0092
Oxygen	0.0001	0.0001	0.0001	0.0001	0.0000	0.0001
Carbon Dioxide	0.1551	0.1551	0.1551	0.1699	0.0001	0.1699
Water	0.1374	0.1374	0.1374	0.0548	0.9999	0.0548
Nitrogen	0.6988	0.6988	0.6988	0.7657	0.0000	0.7657
Monoethanolamine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

	7	8	9	10	11	12
Temperature (°C)	35.00	56.68	49.34	40.00	40.00	40.00
Pressure (bar)	1.36	1.27	1.36	1.12	1.12	1.12
Vapor Mole Fraction	0.00	1.00	0.00	0.94	1.00	0.00
Total (kg/h)	90,834	1,556,837	1,901,578	1,556,837	1,500,439	56,397
Total (kmol/h)	5,041.50	53,905.99	87,477.07	53,905.99	50,783.18	3,122.80
Mole Fraction						
Sulfur Dioxide	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000
Nitric Oxide	0.0000	0.0002	0.0000	0.0002	0.0002	0.0000
Argon	0.0000	0.0089	0.0000	0.0089	0.0095	0.0000
Oxygen	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000
Carbon Dioxide	0.0001	0.1223	0.0362	0.1223	0.1298	0.0008
Water	0.9999	0.1202	0.8992	0.1202	0.0662	0.9987
Nitrogen	0.0000	0.7481	0.0000	0.7481	0.7941	0.0000
Monoethanolamine	0.0000	0.0000	0.0646	0.0000	0.0000	0.0005

	13	14	15	16	17	18
Temperature (^oC)	40.00	49.39	109.00	110.57	118.68	118.50
Pressure (bar)	1.36	2.42	2.27	2.12	1.97	1.82
Vapor Mole Fraction	0.00	0.00	0.02	0.03	0.15	0.31
Total (kg/h)	56,397	1,901,578	1,902,493	1,902,493	1,902,493	1,902,493
Total (kmol/h)	3,122.80	87,477.07	87,527.03	87,527.03	87,527.03	87,527.03
Mole Fraction						
Sulfur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitric Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.0008	0.0362	0.0362	0.0362	0.0362	0.0362
Water	0.9987	0.8992	0.8993	0.8993	0.8993	0.8993
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Monoethanolamine	0.0005	0.0646	0.0646	0.0646	0.0646	0.0646

	19	20	21	22	23	24
Temperature (^oC)	114.36	120.00	110.22	107.20	105.00	105.00
Pressure (bar)	1.75	1.82	1.60	1.45	1.30	1.30
Vapor Mole Fraction	1.00	0.00	0.64	1.00	0.27	1.00
Total (kg/h)	708,227	1,322,567	708,227	707,543	707,543	232,429
Total (kmol/h)	35,686.31	58,954.90	35,686.31	35,649.42	35,649.42	9,505.39
Mole Fraction						
Sulfur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitric Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.0674	0.0130	0.0674	0.0675	0.0675	0.2475
Water	0.9307	0.8923	0.9307	0.9307	0.9307	0.7524
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Monoethanolamine	0.0018	0.0948	0.0018	0.0018	0.0018	0.0000

	25	26	27	28	29	30
Temperature (^oC)	105.00	40.00	40.00	40.00	15.00	15.00
Pressure (bar)	1.30	1.15	1.15	1.15	1.00	1.00
Vapor Mole Fraction	0.00	0.26	1.00	0.00	0.96	1.00
Total (kg/h)	475,113.57	232,429.28	105,653.52	126,775.78	105,653.52	103,937.26
Total (kmol/h)	26,144.03	9,505.39	2,475.50	7,029.88	2,475.50	2,380.37
Mole Fraction						
Sulfur Dioxide	0.0000	0.0000	0.0001	0.0000	0.0001	0.0001
Nitric Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.0020	0.2475	0.9486	0.0007	0.9486	0.9865
Water	0.9955	0.7524	0.0511	0.9993	0.0511	0.0132
Nitrogen	0.0000	0.0001	0.0003	0.0000	0.0003	0.0003
Monoethanolamine	0.0024	0.0000	0.0000	0.0000	0.0000	0.0000

	31	32	33	34	35	36
Temperature (^oC)	15.00	103.47	103.47	103.47	40.01	15.01
Pressure (bar)	1.00	1.36	1.36	1.36	1.78	1.78
Vapor Mole Fraction	0.00	0.00	0.00	0.00	0.00	0.00
Total (kg/h)	1,716.25	475,113.57	86,470.67	388,642.93	126,775.78	1,716.25
Total (kmol/h)	95.13	26,144.03	4,758.21	21,385.82	7,029.88	95.13
Mole Fraction						
Sulfur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitric Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.0010	0.0020	0.0020	0.0020	0.0007	0.0010
Water	0.9990	0.9955	0.9955	0.9955	0.9993	0.9990
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Monoethanolamine	0.0000	0.0024	0.0024	0.0024	0.0000	0.0000

	37	38	39	40	41	42
Temperature (^oC)	39.68	25.00	103.68	100.00	111.38	110.49
Pressure (bar)	1.78	1.36	1.36	1.78	1.36	1.36
Vapor Mole Fraction	0.00	0.00	0.00	0.00	0.02	0.01
Total (kg/h)	128,492	3,481	392,124	128,492	1,322,567	1,714,691
Total (kmol/h)	7,125.01	166.00	21,551.81	7,125.01	58,954.90	80,506.71
Mole Fraction						
Sulfur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitric Oxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide	0.0007	0.0000	0.0020	0.0007	0.0130	0.0100
Water	0.9993	0.9313	0.9950	0.9993	0.8923	0.9198
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Monoethanolamine	0.0000	0.0687	0.0030	0.0000	0.0948	0.0702

	43	44	45
Temperature (^oC)	40.00	40.00	40.03
Pressure (bar)	1.21	1.36	1.36
Vapor Mole Fraction	0.00	0.00	0.00
Total (kg/h)	1,714,691	1,714,691	1,771,089
Total (kmol/h)	80,506.71	80,506.71	83,629.53
Mole Fraction			
Sulfur Dioxide	0.0000	0.0000	0.0000
Nitric Oxide	0.0000	0.0000	0.0000
Argon	0.0000	0.0000	0.0000
Oxygen	0.0000	0.0000	0.0000
Carbon Dioxide	0.0100	0.0100	0.0097
Water	0.9198	0.9198	0.9227
Nitrogen	0.0000	0.0000	0.0000
Monoethanolamine	0.0702	0.0702	0.0676

cooled in E-204. E-212 then cools the flue gas to approximately 35°C. The flue gas is then flashed in V-205 to remove the water that condensed during the cooling, prior to being compressed to 1.36 bar and sent to T-201.

In the absorber, approximately 26% of the carbon dioxide is removed by counter-currently contacting the flue gas with a 20% by weight aqueous solution of MEA. The water condensed from the flue gas (Stream 5) is fed back to the top of T-201 in order to further decrease the temperature inside the column, and allow for a higher removal of CO_2. The gas leaving the top of the column is cooled in E-201 in order to condense any evaporated MEA. The condensed MEA from V-201 is then recycled to the top of T-201.

The rich solution leaving T-201 is pumped to approximately 2.42 bar and sent through a series of heat exchangers in order to partially liberate the CO_2 from the solution. In E-202, the rich solution is contacted with the gas leaving the top of T-202 (Stream 19). The second heat exchanger, E-203, uses low-pressure steam from Unit 300. E-204 uses the hot flue gas from Unit 100 to heat the rich solution, and E-205 uses low-pressure steam from Unit 100 to heat Stream 17 to 118.5°C.

In T-202, both the rich MEA solution and the recycled water are fed to the top of the tower. The carbon dioxide is then stripped from the liquid solution, and the regenerated MEA solution is recycled to T-201 through Stream 20. The vapor stream leaving the top of T-202 is passed through E-202, and is then used in E-207 to heat the water that is recycled to the stripper.

After partially condensing in both E-202 and E-207, the vapor is passed through E-208 where it is cooled to 105°C. The vapor is then flashed to remove the condensed MEA and water. Approximately 80% of Stream 32 is mixed with Stream 38, the fresh MEA solution feed. The remaining 20% is sent to waste treatment to remove any impurities. Stream 39 is then mixed with the regenerated MEA solution, cooled to 40°C in E-211, and recycled back to T-201.

The remaining vapor (Stream 24) is further dehydrated by a two stage flash cycle. E-209 cools the CO_2 stream to 40°C, and E-210 cools the carbon dioxide stream to 15°C. Stream 30, which is 99.4 weight % CO_2 is then sent to Unit 300 for compression and storage.

Unit 300

In Unit 300, the CO_2 that was removed in Unit 200 is stored in a saline aquifer. Sequestering CO_2 in saline aquifers or wells requires two basic steps. The first step, depicted in Figure 6, is the compression, liquefaction, and transportation of the carbon dioxide to the disposal aquifer. Stream tables for Figure 6 are located in Table 4. In Figure 6, the CO_2 is passed through a series of compressors with inter-cooling. The inter-cooling stages utilize boiler feed water to produce low-pressure steam that is then sent to Unit 200 for heating purposes. The compressed CO_2 is liquefied in a series of heat exchangers using cooling water and refrigerated water. After liquefaction, the carbon dioxide is pumped 10 miles through a 6.625 inch diameter carbon steel pipe (6 inch pipe schedule 40 pipe) to the saline aquifer. At the disposal location, the liquid CO_2 is pumped and injected into the aquifer at a pressure of 84 bar. The permeability and the average injection pressure of the saline aquifer determine this pressure.

Simulation Hints

Rigorous simulations of the CO_2 absorber and stripper are complicated by the fact that there is a reaction taking place within the liquid phase. Simulation packages may have special equilibrium/enthalpy options for amine solutions and these should be used whenever possible. The tray efficiency for these towers is usually low (10-15%) and there is a considerable heat of dilution that must be modeled accurately. The reference by Kohl [3] has several examples for amine systems and simulating and understanding these examples is a very good starting point for the design of Unit 200. In addition, heat integration within the whole complex is also very important.

Table 4: Stream Tables for Unit 300							
	1	**2**	**3**	**4**	**5**	**6**	**7**
Temperature (^{o}C)	15.00	167.80	107.00	45.00	210.00	107.00	297.30
Pressure (bar)	1.00	5.00	4.85	4.70	23.50	23.35	116.75
Vapor Mole Fraction	1	1	1	1	1	1	1
Total Flow (kg/h)	103,937	103,937	103,937	103,937	103,937	103,937	103,937
Total Flow (kmol/h)	2,380.370	2,380.370	2,380.370	2,380.370	2,380.370	2,380.370	2,380.370
Component Flows (kmol/h)							
Carbon Dioxide	2,348.184	2,348.184	2,348.184	2,348.184	2,348.184	2,348.184	2,348.184
Water	31.364	31.364	31.364	31.364	31.364	31.364	31.364
Nitric Oxide	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Argon	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Sulfur Dioxide	0.149	0.149	0.149	0.149	0.149	0.149	0.149
Nitrogen	0.654	0.654	0.654	0.654	0.654	0.654	0.654
Oxygen	0.000	0.000	0.000	0.000	0.000	0.000	0.000

	8	9	10	11	12	13
Temperature (°C)	107.00	45.00	18.00	25.40	25.40	27.50
Pressure (bar)	116.60	116.45	116.30	175.80	75.00	84.00
Vapor Mole Fraction	0.997	0.989	0	0	0	0
Flow (kg/h)	103,937	103,937	103,937	103,937	103,937	103,937
Flow (kmol/h)	2,380.370	2,380.370	2,380.370	2,380.370	2,380.370	2,380.370
Component Flows (kmol/h)						
Carbon Dioxide	2,348.184	2,348.184	2,348.184	2,348.184	2,348.184	2,348.184
Water	31.364	31.364	31.364	31.364	31.364	31.364
Nitric Oxide	0.001	0.001	0.001	0.001	0.001	0.001
Argon	0.020	0.020	0.020	0.020	0.020	0.020
Sulfur Dioxide	0.149	0.149	0.149	0.149	0.149	0.149
Nitrogen	0.654	0.654	0.654	0.654	0.654	0.654
Oxygen	0.000	0.000	0.000	0.000	0.000	0.000

References

1. Keeling, C.D. and T.P. Whorf, Atmospheric CO_2 records from sites in the SIO air sampling network, Trends: A compendium of Data on Global Change, Carbon dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, TN (1999)
2. Preliminary Economic and Engineering Evaluation of the Foster Wheeler Advanced Pressurized Fluidized-Bed Combustor (PFBC) Technology with Advanced Turbine System (ATS) Gas Turbines, EPRI, Palo Alto, CA, TR-111912 (1998)
3. Kohl, Arthur L., *Gas Purification Fifth Edition*. Gulf Publishing Company, Houston Texas. Chapter 2 (1997)
4. Personal communication with Union Carbide Corp.
5. Personal communication with Dow Chemical Co.

Figures

Note: We apologize for the low quality of the following figures. However, all attempts at creating quality PDF format figures has failed.

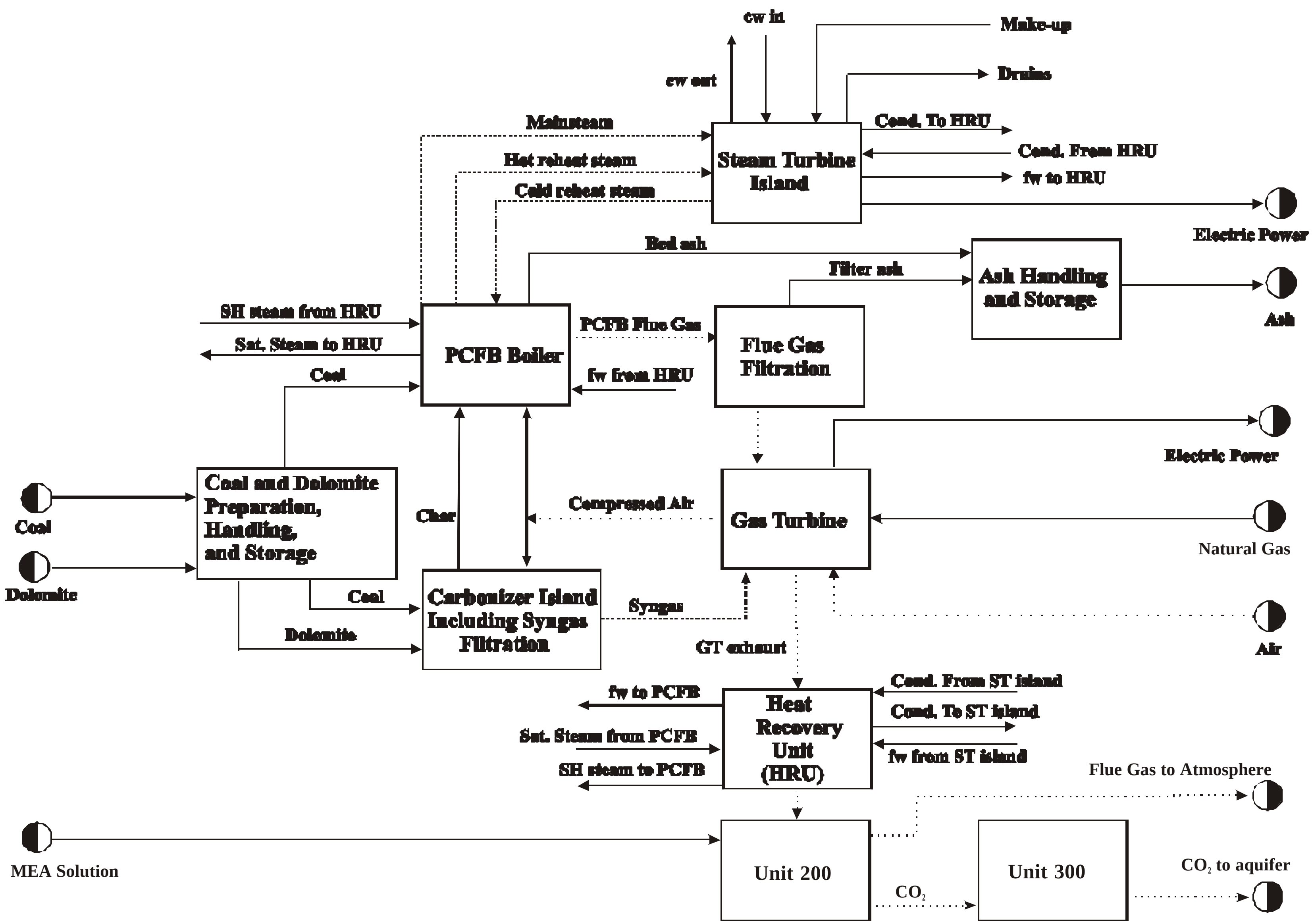

Figure 1: Overall BFD for the Process of Capturing & Removing CO_2 from a 2nd Generation Pressurized Fluidized Bed Power Plant

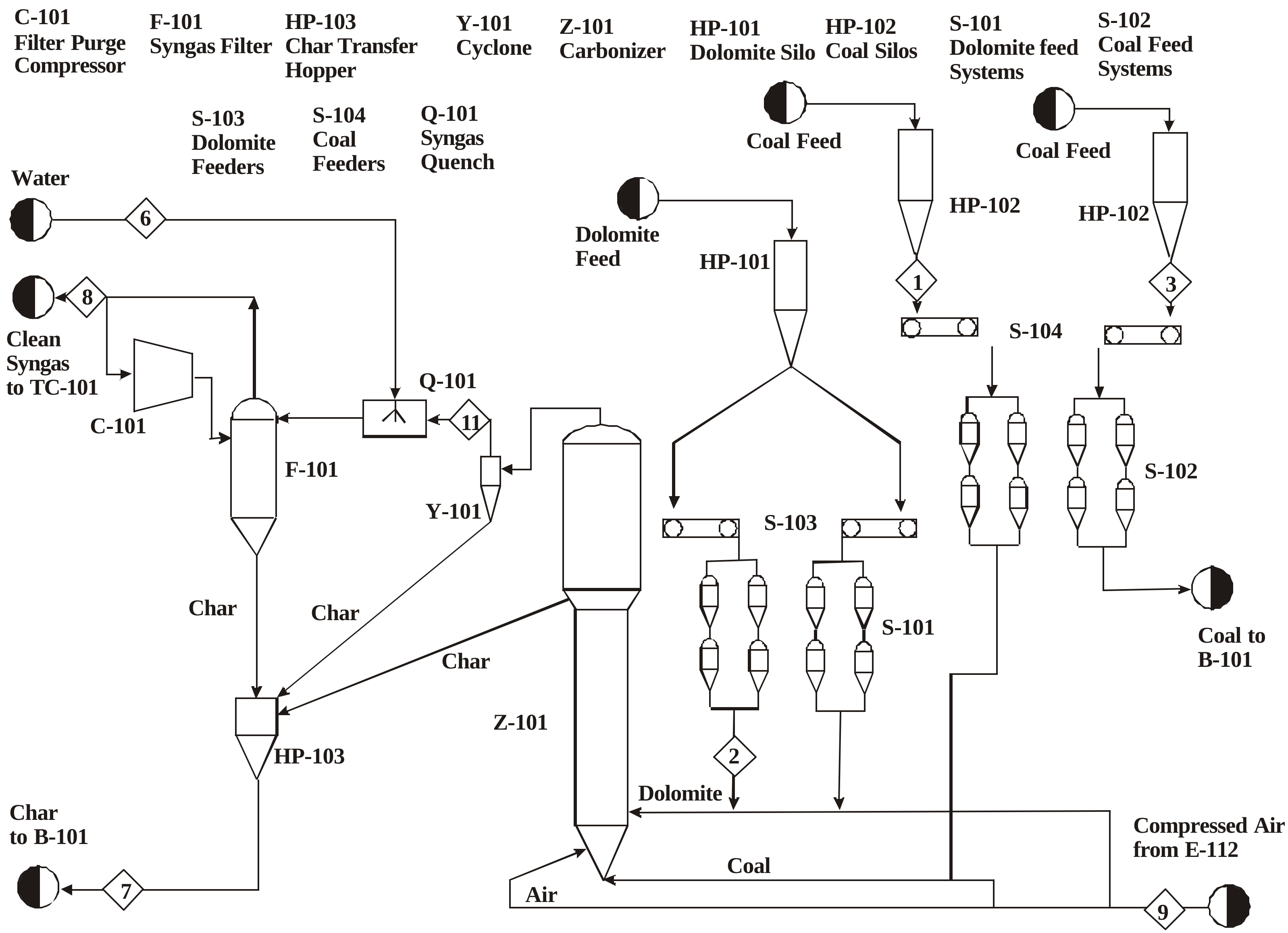

Figure 2: Carbonizer and Coal Dolomite Feed Systems for Unit 100

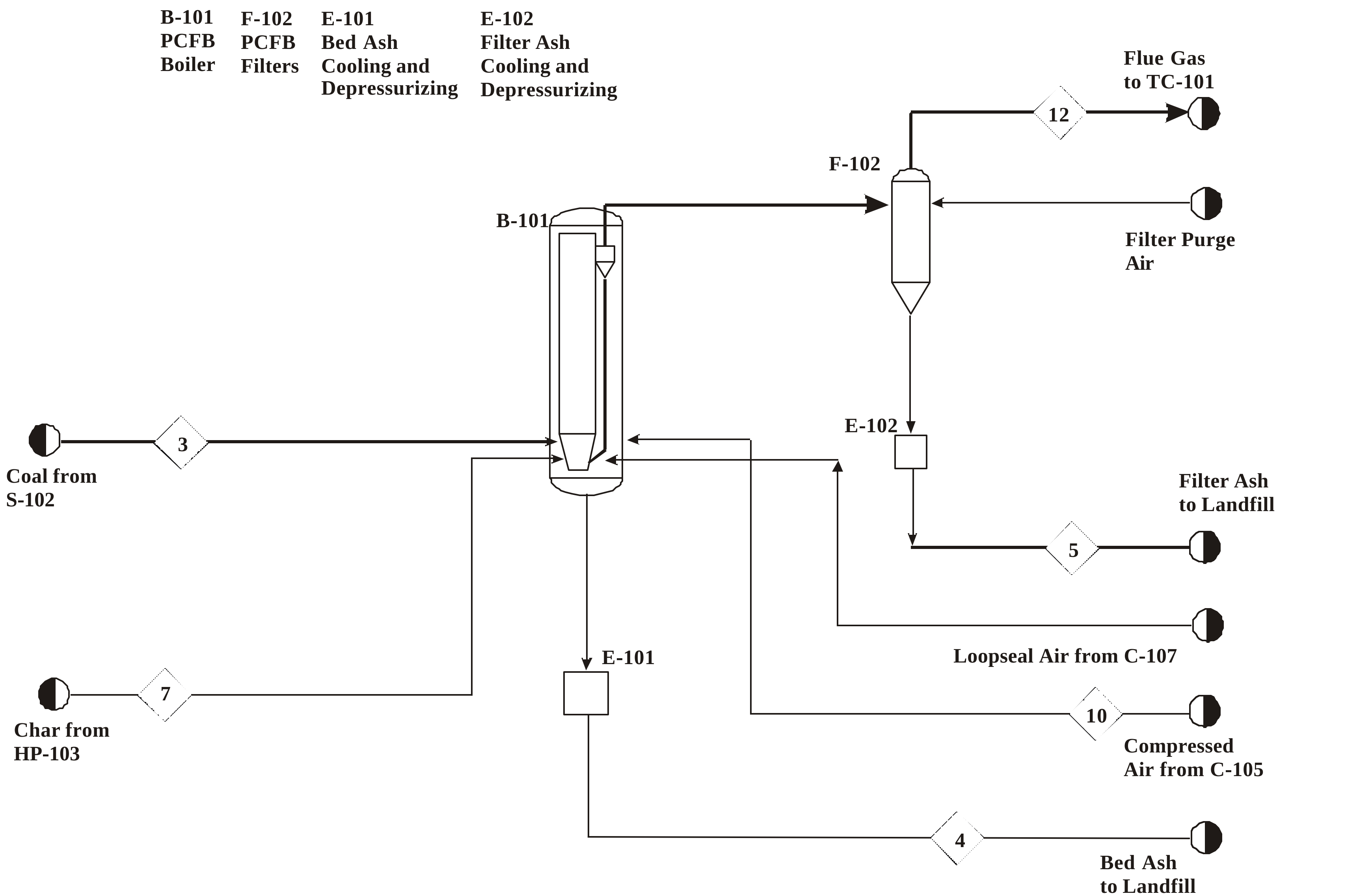

Figure 3: Circulating PFBC System for Unit 100

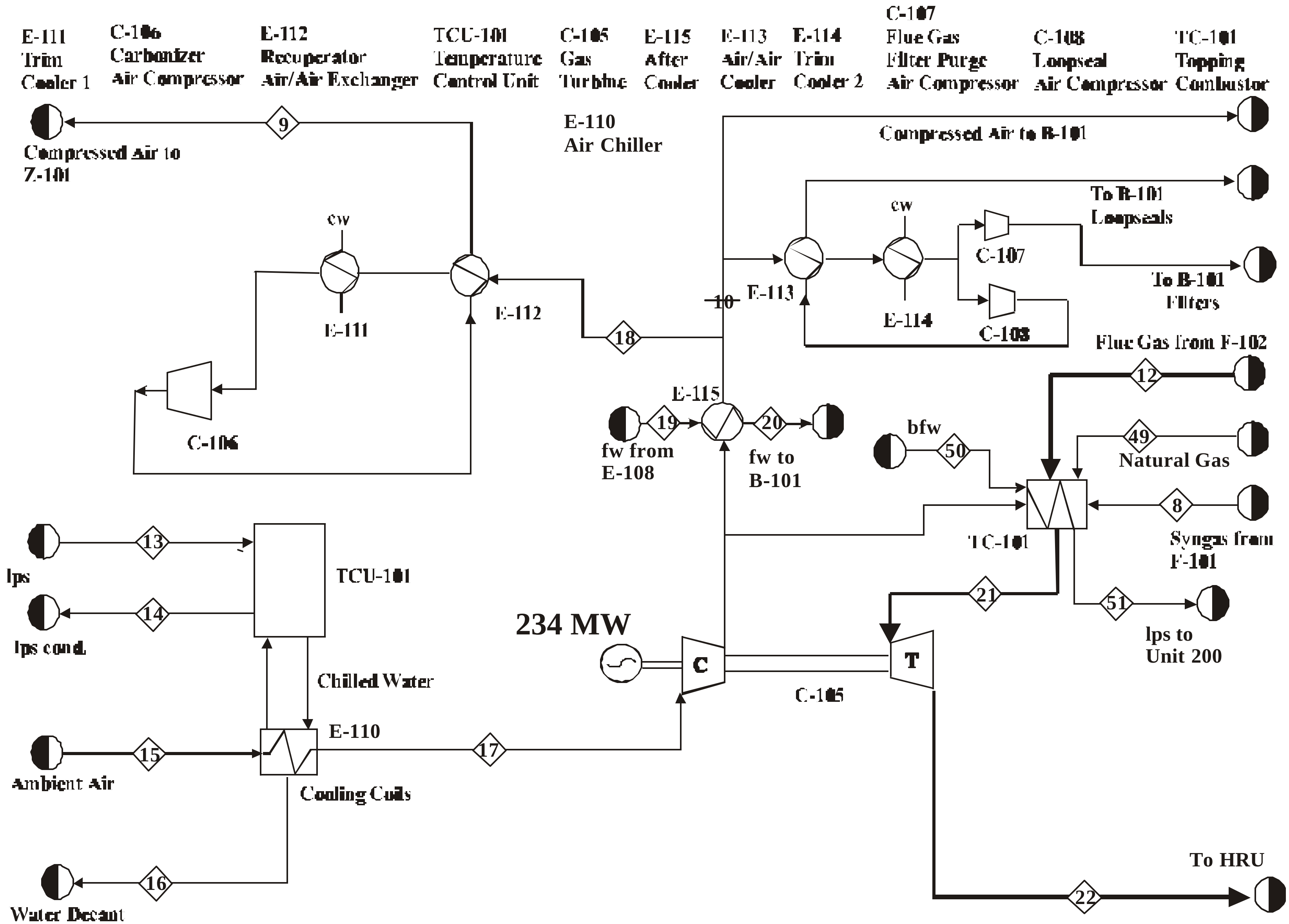

Figure 4: Gas Turbine, MASB, Compressor, and Air Delivery System for Unit 100

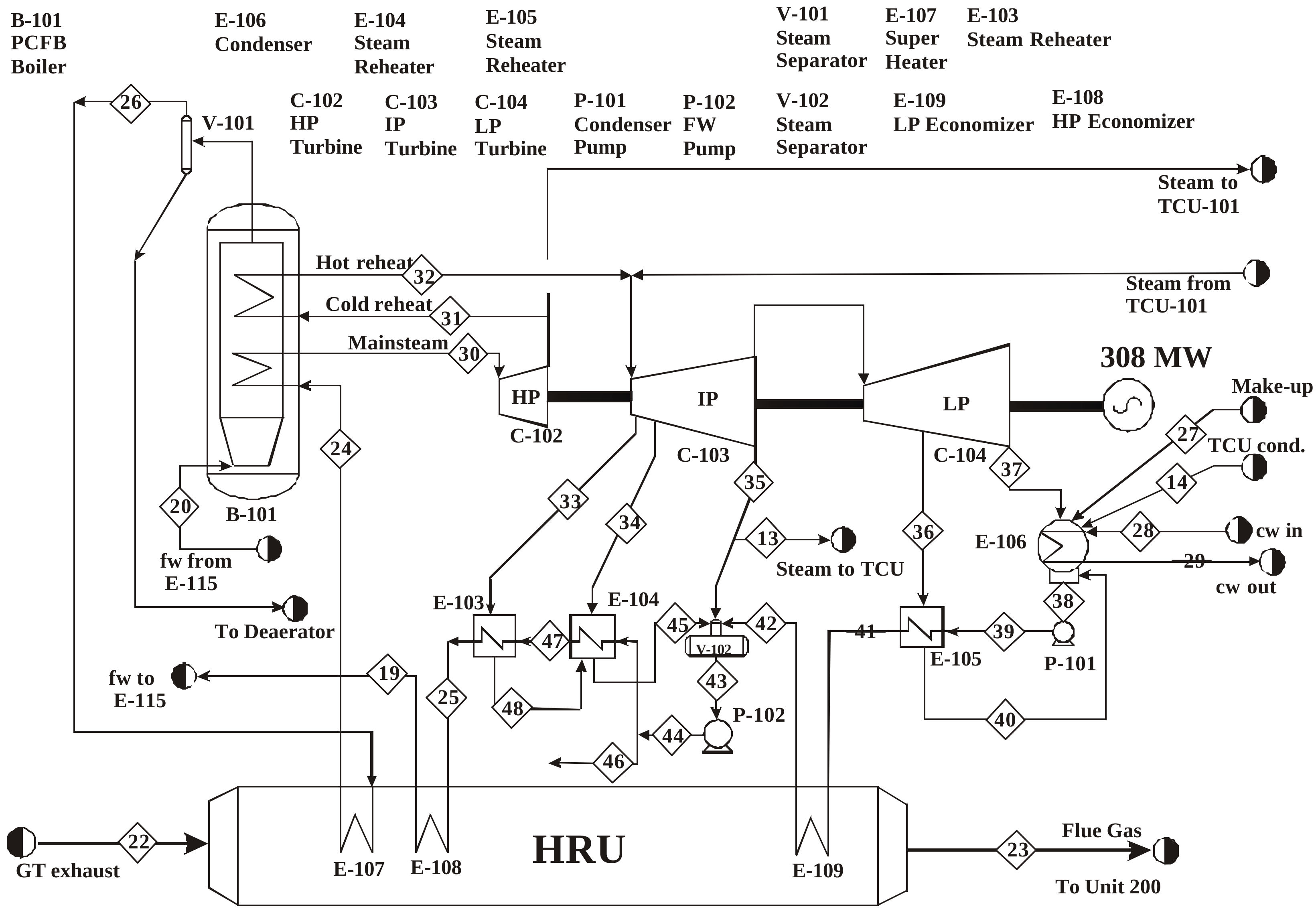

Figure 5: Steam Turbine Cycle for Unit 100

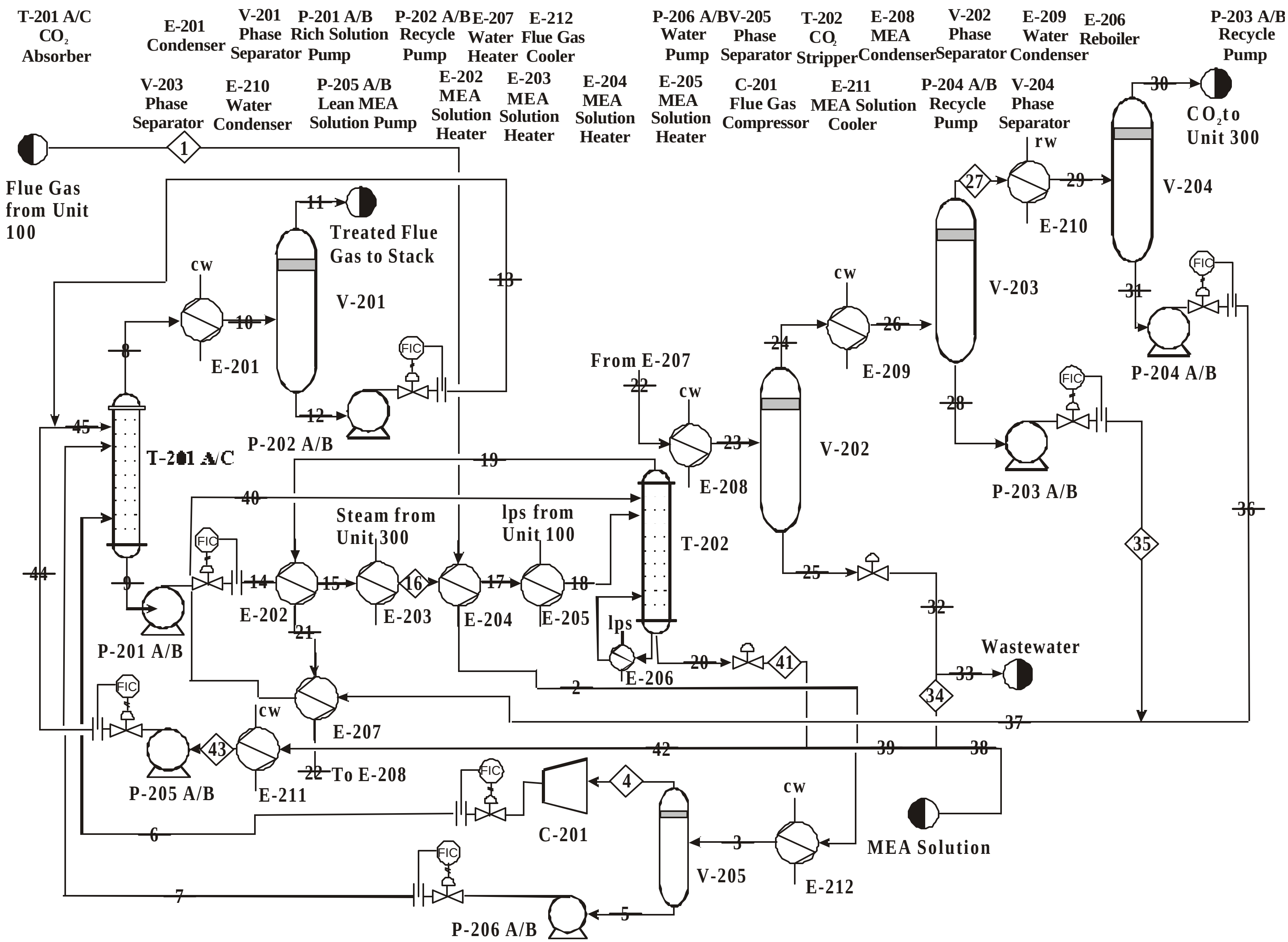

Figure 6: Unit 200: MEA CO_2 Removal Process With Heat Integration

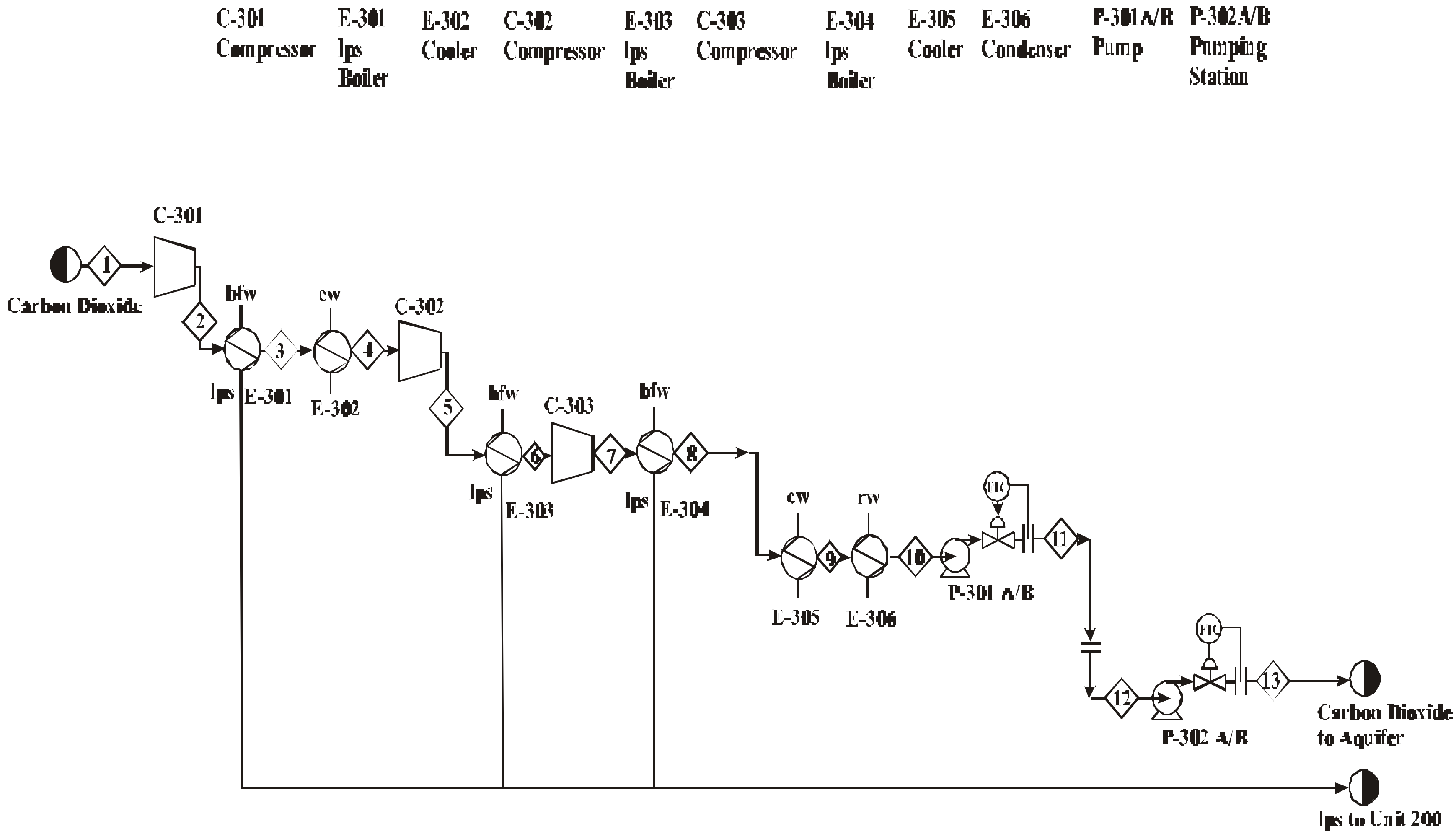

Figure 7: Unit 300: Carbon Dioxide Storage Design

(all lps in this unit is at 120°C and 2.0 bar)