

Midwest Geological Sequestration Consortium

Carbon Dioxide Capture and Transportation Options in the Illinois Basin

Topical Report

Assessment of Geological Carbon Sequestration Options in the Illinois Basin

Task 2: Assess Carbon Capture Options for Illinois Basin Carbon Dioxide Sources

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Task 3: Assess Carbon Dioxide Transportation Options in the Illinois Basin

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Foreword

This Topical Report represents a key Year 1 deliverable of An Assessment of Geological Carbon Sequestration Options in the Illinois Basin by the Midwest Geological Sequestration Consortium (MGSC). It includes the results of Task 2, Assess Carbon Capture Options for Illinois Basin CO₂ Sources, and Task 3, Assess CO₂ Transportation Options in the Illinois Basin. The work of the MGSC is focused on defining the most promising capture-transportation-storage options in the Illinois Basin with an exclusive focus on geological options for storage. The capture options assessment included development of a comprehensive catalog of fixed emission sources with emphasis on the fuel type and plant characteristics for major power plants. We found for example, that the majority of power plant emissions came from a surprisingly small number of plants. Retrofit carbon capture technologies were compared for Powder River Basin coal and Illinois Basin coal, and conventional pulverized coal plants were compared to integrated gasification combined cycle plants. Complete analyses of costs and benefits were undertaken.

Transportation of large volumes of CO₂ captured at fixed emissions sources will no doubt require pipeline transportation to any large-capacity geological storage location. Development of such infrastructure will be costly and will require careful planning optimized to the region under consideration. Task 3 results are focused on pipeline transportation attributes that would impact such infrastructure development in the Illinois Basin. Short-term transportation will also be needed to carry out tests for research purposes and to carry out operational proof-of-concept testing, such as the adaptation of enhanced oil recovery practices to Illinois Basin conditions through the development of commercial pilot tests of CO₂ reservoir flooding. The short-term transportation options will consist of some combination of truck and rail transport involving quantities from a few thousand tons to a few tens of thousands of tons.

A major effort in the second year of MGSC work will be completion of the assessment of coal beds, mature oil reservoirs, and deep, saline reservoirs for geological storage (Tasks 4, 5, and 6 of the project work plan). Once these tasks are completed, a subsequent task (Task 7) will integrate geological storage options with the capture-transportation assessments described herein. The result will be a preliminary sequestration scenario combining favorable technical and economic pathways applicable within the Illinois Basin as a basis for future assessment and planning.

Abstract

This report describes carbon dioxide (CO₂) capture options from large stationary emission sources in the Illinois Basin, primarily focusing on coal-fired utility power plants.

The CO₂ emissions data were collected for utility power plants and industrial facilities over most of Illinois, southwestern Indiana, and western Kentucky. Coal-fired power plants are by far the largest CO₂ emission sources in the Illinois Basin. The data revealed that sources within the Illinois Basin emit about 276 million tonnes of CO₂ annually from 122 utility power plants and industrial facilities. Industrial facilities include 48 emission sources and contribute about 10% of total emissions.

A process analysis study was conducted to review the suitability of various CO₂ capture technologies for large stationary sources. The advantages and disadvantages of each class of technology were investigated. Based on these analyses, a suitable CO₂ capture technology was assigned to each type of emission source in the Illinois Basin.

Techno-economic studies were then conducted to evaluate the energy and economic performances of three coal-based power generation plants with CO₂ capture facilities. The three plants considered were (1) pulverized coal (PC) + post combustion chemical absorption (monoethanolamine, or MEA), (2) integrated gasification combined cycle (IGCC) + pre-combustion physical absorption (Selexol), and (3) oxygen-enriched coal combustion plants. A conventional PC power plant without CO₂ capture was also investigated as a baseline plant for comparison. Gross capacities of 266, 533, and 1,054 MW were investigated at each power plant. The economic study considered the burning of both Illinois No. 6 coal and Powder River Basin (PRB) coal. The cost estimation included the cost for compressing the CO₂ stream to pipeline pressure.

A process simulation software, CHEMCAD, was employed to perform steady-state simulations of power generation systems and CO₂ capture processes. Financial models were developed to estimate the capital cost, operations and maintenance cost, cost of electricity, and CO₂ avoidance cost. Results showed that, depending on the plant size and the type of coal burned, CO₂ avoidance cost is between \$47/t to \$67/t for a PC +MEA plant, between \$22.03/t to \$32.05/t for an oxygen combustion plant, and between \$13.58/t to \$26.78/t for an IGCC + Selexol plant. A sensitivity analysis was conducted to evaluate the impact on the CO₂ avoidance cost of the heat of absorption of solvent in an MEA plant and energy consumption of the ASU in an oxy-coal combustion plant.

An economic analysis of CO₂ capture from an ethanol plant was also conducted. The cost of CO₂ capture from an ethanol plant with a production capacity of 100 million gallons/year was estimated to be about \$13.92/t.

Contents

Disclaimer	ii
Acknowledgments	ii
Foreword	iii
Abstract	iv
Part 1 Capture of Carbon Dioxide from Utility and Industrial Stationary Sources in the Illinois Basin	1
1. Introduction	1
2. CO₂ Emission Sources in the Illinois Basin	2
2.1. Power Generation Sector	3
2.2. Industrial Sector	5
2.2.1. Petroleum Refineries	5
2.2.2. Iron and Steel Manufacturing	6
2.2.3. Ammonia Manufacturing	6
2.2.4. Cement Industry	6
2.2.5. Lime Manufacturing	6
2.2.6. Ethanol Industry	7
2.3. Concentration of CO₂ in Different Flue Gases	7
3. CO₂ Removal Configurations	8
3.1. Post-Combustion Capture	8
3.2. Pre-combustion Separation	9
3.3. Oxygen/Recycled CO₂ Combustion (Oxyfuel Combustion)	9
3.4. Comparison of Different CO₂ Configurations	10
4. Technology Options for CO₂ Capture and Separation	11
4.1. Absorption Process	13
4.2. Adsorption Process	15
4.3. Membrane Processes	17
4.4. Cryogenics	18
4.5. Emerging Power Generation and CO₂ Capture Concepts	20
4.5.1. Zero Emissions Coal Technology	20
4.5.2. CO₂ Hydrate Separation Process for Synthesis Gas	21
4.5.3. Chemical Looping Process	22
5. Comparison of Different CO₂ Capture Technologies	23
6. Selection of CO₂ Capture Technologies for Different Emission Sources	25
7. Selected Scenarios for Illinois Basin	26
8. Techno-economic Analysis of CO₂ Capture in the Illinois Basin	27
8.1. Reference Plant	28

8.1.1. Overall Process Descriptions	28
8.1.2. Process Simulation	29
8.1.3. Performance Summary	31
8.1.4. Cost Analysis	31
8.2. Air-blown PC Plant with MEA Unit	32
8.2.1. Overall Process Descriptions	32
8.2.2. Process Simulation	33
8.2.3. Performance Summary	36
8.2.4. Cost Analysis	37
8.3. Oxy-combustion Process	39
8.3.1. Process Descriptions	39
8.3.2. Process Simulation	40
8.3.3. Performance Summary	42
8.3.4. Cost Analysis	43
8.4. IGCC + Physical absorption	45
8.4.1. Overall Process Descriptions	45
8.4.2. Process Simulation	47
8.4.3. Performance Summary	49
8.4.4. Cost Analysis	49
8.5. Cost Comparisons	50
8.5.1. General Comparisons	50
8.5.2. Economics of Illinois Coal and PRB Coal	54
8.6. Process Optimization and Improvement	55
8.7. CO ₂ Capture from Ethanol Plants	56
8.7.1. Overall Process Descriptions	57
8.7.2. Cost of CO ₂ Recovery from Ethanol Plants	57
9. Conclusions	58
10. References	60
Appendix A1. Reference Air-blown PC Power Plants with 533-MW (Gross) Output	64
Appendix A2. Air-blown PC Power Plants with 533-MW (Gross) Output Installed with the MEA Process	72
Appendix A.3. Oxy-combustion Power Plants with 533-MW (Gross) Output	83
Appendix A4. IGCC Plants with 533-MW (Gross) Output Installed with Selexol Process	93
Appendix B1. Methodology of Cost Analysis for the PC-Based Power Plant	103
1. Capital Cost	103
1.1. Basic PC Plant	103
1.2. Flue Gas Cleanup Units	104
1.2.1. FGD Unit	104

1.2.2. SCR Unit	107
1.3. MEA Unit	108
1.4. Oxy-Combustion Plant	108
1.4.1. ASU	108
1.4.2. Flue Gas Cooling	109
1.4.3. Water Vapor Condenser	109
1.4.4. Cryogenic Unit	109
2. O&M Cost	111
2.1. Fixed O&M Cost	111
2.2. Variable O&M Cost	112
3. Cost of Electricity	113
4. Costs of CO ₂ Avoidance and CO ₂ Capture	114
Appendix B2. Methodology of Cost Analysis for the IGCC Plant with Selexol Unit	115
1. Capital Cost	115
2. O&M Cost	116
3. Cost of Electricity	118
4. Costs of CO ₂ Avoidance and CO ₂ Capture	119
Part 2 Truck and Rail Transportation Options	120
1. Introduction	120
2. Transportation Options	120
3. Truck Transportation	120
4. Rail Transportation	121
5. Secondary Storage Requirements	123
6. Unloading and Injection Equipment	123
7. Regulatory Information	125
8. References	125
Part 3 Assessing CO ₂ Pipeline Transportation Options in the Illinois Basin	126
1. Introduction	126
1.1. Scope	126
1.2. Background	128
2. Route Selection and Design	128
2.1. Preliminary Route Selection	129
2.2. Detailed Route Selection	129
2.3. Detailed Route Design	130
2.4. Corridors	130
2.5. Geohazards	131

2.5.1. Landslides	131
2.5.2. Seismic Hazards	132
2.5.3. Coal Mining Subsidence	136
3. Design Elements	137
3.1. CO ₂ Properties	137
3.2. Flow Rate Design	139
3.3. Design	142
3.3.1. Codes – Federal, State, and Industry	142
3.3.2. Pressure Design Formula	142
3.3.3. Pipe Wall Thickness	144
3.3.4. Pipe Wall Thickness Transitions	144
3.3.5. Pipe Bending Design	144
3.3.6. Depth of Cover	144
3.3.7. Buoyancy Design	145
3.3.8. Horizontal Directional Drill	145
3.4. Materials and Equipment	145
3.4.1. Summary	145
3.4.2. Industry Code	145
3.4.3. Line Pipe	145
3.4.4. Method of Manufacture	146
3.4.5. Grade of Steel	146
3.4.6. Chemistry of Steel	146
3.4.7. Toughness/Ductility of Steel	147
3.4.8. Inspection and Mill Quality	147
3.4.9. Valves	147
3.4.10. Meters	147
3.4.11. Pumps	148
4. Permits	148
4.1. Business Permits	148
4.1.1. Illinois Commerce Commission	148
4.2. Environmental Permits	149
4.2.1. Plans for Pollution Prevention	150
4.3. State and County Highways and Railroad Crossing Permits	150
5. Right-of-Way	150
5.1. Pipeline Right-of-Way/Easement Definition	150
5.2. Negotiations	150
5.3. Eminent Domain	151
5.4. Right-of-Way Widths	152

6. Construction	153
6.1. General	153
6.2. CO₂ Welding and Refrigeration Issues	153
6.3. Agricultural Issues in Illinois	156
7. Operations	159
8. Cost Estimate	162
8.1. Introduction	162
8.2. Pipeline Right-of-Way Cost	162
8.2.1. Land Values	163
8.2.2. Crop Loss Payments	163
8.3. Pipeline Material Cost	164
8.4. Pipeline Construction Cost	165
8.5. Pipeline Services Cost	165
8.6. Pipeline Total Cost	166
8.7. Pump Station Cost	167
8.8. Operating Cost	168
9. References	169
Appendix C1. Contruction Photo Gallery	170
Table 1.1. Characteristics of power plants with and without CO₂ capture	1
Table 2.1. CO₂ Emissions in the United States and Illinois Basin	2
Table 2.2. CO₂ Emission Sources in the Illinois Basin	3
Table 2.3. CO₂ concentrations in flue gases of different sources	7
Table 3.1. Advantages and disadvantages of different configurations	10
Table 5.1. Comparisons of the potential separation technologies	24
Table 6.1. Capture technologies for power plants and industrial facilities	26
Table 7.1. Likely combinations of CO₂ separation and power generation technologies	27
Table 8.1. Typical composition of Illinois coal and PRB coal	28
Table 8.2. Main operating performance of the 533-MW (gross) plant	30
Table 8.3. Auxiliary power use for 533-MW (gross) power plants	31
Table 8.4. Overall process performance of air-blown PC plants	31
Table 8.5. Cost analysis of the air-blown PC reference plants	32
Table 8.6. Main operating performance of the 533-MW (gross) plants	35
Table 8.7. Auxiliary power use of the 533-MW (gross) power plants with MEA unit	36
Table 8.8. Overall process performance of air-blown PC plants with MEA	36
Table 8.9. Cost analysis of the PC plants with MEA unit	37
Table 8.10. Cost analysis of the MEA process	38
Table 8.11. Cost analysis of the PC plants with MEA retrofit	39

Table 8.12. Main operating performance for the 533-MW (gross) oxy-combustion plants	41
Table 8.13. Auxiliary power usage in the 533-MW (gross) oxy-combustion power plants	42
Table 8.14. Overall process performances of the oxy-combustion plants	43
Table 8.15. Cost analysis of the oxy-combustion power plants	43
Table 8.16. Cost analysis of specific components in oxy-combustion process	44
Table 8.17. Cost analysis of the oxy-combustion retrofit	45
Table 8.18. Main operating performance of the 536-MW (gross) IGCC plants	47
Table 8.19. Auxiliary power use in IGCC plants with Selexol process	48
Table 8.20. Overall performance of an IGCC plant with CO₂ removal	49
Table 8.21. Cost of electricity generation of IGCC power plants	50
Table 8.22. Flue gas composition from ethanol plants (at 120°F, 1 atm, H₂O saturated)	57
Table 8.23. Cost analysis of CO₂ recovery from ethanol plants	58
Table A1.1. Illinois coal	64
Table A1.2. PRB coal	65
Table A1.3. Illinois coal and PRB coal	66
Table A1.4. Illinois coal	69
Table A1.5. Flue cleaning (PRB coal)	70
Table A2.1. Illinois coal	72
Table A2.2. PRB coal	73
Table A2.3. Illinois coal	74
Table A2.4. Illinois coal	77
Table A2.5. Illinois coal and PRB coal	78
Table A2.6. Illinois coal	80
Table A2.7. PRB coal	80
Table A2.8. Illinois coal	81
Table A2.9. PRB coal	82
Table A3.1. Illinois coal	83
Table A3.2. PRB coal	84
Table A3.3. Illinois coal and PRB coal	86
Table A3.4. Illinois coal	88
Table A3.5. PRB coal	90
Table A3.6. Illinois coal	91
Table A3.7. PRB coal	92
Table A4.1. Illinois coal	93
Table A4.2. PRB coal	95
Table A4.3. Illinois coal	97
Table A4.4. PRB coal	100
Table B1.1. Classification of process areas in the sub-critical power plant	103

Table B1.2. Capital cost of oxygen generation	109
Table B1.3. Items of capital cost estimation	110
Table B1.4. Assumptions for estimating the total capital requirement (TCR)	111
Table B1.5. Estimation of the fixed O&M cost1	112
Table B1.6. Unit prices of consumables and coals	112
Table B1.7. Financial assumptions for the cost estimation	113
Table B2.1. Classification of process areas in the IGCC plant with the Selexol unit	115
Table B2.2. Estimation of TPC, TPI, and TCR	116
Table B2.3. Assumptions used for estimating the O&M cost of the IGCC plant	117
Table B2.4. Financial assumptions for the cost estimation	118
Table 1.1. Major CO₂ pipelines in operation in the United States	128
Table 3.1. CO₂ composition (example) showing a typical component supply limit	139
Table 3.2. Flow capacity as a function of pipe diameter and pressure drop	141
Table 3.3. Mileage by design factor to accommodate road and river crossings	143
Table 3.4. CO₂ pipeline, 2,800 psig, grade X65 pipe	144
Table 5.1. Pipeline right-of-way easement and work space in southern Illinois	152
Table 7.1. Pipeline incidents in the United States, 1986 to 2001	160
Table 8.1. Land value and crop information, Illinois, as of July 23, 2004	163
Table 8.2. Pipeline right-of-way cost	164
Table 8.3. Pipeline material cost	165
Table 8.4. Pipeline construction cost	165
Table 8.5. Support services cost	166
Table 8.6. Total cost	166
Table 8.7. Summary cost	167
Table 8.8. Annual pipeline operating costs	168
Figure 2.1. CO₂ emission profile of the power plants in Illinois Basin	4
Figure 2.2 Geographical distributions of power plants in Illinois Basin	4
Figure 2.3 Geographical distributions of industrial emission sources in the Illinois Basin	5
Figure 3.1. Different configurations for CO₂ separation processes	8
Figure 4.1. Diagram of a typical separation process (King, 1980)	11
Figure 4.2. Schematic diagram of the amine absorption process (Herzog, 1997)	13
Figure 4.3. Relationship between CO₂ capacity and its partial pressure (Gottlicher, 2004)	14
Figure 4.4. Schematic of a pressure swing adsorption process (Gottlicher, 2004)	16
Figure 4.5. Schematic of a temperature swing adsorption process (Riemer, 1993)	17
Figure 4.6. Schematic diagram of one-stage (left) and two-stage (right) membrane processes (Gottlicher, 2004)	17

Figure 4.7. Commercial membrane and required membrane properties (Van Der Sluijs et al., 1995)	18
Figure 4.8. Schematic diagram of a cryogenic process (Riemer, 1993)	19
Figure 4.9. Phase diagram of CO ₂ (Tc and Pc, critical temperature and pressure; Tt and Pt, triple point temperature and pressure.	19
Figure 4.10. Schematic diagram of zero emission coal technology	21
Figure 4.11. Simple block diagram of a CO ₂ hydrate process (Tam et al., 2001)	22
Figure 4.12. Two proposed processes for the chemical looping technology	23
Figure 5.1. Scale-up behavior of different technologies	25
Figure 8.1. Schematic diagram of the air-blown PC-fired power plant (Illinois coal)	29
Figure 8.2. Schematic diagram of the PC power plant with MEA unit	33
Figure 8.3. Schematic diagram of the oxy-combustion power plant	39
Figure 8.4. Schematic diagram of the Destec IGCC plant with Selexol unit	45
Figure 8.5. Schematic diagram of the Selexol unit for CO ₂ removal	46
Figure 8.6. Net generation efficiency for 533-MW (gross) power plants (OC, oxy-combustion)	51
Figure 8.7. Auxiliary power uses for 533-MW (gross) power plants	51
Figure 8.8. Capital costs for 533-MW (gross) power plants	52
Figure 8.9. Costs of electricity for 533-MW (gross) power plants	52
Figure 8.10. Costs of CO ₂ avoidance and capture for 533-MW (gross) power plants	53
Figure 8.11. Effect of plant size on electricity cost	53
Figure 8.12. Effect of plant size on CO ₂ avoidance cost	54
Figure 8.13. Costs of electricity for Illinois coal-fired and PRB coal-fired 533-MW plants	55
Figure 8.14. CO ₂ avoidance costs for Illinois coal-fired and PRB coal-fired 533-MW plants	55
Figure 8.15. The impact of process variables on CO ₂ avoidance cost	56
Figure 8.16. Flow chart for CO ₂ capture from ethanol plants	57
Figure A1.1. Boiler	64
Figure A1.2. Steam cycle (same for Illinois coal and PRB coal)	66
Figure A1.3. Flue gas cleaning (Illinois coal)	69
Figure A1.4. Flue cleaning (PRB coal)	70
Figure A2.1. Boiler	72
Figure A2.2. Steam cycle (same for Illinois coal and PRN coal)	74
Figure A2.3. Flue gas cleaning (Illinois coal)	77
Figure A2.4. Flue gas cleaning (PRB coal)	78
Figure A2.5. MEA process	79
Figure A2.6. CO ₂ compression	81
Figure A3.1. Boiler	83
Figure A3.2. Steam cycle (same for Illinois coal and PRN coal)	85
Figure A3.3. Flue gas cleaning (Illinois coal)	88

Figure A3.4. Flue gas cleaning (PRB coal)	89
Figure A3.5. CO ₂ purification and compression	90
Figure A4.1. Gasifier, shift reactor, gas cleanup, and gas turbine	93
Figure A4.2. Steam cycle	97
Figure 3.1. Typical CO ₂ truck trailer	121
Figure 4.1. Typical CO ₂ railcar	122
Figure 4.2. Unloading CO ₂ from railcar to truck	122
Figure 5.1. Secondary storage tanks	123
Figure 6.1. Rail towers for unloading CO ₂ from railcars	124
Figure 6.2. Typical CO ₂ compressor	124
Figure 6.3. Typical CO ₂ injection skid	125
Figure 1.1. Conceptual route	127
Figure 2.1. Buried pipeline subjected to landslide	131
Figure 2.2. Epicenters of New Madrid earthquakes and areas of soil disturbance in 1811–1812 (Hopper, 1985; Fuller, 1912)	132
Figure 3.1. Properties of CO ₂ over a range of pressures and temperatures	138
Figure 3.2. Pressure drop per mile for each diameter pipeline	141
Figure 3.3. Required brake horsepower size for the booster station	142
Figure 3.4. Anadarko CO ₂ meter-regulator station	148
Figure 6.1. Process for testing the weld procedures	154
Figure 6.2. CO ₂ venting during pipeline purging	155
Figure 6.3. Dry ice formed by depressuring too rapidly	155
Figure 6.4. Pig damage from depressuring too rapidly	156
Figure 6.5. Backhoe reaches over pipe to clam out ditch	157
Figure 6.6. Crane plugs pipe during backfall operations	157
Figure 6.7. Set-on weights in a low areas where sand subsoil layer is on top of a deep layer of clay subsoil	158
Figure 6.8. String crew working over existing drain tiles where temporary drain tiles (white segments) are in place	158
Figure 6.9. Road bore in a sandy area with high groundwater show ingrequired sheet pile and ground dewatering systems	159
Figure 7.1. CO ₂ venting from mainline block valve site	161
Figure C1.1. Pipe yard	170
Figure C1.2. Spread construction yard	171
Figure C1.3. Survey re-stake	172
Figure C1.4. Topsoil stockpiling progress	173
Figure C1.5. Completed grading. Note that the skids stringing, pipeline centerline stakes, and topsoil are stockpiled at the edge of the right-of-way	174
Figure C1.6. Stringing from the pipe yard	175

Figure C1.7. Setting pipe from the string truck on skids	176
Figure C1.8. Pipe bent to accommodate direction change	177
Figure C1.9. Pipe lifted into bending machine mandrel	178
Figure C1.10. Road boring operation	179
Figure C1.11. Horizontal directional drill site	180
Figure C1.12. Horizontal directional drilling pilot coming out	181
Figure C1.13. Horizontal directional drilling barrel reamer coming out	182
Figure C1.14. Horizontal directional drilling—ready to pull the prewelded pipe	183
Figure C1.15. Pulling operations under way	184
Figure C1.16. Pipe going in under levee canal	185
Figure C1.17. Wheel trencher	186
Figure C1.18. Pipe is ready for pipe gang—the pipe is strung on skids, the ditch is complete, and the ditch spoil is segregated from topsoil	187
Figure C1.19. End facing to ensure the highest weld quality	188
Figure C1.20. Lineup clamp shoes for pipe joint	189
Figure C1.21. Pipe joint being stabbed over internal lineup	190
Figure C1.22. Manual welding from both sides (12 o'clock to 6 o'clock)	191
Figure C1.23. Mechanized welding, large-diameter high-pressure pipeline	192
Figure C1.24. Coating using fusion bond epoxy	193
Figure C1.25. Jeeping for pipe coating defects	194
Figure C1.26. Pipe welded, coated, and ready to be lowered in	195
Figure C1.27. Lower-in tractors in various boom positions	196
Figure C1.28. Lower-in crew making a road crossing	197
Figure C1.29. Surveying weld location and cover	198
Figure C1.30. Lower-in backhoes (foreground) and dozer (background)	199
Figure C1.31. Cleanup (aerial view)	200
Figure C1.32. Prefabricated mainline valve being installed in rock ditch	201
Figure C1.33. Optimal welding conditions are essential	202
Figure C1.34. Tie-ins: Sag and overbend section set in place	203
Figure C1.35. Hydrotest pressures provide accurate measurement using dead weight and testers	204
Figure C1.36. Dewatering pigs	205
Figure C1.37. Bank of air compressors set up for dewatering of the test segment	206
Figure C1.38. Drying pig deflector being installed after test/dewater header has been removed	207

Part 1 Capture of Carbon Dioxide from Utility and Industrial Stationary Sources in the Illinois Basin

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1. Introduction

Research by the U.S. Department of Energy (U.S. DOE) and International Energy Agency has suggested that carbon sequestration can play an important role in reducing carbon dioxide (CO₂) in the atmosphere in the first part of the twenty-first century (Reichle et al., 1999; Gielen, 2003). Although carbon sequestration processes are for the most part technically feasible, their cost-effectiveness must be significantly improved before they become practical.

The CO₂ sequestration processes include CO₂ capture and separation, transportation, and storage. The capture and separation of CO₂ from its emission sources is the first, most expensive step, accounting for more than 60% of the total cost (Herzog et al., 1997; Beecy, 2002). Therefore, reducing the cost of the capture step significantly improves the economics of the whole sequestration process. Table 1.1 lists some of the characteristics of power plants with and without CO₂ capture (Gielen, 2003). With CO₂ capture, the energy efficiency penalty is between 6% for a future (2020) coal-based integrated gasification combined cycle (IGCC) and 12% for a near-term (2010) pulverized coal (PC) boiler. The capital investment and cost of electricity also increases significantly. The energy efficiency penalty is even higher for current PC power plants. For example, one analysis (Dave et al., 2000) shows that the energy efficiency penalty could be as high as 15% (reduced from 37% to 22%).

Table 1.1. Characteristics of power plants with and without CO₂ capture

Technologies	Start year	Capital investment (\$/kW)		Efficiency (%)			CO ₂ capture efficiency (%)	Electricity costs (mils/ kWh)		Capture costs (\$/t CO ₂)
		Without CO ₂ capture	With CO ₂ capture	Without CO ₂ capture	With CO ₂ capture	Loss (%)		Without CO ₂ capture	With CO ₂ capture	
Coal steam cycle (CA) ¹	2010	1,075	1,850	43	31	-12	85	29.1	51.0	24
Coal steam cycle (Membrane + CA)	2020	1,025	1,720	44	36	-8	85	29.2	46.3	21
Coal IGCC (Selexol)	2010	1,455	2,100	46	38	-8	85	37.4	52.3	20
Coal IGCC (Selexsol)	2020	1,260	1,635	46	40	-6	85	33.0	41.0	11
Natural Gas CC (CA)	2005	400	800	56	47	-9	85	26.1	36.8	29
Natural Gas CC (Selexol)	2015	400	800	59	51	-8	85	25.2	34.8	25

¹CA, chemical absorption; CC, combined cycle; IGCC, integrated gasification combined cycle. Comparison based on 10% discount rate, 30-year plant lifespan. Coal price, 1.5 US\$/GJ; gas price, 3 US\$/GJ. CO₂ product is in a supercritical state at 100 bars. CO₂ transportation and storage are not included. CO₂ capture costs are expressed relative to the same power plant without capture.

The cost data in Table 1.1 are the CO₂ capture costs. CO₂ avoidance cost is commonly used to compare various capture technologies. The CO₂ avoidance cost is the ratio of the increase in electricity generating costs to the specific CO₂ emissions (relating to the electrical energy output). The installation of CO₂ capture equipment incurs both the capital cost and an energy efficiency penalty. Due to the low energy efficiency of current power generation technologies, the same degree of energy efficiency penalty translates to a much higher CO₂ avoidance cost. Obviously, it is important to identify cost-effective CO₂ capture and separation technology for specific power production processes.

2. CO₂ Emission Sources in the Illinois Basin

Table 2.1 lists data for CO₂ emissions from the stationary sources for the United States and the Illinois Basin. In the United States, roughly about one third of the CO₂ emissions is from electric power generation, one third from transportation, and one third from other sources including manufacturing industry, commercial, and residential (Energy Information Administration, 2002). The emissions from the manufacturing industry sector, which includes oil refineries, the steel industry, the cement industry, and other industries, represent about 20%.

Table 2.1. CO₂ Emissions in the United States and Illinois Basin

Sources	U.S. total tonnes	Illinois Basin tonnes	Basin to U.S. (%)	Industry (% of Basin)
Power generation	2,239,700,000 ¹	254,260,000 ²	11.4	92.1
Coal	1,868,400,000 ¹	249,216,000 ²	13.3	90.3
Natural gas	299,100,000 ¹	4,996,000 ²	1.7	1.8
Oil	72,200,000 ¹	48,000 ²	0.1	0.02
Industries				
Refinery	184,918,000 ³	9,703,000 ⁴	5.2	3.5
Iron and steel	54,411,000 ⁵	3,857,000 ⁶	7.1	1.4
Cement	42,898,000 ⁵	3,245,000 ⁶	7.6	1.2
Ammonia	17,652,000 ⁵	214,000 ⁶	1.2	0.1
Aluminum	4,223,000 ⁵	820,000 ⁶	19.4	0.3
Lime	12,304,000 ⁵	273,000 ⁶	2.2	0.1
Ethanol	8,383,000 ⁵	3,734,000 ⁷	44.5	1.4
Total	2,564,489,000	276,106,000		100

¹ U.S. Environmental Protection Agency (U.S. EPA) greenhouse gas inventory sector analysis.

² U.S. EPA acid rain and EGRID data (classified by primary fuel type).

³ Estimate from U.S. DOE, 2002 BPD totals.

⁴ Projected estimates from representative facilities.

⁵ U.S. EPA greenhouse gas inventory industrial process analysis.

⁶ Source data from U.S. Geological Survey, *Minerals Yearbook 2002*.

⁷ Source data from Iowa Department of Agriculture and Land Stewardship: www.distillergains.com.

Electric power generation plants emit about 2.24 Gt of CO₂ annually in the United States. The Illinois Basin contributes about 11.4% of the total U.S. CO₂ emissions from electric power generation plants. Coal is the dominant fossil fuel for electric power plants and contributes 83% of the total U.S. emissions and 98% of the Illinois Basin CO₂ emissions, respectively. CO₂ emissions from manufacturing industries in the Illinois Basin vary from industry to industry. For example, there is only one ammonia manufacturing plant, and its CO₂ emissions account for only 1.2% of the U.S. total in the industry. Ethanol production facilities in the Basin, however, contribute about 44.5% of total U.S. CO₂ emissions from that industry.

Table 2.2. CO₂ Emission Sources in the Illinois Basin

Sources	Illinois		Indiana		Kentucky		Total no. in basin
	CO ₂ (total tonnes)	(no.)	CO ₂ (total tonnes)	(no.)	CO ₂ (total tonnes)	(no.)	
Power generation							
Coal	89,555,000		87,983,000		71,677,000		
Natural gas	4,476,000	75	321,000	26	200,000	21	122
Oil	48,000		0		0		
Industries							
Refinery	9,455,000	4	248,000	1	0	0	5
Iron and steel	3,685,000	17	142,000	5	30,000	1	23
Cement	1,301,000	4	1,353,000	3	591,000	1	8
Ammonia	214,000	1	0	0	0	0	1
Aluminum	0	0	464,000	1	356,000	1	2
Lime	273,000	1	0	0	0	0	1
Ethanol	3,665,000	6	0	0	69,000	2	8
Total	112,672,000	108	90,511,000	36	72,923,000	26	170

2.1. Power Generation Sector

Table 2.2 lists the total CO₂ emissions and the number of emission sources in Illinois, Indiana, and Kentucky that are in the geological boundary of the Basin. Coal-fired electric power plants are by far the largest point sources of emissions. About 254 million tonnes of CO₂ are emitted annually in the Illinois Basin from more than 122 coal-fired power plants. Figure 2.1 illustrates the relationship between CO₂ emissions and the number of power plants in the Illinois Basin. The figure is plotted according to the volume of CO₂ emissions from individual plants. The four largest power plants emit about 22% of the total CO₂ emissions, the 13 largest power plants emit more than 50% of total CO₂ emissions, and the 30 largest power plants emit over 80% of total CO₂ emissions. The largest coal-fired power plant in the Basin is the Rockport power plant in Spencer County, Indiana, which emits about 16 million tonnes of CO₂ annually. Considering the economy of scale, the larger power plants are the most suitable sources for any CO₂ capture and sequestration retrofits to existing power plants in the Basin. The geographical distribution of these power plants is shown in Figure 2.2.

Most of the power plants in the Illinois Basin are equipped with pulverized coal boilers and use a simple steam cycle. The flue gas from these power plants contains about 14% CO₂. Other contaminants in the flue gas, such as nitrogen (NO_x) and sulfur (SO_x), may have to be removed before the gas enters a CO₂ capturing system. Most of the power plants that burn high-sulfur bituminous coals are equipped with wet flue gas desulfurization (FGD) processes. These plants may have an advantage over the power plants without the FGD process (mostly burning western Powder River Basin (PRB) coal).

The power plants that burn natural gas tend to be small and are mostly peak power plants. Total CO₂ emissions from these power plants are about 5 million tons annually, which is about 2% of total emissions in the Illinois Basin.

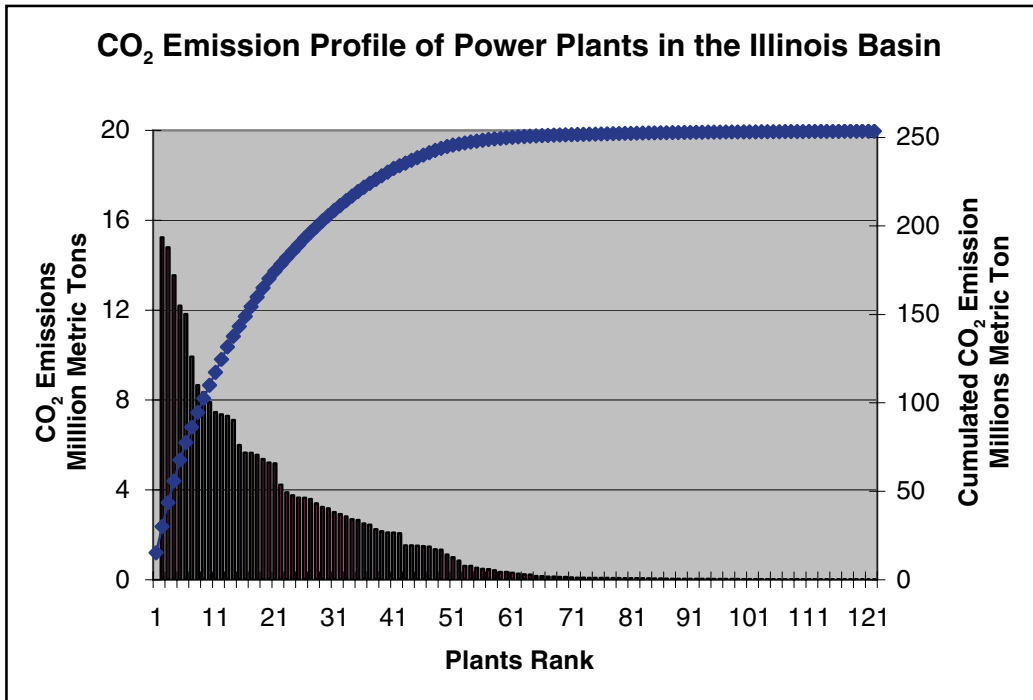


Figure 2.1. CO₂ emission profile of the power plants in Illinois Basin

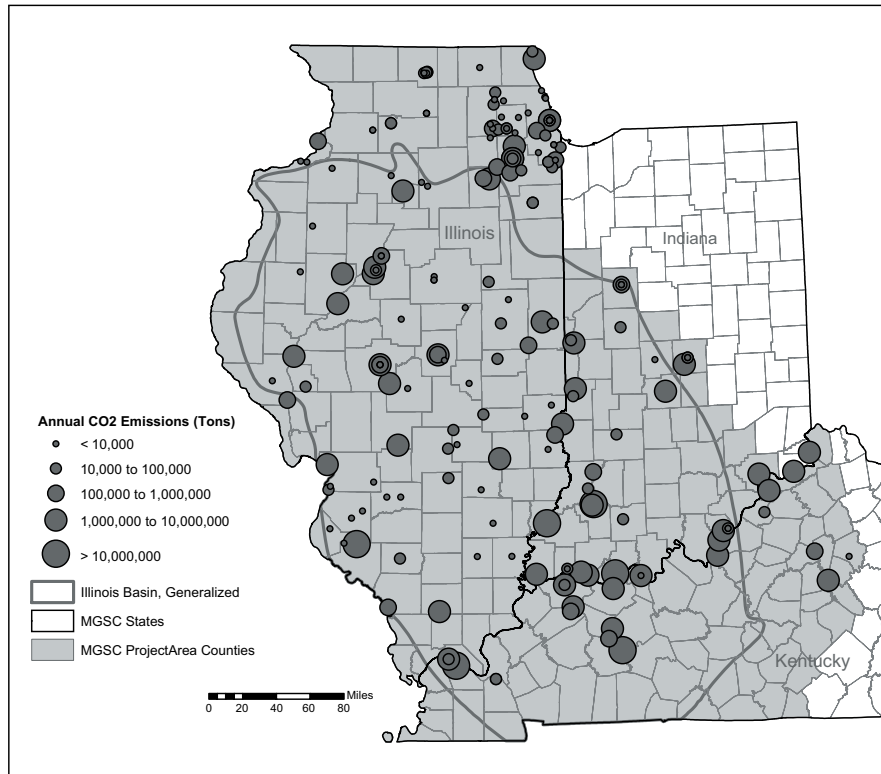


Figure 2.2 Geographical distributions of power plants in Illinois Basin

2.2. Industrial Sector

Combustion of fossil fuels is the main source of energy in energy-intensive industries such as petroleum refining, iron and steel manufacturing, and cement and lime production. The opportunity for carbon capture from these processes varies from industry to industry and even from plant to plant. The geographic distribution of these industrial sources in Illinois Basin is shown in Figure 2.3. A brief review of these industries is provided.

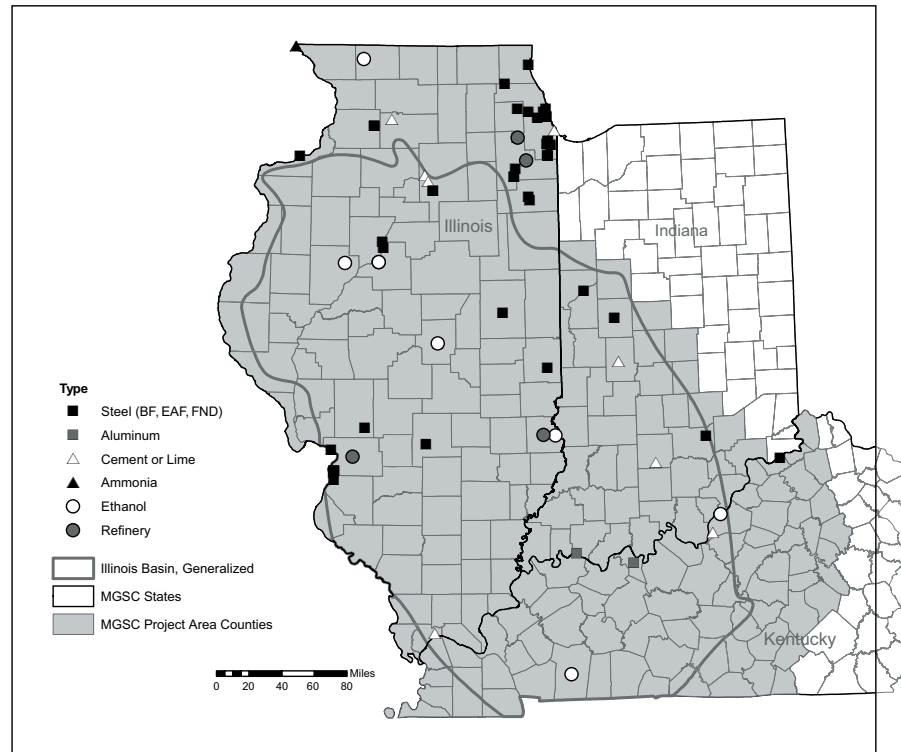


Figure 2.3 Geographical distributions of industrial emission sources in the Illinois Basin

2.2.1. Petroleum Refineries

Of the five petroleum refineries in the Illinois Basin, four are in Illinois, and one is in Indiana. Petroleum refining is an energy-intensive process, consuming about 5% of the total energy contained in crude oil (Phillips, 2002; Clarke, 2002). The refineries in the Illinois Basin emit about 9.7 million tons of CO₂ annually, the majority of which is from the combustion of the refinery off-gas and heavy components of petroleum oil, which provide process heat, and from the regeneration of the catalyst used in the fluid catalytic cracking process. About one quarter of CO₂ emissions from a refinery is attributed to fluid catalytic cracking regeneration (Clarke, 2002). The CO₂ concentrations in these flue gases are comparable to those of flue gases generated from burning coal in a PC-fired boiler. Another source, which is especially attractive for CO₂ sequestration, is refinery hydrogen plants. Some hydrogen plants produce a relatively pure (>95%) CO₂ stream and may provide the least expensive CO₂ source for sequestration, even though the quantity is relatively small.

A refinery is a complex of many processes, and flue gas (CO₂ emissions) stacks connected to various process heaters and boilers are scattered within the entire area of the plant. It might not be economical or practical to bring all of these scattered CO₂ emission sources to a centralized treatment site.

2.2.2. Iron and Steel Manufacturing

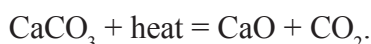
There are 23 iron and steel plants in the Illinois Basin (17 are located in Illinois), and they emit about 3.86 million tons of CO₂ annually. Two major sources of CO₂ emissions from iron and steel production facilities are the blast furnace and the coke oven. About 70% of the total CO₂ emissions from an iron and steel production facility is from blast furnaces. Typically, blast furnace gas consists of a mixture of CO₂, CO, N₂ and H₂. The concentration of both CO₂ and CO in the process gas is about 20 vol%, and the pressure of blast furnace gas is about 1 to 3 bars. The furnace flue gas is usually burned to recover heat. The concentration of the CO₂ in the flue gas is about 27% (about double of that in the flue gas from a PC-fired power plant). The blast furnace gas contains about 20 vol% CO and may be shifted to CO₂ through a water-gas-shift reaction to increase the CO₂ concentration to about 40 vol% (Farla et al., 1995; Gielen, 2003).

2.2.3. Ammonia Manufacturing

There is only one ammonia manufacturing plant in the Illinois Basin. It emits about 214,000 tonnes of CO₂ annually. In the ammonia synthesis process, pure hydrogen is produced. Hydrogen is generated through natural gas reforming or coal gasification followed by a water-gas-shift reaction. CO₂ can be separated from the shift gas through an absorption process producing a gas stream with >95 vol% CO₂. Sometimes, the shifted gas is subject to a pressure swing adsorption (PSA) process to produce high-purity hydrogen gas. After the PSA process, the off-gas stream still contains significant amounts of CO and H₂. This off-gas usually is mixed with other fuel gases and combusted. If the gas mixture is burned in air, the CO₂ in the flue gas is diluted with nitrogen.

2.2.4. Cement Industry

There are 8 cement plants in the Illinois Basin. They emit about 3.2 million tonnes of CO₂ annually. Cement production is an energy-intensive process (Van Oss and Padovani, 2002). There are two main sources of CO₂ emissions in a cement production facility. The first source is the decomposition (calcination) of the limestone that occurs in a kiln:



CaO is one of the major (about 62%) components of cement. The second source of CO₂ is from the combustion of fossil fuel (coal, natural gas, or other fuels) to heat the kiln. The CO₂ emissions from calcination and from process heat are about 0.51 ton of CO₂ per ton of cement and about 0.43 ton of CO₂ per ton of cement, respectively. The two CO₂ streams are generally mixed together, which results in a gas stream that has a CO₂ concentration ranging from 13 to 33 vol%.

2.2.5. Lime Manufacturing

The one lime manufacturing plant in the Illinois Basin emits about 273,000 tonnes of CO₂ annually. As with cement, lime is produced from limestone through a calcination process:



The process heat is generated by direct firing of coal or natural gas in the kiln. The CO₂ formed during combustion is mixed with the CO₂ released from the decomposition of limestone. The CO₂ released from limestone is relatively pure and thus increases the CO₂ concentration in the flue gas. The CO₂ concentration in a lime plant ranges from 13 to 33% depending on the type of kiln and the fuel used.

2.2.6. Ethanol Industry

About 44.5% (3.7 million tons) of the total U.S. ethanol is produced in the Illinois Basin. There are 8 ethanol plants (6 in Illinois) with total CO₂ emissions of more than 50,000 tons annually. Because some of the CO₂ is recovered for various uses, the actual volume of emissions that is potentially available is less than reported by this industry.

Ethanol is mostly produced from corn through a fermentation process, and CO₂ is a by-product in this process. Each unit (mass) of ethanol produced generates an almost equal amount of CO₂. The CO₂ stream has a very high purity (>85%). Many ethanol plants recover and market the CO₂. The plants without CO₂ recovery are excellent sources for pilot CO₂ sequestration demonstration studies because the CO₂ is relatively easy to capture and inexpensive to dry (if needed to increase the CO₂ concentrations to >95 vol%). The cost of compression may be the greatest incremental cost to make these volumes of CO₂ available for research.

2.3. Concentration of CO₂ in Different Flue Gases

The CO₂ concentration in the flue gases is an important parameter in selecting cost-effective CO₂ separation and capture technologies. A higher CO₂ concentration usually translates into lower energy consumption and capture costs. Table 2.3 lists the typical CO₂ concentrations in different flue gas streams (Thambinuthu et al., 2002).

Table 2.3. CO₂ concentrations in flue gases of different sources

Types of flue gases	Pressure (atm)	CO ₂ concentration ¹ (vol%)
Power station flue gas		
PC combustion	~1	14
Natural gas combustion (simple steam cycle)	~1	8
NGCC	~1	4
Coal O ₂ /CO ₂ combustion	~1	>80
Power station, pre-combustion capture of CO ₂		
Coal gasification fuel gas	~30	40
Natural gas partial oxidation fuel gas	~30	24
Iron and steel blast furnace gas		
Before combustion	~2	20
After combustion in air	~1	27
Cement kiln off-gas	~1	13–33
Lime manufacturing	~1	13–33
Oil refinery		
Process heaters	~1	8–15
FCC regenerator	~1	15
Ethanol plants	~1	>85

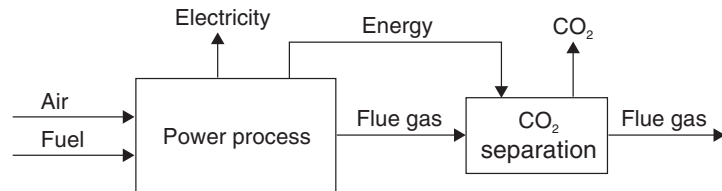
¹The concentration of CO₂ varies from 4 vol% in the post-combustion flue gas of a natural gas combined cycle (NGCC) power plant to 95 vol% in the gas stream from a an ethanol production plant (after dehydration). The pressure of the most combustion flue gases is atmospheric pressure. Pre-combustion gas streams in an integrated gasification combined cycle (IGCC) and NGCC plants are at pressures higher than 25 atmospheres (atm). Under these conditions, the partial pressure of CO₂ is as high as 10 atm. FCC, fluid catalytic cracking.

3. CO₂ Removal Configurations

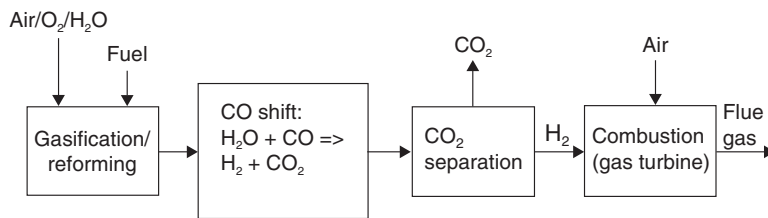
CO₂ separation and capture from flue gases of various stationary sources can be described by either post-combustion or pre-combustion configurations (Lyngfelt and Leckner, 1999; CO₂ Capture Project workshop, 2004). Figure 3.1 is a schematic of these configurations. Oxygen-enriched coal combustion can also be considered as a special case of the pre-combustion concept and is discussed later in this section. For the power generation sector, the selection of a capture concept mainly depends on the power generation process used. For most industrial emission sources, post-combustion capture is potentially the most suitable option.

3.1. Post-Combustion Capture

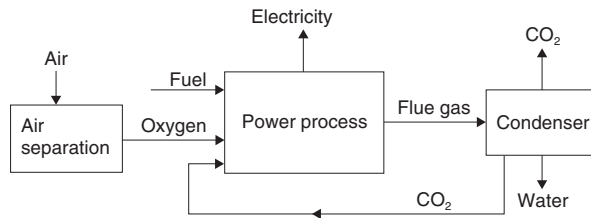
In the post-combustion configuration, CO₂ is captured from the flue gas after the fuel is combusted. When air is used as an oxidant, the combustion flue gas is diluted with the nitrogen in air. Thus, the CO₂ concentration in post-combustion flue gas is usually low and ranges from 4 vol% for a NGCC process to 14 vol% for a PC-fired power plant. The operating pressure of PC boilers is usually near atmospheric pressure. Due to the low CO₂ concentration of the flue gas and the low operating pressure, post-combustion capture tends to require large equipment sizes and, hence, higher capital costs. In addition, the low CO₂ partial pressure (concentration) in flue gas requires a stronger separation agent (solvent or adsorbent) to capture the CO₂, which, in turn, results in higher energy consumption. For most of the existing conventional coal-fired power plants and most industrial combustion processes, the post-combustion configuration is probably the only choice because it requires the minimum retrofit of the existing power plant.



a. Post-combustion capture



b. Pre-combustion capture



c. Oxygen combustion

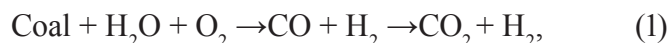
Figure 3.1. Different configurations for CO₂ separation processes

Figure 3.1a is a simplified diagram of a power plant with post-combustion capture of CO₂. The configuration may also be used for IGCC and NGCC plants. However, because gasification processes are usually performed at high pressure (30 bars) and possess higher CO₂ partial pressure, a pre-combustion capture configuration operating at a high pressure is more attractive.

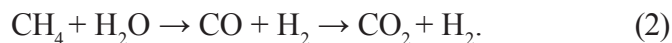
3.2. Pre-combustion Separation

If the CO₂ concentration and flue gas pressure could be increased, the size of CO₂ capture equipment would be significantly smaller, and weaker solvents, such as physical solvents, could be used. This would result in lowering the overall energy consumption of the separation process. Such a rationale is behind the pre-combustion configuration (Figure 3.1b) in which the original carbon-containing fuel is transformed to a non-carbon-containing fuel (usually hydrogen). Carbon in the fuel is converted to CO₂ prior to combustion and separated. Hydrogen is then used to produce power in a gas turbine or a fuel cell process.

Typical fuel reactions under a pre-combustion capture concept are fuel gasification to produce a synthesis gas (known as syngas), followed by water-gas-shift reaction,



or steam reforming of natural gas followed by a water-gas-shift reaction,



CO₂ in the final product gas is separated from H₂ by different separation processes such as absorption processes, membrane processes, or adsorption processes. Pre-combustion separation processes operate at high pressure, which leads to higher CO₂ concentrations and smaller equipment size than are required in post-combustion CO₂ separation processes operating at near-atmospheric pressures.

The overall gasification process is, in principle, the same for coal, oil, or natural gas. But, when coal or oil is used as a fuel, the synthesis gas (syngas) has to be purified. A gas purification process is required to remove ash particles, sulfur compounds, and other minor impurities.

The pre-combustion separation process just described, without CO₂ capture, is already used in several commercial-scale IGCC plants fueled by coal, residual oil, and petroleum coke (SFA Pacific, Inc., 1999). One advantage of an IGCC power plant equipped with a CO₂ separation process is that it produces a pure hydrogen stream after the water-gas-shift reaction. The combination of the gasification process and the water-gas-shift reaction is the basis for the FutureGen Process (U.S. DOE, 2004).

3.3. Oxygen/Recycled CO₂ Combustion (Oxyfuel Combustion)

Conventional PC power plants use air as an oxidant. Air contains 80 vol% of N₂ and dilutes the CO₂ in the flue gas. If concentrated oxygen instead of air is used for combustion, either in a boiler or gas turbine, the concentration of CO₂ in flue gas can be increased greatly. High-purity oxygen can be produced by a large-scale, commercially available cryogenic process.

If fuel is combusted in very pure oxygen, the flame temperature will be excessively high, so a CO₂-rich flue gas is recycled to the boiler to reduce the flame temperature. The major advantage of the

oxygen-blown coal combustion process is that the flue gas has a CO₂ concentration of 80 vol% or higher compared with 4 to 14 vol% for an air-blown coal combustion process. This greater CO₂ concentration results in a simpler post-combustion CO₂ purification process. The oxygen-blown combustion process has the further benefit of suppressing NO_x formation. Since N₂ gas is not introduced to the boiler, the source for thermal NO_x is eliminated, and only fuel NO_x is present. This fuel NO_x could be reduced or eliminated through staged combustion. In addition, for sequestration purposes, it also may be possible to eliminate the FGD process (required if the flue gas is treated by an amine-based solvent to capture CO₂) if concentrations of SO₂ in the 500 to 3,000 ppm range are proved to have minimal impact on the sequestration step.

The disadvantage of oxygen-blown coal combustion is that a large quantity of oxygen is required, which is expensive both in terms of capital cost and energy consumption. Advances in oxygen production processes, such as new and improved membranes that can operate at high temperatures, could improve the overall plant efficiency and economics of oxygen production facilities.

Oxygen-blown coal combustion could be an attractive option for retrofitting existing steam cycle power stations. The required modifications would be relatively minor and in some places supplies of oxygen could be obtained from existing commercial air separation plants. The technology aimed at power plants has so far only been demonstrated in small-scale test facilities (Varagani et al., 2004). Large-scale demonstration of the technology is needed to fully evaluate the technical and economic advantages of this process as a power generation technology and a source of high-purity sequestration-ready flue gas.

3.4. Comparison of Different CO₂ Configurations

A summary of the advantages and disadvantages of each of the CO₂ removal configurations is presented in Table 3.1.

Table 3.1. Advantages and disadvantages of different configurations

Category	Advantages	Disadvantages	Improvement options
Post-combustion	<ul style="list-style-type: none"> • Can be used for existing systems • High recovery rates • High product purity • Low pressure operation • Mature technologies 	<ul style="list-style-type: none"> • Low CO₂ partial pressure • Energy intensive • Large equipment size (due to low pressure) • Acid gases need to be removed 	<ul style="list-style-type: none"> • Better solvents • Better gas-liquid contacting device • Further process optimization
Pre-combustion	<ul style="list-style-type: none"> • Possible step toward use of H₂ fuel • Small equipment size • Higher CO₂ concentration • Less energy intensity • Mature technologies 	<ul style="list-style-type: none"> • High pressure operation • Can not be used for PC plants • High temperature operation 	<ul style="list-style-type: none"> • H₂ gas turbine • H₂ fuel cell • H₂ separation membrane • H₂ membrane reactor
Oxygen/ CO ₂ recycle combustion	<ul style="list-style-type: none"> • Based on existing technologies • High CO₂ concentrations (>90%) • Can be used for existing systems 	<ul style="list-style-type: none"> • Production of O₂ is expensive • Acid gases needs to be removed • Uncertain for use with NGCC 	<ul style="list-style-type: none"> • CO₂ gas turbine • More economic O₂ separation processes

4. Technology Options for CO₂ Capture and Separation

A typical gas separation process has several components: feed, separating agent, separation device, and product stream (King, 1980) (Figure 4.1).

The degree of a separation process can be expressed in terms of a separation factor, α_{ij} :

$$\alpha_{ij}^S = \frac{x_{i1}/x_{j1}}{x_{i2}/x_{j2}},$$

where x is the mole composition in the streams; 1 and 2 refer to product and feed streams, respectively; and i and j refers to the components (e.g., CO₂ and N₂ in a binary gas mixture) of the stream. When $\alpha_{ij} = 1$, no separation is achieved.

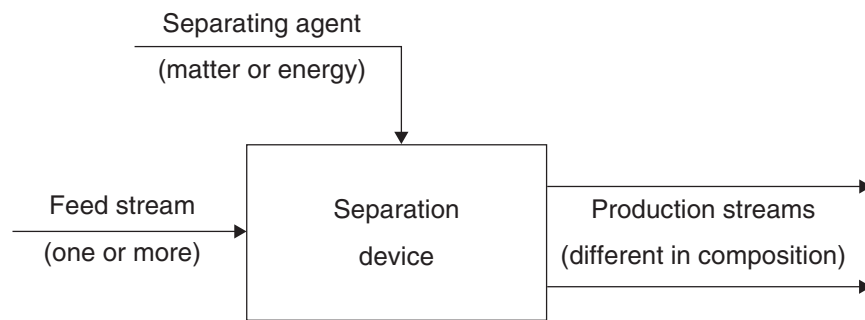


Figure 4.1. Diagram of a typical separation process (King, 1980)

Separation processes can be categorized as either equilibration processes or rate-governed processes. Most separation processes are equilibration, also called reversible separation, processes. They operate by equilibration of two immiscible phases that have different compositions at equilibrium. Evaporation, distillation (including cryogenic processes), absorption, and liquid extraction processes are examples of equilibration processes. Rate-governed processes are based on the differences in the transport rate of the gases (or liquids) through some medium. Membrane separation (membrane is the medium) and PSA (adsorbent is the medium) processes are examples of rate-governed processes.

Because the product phases of an equilibration process are immiscible, many equilibration stages can be arranged into one separation device (at the same pressure). For example, distillation processes can have many stages in one column. The advantage of the multi-staging is that the overall separation factor, which is the product of the individual separation factors in all stages, is large even though the separation factor in each stage is small (α_{ij} is close to 1). In the rate-governed processes, product phases are fully miscible with each other, and, as such, several rate-governed stages cannot be installed in one separation device. Due to this limitation, rate-governed processes often have one or only a few stages, and most membrane processes have only one or two stages. For effective separation, the stage separation factor of a rate-governed process has to be large because a small separation factor leads either to low product purity or low product recovery. Although a multi-staged, rate-governed process is possible, multiple separation devices (equipment) would be required, and the capital and operating costs of the separation process would increase, resulting in a costly and generally uneconomical process.

A separating agent (energy or matter) is used in a separation process to achieve a higher degree of separation. Depending on the agent, the process can be categorized as either an energy-separation agent or a mass-separation agent process. Energy is the most common separation agent. Distillation is an energy-separation agent process. Absorption and extraction processes are mass-separation agent processes that use solvents to separate the target components.

An energy-separation agent process usually requires fewer processing steps than does a mass-separation agent process because, in the latter, the separation agent usually has to be recovered through another separation process. For example, in an amine-based absorption process, the absorbed CO₂ is stripped out of the solution in a regeneration process to recover the solvent, which is then recycled to the absorption column. The addition of a mass-separation agent also causes corrosion and environmental risks in addition to increased process cost. In adsorption processes, solid adsorbents are used as mass-separation agents. Once the bed of the adsorbent materials reaches its saturation capacity, the bed has to be regenerated. Because a solid adsorbent is involved, adsorption processes often operate in batch mode (unless a fluidized bed is used). The batch-wise operation significantly reduces working capacity of the adsorption column. This disadvantage is critical if the adsorption capacity of the solid adsorbent is small or the concentration of sorbate (CO₂) in gas phase is high.

Some important factors to be considered in selecting a separation process are feasibility of the separation process, type of separation process, separation factor and equipment capacity, product value, and maturity. The first and most important criterion for selecting a separation technology is that the process has to be technically feasible. For example, an ion-exchange process is not be feasible for post-combustion CO₂ capture because all of the components in the coal combustion flue gas are non-ionic. Second is economic feasibility. A technically feasible separation process may not be economically feasible. Economic feasibility is determined by the cost of the separation process and the value of the products. The separation process (equilibration process vs. rate-governed process, energy-separation agent process vs. mass-separation agent process), separation factor, and equipment capacity of the separation process are all important factors in determining overall cost. The value of the product plays the most important role in the economics of a separation process. Finally, the maturity of the process has to be considered. A well-tested, mature separation process is often preferred to a less-tested, immature separation process, even if the latter process might be economically more favorable. Other specific requirements such as product purity and recovery rate also should be considered. For example, PSA and membrane separation processes tend to have low recovery if high purity is required, or have low purity if high recovery rate is required.

Two factors dominate the selection of a process for separating and capturing CO₂ from coal combustion flue gases. First, CO₂ is considered to be a relatively low-value product, even when it can be used for enhanced oil recovery (EOR) or coal-bed methane recovery. This factor makes many of the separation processes for this application uneconomical. Second, the scale of the CO₂ emissions from power plants is such that many of the commercially available separation technologies are not practical or economical for this application. For example, adsorption-based processes are unrealistic for CO₂ capture from flue gas because they require large quantities of adsorbents. Absorption, cryogenic, and membrane processes are potentially favorable for CO₂ capture from coal-power plant flue gases. Of these, absorption-based processes have many advantages over the other processes.

4.1. Absorption Process

Absorption is a mass-separation agent equilibration process. A chemical or physical solvent is used as the agent to capture the CO_2 in flue gas. Figure 4.2 is a schematic diagram of the absorption process using MEA as a solvent. A brief description of the process follows (Thambimuthu et al., 2002). In an absorption process, the flue gas enters into an absorption tower where it comes in contact with the chemical solvent. The solvent absorbs most of the CO_2 through a chemical reaction. The CO_2 -rich solvent exits the bottom of the absorber and is passed into a stripper (desorption) column where it is heated with steam to release a concentrated CO_2 . The CO_2 released in the stripper is recovered, and the CO_2 -lean solvent is recycled to the absorption tower. Usually, CO_2 recovery rate (>98%) and CO_2 product purity (in excess of 99%) are high when a chemical solvent such as MEA is used.

Contaminants such as SO_x and NO_x that are present in flue gases from conventional coal or heavy oil-burning power plants have stronger affinities to react with chemical solvents, such as MEA, than CO_2 does. The presence of these contaminants will gradually reduce the absorption capacity of the chemical solvent. In order to avoid such detrimental effects, pretreatment of the flue gas may be needed.

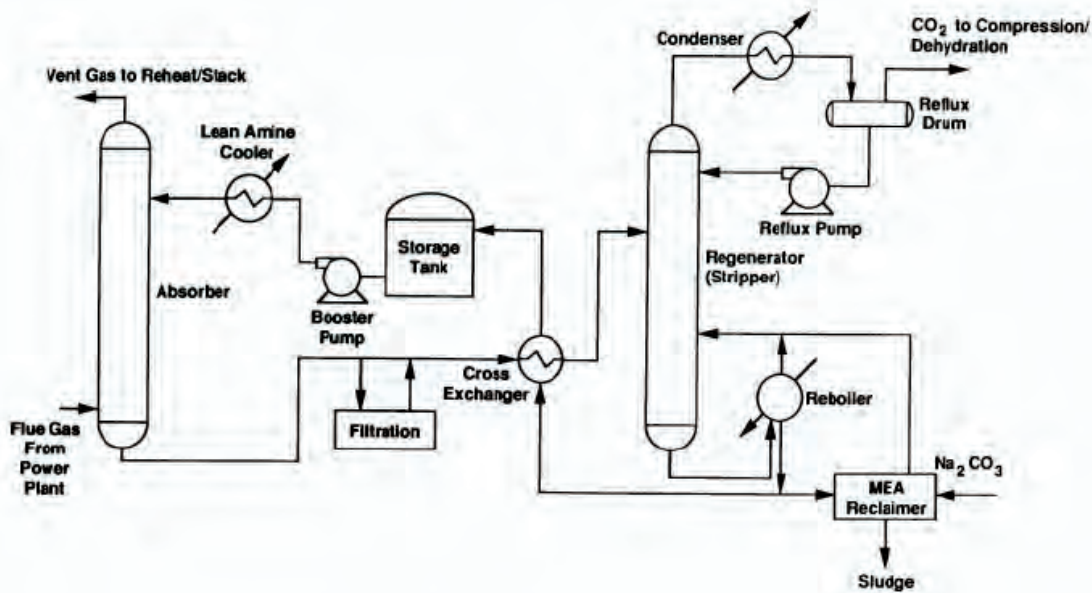


Figure 4.2. Schematic diagram of the amine absorption process (Herzog, 1997)

CO_2 absorption capacity (the solubility of CO_2 in the solvent) in a chemical or physical solvent depends on the properties of the solvent, the partial pressure of CO_2 in flue gas, and the operating temperature of the process. For chemical solvents, absorption is achieved through chemical interaction between CO_2 and solvent molecules. Chemical interaction is often selective, and chemical solvents tend to have limited absorption capacities. That is, absorption capacity levels off as the CO_2 partial pressure increases. For physical solvents, absorption is achieved through physical interaction (van der Waals forces) of CO_2 with the solvent molecules, and absorption capacity is approximately proportional to the partial pressure of CO_2 in the gas phase (Henry's Law).

Figure 4.3 illustrates the relationship between CO₂ capacity in a solvent and the CO₂ partial pressure in the gas phase (partial pressure of solute). At low CO₂ partial pressures, chemical solvents have higher absorption capacities than do physical solvents because they have stronger interactions with CO₂. At higher partial pressures, physical solvents have higher CO₂ absorption capacities.

Chemical absorption processes are recommended for post-combustion capture configuration because the CO₂ concentration in the flue gases of conventional power plants is about 14%, and the corresponding partial pressure is about 0.13 bar. The partial pressure is even lower in the flue gases of NGCC power plants. At these low partial pressures, physical solvents have little capacity for CO₂ capture due to their weaker intermolecular forces

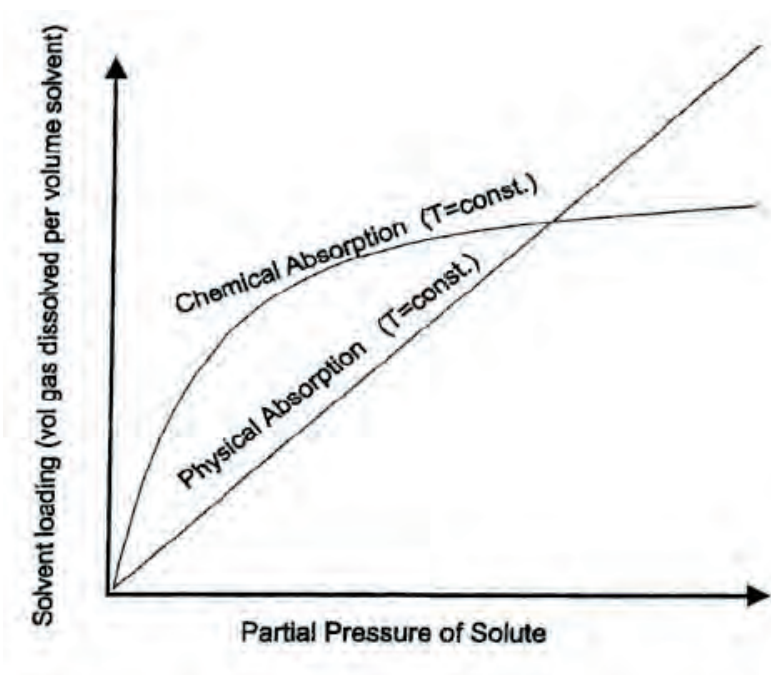


Figure 4.3. Relationship between CO₂ capacity and its partial pressure (Gottlicher, 2004)

Chemical absorption processes are well-understood unit operations in chemical engineering. Amine-based absorption processes to remove CO₂ from gas streams have been in practice for over 60 years in the chemical and oil industries, and absorption processes are expected to have few obstacles in scaling up from current commercial application processes to future CO₂ removal processes at power plants.

The main concerns with MEA and other amine solvents are corrosion in the presence of O₂ (DuPart, 1993a, 1993b) and other impurities, high solvent degradation rates from reaction with SO₂ and NO_x (Strazisar et al., 2003; Stewart, 1994a, 1994b), and the large amounts of energy required for the regeneration step. These factors generally contribute to high energy consumption and large solvent losses (Chapel et al., 2001). However, if solvents with higher CO₂ absorption capacities, faster CO₂ absorption rates, lower degradation rates, lower corrosiveness, and lower energy requirements for regeneration than those of the currently available solvents could be developed, then the economics of chemical absorption processes could be greatly improved. Nevertheless, chemical absorption processes are the best

technologies currently available for CO₂ separation from dilute, atmospheric pressure, post-combustion flue gas.

Physical absorption processes are more suitable for high pressure systems. For example, in an IGCC power plant, the CO₂ concentration in the syngas after the water-gas-shift step is about 40%. In addition, because the process operates at high pressures (around 30 bars), the CO₂ partial pressure is more than 10 bars, which is about 70 times higher than the CO₂ concentration in the flue gas from a conventional power plant. At this level of CO₂ partial pressure, the physical absorption process is preferable to chemical absorption. The weaker bonding between the CO₂ and the physical solvent allows the CO₂ to be separated from the solvent in a stripper by reducing the total pressure. Such a mechanism results in low energy consumption. The most common physical solvents that are commercially used for CO₂ capture include cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor process), and sulfolane (Gupta et al., 2003; Kohl and Nielsen, 1997).

Physical absorption processes are also well established in ammonia and hydrogen production plants. The developmental improvements for the physical absorption processes are similar to those for the chemical absorption processes, in particular, the need for higher efficiency gas-liquid contactors and novel solvents with lower energy requirements for regeneration.

4.2. Adsorption Process

Adsorption is a mass-separation agent process. A porous solid adsorbent, such as zeolites or activated carbon, is used as a mass-separation agent. Gases or vapors can be captured by contact with an adsorbent through chemical or physical interaction. Adsorption can be either a rate-governed process or an equilibration process. Adsorption is a surface phenomenon. The adsorption capacity depends on the properties of the adsorbent and adsorbate (such as CO₂ or H₂) and the partial pressure of the adsorbate. Adsorption capacity is often limited by surface area, pore size, pore size distribution, and porosity of the adsorbent. Adsorption capacity tends to be low compared with a bulk process such as absorption process. In addition, because a solid phase is involved, the continuous operation of an adsorption process is more difficult. In fact, most adsorption processes operate on a repeated cycle between adsorption and desorption (regeneration) steps. Due to these drawbacks, adsorption processes are often used to separate low-concentration components from a mixture.

In an adsorption-based process for CO₂ capture, flue gas is fed into an adsorption column where CO₂ is selectively adsorbed on the surface of the adsorbent. The bed of CO₂-rich adsorbent is then subjected to a regeneration step to recover CO₂. Depending on the regeneration step used, the adsorption process can be PSA, temperature swing adsorption (TSA), or electric swing adsorption (ESA). Figures 4.4 and 4.5 are schematic diagrams of the PSA and TSA processes.

TSA processes are not generally suitable for capturing CO₂ from flue gases of coal-fired power plants, mainly because of the huge amount of CO₂ to be recovered and the relative low capacity of adsorbents (Riemer, 1993; Gottlicher, 2004).

PSA processes, in contrast, use rapid cycles of pressure change, which can partially compensate for the low capacity of the adsorption process. However, PSA processes tend to have either low product recovery rate or low product purity. It is very difficult to achieve both high recovery and high purity at the same time. PSA is not an attractive post-combustion capture process for CO₂ removal from flue

gases; however, it may offer applications for co-production of power and H₂ in an IGCC plant where H₂ separation from syngas requires only high purity H₂, but not a high recovery rate.

The equipment capacity of an adsorption process is comparable to or less than that of an absorption-based process. However, because an adsorption process is performed in repeated cycles and the equipment capacity is not fully used all the time, the working (actual) capacity is much lower than that of absorption processes. As a result, the size of adsorption equipment is larger than the size of absorption equipment for the same gas separation application.

The process equipment for the adsorption process is similar to that for the absorption process. The unit equipment cost of adsorption process is also similar to that for the absorption processes. The total equipment cost for adsorption-based CO₂ capture, however, will be higher than that for absorption-based CO₂ capture processes.

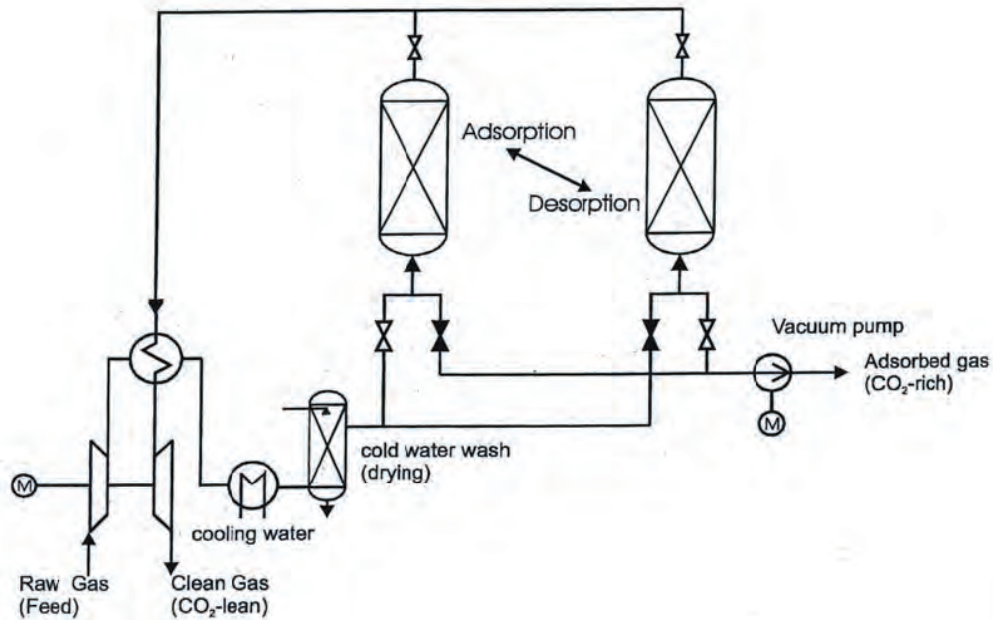


Figure 4.4. Schematic of a pressure swing adsorption process (Gottlicher, 2004)

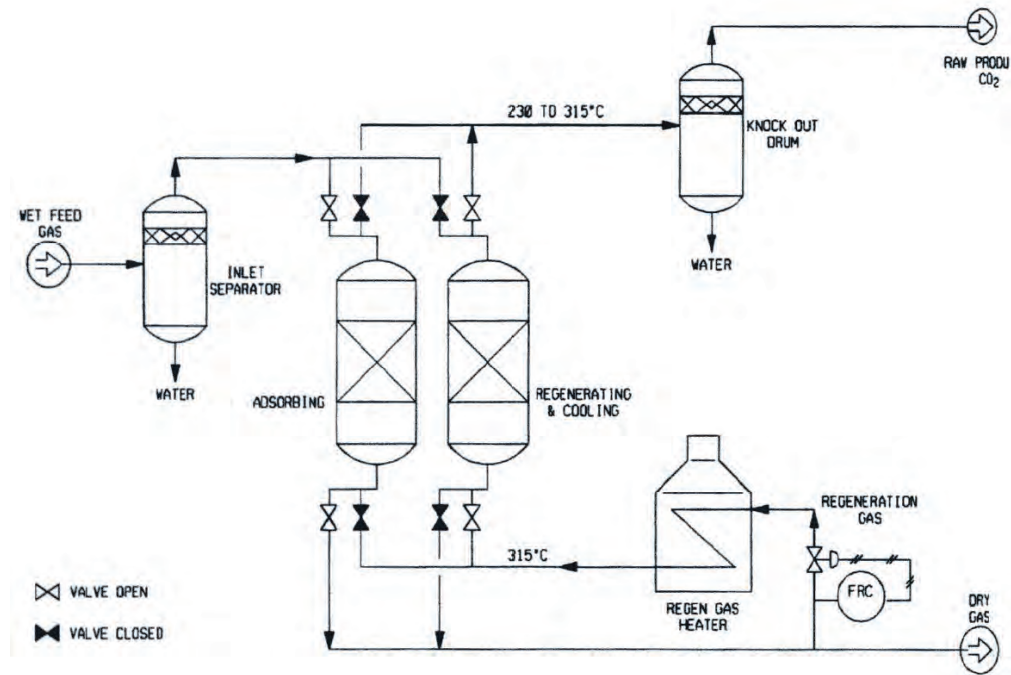


Figure 4.5. Schematic of a temperature swing adsorption process (Riemer, 1993)

4.3. Membrane Processes

Membrane separation is an energy-separation agent and rate-governed process. This process is based on the differences in physical or chemical interactions between gases and a membrane material, thereby causing one component to pass through the membrane faster than others. Various types of membranes are currently available, including porous inorganic membranes, palladium membranes, polymeric membranes, and zeolite membranes. Figure 4.6 is a schematic diagram of one-stage (left) and two-stage (right) membrane processes.

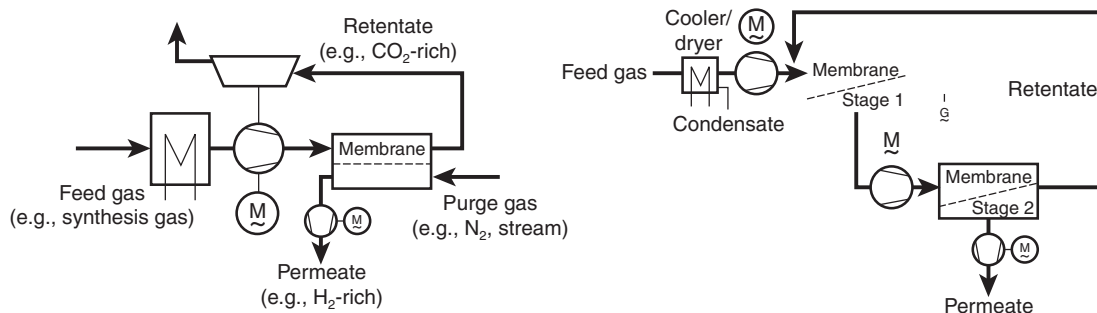


Figure 4.6. Schematic diagram of one-stage (left) and two-stage (right) membrane processes (Gottlicher, 2004)

Selectivity and permeability of the membrane are two of the important factors in determining the economics of a given membrane process. High selectivity is required to produce a high-purity product gas stream. To achieve high purity at an acceptable recovery rate, multiple stages and/or recycle of one of the streams may be necessary. This option, however, significantly increases the capital cost and energy

consumption. Permeability determines the capacity of a membrane system. Low permeability translates to a larger membrane area and higher equipment cost. One study (Van Der Sluijs et al., 1995) concluded that for a post-combustion membrane separation process to compete economically with an amine-based absorption process, the CO_2/N_2 selectivity and CO_2 permeability of the polymeric membrane should be >200 and 100 Barrer, respectively (see Figure 4.7). The selectivity and permeability of currently available commercial membranes (the data points in Figure 4.7) are far smaller than the required target values (shaded area). Membrane processes are not an attractive option for removal of CO_2 from post-combustion flue gas at the present time. The future application of this technology depends mainly on the development of improved membranes.

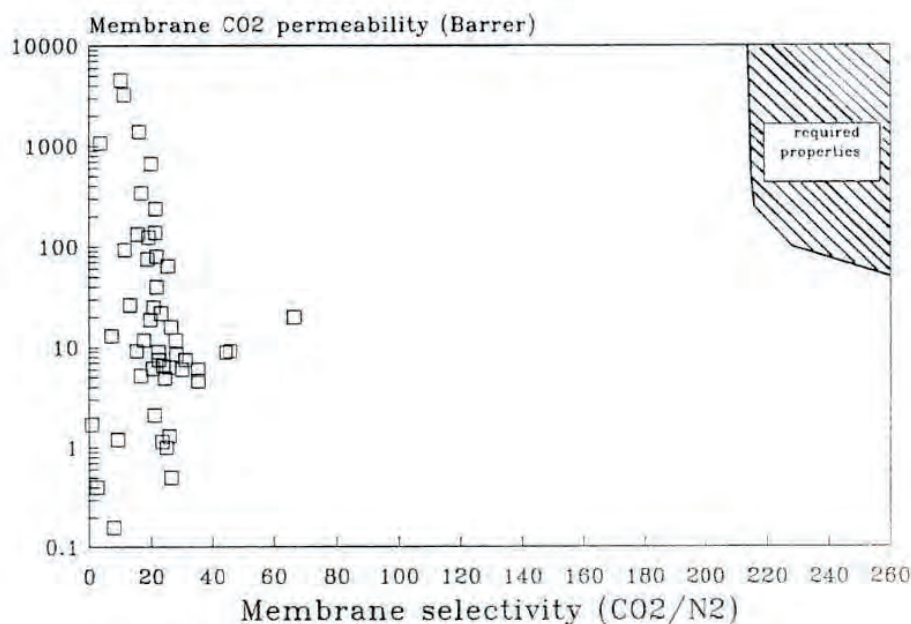


Figure 4.7. Commercial membrane and required membrane properties (Van Der Sluijs et al., 1995)

Membrane processes could be used to separate CO_2 from the shift syngas in an IGCC power plant (membrane shift reactor). In this case, gas cooling and heating would not be required, and the equipment cost for CO_2 separation could be significantly reduced. Indeed, conceptual level techno-economic studies have shown that the IGCC + membrane reactor is a very attractive pre-combustion CO_2 removal process (Middleton, 2004). The unit equipment cost for a membrane separation system generally is much higher than that of absorption and adsorption processes.

4.4. Cryogenics

A cryogenic process, also called low-temperature distillation, is an energy-separation agent and an equilibration separation process (Riemer, 1993) (Figure 4.8). This process relies on component volatility conditions in the mixture at cryogenic conditions. CO_2 can be separated from flue gases by cooling and condensation.

To analyze the suitability for CO₂ separation by cryogenic processes, it is important to study the CO₂ phase diagram (Figure 4.9). Because distillation processes can operate only in the vapor-liquid region of the phase diagram, the flue gas temperature must be cooled to between -56.6°C to 31°C. The vapor pressures of CO₂ at these two temperatures are 5 and 74 atm, respectively, which is much higher than the partial pressure of CO₂ in most flue gases. To employ a distillation process, the flue gas must be pressurized. For example, in conventional PC power plants with a CO₂ concentration of 14% (or 16% dry basis) in the flue gas, the flue gas has to be compressed to a total pressure of at least 30 atm to recover any CO₂ at -56°C. If 90% recovery is required, total pressure needs to be 300 atm. Obviously, to compress and cool the flue gas to such high pressure and low temperature is extremely energy intensive. Clearly, cryogenic processes are not an attractive option for low-concentration CO₂ streams.

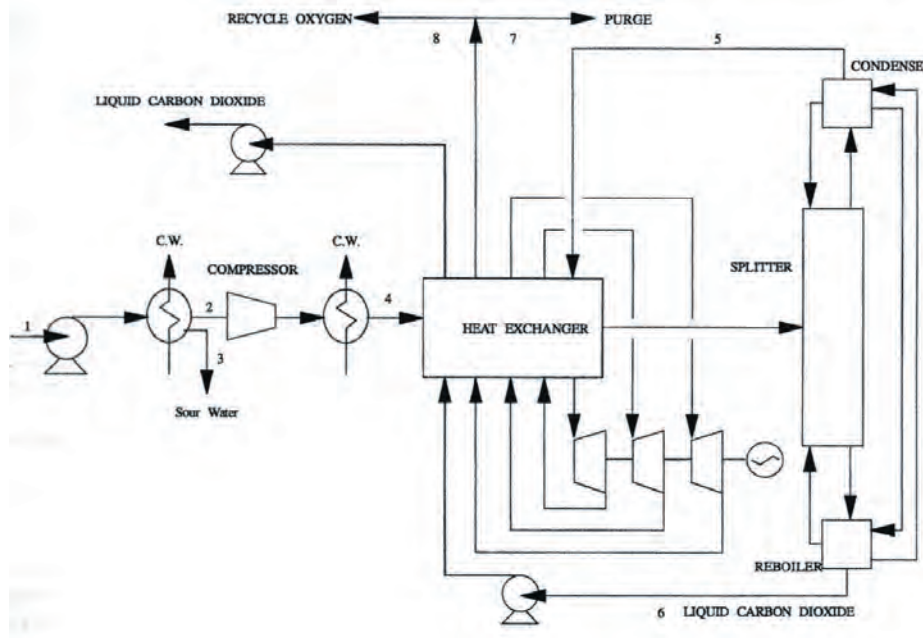


Figure 4.8. Schematic diagram of a cryogenic process (Riemer, 1993)

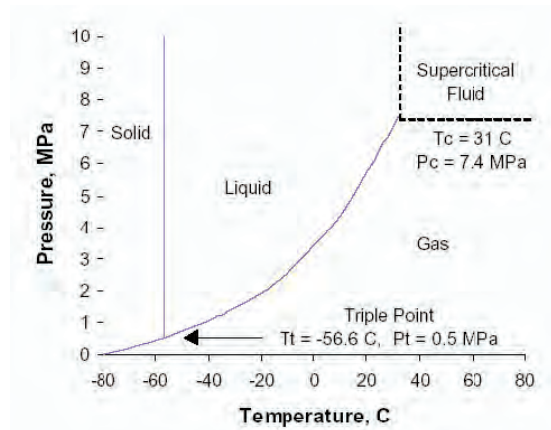


Figure 4.9. Phase diagram of CO₂ (T_c and P_c, critical temperature and pressure; T_t and P_t, triple point temperature and pressure).

A cryogenic process is more attractive for IGCC plants because CO₂ concentration in the shifted syngas is about 40% and the total partial pressure of CO₂ is about 12 bars. A system pressure of about 120 bars is required for 90% recovery of CO₂ from the shifted syngas stream. Cryogenic processes are even more favorable for an oxyfuel combustion process in which the flue gas stream contains >90% of CO₂ (dry basis). A 90% recovery of CO₂ requires an operating pressure of 50 bars.

Cryogenic processes are commercially employed for the purification of CO₂ from streams that contain high CO₂ concentrations (typically >90%). A major disadvantage of cryogenic separation of CO₂ is the amount of energy required to provide the necessary refrigeration, particularly for dilute gas streams. Another disadvantage is that some of the components in the gas, such as water, have to be removed before the gas stream is cooled to avoid freezing and blockage in the heat exchangers. The most promising applications of the cryogenic process are separation of CO₂ from high-pressure gases, such as in pre-combustion capture processes or in oxyfuel combustion in which the input gas contains a high concentration of CO₂.

The equipment capacity of a cryogenic process is comparable to that of a distillation process and is similar to that of absorption processes. The unit equipment cost is similar to that of absorption processes. Thus, the capital cost of this process would be similar to the absorption process and lower than that of the membrane and adsorption processes.

4.5. Emerging Power Generation and CO₂ Capture Concepts

Zero emissions coal technology and chemical looping process CO₂ have been proposed as new concepts for power generation, and the hydrate separation process is considered as a potential CO₂ capture method for IGCC power plants. Each of the emerging power generation concepts has incorporated a CO₂ capture step in the overall process scheme. Each of these concepts is described briefly.

4.5.1. Zero Emissions Coal Technology

Zero emissions coal technology (Ziock et al., 2001) has four components: hydrogasifier, CaO reformer, calciner, and fuel cell (Figure 4.10). The reactions involved in each stage are

Hydrogasifier:



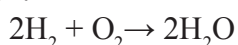
CaO reformer:



Calciner:



Fuel cell:



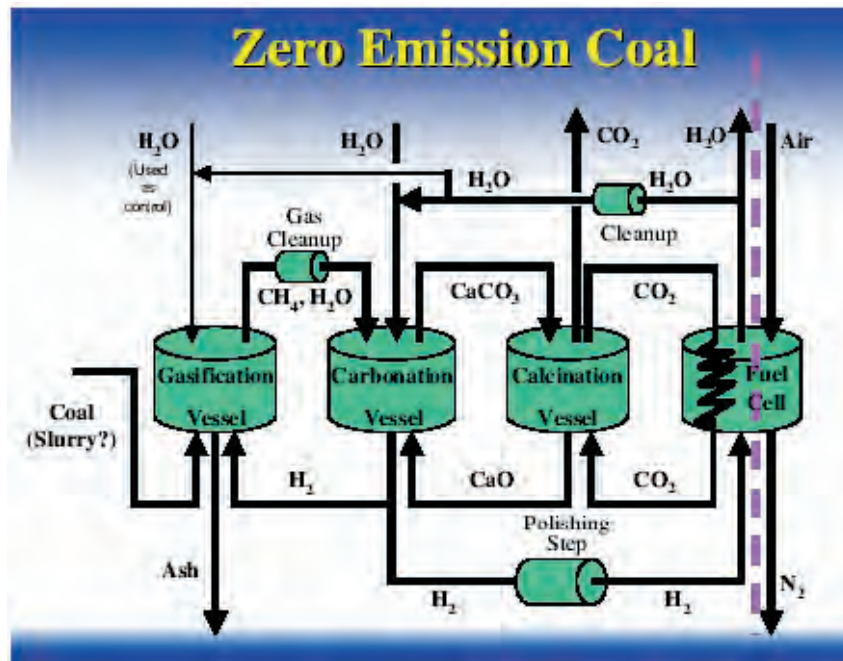


Figure 4.10. Schematic diagram of zero emission coal technology

In the hydrogasification stage, both hydrogen and water are used to gasify coal to produce a methane-rich fuel gas, which is reformed to hydrogen and CO_2 . CO_2 is removed by CaO to form CaCO_3 . High-purity CO_2 is recovered during the decomposition of the CaCO_3 in a calciner. The CO_2 recovery is a pre-combustion stage. The process is attractive when it is coupled with a solid oxide fuel cell process. The waste heat from the exhaust gas of a solid oxide fuel cell process can be used to decompose CaCO_3 .

4.5.2. CO_2 Hydrate Separation Process for Synthesis Gas

The CO_2 hydrate separation process is used to separate CO_2 and H_2 in a shifted syngas (Tam et al., 2001). The hydrate is a mixture of water and a gas. The gas molecules are trapped in the cavity of a crystal water (ice) structure. Many small gas molecules can form gas hydrate at certain temperatures and pressures. CO_2 hydrate forms at temperatures near 0°C and pressures from 10 to 70 atm, depending on the gas composition. The CO_2 hydrate separation process consists of two stages (Figure 4.11). In the first stage, nucleated water, also called seeds, are formed by an ammonia cooling process. The nucleated water and shifted syngas enters the second reactor at pressures ranging from 6 to 20 bars. CO_2 in the gas phase reacts rapidly with nucleated water to form CO_2 hydrates. CO_2 hydrates are separated from the gas to produce an H_2 -rich product gas.

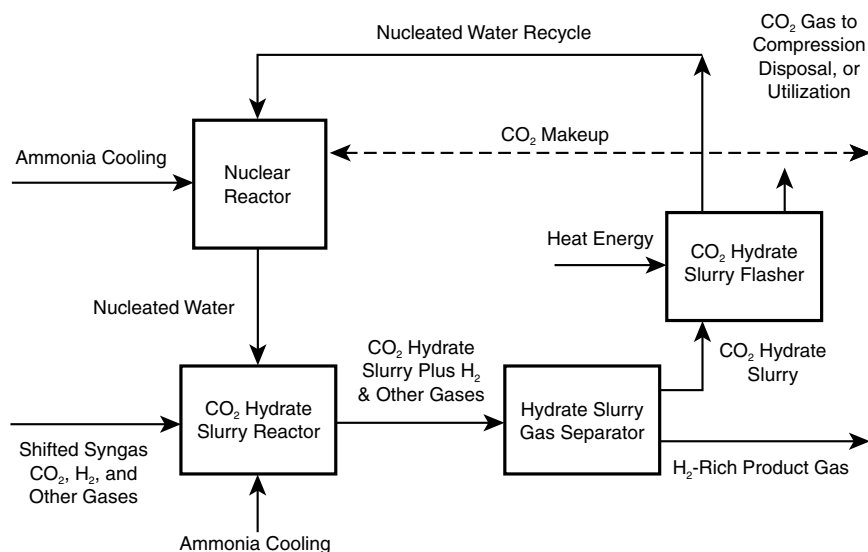


Figure 4.11. Simple block diagram of a CO₂ hydrate process (Tam et al., 2001)

The potential technical barriers of CO₂ hydrate separation include efficient release of CO₂ from the hydrate; efficient capture of CO₂ (increased recovery rate); formation of stable pre-hydrate; and the interference of trace contaminants with hydrate formation. The hydration process is suitable for IGCC processes where the gas streams are at pressures of 20 atm or above and the CO₂ partial pressure is at 8 atmospheres or above. These conditions ideally meet CO₂ hydrate-forming requirements.

4.5.3. Chemical Looping Process

The chemical looping combustion processes (Figure 4.12) use a metal oxide (or other oxygen carriers) to transfer oxygen to the fuel in a two-stage process (Mattisson and Lyngfelt, 2001). In the reduction reactor, the metal oxide oxidizes the fuel, and the metal oxide itself is reduced. The metal oxide is transported to an oxidation reactor where the reduced metal oxide is re-oxidized in air. The oxidation and reduction processes are repeated.

The major advantage of the chemical looping process is that no oxygen separation process is required, which eliminates the air separation unit and significantly reduces capital cost. The major disadvantage is that the process cannot be directly used with coal because coal is a solid fuel and is not able to efficiently contact the metal oxide, which is also a solid.

Other new power generation concepts and CO₂ capture technologies have also been proposed, but all of them are still at conceptual stages (White et al., 2003; Gupta et al., 2003).

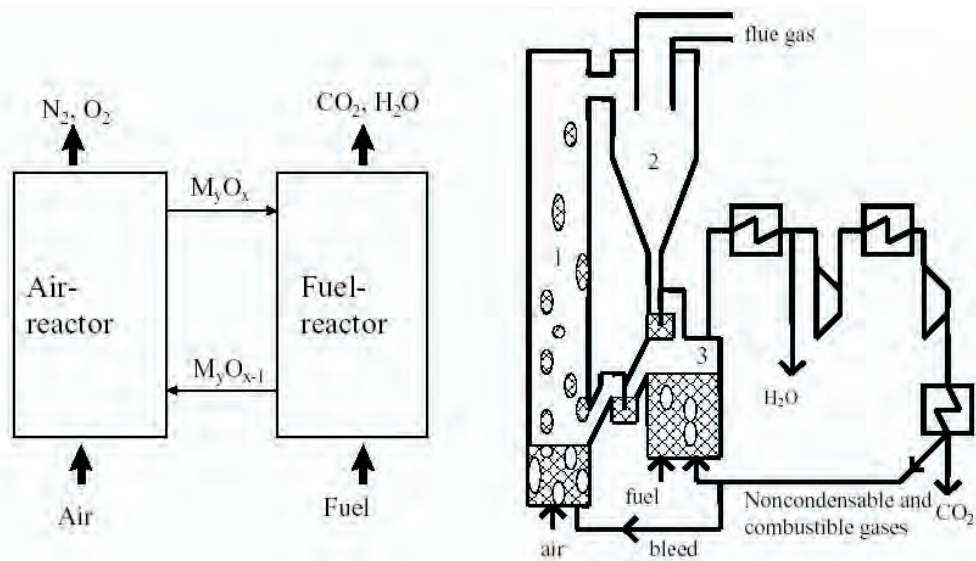


Figure 4.12. Two proposed processes for the chemical looping technology

5. Comparison of Different CO₂ Capture Technologies

The CO₂ capture technologies discussed in the previous section are potential candidates for CO₂ capture from large-scale power plants and industrial facilities. Some of the advantages and disadvantages of these technologies have been discussed in previous sections. In this section, a more complete comparison is presented.

When comparing different separation technologies, the ultimate criteria are cost and safety. The most important factors include equipment size, unit equipment cost, energy consumption of the process, operating cost, reliability of the process, product recovery rate, product purity, flexibility of the process, and other parameters. Table 5.1 lists these factors for selected separation processes.

The exergy (useful energy, not heat) efficiencies of these processes are also listed in Table 5.1 (Gottlicher, 2004). Since the minimum (theoretical) energy requirements are the same for all capture technologies listed, exergy efficiency is thus an indication of the actual energy requirement of each process:

$$\text{Exergy efficiency} = \text{theoretical energy requirement} / \text{actual energy consumed.}$$

Energy consumption often dominates the operating cost of a separation process. From the data in Table 5.1, it can be seen that, when CO₂ partial pressure in the gas mixture is low, chemical absorption process generally has a higher exergy efficiency. When CO₂ partial pressure is high (e.g., ~10 bars), the physical absorption process has higher exergy efficiency. Membrane processes have high exergy efficiency when they are used for H₂ separation rather than for CO₂ separation. The exergy efficiency of a membrane process is strongly correlated to the selectivity of the membrane used and, to a lesser extent, to its permeability (Van Der Sluijs et al., 1992; Hendriks, 1994; Gottlicher, 2004). Due to the high selectivity and permeability of H₂/CO₂ membrane, the membrane system can achieve higher exergy efficiency.

Table 5.1. Comparisons of the potential separation technologies

	Absorption	PSA/TSA	Membrane	Cryogenic
Exergy efficiency (%)				
Post-combustion				
PC (P = 1.2 bars; CO ₂ = 14%)	21 (CA)	9	10~14	
IGCC (P = 1.2 bars; CO ₂ = 8%)	14 (CA)	5	6.5~8	
NGCC (P = 1.2 bars; CO ₂ = 4%)	13 (CA)	1.5	1.5~2	
Pre-combustion				N/A
IGCC (P = 24 bars; CO ₂ = 40%)	20~32 (PA)	8~12	25~32 (H ₂)	
NGCC (P = 24 bars; CO ₂ = 36%)		8~12	25~32 (H ₂)	
Ease of scaling-up	good	poor	good	good
Economy of scale	good	fair	poor	good
CO ₂ recovery rate	good	poor	poor	good
CO ₂ purity	good	fair	fair	good
H ₂ recovery (for IGCC after shift)	good	poor	fair	good
H ₂ purity (for IGCC after shift)	good	good	good	good
Equipment size	fair	poor	good	fair
Unit equipment cost	good	fair	poor	good
Operating cost	fair	fair	good	fair
Maintenance	fair	fair	good	fair
Maturity	good	fair	fair	good
Pre-treatment requirement	fair	fair	good	good

It is difficult for a membrane process or a PSA process to achieve high CO₂ recovery percentage in a one- or two-stage process (unless the selectivity of the membrane or sorbent is extremely high), especially when high product purity is required. For these processes, there is often a trade-off between product purity and recovery rate. When high recovery is not required, PSA and membrane systems may have potential.

The relationship between oxygen cost and different scales of membrane, cryogenic, and adsorption processes is shown in Figure 5.1 to illustrate some conclusions for large scale CO₂ separation and capture. Membrane separation processes do not have good economy of scale. It is expected that the scale-up behavior of an absorption process will be similar to that of a cryogenic process because the process equipment of these two processes is similar. Obviously, large-scale processes such as CO₂ capture from utility flue gas definitely favor absorption processes.

The study cited in Figure 5.1 is about 10 years old. However, the relative cost-capacity trends shown are still valid because they are mainly influenced by the nature of the separation processes.

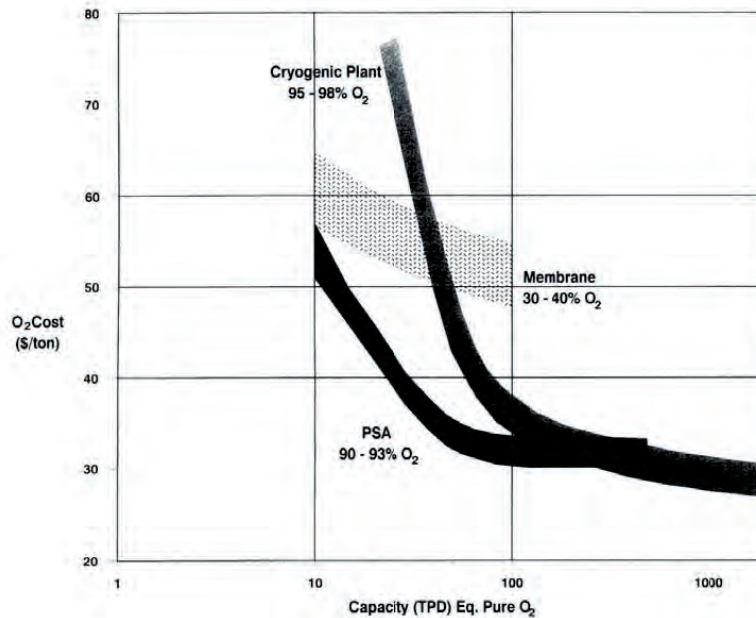


Figure 5.1. Scale-up behavior of different technologies for O₂ separation (Prasad et al., 1994)

6. Selection of CO₂ Capture Technologies for Different Emission Sources

The selection of a CO₂ capture technology mostly depends on the characteristics of the emission source and the subsequent disposal of the captured CO₂. The most important parameters are the CO₂ concentration and the total pressure in the flue gas stream. Others include contaminants in the gas stream, transportation, and disposal methods. Table 6.1 lists the characteristics of different CO₂ emission sources and recommended capture technologies.

For a post-combustion flue gas, CO₂ partial pressure (both concentration and total pressure) is low, and a chemical absorption process is the best choice for the present and the near future. Development of new solvents and gas/liquid contactors is expected to improve the economics of absorption-based processes for CO₂ capture in the future.

Another possible alternative for conventional PC power plants is to retrofit them with the oxyfuel combustion process. This technology may offer a low-cost option for CO₂ capture if combustion with recycled CO₂ is demonstrated to be a viable low-cost technology for the existing PC boilers.

Table 6.1. Capture technologies for power plants and industrial facilities

Emission source	Pressure (bar)	CO ₂ (%)	Impurities	Capture technology
Power plants				
PC	1.2	14	SO _x , NO _x	CA
IGCC post-combustion	1.2	8	NO _x	CA
IGCC shifted syngas	30	40	H ₂ S	PA or H ₂ membrane
NGCC post-combustion	1.2	4	NO _x	CA
NGCC shifted syngas				PA or H ₂ membrane
PC + O ₂ /CO ₂	1.2	>90	SO _x , NO _x , H ₂ O	Cryogenic
Industrial processes				
Iron and steel	1.2	20–27		CA or shift + PA
Refineries		8–15	SO _x , NO _x	CA
Cement	1.2	14–33		CA
Lime		14–33		CA
Ammonia	30	>95		Pure
Ethanol	1.0	95	VOCs, H ₂ O	Cryogenic

For pre-combustion capture, such as in IGCC + shift or NGCC + shift power plants, the best technology would be to shift CO in syngas to CO₂ followed by a physical absorption process to separate CO₂. Another option is to separate H₂ from the shifted syngas instead of separating CO₂ from the syngas. H₂ can be separated by using a membrane separation process or a membrane reactor, which integrates water-gas-shift reaction and H₂ separation in the same unit. Because inorganic membranes can operate at high temperatures, this option may increase the thermal efficiency of the power plant. The membrane reactor may represent the best future opportunities for CO₂ capture in IGCC and NGCC processes. The key to the success of the membrane reactor process is the development of high H₂ selectivity and permeability separation membranes.

For industrial processes with a low CO₂ concentration in the flue gas, chemical absorption processes offer the best option at the present time.

7. Selected Scenarios for Illinois Basin

Currently, the predominant power generation technology is simple steam cycle PC power plants. As discussed in the previous sections, the chemical absorption process is the most suitable CO₂ capture technology for these power plants. Chemical absorption is also the best option for most of selected industrial processes. The oxyfuel combustion process could be a near term alternative for PC power plants. Because the oxyfuel combustion process does not increase the thermal efficiency of the power plants, such technology will not be attractive if CO₂ removal becomes mandatory. This technology will likely be phased out with PC boilers.

IGCC technology is potentially the next coal-based power generation technology to replace PC technology. IGCC offers higher thermal efficiency and, thus, fewer CO₂ emissions, and is a bridge to a hydrogen-based economy. For the distant future, higher thermal efficiency power generation technologies, such as solid oxide fuel cell and zero emissions coal technologies, have good potential.

Table 7.1. Likely combinations of CO₂ separation and power generation technologies

Current technologies	Near term	Future
PC + chemical absorption	IGCC + shift + Selexol IGCC + shift + Membrane reactor	Coal gasification + shift + Selexol + SOFC ¹ NG reforming + shift + Selexol + SOFC
PC + oxyfuel process	NG reforming + shift + Selexol NG reforming + shift + membrane reactor	ZEC technology Innovative technologies

¹SOFC, solid oxide fuel cell; NG, natural gas; and ZEC, zero emissions coal.

Table 7.1 lists the likely combination of CO₂ capture technologies and power generation technologies in the near and more distant future. From this review, the following three processes are selected for techno-economic analysis: PC + chemical absorption (MEA), IGCC + shift + absorption (Selexol), and oxyfuel combustion processes.

In addition, a techno-economic analysis is performed for capturing CO₂ from ethanol plants. Ethanol plants may be a good CO₂ source for phase II of the DOE sequestration program in the Illinois Basin, which involves actual field demonstration of CO₂ sequestration at a selected site.

8. Techno-economic Analysis of CO₂ Capture in the Illinois Basin

Existing coal-fired power plants will be in operation for some time in the future and, therefore, their CO₂ emissions are potential targets for sequestration. As stated earlier, the initial results from the analysis of various CO₂ capture processes indicate that a post-combustion chemical (MEA) absorption process would be the most suitable option for capturing CO₂ from the flue gases of the existing coal-fired power plants. IGCC is expected to be a promising future coal-based power generation technology, especially if hydrogen becomes a more attractive fuel for the transportation sector. A pre-combustion physical absorption process (Selexol) is thought to be the most promising CO₂ capture process for this technology at the present time. A promising retrofit and/or new technology for generating high-purity CO₂ coal combustion flue gas is oxygen-enriched combustion (OEC) with CO₂/O₂ flue gas recycle. A techno-economic study was performed to evaluate the relative performance and cost of these three power generation systems (i.e., PC + MEA, IGCC + Selexol, and OEC). The study determined the cost of electricity generation and the CO₂ avoidance costs. A conventional PC power plant without CO₂ capture was also investigated to provide a baseline for comparison.

The scale of a power plant, especially when the plant scale is small, can strongly influence its economics. The economic analysis for three plant capacities, around 250, 500, and 1,000 MW, was conducted to examine economies of scale. Plants with capacities less than 250 MW were not considered because they only account for 4% of the total utility emissions in the Illinois Basin (Figure 2.1).

Illinois bituminous coal and western Powder River Basin (PRB) sub-bituminous coal are the two main coals used in utilities in the Illinois Basin. The techno-economics of these coals in the CO₂ capture process were therefore evaluated. The largest currently active coal mine in Illinois is the Galatia Mine located in southern Illinois. Because coal compositions can change from mine to mine in the same seam

and from seam to seam, an average composition of the coal samples was used in this study. The PRB coal selected was the Antelope Mine coal. The ultimate analyses of the two coals are listed in Table 8.1 (Chen et al., 2002).

Table 8.1. Typical composition of Illinois coal and PRB coal

Composition, wt%	Illinois coal		PRB coal	
	As-received basis	Dry basis	As-received basis	Dry basis
Moisture	6.08	-	26.7	-
Carbon, C	70.28	74.83	51.35	70.05
Hydrogen, H	4.77	5.08	3.59	4.9
Nitrogen, N	1.44	1.53	0.78	1.06
Chlorine, Cl	0.21	0.22	0.01	0.01
Sulfur, S	2.28	2.43	0.24	0.33
Oxygen, O	6.25	6.65	12.08	16.48
Ash	8.90	9.48	5.25	7.16
Total	100.00	100.00	100.00	100.00
HHV ¹ , BTU/lb	12,475	13,283	8,800	12,005

¹HHV, higher heating value.

8.1. Reference Plant

8.1.1. Overall Process Descriptions

The reference plant is a conventional air-blown power plant (Figure 8.1). The design and configuration of the reference PC plant were based on those of a standard plant developed in a U.S. DOE-funded study (Gilbert/Commonwealth Inc., 1995).

A PC power plant consists of a boiler, a super heater, a reheater, an economizer, and air heater components. Air at a 15 vol% excess is generally used for the combustion process. The temperature of the flue gas exiting the air preheater is about 295°C. The plant uses a single reheat sub-critical steam power cycle. In this study, the performance of the steam power cycle was based on the nominal 2,415 psi throttle steam conditions. The following nominal steam conditions were employed:

Main steam to high-pressure (HP) turbine: 2,415 psi/1,000°F;

Reheat steam to intermediate-pressure (IP) turbine: 545 psi/1,000°F.

The NO_x, fly ash, and SO₂ in the flue gas are removed by means of a selective catalytic reduction (SCR) unit, an electro-static precipitator (ESP) unit, and a limestone slurry forced oxidation (LSFO) unit if necessary. A 90% NO_x removal efficiency was assumed for the SCR. A 99% fly ash removal efficiency was assumed for the ESP, and a size distribution of fly ash particles prior to the ESP is referred to that provided in the AP-42 guideline (U.S. EPA, 1998). The LSFO is applied only to Illinois coal with a removal efficiency of 95%. No flue gas desulfurization was assumed for the PRB coal in the reference plant.

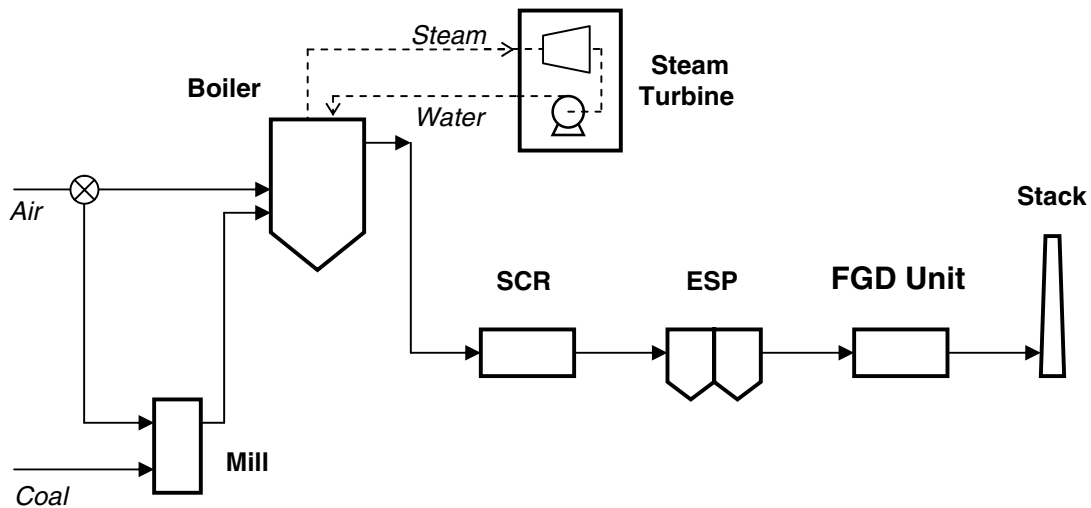


Figure 8.1. Schematic diagram of the air-blown PC-fired power plant (Illinois coal)

8.1.2. Process Simulation

Process simulation software, CHEMCAD, developed by Chemstation Inc., was employed in this study. CHEMCAD can be used to perform steady-state simulations for mass and energy balances of the power plant.

The simulation was conducted for three main process areas in the power plant: a boiler system, a steam turbine system, and a gas cleaning system. Table 8.2 lists the performance of the main streams for the 533-MW (gross) plants burning Illinois and PRB coals. The detailed results of the mass/energy balance simulation are available in Appendix A1.

Table 8.2. Main operating performance of the 533-MW (gross) plant

	Illinois coal		PRB coal
Combustion			
Air/coal equivalent ratio	1.15		1.15
Air flow rate, lb/hr	3,991,198		4,029,474
Coal feed rate, lb/hr	360,611		524,982
Steam generation			
Hot reheat steam, lb/hr	3,022,125		3,022,125
Superheat steam, lb/hr	3,422,824		3,422,824
Steam condensate, lb/hr	2,802,051		2,802,051
Main feed-water, lb/hr	3,321,228		3,321,228
Heat duty in cooling tower, mBTU/hr	2,178		2,178
Flue gas			
	from boiler	from FGD	from boiler
Flue gas volume, lb/h	4,319,700	4,497,871	4,526,825
Flue gas temperature, °F	295	125	295
Composition			
N ₂ , vol%	75.69	70.73	71.73
O ₂ , vol%	2.73	2.47	2.49
CO ₂ , vol%	14.55	13.75	14.55
H ₂ O, vol%	6.78	13.04	11.15
SO ₂ , vol%	0.1774	0.0080	0.0257
NO _x , vol%	0.0325	0.0032	0.0444
Fly ash flow rate, lb/hr	25,676	257	22,049

Certain components of the power plant, such as pumps, fans, and conveyors, consume significant amounts of electricity. The auxiliary power uses of the coal handling, pulverizing, ash handling, and miscellaneous systems were scaled linearly based on coal consumption. For other components, energy usage was obtained from the process simulation. The results of the auxiliary power use analysis for 533-MW (gross) power plants are summarized in Table 8.3. For other plant capacities, auxiliary power uses are almost linearly proportional to the plant scale if the same coal is fired.

Table 8.3. Auxiliary power use for 533-MW (gross) power plants

	Illinois coal	PRB coal
Auxiliary load, kW		
Coal handling	233	339
Pulverizers	2,017	2,937
Primary air fans	1,199	1,212
Forced draft fans	1,142	1,154
Induced draft fans	4,921	5,122
Seal air blowers	45	46
Steam turbine auxiliaries	884	884
Condensate pumps	949	949
Main feed pump ¹	10,938	10,938
Circulating water pumps	4,187	4,187
Cooling tower fans	2,367	2,367
Ash handling	1,658	1,424
Miscellaneous	2,411	2,411
Transformer loss	1,215	1,215
ESP	1,259	1,319
FGD	7,500	0
SCR	2,750	2,750
Subtotal	34,737	28,316

¹Driven by auxiliary steam turbine; electric equivalent not included in total.

8.1.3. Performance Summary

The overall process performance for the reference air-blown PC plants without CO₂ capture is shown in Table 8.4. The power generation efficiency for the sub-critical PC plant without CO₂ capture is about 37 to 38%. The Illinois coal-fired power plant has a slightly higher generation efficiency than the PRB coal plant due to the lower moisture content of the Illinois coal.

Table 8.4. Overall process performance of air-blown PC plants

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Coal feed, as-received, lb/hr	179,766	360,611	710,569	261,598	524,982	1,035,679
Steam turbine power, MW	266.4	533.2	1,053.6	266.4	533.2	1,053.6
Auxiliary power use, MW	17.6	34.7	67.9	14.4	28.3	55.1
Net power output, MW	248.7	498.5	985.7	251.9	504.9	998.5
Net efficiency, % (HHV)	37.8	37.8	37.9	37.3	37.3	37.4
Heat rate, BTU/kWh (HHV)	9,024	9,016	8,993	9,150	9,137	9,128

8.1.4. Cost Analysis

The methodology of cost modeling and main financial assumptions are detailed in Appendix B.1. The cost model of conventional process areas in the PC power plant was that developed in U.S. DOE-funded studies (Gilbert/Commonwealth Inc., 1995; Office of Fossil Energy, U.S. DOE, 1999). Those of the LSFO unit and SCR unit were updated according to the latest EPA reports (Srivastava, 2000; Foerter and Jozewicz, 2001; U.S. EPA, 2002).

Table 8.5 summarizes the cost results of reference plants. The PRB coal-fired plant has a lower cost of electricity than the Illinois coal-fired plant mainly because no FGD unit was used for the power plant burning this coal (any new power plant burning PRB has to be equipped with a SO₂ sulfur removal process). As expected, the cost of electricity increases sharply with the decrease in plant capacity. In general, the estimated capital costs, operation and maintenance (O&M) costs, and costs of electricity are well within the range reported in references (Gilbert/Commonwealth Inc., 1995; Office of Fossil Energy, U.S. DOE, 1999).

Table 8.5. Cost analysis of the air-blown PC reference plants

Gross output (terminal)	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Net output, MW	248.7	498.5	985.7	251.9	504.9	998.5
Capital cost, \$/kW						
Total plant cost	1,403	1,119	914	1,339	1,019	877
Total plant investment	1,529	1,220	996	1,460	1,110	957
Total capital requirement	1,602	1,282	1,051	1,528	1,167	1,007
O&M costs, mills/kWh						
Fixed O&M	9.12	5.83	4.01	8.02	5.08	3.41
Variable O&M	4.91	3.14	2.16	4.32	2.74	1.84
Consumables	2.92	2.88	2.84	2.16	2.11	2.08
Fuel cost	10.84	10.85	10.81	10.38	10.40	10.37
Annual carrying charge, mills/kWh	36.06	28.84	23.64	34.38	26.26	22.66
Levelized cost of electricity, mills/kWh	63.84	51.54	43.47	59.27	46.58	40.36

8.2. Air-blown PC Plant with MEA Unit

8.2.1. Overall Process Descriptions

The air-blown PC plant with CO₂ capture employs a sub-critical steam power cycle similar to that of the reference plant. The combustion and flue gas conditions are the same as the reference plant. The schematic diagram of the power plant equipped with an MEA plant is illustrated in Figure 8.2. The flue gas from the FGD unit flows vertically upward through the absorber countercurrent to the MEA solution. The cleaned gases then leave through the stack. The CO₂-rich MEA solution leaves the absorber and passes through a heat exchanger and then is further heated in a stripper using low-pressure steam to produce a concentrated CO₂ stream. The regenerated CO₂-lean solution is then cooled and re-circulates to the absorber. The CO₂ stream from the stripper is cooled in a condenser to remove moisture and then passes through a two-stage compressor with inter-stage coolers. The CO₂ stream is compressed to 83 bars through the three-stage compressors with inter-stage coolers. The high-pressure CO₂-rich product stream from the compressor is liquefied by cooling to ambient temperatures. Any residual trace gases are flashed off in a gas separator before transportation.

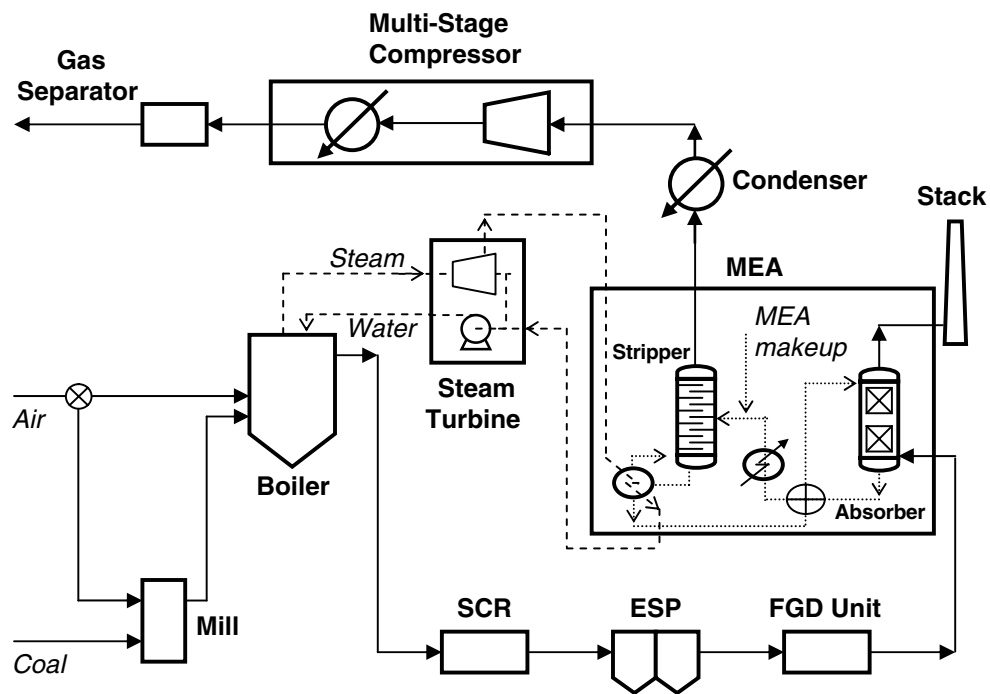


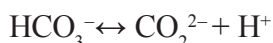
Figure 8.2. Schematic diagram of the PC power plant with MEA unit

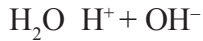
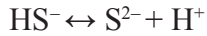
Because steam is used for MEA regeneration, the operating condition of the steam turbine system is partly changed from that of the reference plant. The hot steam is drawn before entering the LP turbine at a pressure of 175 psi and then expands to 60 psi before reaching the stripper. The condensed water from the stripper is returned to a heat exchanger in the feed-water cycle.

MEA has strong affinity for absorbing various acid gases such as SO_2 , NO_x , and HCl . Therefore, for cost-effective operation of an MEA unit, the flue gas should contain low levels of acid gases. In this regard, both for the Illinois coal and low-sulfur PRB coal, a FGD unit is required upstream of the MEA unit. The LSFO process was employed for the Illinois coal with an SO_2 removal efficiency of 95%. A lime spray dryer process was employed for the PRB coal with a removal efficiency of 90%.

8.2.2. Process Simulation

Simulations of common process areas of the reference PC plant and of the PC + MEA plant were identical. The simulation of the MEA process was conducted using the K-value model and enthalpy model for amine. The chemical reactions in a CO_2 - H_2S -amine system are described by the following reactions in CHEMCAD (Chemstations Inc., 2004):





where R and R' represent alcohol groups. The reaction equations are solved simultaneously to obtain the free concentration of H₂S and CO₂. The partial pressure of H₂S and CO₂ are calculated using the Henry's constants and free concentration in the liquid phase. The chemical reaction constants and Henry's constants are built into the software.

The typical operating parameters were referred to in some recent publications (White, 2002; Freguia and Rochelle, 2003; Alie et al., 2004). Main parameters used in simulation are listed:

- Inlet flue gas temperature: ~129 °F
- MEA concentration: 30 wt%
- Liquid/gas molar ratio: 5.0
- Reboiler heat duty: ~3900 kJ/ kg of captured CO₂
- LP steam: 60 psi, 475°F
- CO₂ capture efficiency: 90%
- Inter-stage cooler temperature: 104°F
- Compressor efficiency: 85%
- CO₂ product pressure: 83 bars

Table 8.6 lists the performance of main streams for the 533-MW (gross) plants fired with the Illinois and PRB coals, respectively. The detailed results of the mass/energy balance simulation are available in Appendix A2.

Table 8.6. Main operating performance of the 533-MW (gross) plants

	Illinois coal	PRB coal
Combustion		
Air/coal equivalent ratio	1.15	1.15
Air flow rate, lb/hr	3,991,198	4,029,474
Coal feed rate, lb/hr	360,611	524,982
Steam generation		
Hot reheat steam, lb/hr	3,022,125	3,022,125
Superheat steam, lb/hr	3,422,824	3,422,824
Steam condensate, lb/hr	1,421,687	1,331,136
Main feed-water, lb/hr	3,321,228	3,321,228
Heat duty of cooling tower, mmBTU/hr	1,104	1,034
MEA unit		
Inlet flue gas volume, lb/hr	4,472,743	4,683,939
Gas inlet temperature, °F	129	157
MEA make-up, lb/hr	2,794	1,827
LP steam consumption, lb/hr	1,380,364	1,470,914
CO ₂ captured, lb/hr	834,748	894,354
CO ₂ product		
Flow rate, lb/hr	835,083	894,680
Temperature, °F	68	68
Composition		
O ₂ , mol%	0.001144	0.001172
N ₂ , mol%	0.018566	0.017991
Ar, mol%	0.000081	0.000068
CO ₂ , mol%	99.856110	99.859020
H ₂ O, mol%	0.120856	0.120859
SO ₂ , mol%	0.003230	0.000874
NO _x , mol%	0.000002	0.000003
NH ₃ , mol%	0.000011	0.000015

The MEA unit and CO₂ compressors consume considerable in-plant power. The results of the auxiliary power uses for 533-MW (gross) power plants with MEA unit are listed in Table 8.7. Induced draft fans and liquid pumps used in the MEA unit shared about 20% of the total auxiliary power use, while the CO₂ compression shared near half of the total.

Table 8.7. Auxiliary power use of the 533-MW (gross) power plants with MEA unit

	Illinois coal	PRB coal
Auxiliary load, kW		
Coal handling	233	339
Pulverizers	2,017	2,937
Primary air fans	1,199	1,212
Forced draft fans	1,142	1,154
Induced draft fans	4,921	5,122
Seal air blowers	45	46
Steam turbine auxiliaries	884	884
Condensate pumps	895	891
Main feed pump ¹	10,938	10,938
Circulating water pumps	2,124	1,989
Cooling tower fans	1,201	1,125
Ash handling	1,658	1,424
Miscellaneous	2,411	2,411
Transformer loss	1,215	1,215
ESP	1,259	1,319
FGD	7,500	3,500
SCR	2,750	2,750
MEA: induced draft fans	13,098	15,837
pumps	2,801	2,980
CO ₂ compressor	35,423	37,951
Subtotal	82,777	85,086

¹Driven by auxiliary steam turbine; electric equivalent not included in total.

8.2.3. Performance Summary

The overall process performance for the PC + MEA unit for CO₂ capture is shown in Table 8.8. A large energy penalty exists due to the steam use for the MEA unit. The terminal power output of the steam turbine was reduced by about 17% compared to the reference plant without CO₂ capture. As mentioned before, the CO₂ compression and MEA unit also largely increased the auxiliary power use. As a result, the net efficiency of power generation was reduced to about 27% for the Illinois coal and 26% for the PRB coal, compared to 38% and 37% in the reference plants, respectively.

Table 8.8. Overall process performance of air-blown PC plants with MEA

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Coal feed as-received, lb/hr	179,766	360,611	710,569	261,598	524,982	1,035,679
Steam turbine power, MW	220.3	440.9	871.6	217.4	434.9	859.4
Auxiliary power use, MW	41.6	82.8	163.6	42.8	85.1	168.2
Net power output, MW	178.7	358.1	708.0	174.6	349.8	691.2
Net efficiency, % (HHV)	27.2%	27.2%	27.3%	25.8%	25.8%	25.9%
Heat rate, BTU/kWh (HHV)	12,562	12,549	12,519	13,208	13,189	13,186

8.2.4. Cost Analysis

8.2.4.1. *New Plant.* The cost model developed to estimate the MEA unit is detailed in Appendix B.1. The cost models used were those developed in recent DOE project reports (Parsons Energy and Chemicals Group Inc. and Wolk Integrated Technical Services, 2000; Parsons Infrastructure & Technology Group, Inc., 2002; Rao and Rubin, 2002; Rao et al., 2004). Cost models for other process areas are the same as for the reference plants.

The results of cost analyses for the power plants are summarized in Table 8.9. The definitions of the cost of CO₂ avoidance and the cost of CO₂ removal can be found in Appendix B1. From the table, the costs of electricity increase by about 77% for the Illinois coal and 95% for the PRB coal, compared to the cost of electricity for the reference plants, respectively. The CO₂ avoidance cost ranges from \$47 to \$67/ton for the selected plant capacities.

Table 8.9. Cost analysis of the PC plants with MEA unit

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Net output, MW	178.7	358.1	708.0	174.6	349.8	691.2
Capital cost, \$/kW						
Total plant cost	2,414	1,938	1,586	2,461	2,015	1,627
Total plant investment	2,632	2,112	1,729	2,683	2,197	1,774
Total capital requirement	2,761	2,224	1,828	2,810	2,307	1,870
O&M ¹ costs, mills/kWh						
Fixed O&M	14.65	9.56	6.69	14.67	9.60	6.55
Variable O&M	7.89	5.15	3.60	7.90	5.17	3.53
Consumables	11.07	11.20	11.14	9.29	9.22	9.19
Fuel cost	15.09	15.11	15.05	14.99	15.01	14.98
Annual carrying charge, mills/kWh	62.14	50.05	41.13	63.24	51.91	42.08
Levelized cost						
Cost of electricity, mills/kWh	110.84	91.06	77.62	110.09	90.90	76.34
Cost of CO ₂ avoidance, \$/t CO ₂	64.73	54.38	47.15	66.94	58.31	47.44
Cost of CO ₂ removal, \$/t CO ₂	44.48	37.36	32.39	44.09	38.40	31.22

¹Operating and maintenance.

Table 8.10. Cost analysis of the MEA process

	Illinois coal			PRB coal		
	267 MW	533 MW	1,054 MW	267 MW	533 MW	1,054 MW
Total plant cost, \$1,000	89,252	147,331	240,095	92,286	152,384	248,543
O&M cost, \$1,000/year						
Fixed O&M						
Operating labor	701	701	701	701	701	701
Maintenance	2,231	3,683	6,002	2,307	3,810	6,214
Admin. & support labor	478	652	931	487	667	956
Subtotal	3,410	5,036	7,634	3,495	5,178	7,870
Variable O&M						
Amine make-up	4,847	9,722	19,158	3,168	6,356	12,542
Inhibitor	969	1,944	3,832	634	1,271	2,508
Acoustic soda	301	603	1,189	320	643	1,268
Activated carbon	173	348	686	185	371	732
Waste disposal	52	518	1,020	30	61	121
Water	1,330	2,660	5,319	1,602	3,204	6,408
Subtotal	7,673	15,796	31,202	5,939	11,906	23,579

Table 8.10 presents the cost breakdown for the MEA process. For the example, for the 533-MW (gross) power plant, the installation of the MEA process resulted in an 26% increase in total capital costs and a 30% increase in operating and maintenance costs.

8.2.4.2. MEA Retrofit. In the retrofit case, all existing capital cost and operating and maintenance costs were assumed to be same before and after retrofit. Therefore, the cost analysis for retrofit only considers new expenditures in retrofit for CO₂ capture, which mainly consist of the costs related to the MEA and CO₂ compression facilities.

Three assumptions were adopted in this study. First, a retrofit factor of 1.2 was used to estimate the retrofit capital cost. Second, a 15-year remaining life was assumed for the retrofitted plant, and, based on the same financial criteria as for the new plant, a capital factor of 0.155 was adopted for amortizing the new capitals. Third, the reduced power generation due to CO₂ capture was assumed to be balanced with construction of a new NGCC plant. An electricity cost of 34 mills/kWh for NGCC was adopted in this study. The CO₂ emissions from the new NGCC plant were deducted in estimating the net CO₂ reduction.

The results are shown in the following table. The CO₂ avoidance cost in the MEA retrofit ranges from \$35 to \$45/t. The costs are lower than the new plants. This is a benefit of the construction of the new NGCC plant with electricity generation cost and CO₂ emissions both significantly lower than those of the coal-fired power plant.

Table 8.11. Cost analysis of the PC plants with MEA retrofit

	Illinois coal			PRB coal		
	266 MW	533 MW	266 MW	533 MW	266 MW	533 MW
Net output, MW	249	498	986	252	505	998
Retrofit TCR, \$,1,000	102,416	170,008	278,741	105,261	174,427	285,771
Increase of levelized capital, \$,1,000/yr	18,619	30,908	50,675	19,136	31,711	51,953
Increase of O&M, \$,1,000/yr	11,083	20,832	38,836	11,794	20,867	37,116
Electricity loss, \$,1,000/yr	14,602	29,269	57,889	16,134	32,347	64,064
CO ₂ reduction, kt/yr	1,157	2,320	4,572	1,232	2,472	4,878
CO ₂ emissions of NGCC, kt/yr	156	314	620	173	347	686
Cost of CO ₂ avoided, \$/t	44.30	40.37	37.30	44.43	39.95	36.53

8.3. Oxy-combustion Process

8.3.1. Process Descriptions

A sub-critical steam power cycle similar to the air-blown PC plant is employed in the oxy-combustion process (Figure 8.3). The steam turbine generation system is based on the nominal 2,415 psi throttle steam conditions. The boiler for the oxy-combustion is similar to that for the air-blown combustion because in the former process a portion (70 to 75%) of the CO₂-rich combustion flue gas exiting the boiler is recycled to the boiler to provide an oxygen-containing gas comparable to that of an air-blown PC.

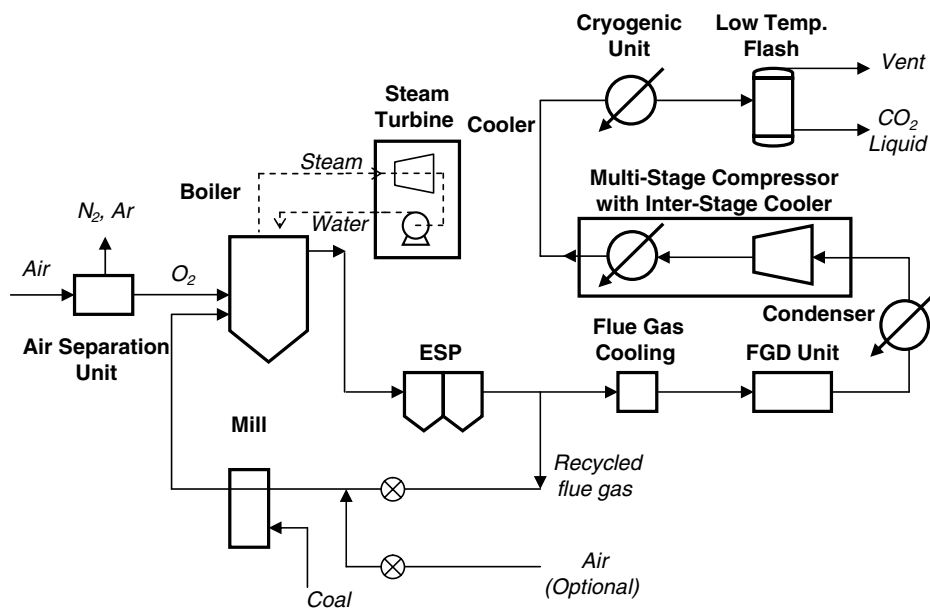


Figure 8.3. Schematic diagram of the oxy-combustion power plant

The replacement of combustion air with oxygen provides a nitrogen-free atmosphere in the boiler. A cryogenic ASU for separating nitrogen from oxygen is employed to produce a 95% purity oxygen stream. When oxygen instead of air is used, the volume of the flue gas is reduced fivefold. The flue gas generated in the OEC process is also highly enriched (>90% dry) with CO₂.

The NO_x removal by the SCR process was not considered for the OEC process because NO_x emissions as low as 0.15 lb/mmBTU can be obtained without NO_x control (Châtel-Pélage et al., 2004).

A FGD unit is required for power plants burning both coals. An LSFO process is considered for the Illinois coal with a removal efficiency of 95%, and an LSD process is considered for the PRB coal with an efficiency of 90%. Because the flue gas temperature in the oxy-combustion process (~395°F) is higher than that of the air-blown process (~295°F), flue gas cooling is necessary before the gas enters the FGD unit.

The flue gas leaving the FGD unit is condensed to remove most moisture in the gas. The flue gas then passes through the three-stage compressors, where remaining moisture is also removed in the inter-stage coolers. The high-pressure gas from the compressor is further cooled to about -33°C in a cryogenic unit using ammonia as the cooling medium. Finally, the cold liquid CO₂ stream enters a low-temperature flash process to remove trace amounts of any gaseous impurity before transportation.

8.3.2. Process Simulation

The process simulation was conducted for various process areas (i.e., the combustion system, steam turbine system, gas cleaning system, and CO₂ purification and compression system). The ASU was not simulated; its performance data were provided by American Air Liquide (personal communications, 2004)

The operating parameters selected for simulation were adopted using those reported in recent studies (Birkestad, 2002; Anderson and Maksinen, 2002; Singh et al., 2003):

- O₂/fuel equivalent ratio: 1.03
- Oxygen purity: 95%
- Flue gas recirculation ratio: 72%
- Flue gas temperature: 395°F
- Condenser operating temperature: 104°F
- Inter-stage cooler temperature: 104°F
- CO₂ product pressure: 83 bars
- Compression efficiency: 85%
- Cryogenic temperature: -33°C
- Cryogenic medium: ammonia
- Low temperature flash (LTF): 83 bars, -33°C
- CO₂ recovery in LTF: ~97%

Table 8.11 lists the main operating performance for the 533-MW (gross) oxy-combustion power plants. The detailed results of mass/energy balance calculations are listed in Appendix A3.

Table 8.12. Main operating performance for the 533-MW (gross) oxy-combustion plants

	Illinois coal		PRB coal	
Combustion				
O ₂ /fuel equivalent ratio, lb/hr	1.03		1.03	
O ₂ flow rate (95% purity), lb/hr	843,599		817,540	
Coal feed rate, lb/hr	348,375		506,615	
Flue gas recycle ratio, lb/hr	0.72		0.72	
Steam generation				
Hot reheat steam, lb/hr	3,022,125		3,022,125	
Superheat steam, lb/hr	3,422,824		3,422,824	
Steam condensate, lb/hr	2,802,051		2,802,051	
Main feedwater, lb/hr	3,321,228		3,321,228	
Heat duty of cooling tower, mBTU/hr	2,178		2,178	
Gas stream				
	Flue gas	CO₂ product	Flue gas	CO₂ product
Flow rate, lb/hr	1,161,068	874,274	1,297,622	927,390
Temperature, °F	395	68	395	68
Composition				
O ₂ , mol%	2.93	0.0236	0.33	0.0232
N ₂ , mol%	0.57	0.0016	1.80	0.0020
Ar, mol%	3.34	0.0382	2.97	0.0353
CO ₂ , mol%	63.01	99.7366	53.74	99.7887
H ₂ O, mol%	29.38	0.1383	41.05	0.1318
SO ₂ , mol%	0.77	0.0609	0.10	0.0176
NO _x , mol%	0.04	0.0009	0.05	0.0015
Fly ash flow rate, lb/hr	24,804	-	21,278	-

The auxiliary power use in the oxy-combustion power plants is presented in Table 8.12. The auxiliary power use of the ASU is based on 0.394 kWh/Nm³ pure O₂ and is almost independent of the O₂ purity, according to American Air Liquide. The ASU and CO₂ compression processes consume about 20% and 10% of the total gross output of the power plant, respectively. However, due to the reduced flue gas volume, the auxiliary power use by ESP, FGD, and induced draft fans decreases fourfold compared to the air-blown PC plant.

Table 8.13. Auxiliary power usage in the 533-MW (gross) oxy-combustion power plants

	Illinois coal	PRB coal
Auxiliary load summary, KWe		
Coal handling	225	328
Pulverizers	1,949	2,834
Primary air fans	1,133	1,221
Forced draft fans	1,079	1,163
Induced draft fans	1,353	1,470
Seal air blowers	43	46
Steam turbine auxiliaries	884	884
Condensate pumps	949	949
Main feed pump ¹	10,938	10,938
Circulating water pumps	4,187	4,187
Cooling tower fans	2,367	2,367
Ash handling	1,602	1,374
Miscellaneous	2,411	2,411
Transformer loss	1,215	1,215
ESP	338	376
FGD	2,016	998
Oxy-combustion-specific		
Flue gas recycle fan	1,634	1,817
Water pumps	200	507
Cryogenic unit	13,064	13,710
ASU	100,230	101,081
Compressor	48,999	49,258
Subtotal	185,879	188,196

¹Driven by auxiliary steam turbine; electric equivalent not included in total.

8.3.3. Performance Summary

Table 8.13 lists the overall performances of the oxy-combustion power plants. The generation efficiency of the oxy-combustion process is about 26 to 27% compared to about 37 to 38% for the air-blown plant without CO₂ capture (due to ASU). However, the oxy-combustion process is slightly more efficient than the air-blown plant + MEA unit (Table 8.8).

Table 8.14. Overall process performances of the oxy-combustion plants

	Illinois coal			PRB coal		
	266 MW	533 MW	1054 MW	266 MW	533 MW	1054 MW
Coal feed, as-received, lb/hr	17,3558	348,375	686,672	252,670	506,615	991,497
Steam turbine power, MW	266.4	533.2	1,053.6	266.4	533.2	1,053.6
ASU power, MWe	49.9	100.2	197.6	50.4	101.2	197.8
Other aux. power use, MW	43.1	85.6	169.8	43.9	87.1	172.6
Net power output, MW	173.3	347.4	686.2	172.1	345.0	683.1
Net efficiency, % (HHV)	27.3%	27.3%	27.3%	26.4%	26.4%	26.7%
Heat rate, BTU/kWh (HHV)	12,512	12,490	12,483	12,921	12,919	12,772

8.3.4. Cost Analysis

8.3.4.1. *New Plant.* The cost model developed to estimate the oxy-combustion process is detailed in Appendix B1. The cost data for the ASU was provided by American Air Liquide (personal communications, 2004; Singh et al., 2003; Châtel-Pélage et al., 2004; Sangras et al., 2004).

The cost was estimated for 266-MW, 533-MW, and 1,054-MW (gross) oxy-combustion power plants (Table 8.14). The cost of electricity increased by about 56% for the Illinois coal and about 70% for the PRB coal compared to the air-blown PC reference plants. The costs of CO₂ avoidance range from \$31 to \$43/t of CO₂ for the Illinois coal and from \$33 to \$46/t of CO₂ for the PRB coal. These costs are about 70% of those of the PC plant with a MEA unit.

Table 8.15. Cost analysis of the oxy-combustion power plants

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Net output, MW	173.3	347.4	686.2	172.1	345.0	683.1
Capital cost, \$/kW						
Total plant cost	2,221	1,836	1,528	2,230	1,863	1,549
Total plant investment	2,422	2,001	1,666	2,431	2,031	1,688
Total capital requirement	2,532	2,096	1,749	2,540	2,125	1,771
O& M costs, mills/kWh						
Fixed O&M	14.57	9.41	6.52	14.50	9.41	6.51
Variable O&M	7.85	5.07	3.51	7.81	5.07	3.51
Consumables	3.85	3.84	3.85	3.82	3.81	3.81
Fuel cost	15.02	15.04	15.01	14.68	14.68	14.51
Annual carrying charge, mills/kWh	56.97	47.16	39.36	57.17	47.83	39.86
Levelized cost						
Electricity, mills/kWh	98.26	80.52	68.25	97.98	80.81	68.20
CO ₂ avoidance, \$/t of CO ₂	43.00	36.19	31.05	46.04	40.66	33.14
CO ₂ removal, \$/t of CO ₂	30.58	25.71	22.03	32.05	28.33	23.16

Table 8.16. Cost analysis of specific components in oxy-combustion process

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Total plant cost, \$1,000						
ASU	44,672	89,667	176,741	45,100	90,429	176,978
Flue gas cooling	1,528	2,403	3,733	507	3,185	4,934
Condenser	3,686	6,071	10,000	3,686	6,071	10,000
Cryogenic unit						
Flashes	1,908	3,372	5,970	1,969	3,590	6,196
Heat exchangers	10,179	14,808	25,065	10,504	15,279	25,863
NH ₃ compressor	5,836	10,401	14,161	6,017	10,736	14,608
NH ₃ expander	251	457	773	261	475	803
Compression	18,721	33,463	45,628	18,769	33,549	45,748
Subtotal	86,781	160,641	282,070	86,814	163,314	285,131
O&M cost						
1. FOM						
Operating labor	1,402	1,402	1,402	1,402	1,402	1,402
Maintenance	2,170	4,016	7,052	2,170	4,083	7,128
Admin. & support labor	681	902	1,267	681	910	1,276
Subtotal	4,252	6,320	9,720	4,253	6,395	9,806
2. VOM						
Cooling water	526	1,051	2,102	652	1,303	2,606

The cost breakdown of the process areas specific to the oxy-combustion process is listed in Table 8.15. For the example, for a 533-MW (gross) plant, the oxy-combustion specific components require a 29% increase in capital costs and a 12% increase in operating and maintenance costs.

8.3.4.2. Retrofit with Oxy-combustion. The cost analysis for oxy-combustion retrofit only considers new expenditure for CO₂ capture. The new costs are mainly related to the ASU, moisture condensation, and CO₂ compression facilities.

The assumptions same as for the MEA retrofit (i.e., the retrofit factor of 1.2) the remaining 15-year life time, and the new NGCC plant for supplement the generation, were used in the oxy-combustion retrofit.

The results are shown in Table 8.17. The CO₂ avoidance cost in the oxy-combustion retrofit ranges from \$30 to \$36/t. The costs for the Illinois coal are only slightly lower than those for the new plants. Despite the advantages of the new NGCC plant, the existing FGD unit wouldn't benefit from the reduced volume of flue gas in the retrofit case.

Table 8.17. Cost analysis of the oxy-combustion retrofit

	Illinois coal			PRB coal		
	266 MW	533 MW	1,054 MW	266 MW	533 MW	1,054 MW
Gross output, MW	179	358	708	175	350	691
Retrofit TCR, \$1,000	97,452	180,290	316,540	97,529	183,363	319,297
Increase of levelized capital, \$1,000/yr	17,717	32,777	57,547	17,731	33,335	58,048
Increase of O&M, \$1,000/yr	4,777	7,371	11,822	4,904	7,698	9,806
Electricity loss, \$1,000/yr	15,718	31,511	62,438	16,644	33,333	65,747
Coal savings of OEC, kt/yr	-571	-1,125	-2,198	-547	-1,126	-2,709
CO ₂ reduction, kt/yr	1,196	2,401	4,733	1,275	2,556	5,035
CO ₂ emissions of NGCC, kt/yr	168	338	669	178	357	704
Cost of CO ₂ avoided, \$/t	36.63	34.18	31.89	35.33	33.31	30.23

8.4. IGCC + Physical absorption

8.4.1. Overall Process Descriptions

The IGCC plant is based on the General Electric H-type advanced turbine system combustion turbine coupled with a heat recovery unit that generates steam for a single steam turbine generator. An E-Gas gasifier is chosen as the basis for this IGCC configuration. The schematic diagram of the IGCC plant with a Selexol unit is displayed in Figure 8.4 (Parsons Energy and Chemicals Group Inc. and Wolk, 2000).

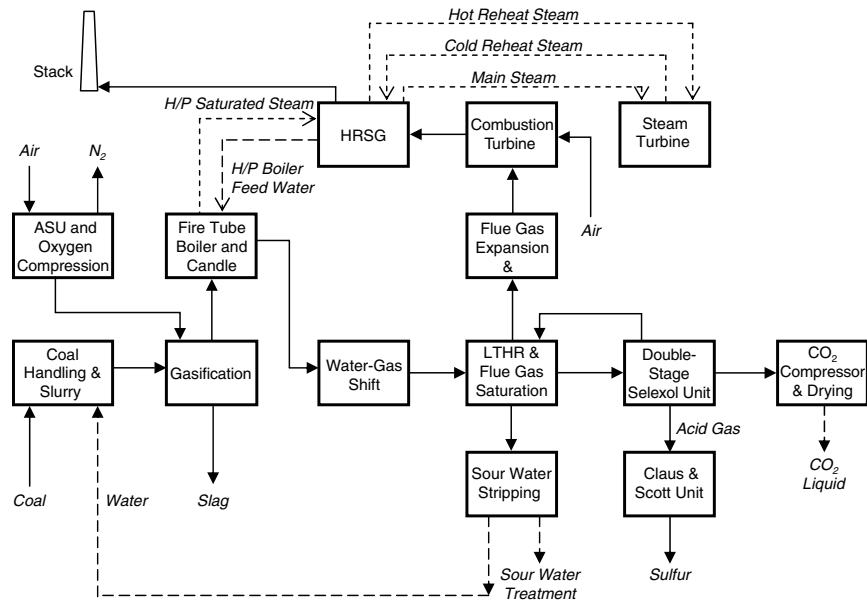


Figure 8.4. Schematic diagram of the Destec IGCC plant with Selexol unit

Coal-water slurry containing 63 wt% coal and a 95% oxygen stream from the ASU are fed to the gasifier. The E-gas gasifier is a two-stage, oxygen-blown, entrained flow, slagging gasifier. In the first stage, partial combustion of the coal maintains a temperature of about 2,500°F in the gasifier. Most of the coal reacts with steam to produce a raw fuel gas. Additional coal-water slurry added to the second stage undergoes de-volatilization, pyrolysis, and partial gasification to cool the raw fuel gas and enhance its heating value.

The fuel gas is further cooled using a fire tube boiler integrated with the gasifier and other heat exchangers to generate high-pressure, superheated steam for power generation. A candle filter is used to remove particulates, which are recycled to the gasifier. The fuel gas stream is mixed with steam and passes through the three-stage shift reactors at reduced entry temperatures. Heat exchangers between reaction stages help maintain the temperatures.

The fuel gas is treated in a double-stage Selexol unit to remove H₂S and CO₂ (Figure 8.5). H₂S is preferentially removed in the first absorber (705 psi, 105°F), and CO₂ is removed in the second absorber (90°F, 700 psi). The rich solvent from the first absorber enters two sets of flash where CO₂ is recovered at 50 psi in the first flash and the remainder at atmospheric pressure in the second flash with a total CO₂ removal efficiency of 98 to 99%. The H₂S-rich solvent is regenerated in a stripper through indirect heating by low-pressure steam in a reboiler. The resulting stripper acid gas stream is sent to a Claus unit.

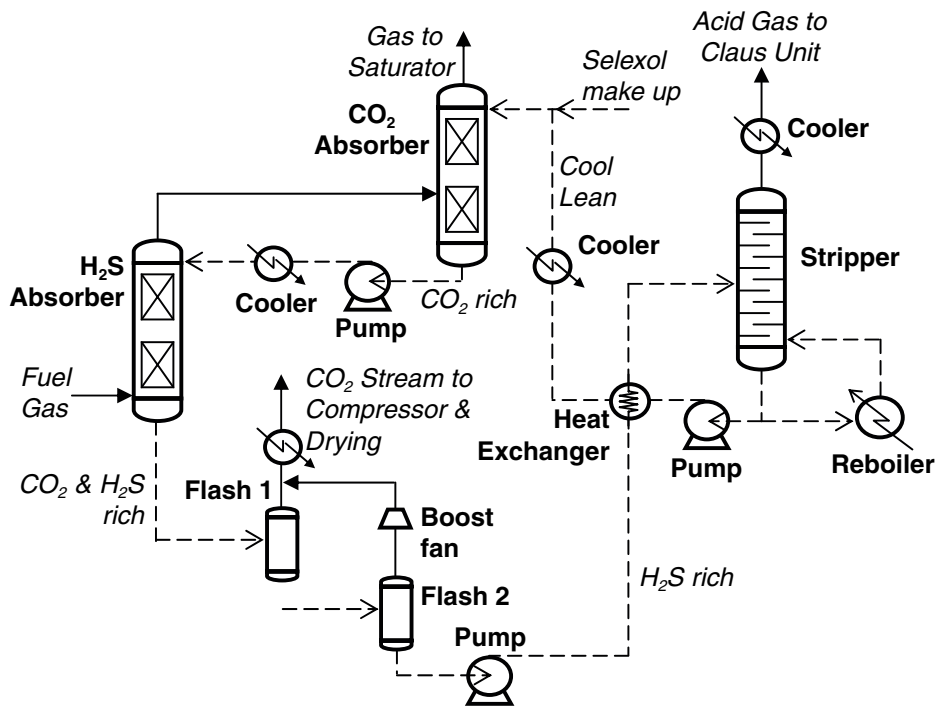


Figure 8.5. Schematic diagram of the Selexol unit for CO₂ removal

The cleaned gas passes to a moisture saturator to humidify the fuel gas and also increase its sensible heat content before entering an air-fired combustion turbine. The exhaust heat from the turbine is recovered in an HRSG to produce steam used in the steam turbines. The electricity generation is based on a combined cycle.

8.4.2. Process Simulation

The IGCC simulation included two process blocks. One included the gasifier, the shift reactors, the saturators, the Selexol unit, and the gas combustion turbine, and the other included the steam turbine system. The heat exchanges involving in the combined cycle and other heat exchangers are balanced between the two blocks. The Selexol unit was not simulated in detail due to lack of thermodynamic data in CHEMCAD. However, a simple mass/heat balance was included assuming 99% and 98% recovery of H₂S and CO₂, respectively, from the fuel gas after shift reactions.

The main operating parameters used in simulation were those reported in related recent studies (Parsons Energy and Chemicals Group Inc. and Wolk Integrated Technical Services, 2000; EG&G, 2000; IEA Greenhouse Gas R&D Programme, 2003). The overall CO₂ removal efficiency was assumed to be 90%. Table 8.18 lists the main performance of a 536-MW (gross) IGCC plants. The detailed results of the mass/energy balance simulations are available in Appendix A4.

Table 8.18. Main operating performance of the 536-MW (gross) IGCC plants

	Illinois coal		PRB coal	
Coal feed rate, lb/h	324,152		466,262	
O ₂ (95% purity) flow rate, lb/h	268,911		288,533	
Water make-up, lb/h	584,349		584,349	
Raw fuel gas, lb/h	777,543		934,997	
Slag, lb/h	28,850		24,471	
Steam to gas shift reactor, lb/h	293,937		293,937	
Air to gas combustor, lb/h	5,140,434		5,022,433	
CO ₂ captured, lb/h	738,801		788,136	
CO ₂ capture efficiency, %	89.6		89.8	
Gas composition	Fuel gas	Flue gas	Fuel gas	Flue gas
H ₂ O, %	17.06	21.86	25.42	22.39
O ₂ , %	-	10.88	-	10.74
N ₂ , %	0.56	65.32	0.37	64.93
Ar, %	0.97	1.00	0.88	1.01
H ₂ , %	31.21	0.00021	29.22	0.00024
CO, %	37.30	0.00003	29.63	0.000034
CO ₂ , %	10.96	0.93	13.84	0.92
CH ₄ , %	1.30	-	0.57%	-
H ₂ S, %	0.5618	-	0.0742%	-
NH ₃ , %	0.0087	-	0.0064%	-

Table 8.19. Auxiliary power use in IGCC plants with Selexol process

	Illinois coal	PRB coal
Gross power summary, kW		
Gas turbine power	358,618	358,541
Steam turbine power	174,601	174,601
Generator loss	-7,997	-7,996
Turbo-set power	525,222	525,146
Fuel gas expander power	10,392	10,611
Gross power	535,614	535,757
Auxiliary load summary, kW		
Coal handling and conveying	366	526
Coal milling	843	1,213
Coal slurry pumps	168	235
Slag handling and dewatering	145	123
Recycle gas blower	113	127
Air separation plant	26,138	28,045
Oxygen boost compressor	15,153	16,259
Selexol plant	7,551	7,977
Claus/TGTU ¹	102	15
Tail gas recycle	1,016	154
Humidification tower pump	63	65
Humidifier makeup pump	141	141
Low-pressure CO ₂ compressor	823	865
High-pressure CO ₂ compressor	24,532	25,782
Condensate pumps	329	329
High-pressure boiler feed pump	3,294	3,294
Low-pressure boiler feed pump	61	61
Miscellaneous balance of plant	1,092	1,092
Gas turbine auxiliaries	623	623
Steam turbine auxiliaries	244	244
Circulating water pumps	1,636	1,636
Cooling tower fans	1,028	1,028
Flash bottoms pump	55	55
Transformer loss	1,660	1,661
Subtotal	87,175	91,549

¹TGTU, tail gas treating unit.

The auxiliary power use for the 535 (gross) IGCC plants with CO₂ capture are summarized in Table 8.19. The total auxiliary power use amounts to about 17% of the gross power output, of which the Selexol unit consumes about 1.4 to 1.5%, and CO₂ compression consumes about 5%.

8.4.3. Performance Summary

The overall performance data for IGCC plants equipped with Selexol units are listed in Table 8.20. The net generation efficiency for an Illinois coal is about 38% which is comparable to that for the PRB coal (~37%). The net generation efficiency of the IGCC plant decreases significantly due to the power use for CO₂ capture and compression compared to the net efficiency of 45 to 56% in the IGCC plant without CO₂ capture. However, the net efficiency of IGCC plant with Selexol unit is comparable to an air-blown PC plant without CO₂ removal (see Table 8.5).

Table 8.20. Overall performance of an IGCC plant with CO₂ removal

	Illinois coal			PRB coal		
	268 MW	536 MW	1,071 MW	268 MW	536 MW	1,071 MW
Coal feed as received, lb/hr	162,097	324,152	648,133	233,163	466,262	932,271
Oxygen feed, lb/hr	134,473	268,911	537,680	144,286	288,533	576,910
Water, lb/hr	292,213	584,349	1,168,389	292,214	584,349	1,168,381
Gross power, MWe						
Steam turbine	179.3	358.6	717.4	179.2	358.5	717.3
Gas turbine	87.3	174.6	349.3	87.3	174.6	349.3
Generator loss	-4.0	-8.0	-16.0	-4.0	-8.0	-16.0
Fuel gas expander	5.2	10.4	20.8	5.3	10.6	21.2
Aux. power use, MWe	-43.6	-87.2	-174.4	-45.8	-91.5	-183.1
Net power, MWe	224.2	448.4	897.1	222.1	444.2	888.7
Net efficiency, HHV %	37.80	37.81	37.83	36.90	36.91	36.93
Heat rate, BTU/kWh (HHV)	9,020	9,017	9,013	9,239	9,237	9,232

8.4.4. Cost Analysis

The cost model developed to estimate the IGCC plant with Selexol unit is detailed in Appendix B.2. The estimation approach and financial assumptions were mainly referred to the studies on the E-gas gasifier-based IGCC technology (Parsons Energy and Chemicals Group Inc. and Wolk Integrated Technical Services, 2000; EG&G, 2000; Akunuri, 2000).

The cost was estimated for the 268-MW, 536-MW and 1,071-MW (gross) IGCC plants with the Selexol process. The results are listed in Table 8.21. The cost of electricity for the Illinois coal is about 10% lower than the PRB coal, mainly because the sulfur by-product credit for the Illinois coal is 50 mills/kWh more than for the PRB coal. The cost of CO₂ avoidance, for both the Illinois coal and the PRB coal, for an IGCC plant with Selexol process is the lowest among the three CO₂ capture processes examined in this study.

Table 8.21. Cost of electricity generation of IGCC power plants

	Illinois coal			PRB coal		
	268 MW	536 MW	1,071 MW	268 MW	536 MW	1,071 MW
Capital cost, \$/kW						
Total plant cost	1,967	1,610	1,318	2,196	1,795	1,467
Total plant investment	2,241	1,834	1,501	2,502	2,045	1,672
Total capital requirement	2,338	1,915	1,571	2,606	2,132	1,746
O&M costs, mills/kWh						
Fixed O&M	14.36	9.84	7.11	15.37	10.64	7.74
Consumables	1.09	1.09	1.09	1.04	1.04	1.04
Fuel cost	10.84	10.84	10.84	10.50	10.50	10.50
Sulfur credit	0.59	0.59	0.59	0.09	0.09	0.09
Annual carrying charge, mills/kWh	52.61	43.10	35.35	58.65	47.98	39.29
Levelized cost						
Electricity, mills/kWh	78.32	64.29	53.80	85.47	70.06	58.48
CO ₂ avoided, \$/t of CO ₂	19.06	16.79	13.61	28.67	24.17	19.90
CO ₂ capture, \$/t of CO ₂	19.02	16.75	13.58	26.78	22.58	18.59

8.5. Cost Comparisons

8.5.1. General Comparisons

Compared to the conventional PC power plant without CO₂ capture, the MEA unit and the oxy-combustion process significantly decreases the electricity generation efficiency (Figure 8.6). Installation of an MEA unit decreases the generation efficiency by about 28.2%. The oxy-combustion process decreases the generation efficiency by about 27.9%, just slightly lower than the MEA unit. The IGCC plant with CO₂ capture has a generation efficiency comparable to the PC plant without CO₂ capture. However, the IGCC plant without CO₂ capture could have a generation efficiency as high as 46%.

When a power generation plant is equipped with a CO₂ capture unit, the reduction of the net power output is largely due to energy use in the CO₂ capture process and the compression of CO₂ gas. Both the MEA unit and the oxy-combustion process consume about one third of the gross output of a power plant (Figure 8.7). The MEA unit and the ASU contribute to 50 to 60%, and CO₂ compression contributes to 20 to 25% of the total in-plant power use. In the IGCC plant the energy use of the Selexol unit is not significant because the bonding energy of CO₂ is not as strong with a physical absorbent as with a chemical absorbent. The IGCC plant also consumes much less oxygen than the oxy-combustion PC plant. In the IGCC plant, oxygen is only used for the gasification of coal rather than for combustion in the gas turbine.

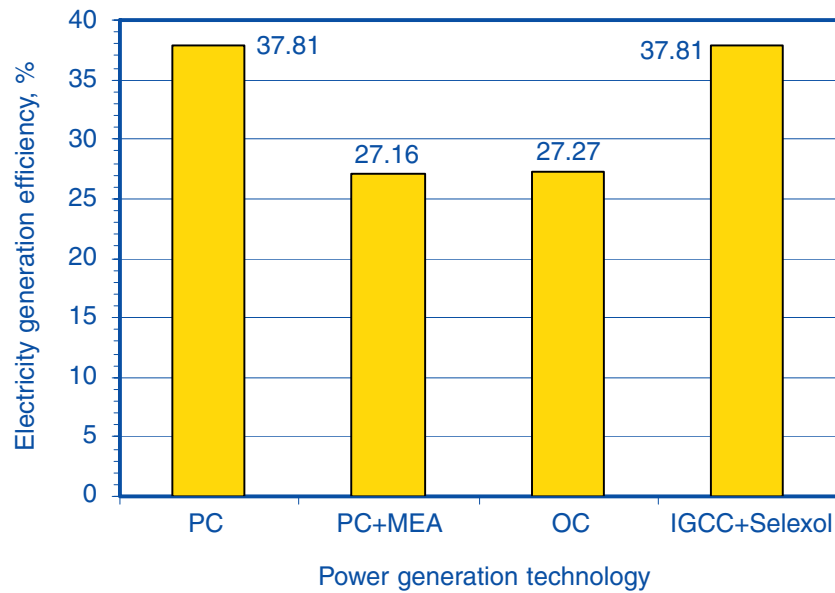


Figure 8.6. Net generation efficiency for 533-MW (gross) power plants (OC, oxy-combustion)

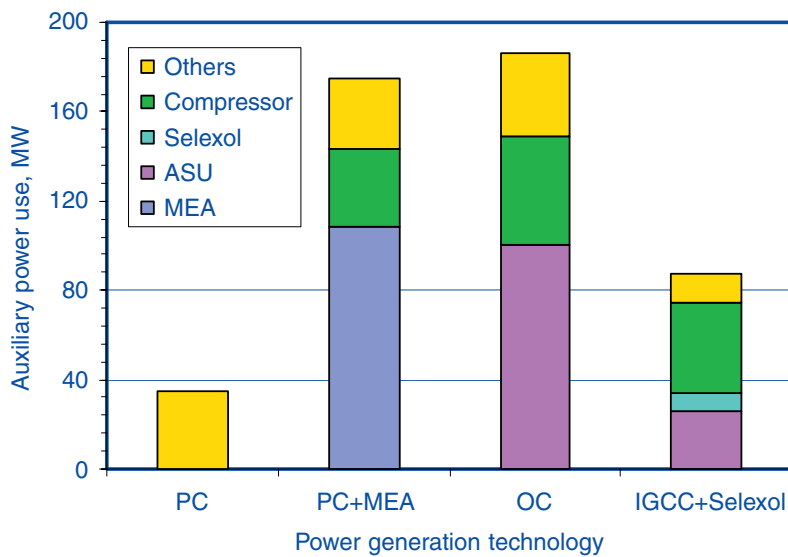


Figure 8.7. Auxiliary power uses for 533-MW (gross) power plants

The total plant cost for a PC plant without CO₂ capture is estimated to be \$1,110 /kW (Figure 8.8). When the MEA unit is installed, capital costs per unit output of the plant increases by about 73%. The unit capital cost of an oxy-combustion process is about 64% higher than the reference PC plant without CO₂ capture. The increase is mainly due to the installations of the ASU and cryogenic equipment. The capital cost of the IGCC plant with a Selexol unit is about 40% higher than the reference PC plant. The cost of electricity increased by 77%, 56%, and 25% for the PC + MEA plant, oxy-combustion process, and the IGCC plant with Selexol process, respectively, compared to that of the reference plant (Figure 8.9). The increased cost of electricity for the IGCC plant is mainly due to the increase in capital cost. For the MEA and oxy-combustion processes, the increase is contributed to higher capital cost and an increase in fixed operating cost plus the expenses associated with MEA chemicals.

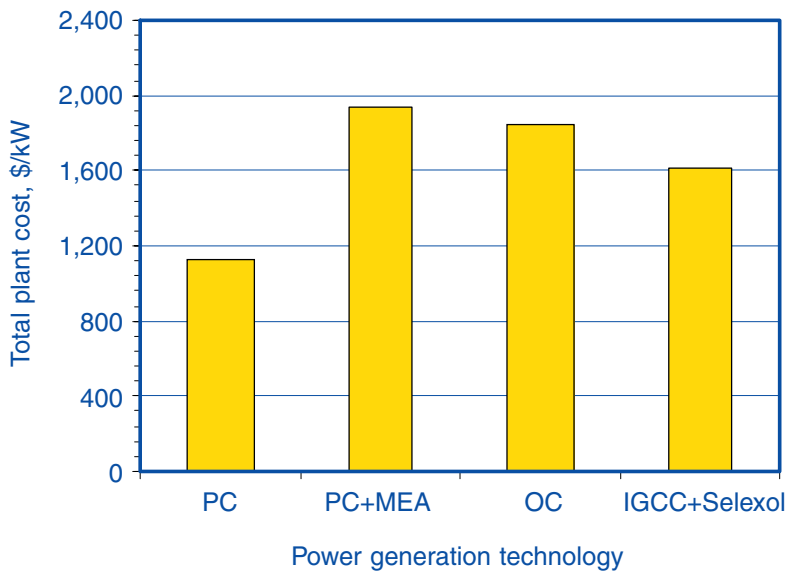


Figure 8.8. Capital costs for 533-MW (gross) power plants

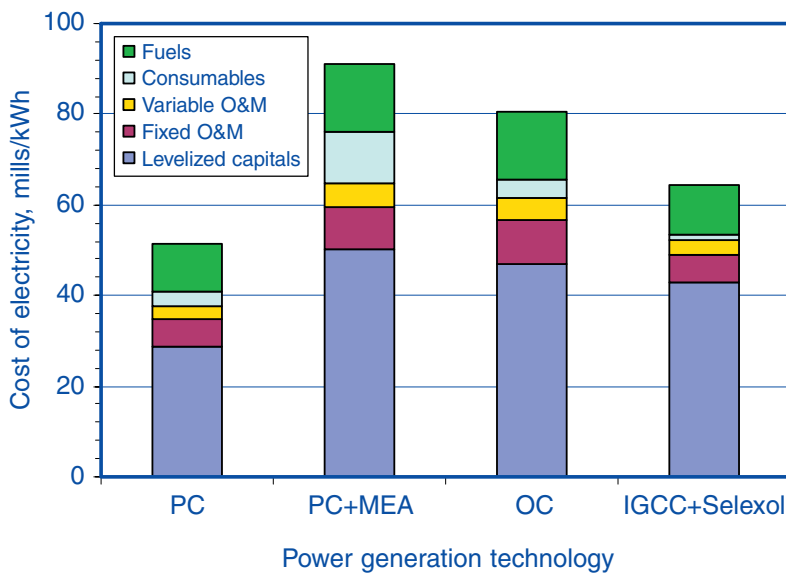


Figure 8.9. Costs of electricity for 533-MW (gross) power plants

The costs of CO₂ avoidance and CO₂ capture are based relative to the reference PC plant. For the PC + MEA power plant and the oxy-combustion process, the costs of CO₂ avoidance are much larger than the costs of CO₂ capture because the total amounts of the avoided CO₂ emissions are smaller than the captured CO₂ emissions. For the IGCC plant with Selexol process, the CO₂ capture and CO₂ avoidance are the same because CO₂ emissions per unit of electricity generation are comparable to those of the reference plant. The CO₂ avoidance costs for these three 533-MW (gross) power plants are \$54/t, \$36/t, and \$17/t, respectively (Figure 8.10).

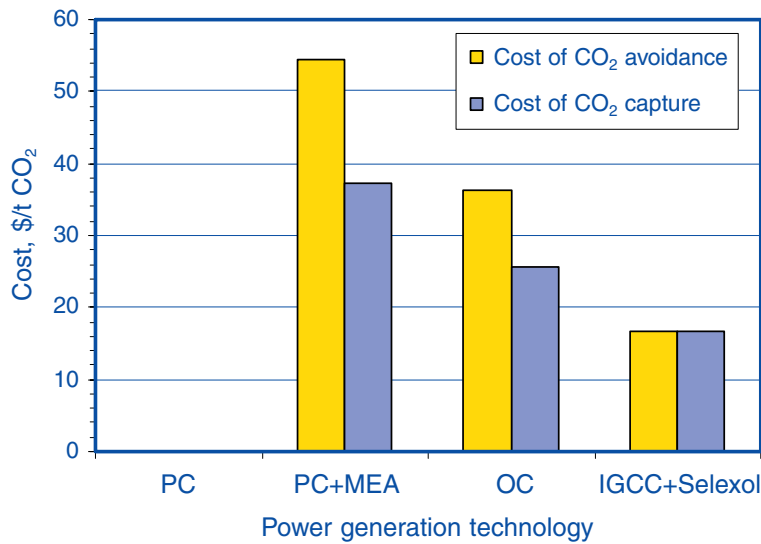


Figure 8.10. Costs of CO₂ avoidance and capture for 533-MW (gross) power plants

Three plant scales—266 MW, 533 MW, and 1,066 MW (gross)—were analyzed for all case studies. The costs of electricity increased as plant size decreased and increased more sharply as capacity decreased (Figure 8.11). The cost of electricity was well correlated to the plant size using a power rule with a factor of -0.28 to -0.26 .

The cost of CO₂ avoidance and plant size (Figure 8.12) followed a similar trend. The power rule was also applied to correlate the costs to plant size. A power factor of -0.24 to -0.23 fit the data sets well for the three CO₂ capture processes studied.

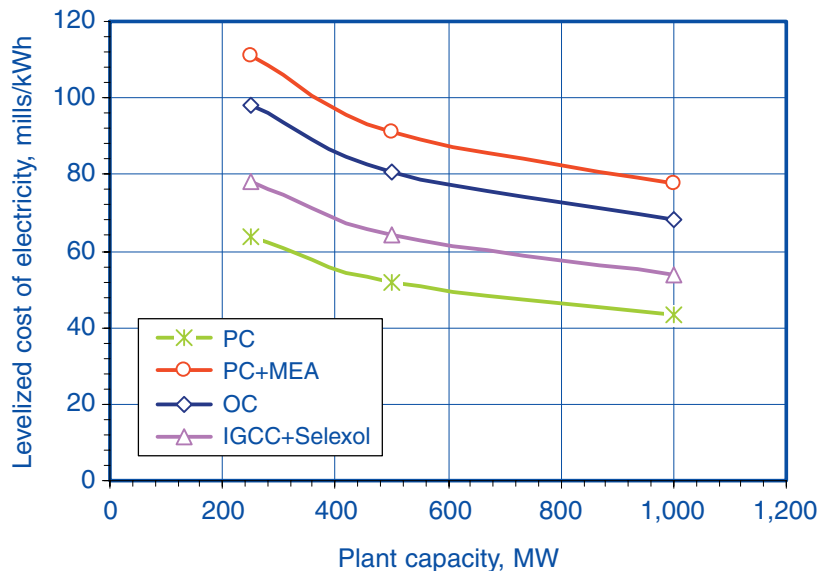


Figure 8.11. Effect of plant size on electricity cost

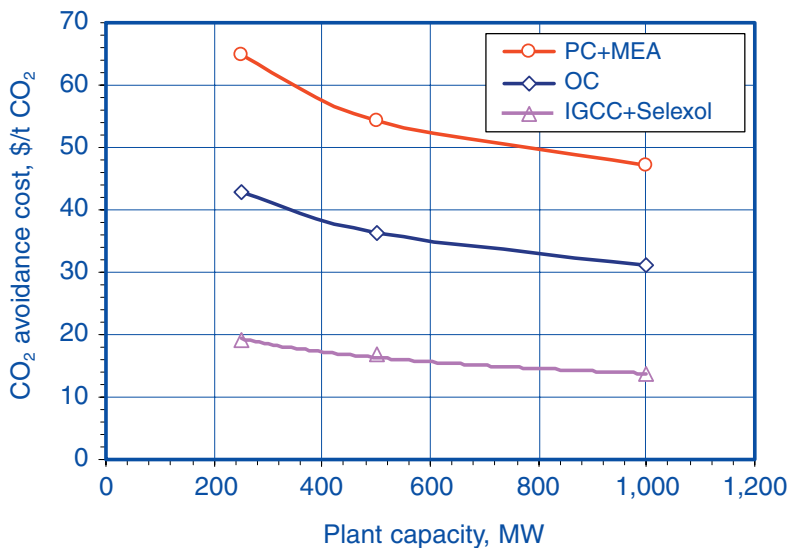


Figure 8.12. Effect of plant size on CO₂ avoidance cost

8.5.2. Economics of Illinois Coal and PRB Coal

Additional techno-economic studies were conducted to compare the costs of electricity and CO₂ avoidance for power plants burning high-sulfur Illinois coal and PRB coal. Almost equal amounts of both coals are currently burned in power plants in the Illinois Basin. The reference PC plant burning the PRB coal has lower electricity costs than does the plant burning Illinois coal because no FGD installation was considered for the PC plant. However, for power plants that are equipped with the MEA units, the coal choice does not impact the cost of electricity. When an MEA unit is installed, an FGD unit is required to remove SO₂ emissions from the flue gas before it enters the MEA unit. Similarly, electricity costs for oxy-combustion plants burning Illinois coal and PRB coal were comparable. An IGCC plant + Selexol process burning Illinois high-sulfur is more attractive than burning PRB coal, mainly because sulfur in the former plant is recovered as a salable by-product (i.e., elemental sulfur) (Figure 8.13).

The calculated CO₂ avoidance costs favor burning high-sulfur coal rather than PRB coal in the three power generation plants studied. CO₂ avoidance cost is related to the cost of electricity. As shown in Figure 8.14, the CO₂ avoidance costs for the PRB coal are 7%, 12%, and 44% larger than the Illinois coal for the PC + MEA plant, the oxy-combustion process, and the IGCC plant, respectively.

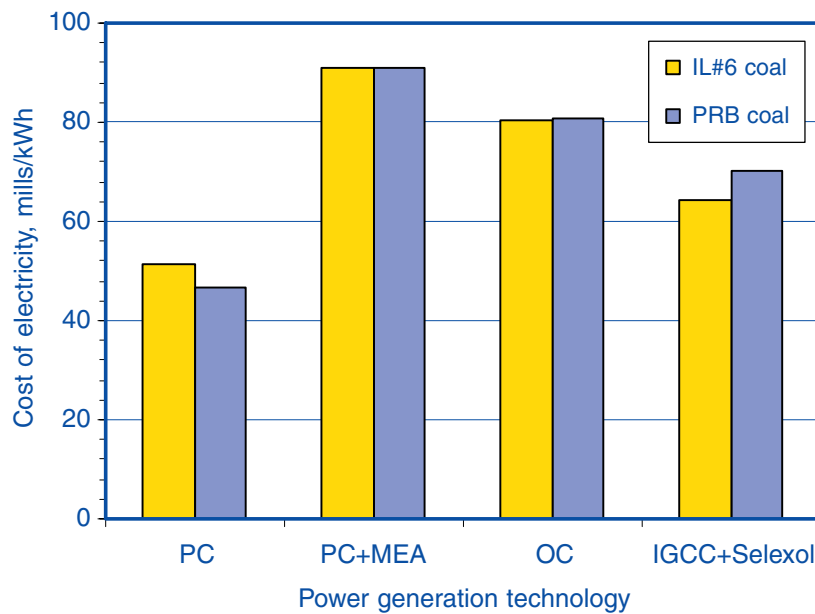


Figure 8.13. Costs of electricity for Illinois coal-fired and PRB coal-fired 533-MW plants

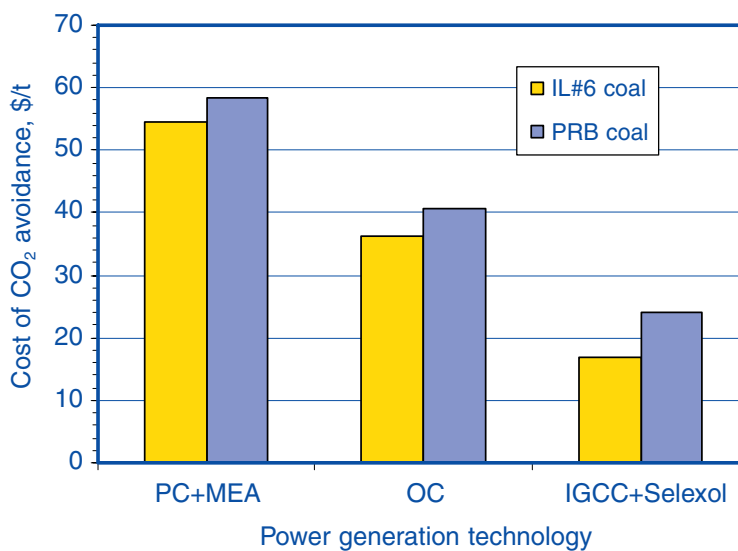


Figure 8.14. CO₂ avoidance costs for Illinois coal-fired and PRB coal-fired 533-MW plants

8.6. Process Optimization and Improvement

A sensitivity study was performed to evaluate the impact of absorption heat of MEA solvent used in chemical absorption process and energy consumption of the ASU in an oxy-combustion process on the cost of CO₂ avoidance. This type of analysis could provide some guide to scientists and engineers to improve existing, or develop advanced, CO₂ capture processes.

For the chemical absorption process, the sensitivity analysis was performed for the absorption heat of solvent. The sensitivity of absorption capacity of MEA was not studied because it would not greatly impact the process economics without improvement in absorption heat. The following parameters and assumptions were used in analysis:

1. Absorption heat of MEA reduces by 10%, 20%, 30%, 40%, and 50%.
2. Energy (or steam) requirement is proportional to absorption heat of solvent.
3. Absorption capacity of MEA remains the same as in the reference plant.
4. Capital cost of MEA does not change.
5. Reference plant is a 533-MW (gross) high-sulfur coal-fired power plant +MEA.

For the oxy-combustion process, the sensitivity analysis was performed considering the following parameters and assumptions:

1. Energy requirement of ASU reduces by 10%, 20%, 30%, 40%, 50%.
2. Capital cost of ASU does not change.
3. Reference plant is a 533 MW (gross) high-sulfur coal power plant.

The results of the sensitivity analysis (Figure 8.15) revealed that the CO₂ avoidance costs decreased for both cases studied. However, the CO₂ avoidance cost of the MEA process with 50% lower absorption heat requirement is still higher than the reference oxy-combustion power plant. The avoidance cost for the oxy-combustion power plant decreased by about 35% when energy requirement of the ASU is reduced by 50%. Additional sensitivity studies are required to evaluate the impact of chemical solvent absorption capacity, equipment size, cost of the solvent, and the size of power plant on the CO₂ avoidance cost.

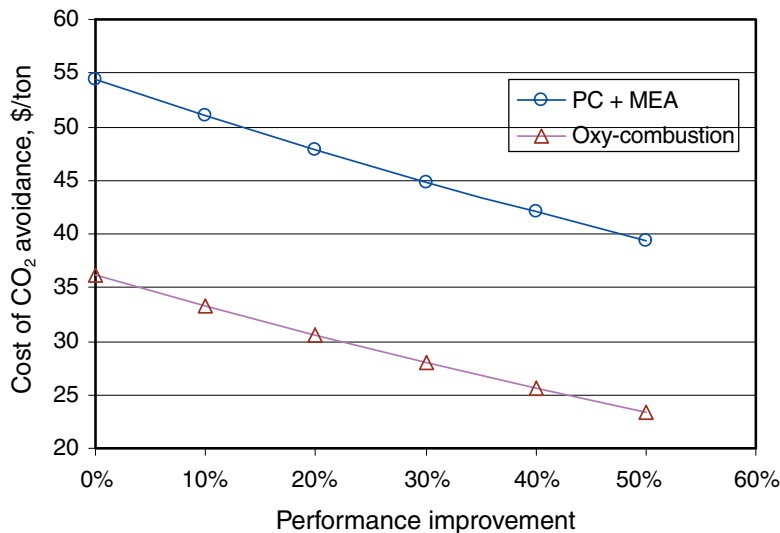


Figure 8.15. The impact of process variables on CO₂ avoidance cost

8.7. CO₂ Capture from Ethanol Plants

There are eight ethanol plants in the Illinois Basin generating about 3.7 million tons of CO₂ annually. Due to its high purity, much of the CO₂ is recovered and utilized for food and beverage industries. An average ethanol plant produces about 100 million gallons of ethanol per year. At this scale, the CO₂ emissions from an ethanol plant are comparable to the emissions from a 25-MW coal-fired power plant. But, because the concentration of the CO₂ is much higher in the product gas of an ethanol plant than in a coal combustion flue gas (87 vol% vs. 14 vol%), ethanol plants may offer a low-cost CO₂ source for sequestration research and testing, especially for small-scale field demonstration studies.

The concentration of CO₂ in the flue gas of ethanol plants is about 87% (120°F) on a wet basis and about 98% on a dry basis. Typical compositions of the CO₂ stream are listed in Table 8.22. Two major contaminants that exist in the gas stream are water and ethanol. Ethanol can be removed with water in a washing column operating at room temperature. The ethanol-water solution is then condensed, and high purity CO₂ is compressed to a desired pressure.

Table 8.22. Flue gas composition from ethanol plants (at 120°F, 1 atm, H₂O saturated)

Component	Concentration	Component	Concentration
CO ₂	87.2%	Acetic acid	10 PPMV
H ₂ O	11.1%	Amyl alcohol	50 PPMV
Air	1.2%	Isopropanol	25 PPMV
Ethanol	1,350 PPMV	Butanol	25 PPMV
Methanol	180 PPMV	Methane	20 PPMV
Acetaldehyde	270 PPMV	Ethyl acetate	80 PPMV
Sulfur compounds (H ₂ S, CS ₂)	35 PPMV		

8.7.1. Overall Process Descriptions

The flow chart used for process simulation using CHEMCAD is shown in Figure 8.16. Raw CO₂ stream from the ethanol plant enters a washing tower through a blower where ethanol and other water-soluble contaminants are dissolved into water. The washed gas stream is compressed and cooled. After removing the condensed water, the gas stream is compressed to 1,500 psi for transportation.

8.7.2. Cost of CO₂ Recovery from Ethanol Plants

The cost of CO₂ recovery from ethanol plants was analyzed based on the following assumptions:

- Scale: 800 tons of CO₂ per day
- Life of the plant: 30 years
- Product CO₂ pressure: 1,200 psi
- Product CO₂ temperature: 68°F
- Capacity usage: 85%

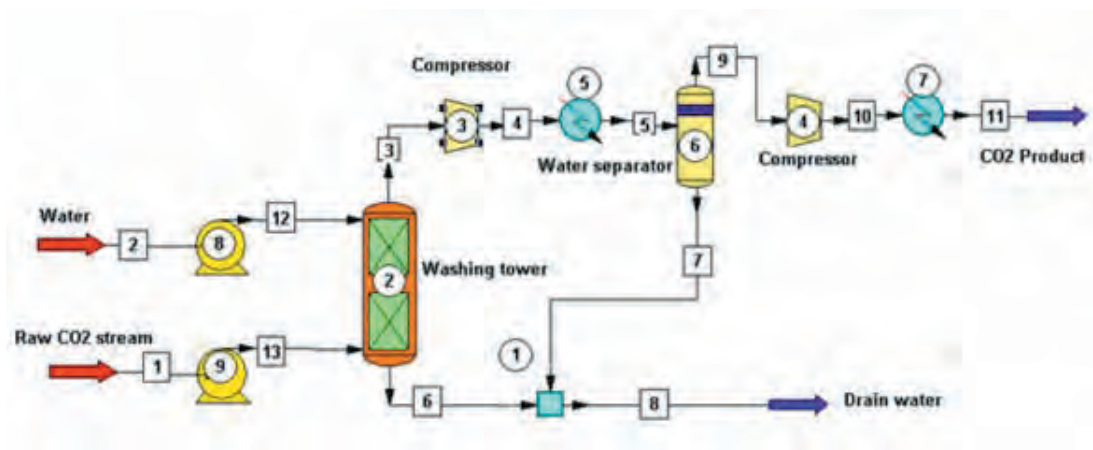


Figure 8.16. Flow chart for CO₂ capture from ethanol plants

The financial terms used are similar to those listed in Appendix B1 for the power generation plants. The equipment cost data were obtained using CHEMCAD, and costs for other items such as installation, piping, instrumentation, building, and land were chosen from literature values (Peter and Timmerhaus, 1991). The total cost for purchased equipment is about \$3.225 million, and the total plant cost is about \$7.1 million. The major equipment includes two compressors, and the major operating cost is associated with the compression of CO₂. The results of the cost analysis are presented in Table 8.23.

Table 8.23. Cost analysis of CO₂ recovery from ethanol plants

Item	Unit cost (\$1,000)	Units	Total cost (\$1,000)
Purchased equipment cost			
Compressor	1,200	2	2,400
Heat exchangers	150	2	300
Washing tower	350	1	350
Water condenser	25	1	25
Fan	150	1	150
Total purchased equipment cost (TPEC)			3,225
Installation, % of TPEC		30% of TPEC	968
Piping, % of TPEC		30% of TPEC	968
Instrumentation, % of TPEC		20% of TPEC	806
Electrical, % of TPEC		10% of TPEC	323
Building, % of TPEC		20% of TPEC	645
Land, % of TPEC		10% of TPEC	323
Total plant cost (TPC)			7,095
Levelized capital cost		0.138 × 7,095	979
O&M cost			
Fixed O&M			
Maintenance	3% of TPC		213
Admin. & support			236
Labor cost	40 × 8,760	2	701
Consumable			
Water	\$0.06/m ³		60
Electricity	\$50/MWh	3.166 MW	1,266
Total O&M cost			2,476
CO ₂ capture cost, \$/metric ton			13.92

The levelized CO₂ recovery cost is \$13.92/t. Since the electricity consumption for CO₂ compression is included in CO₂ recovery process cost, the recovery cost here equals the CO₂ avoidance cost. This cost is much lower than that of capturing of CO₂ from a coal-fired power plant + MEA, which is about \$47/t to \$67/t, depending on the plant size and type of coal burned (see Table 8.9).

9. Conclusions

1. There are 122 utility power plants in the Illinois Basin. They emit about 90% of 276 million t of CO₂ from stationary sources in the Illinois Basin annually. Power plant CO₂ emissions in the Illinois Basin contribute about 11.4% of total U.S. CO₂ emissions from electric power generation plants. The four largest power plants emit 22% of the total utility CO₂, the 13 largest plants emit 50% of total utility CO₂, and the 29 largest emit about 80% of the total utility CO₂.

2. Non-utility sources contribute to about 10% of total CO₂ emissions in the Illinois Basin. These sources include 5 refineries, 23 iron and steel plants, 8 cement plants, 1 lime plant, 2 aluminum plants, 1 ammonia plant, and 8 ethanol plants.
3. The most technically and economically viable commercial technology currently available for separating and capturing CO₂ from power plants is a post-combustion absorption process that uses MEA as a chemical solvent. A substantial increase in electricity cost results when an MEA process is installed to capture power plant CO₂. The results from a techno-economic study conducted revealed that for a 533-MW (gross) Illinois coal-fired plant, the cost of electricity is 91 mills/kWh for the MEA + PC plant and 52 mills/kWh for the conventional PC plant without CO₂ capture.
4. Burning coal in an oxygen-enriched flue gas is a potentially attractive technology for producing high-purity CO₂ flue gas for sequestration. The cost of electricity was estimated to be 81 mills/kWh for a 533-MW (gross) oxy-combustion power plant.
5. The cost of CO₂ avoidance was \$54/t for the MEA + PC plant and \$36/t for the 533-MW (gross) oxy-combustion plant.
6. The MEA process and the operation of the ASU in an oxy-combustion power plant are energy-intensive. Each process consumes about 20% of the gross electricity of a PC plant. Technological advances that result in lowering heat duty requirement during the regeneration of MEA solvent and electricity consumption in the ASU would substantially benefit the economics of CO₂ capture and separation by chemical absorption and oxy-combustion processes.
7. The cost of electricity for an IGCC + physical absorption (Selexol) plant is lower than a PC + MEA plant. For a 533-MW Illinois coal-fired IGCC + Selexol plant, the cost of electricity and of CO₂ avoidance are 64 mills/kWh and \$17/t, respectively.
8. The cost of electricity for the PC + MEA plant and the oxy-combustion plant was determined to be independent of the type of coal used (Illinois No. 6 coal or PRB coal). The CO₂ avoidance cost for the Illinois coal was slightly lower than that of the PRB coal. However, an IGCC plant + Selexol process burning Illinois high-sulfur coal was more attractive than burning PRB coal if the elemental sulfur by-product is considered a salable product.
9. The costs of electricity increase as plant size decreases from about 250 MW to around 1,070 MW (gross) in a power rule with an exponent of -0.28 to -0.26 for the examined power generation systems. The dependence of CO₂ avoidance cost on the plant size also fit the power rule, with an exponent of -0.24 to -0.23 .
10. Ethanol plants are excellent sources of high-purity CO₂ for small-scale field demonstration sequestration tests in Illinois Basin. The cost of CO₂ capture from an ethanol plant with a production capacity of 100 million gallons/year was estimated to be about \$13.92/t.
11. The results of a sensitivity analysis revealed the impact on CO₂ avoidance cost of the heat of absorption of the solvent in an MEA plant and the energy consumption of the ASU plant in an oxy-

coal combustion plant. A 50% reduction in heat of absorption and 50% lower energy consumption in the ASU resulted in 27% and 37% reduction in CO₂ avoidance costs for the two processes, respectively.

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Appendix A1. Reference Air-blown PC Power Plants with 533-MW (Gross) Output

Figure A1.1. Boiler

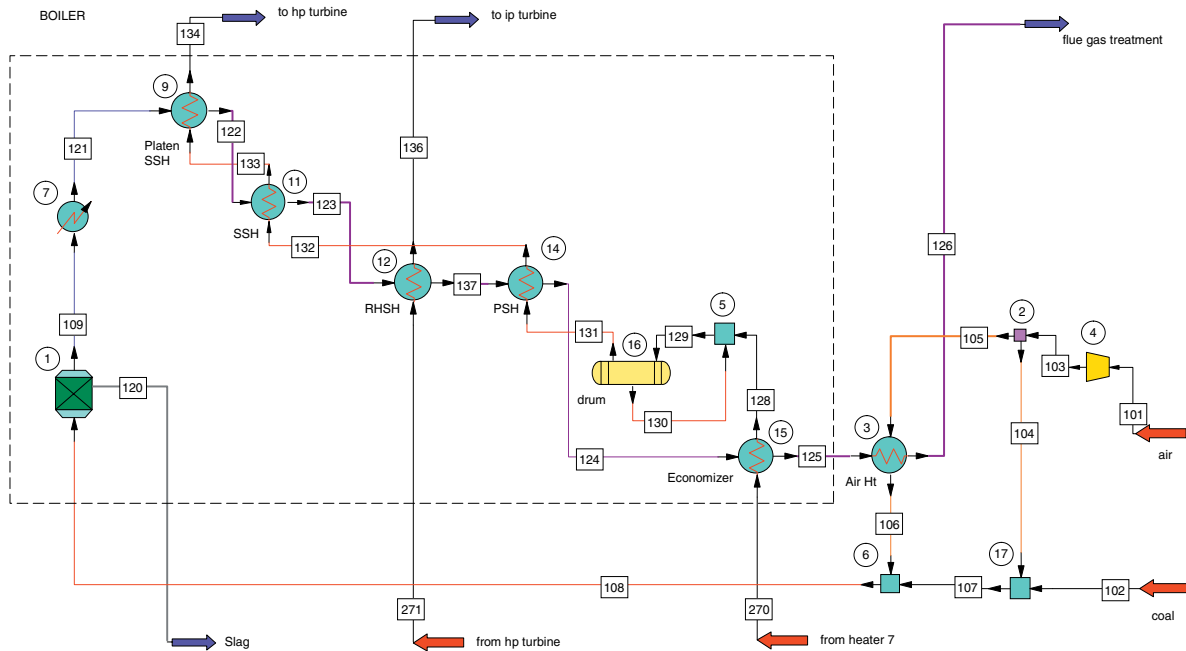


Table A1.1. Illinois coal

Stream no.	101	102	103	104
Temp., °F	63.0000	63.0000	81.6783	81.6783
Pres., psia	4.4000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	-13.910	-432.10	4.0910	0.20455
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	3,991,198.00	360,610.00	3,991,198.00	199,560.00
Stream no.	105	106	107	108
Temp., °F	81.6783	510.0580	52.9506	457.8348
Pres., psia	15.8000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	3.8865	401.70	-431.90	-30.193
Vapor, mass fraction	1.0000	1.0000	0.38092	0.92903
Total, lb/hr	3,791,638.00	3,791,638.00	560,170.00	4,351,798.00
Stream no.	109	120	121	122
Temp., °F	2,400.0000	2,400.0000	2,285.7006	1,900.0000
Pres., psia	15.3000	15.3000	15.3000	15.1000
Enth., mm BTU/hr	-1,748.3	-39.884	-1,904.3	-2,422.9
Vapor mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/h	4,319,700.00	32,094.00	4,319,700.00	4,319,700.00
Stream no.	123	124	125	126
Temp., °F	1,700.0000	900.0000	650.0000	295.0000
Pres., psia	14.9000	14.5000	14.3000	14.1000
Enth., mm BTU/hr	-2,686.3	-3,689.5	-3,982.3	-4,380.1
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,319,700.00	4,319,700.00	4,319,700.00	4,319,700.00

Stream no.	128	129	130	131
Temp., °F	557.8544	557.8544	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-21,590	-21,590	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	.0000
Total, lb/h	3,422,824.00	3,422,824.00	0.00	3,422,824.00
Stream no.	32	133	134	136
Temp., °F	731.8905	802.0647	1,000.7155	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,298	-19,034	-18,516	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00
Stream no.	137	270	271	
Temp., °F	1,210.4062	488.9000	634.5002	
Pres., psia	14.7000	2,800.0000	603.6000	
Enth., mm BTU/hr	-3,311.3	-21,883	-16,802	
Vapor, mass fraction	1.0000	0.00000	1.0000	
Total, lb/h	4,319,700.00	3,422,824.00	3,022,124.00	
IL6# coal-new1	0.00	0.00	0.00	
Nitrogen dioxide	7.90	0.00	0.00	

Table A1.2. PRB coal

Stream no.	101	102	103	104
Temp., °F	63.0000	63.0000	81.6783	81.6783
Pres., psia	14.4000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	-14.043	-1,378.5	4.1302	0.20651
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	4,029,474.00	524,982.00	4,029,474.00	201,473.70
Stream no.	105	106	107	108
Temp., °F	81.6783	536.3796	57.3598	345.5448
Pres., psia	15.8000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	3.9237	430.74	-1,378.3	-947.51
Vapor, mass fraction	1.0000	1.0000	0.29099	0.92109
Total, lb/hr	3,828,000.25	3,828,000.25	726,456.00	4,554,397.50
Stream no.	109	120	121	122
Temp., °F	2,400.0000	2,400.0000	2,191.6589	1,900.0000
Pres., psia	15.3000	15.3000	15.3000	15.1000
Enth., mm BTU/hr	-2,498.4	-34.252	-2,804.7	-3,226.5
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	4,526,829.50	27,562.00	4,526,829.50	4,526,829.50
Stream no.	123	124	125	126
Temp., °F	1700.0000	900.0000	650.0000	295.0000
Pres., psia	14.9000	14.5000	14.3000	14.1000
Enth., mm BTU/hr	-3,510.3	-4,588.9	-4,903.2	-5,330.0
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,526,829.50	4,526,829.50	4,526,829.50	4,526,829.50
Stream no.	128	129	130	131
Temp., °F	562.6944	562.6944	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-21,568	-21,568	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	0.00	3,422,824.00
Stream no.	132	133	134	136
Temp., °F	749.9162	833.4616	1,000.2580	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,222	-18,938	-18,517	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00

Stream no.	137	270	271
Temp., °F	1,245.7663	488.9000	634.5002
Pres., psia	14.7000	2,800.0000	603.6000
Enth., mm BTU/hr	-4,135.2	-21,883	-16,802
Vapor, mass fraction	1.0000	0.00000	1.0000
Total, lb/hr	4,526,829.50	3,422,824.00	3,022,124.00

Figure A1.2. Steam cycle (same for Illinois coal and PRB coal)

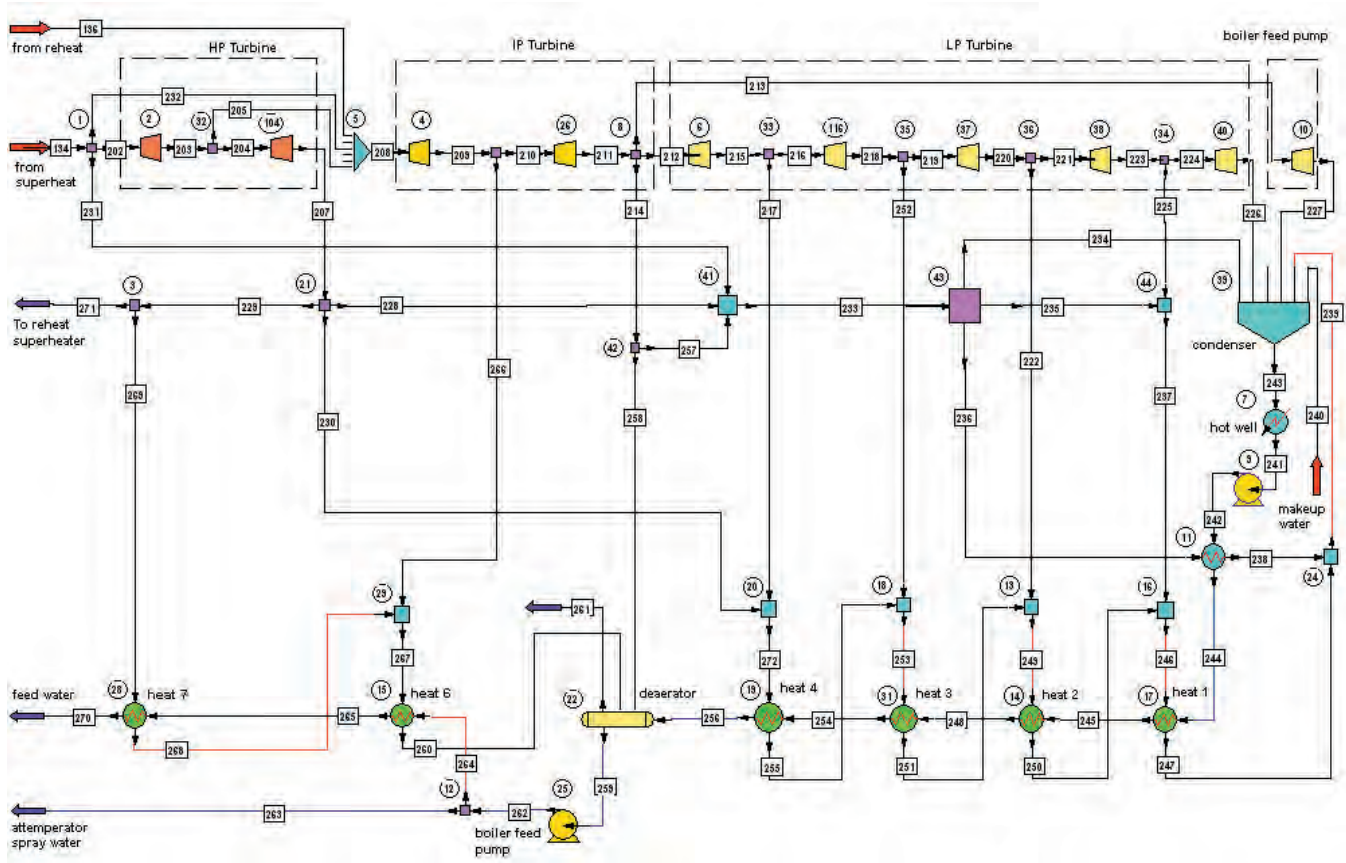


Table A1.3. Illinois coal and PRB coal

Stream no.	134	136	202	203
Temp., °F	1,000.0000	1,000.0000	1,000.0000	908.1930
Pres., psia	2,414.7000	545.4000	2,414.7000	1,775.0000
Enth., mm BTU/hr	5,000.4	4,587.5	4,991.5	4,863.3
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,022,125.00	3,416,724.50	3,416,724.50
Stream no.	204	205	207	208
Temp., °F	908.1930	908.1930	631.1807	997.5285
Pres., psia	1,775.0000	1,775.0000	603.6000	545.4000
Enth., mm BTU/hr	4,806.0	57.392	4,420.2	4,651.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,376,403.75	40,320.77	3,376,403.75	3,067,190.00

Stream no.	209	210	211	212
Temp., °F	817.2190	817.2190	702.8816	702.8816
Pres., psia	278.9000	278.9000	174.9000	174.9000
Enth., mm BTU/hr	4,386.6	4,240.6	4,080.4	3,626.8
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,067,190.00	2,965,172.00	2,965,172.00	2,635,575.50
Stream no.	213	214	215	216
Temp., °F	702.8816	702.8816	494.9297	494.9297
Pres., psia	174.9000	174.9000	66.5000	66.5000
Enth., mm BTU/hr	171.69	281.87	3,372.3	3,171.7
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	124,762.58	204,834.09	2,635,575.50	2,478,811.50
Stream no.	217	218	219	220
Temp., °F	494.9297	312.4631	312.4631	216.4566
Pres., psia	66.5000	24.0000	24.0000	12.8000
Enth., mm BTU/hr	200.58	2,965.7	2,864.0	2,760.2
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	156,764.03	2,478,811.50	2,393,808.00	2,393,808.00
Stream no.	221	222	223	224
Temp., °F	216.4566	216.4566	172.1188	172.1188
Pres., psia	12.8000	12.8000	6.3000	6.3000
Enth., mm BTU/hr	2,667.4	92.755	2,566.2	2,397.0
Vapor, mass fraction	1.0000	1.0000	0.97448	0.97448
Total, lb/hr	2,313,364.25	80,443.91	2,313,364.25	2,160,797.75
Stream no.	225	226	227	228
Temp., °F	172.1188	101.5784	104.7907	631.1807
Pres., psia	6.3000	1.0000	1.1000	603.6000
Enth., mm BTU/hr	169.24	2,182.6	128.88	16.235
Vapor, mass fraction	0.97448	0.90786	0.92852	1.0000
Total, lb/hr	152,566.38	2,160,797.75	124,762.58	12,401.53
Stream no.	229	230	231	232
Temp., °F	631.1807	631.1807	1,000.0000	1,000.0000
Pres., psia	603.6000	603.6000	2,414.7000	2,414.7000
Enth., mm BTU/hr	4,395.0	8.9243	1.9801	6.9305
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,357,185.25	6,816.96	1,355.44	4,744.03
Stream no.	233	234	235	236
Temp., °F	626.4604	626.4604	626.4604	626.4604
Pres., psia	174.9000	174.9000	174.9000	174.9000
Enth., mm BTU/hr	24.561	4.0125	15.866	4.6827
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	18,368.40	3,000.79	11,865.62	3,501.99
Stream no.	237	238	239	240
Temp., °F	172.1188	200.0000	118.1270	70.0000
Pres., psia	6.3000	174.9000	6.0000	14.7000
Enth., mm BTU/hr	185.11	0.58921	42.801	0.62795
Vapor, mass fraction	0.99101	0.00000	0.00000	0.00000
Total, lb/hr	164,432.00	3,501.99	496,962.22	16,527.00
Stream no.	241	242	243	244
Temp., °F	96.4000	97.5560	98.0755	99.0167
Pres., psia	0.9000	330.0000	0.9000	330.0000
Enth., mm BTU/hr	180.43	183.67	2,358.9	187.77
Vapor, mass fraction	0.00000	0.00000	0.74740	0.00000
Total, lb/hr	2,802,050.50	2,802,050.50	2,802,050.50	2,802,050.50
Stream no.	245	246	247	248
Temp., °F	167.4000	169.9850	117.5445	198.7000
Pres., psia	300.0000	6.0000	6.0000	270.0000
Enth., mm BTU/hr	379.63	234.07	42.212	467.78
Vapor, mass fraction	0.00000	0.33771	0.00000	0.00000
Total, lb/hr	2,802,050.50	493,460.25	493,460.25	2,802,050.50

Stream no.	249	250	251	252
Temp., °F	201.5301	180.6844	210.1221	312.4631
Pres., psia	11.9000	11.9000	22.4000	24.0000
Enth., mm BTU/hr	137.12	48.966	44.361	101.70
Vapor, mass fraction	0.25293	0.00000	0.00000	1.0000
Total, lb/hr	329,028.28	329,028.28	248,584.39	85,003.41
Stream no.	253	254	255	256
Temp., °F	234.0796	231.1000	241.2455	292.3000
Pres., psia	22.4000	240.0000	62.4000	160.0000
Enth., mm BTU/hr	136.04	559.46	34.344	734.62
Vapor, mass fraction	0.36067	0.00000	0.00000	0.00000
Total, lb/hr	248,584.39	2,802,050.50	163,581.00	2,802,050.50
Stream no.	257	258	259	260
Temp., °F	702.8816	702.8816	366.0413	399.4454
Pres., psia	174.9000	174.9000	164.8000	263.8000
Enth., mm BTU/hr	6.3458	275.53	1,167.9	164.23
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	4,611.43	200,222.67	3,439,352.50	437,079.31
Stream no.	261	262	263	264
Temp., °F	366.0413	376.1441	376.1441	376.1441
Pres., psia	164.8000	2,903.3000	2,903.3000	2,903.3000
Enth., mm BTU/hr	0.00000	1,205.2	41.393	1,163.8
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	0.00	3,439,352.50	118,124.56	3,321,228.00
Stream no.	265	266	267	268
Temp., °F	407.5000	817.2190	410.8008	415.5000
Pres., psia	2,853.3000	278.9000	278.8000	588.5000
Enth., mm BTU/hr	1277.3	145.90	277.73	131.83
Vapor, mass fraction	0.00000	1.0000	0.30377	0.00000
Total, lb/hr	3,321,228.00	102,017.80	437,079.31	335,061.50
Stream no.	269	270	271	272
Temp., °F	631.1807	488.3002	631.1807	496.6450
Pres., psia	603.6000	2,800.0000	603.6000	62.4000
Enth., mm BTU/hr	438.64	1584.1	3956.4	209.51
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	335,061.50	3,321,228.00	3,022,123.75	163,581.00

Figure A1.3. Flue gas cleaning (Illinois coal)

To stack

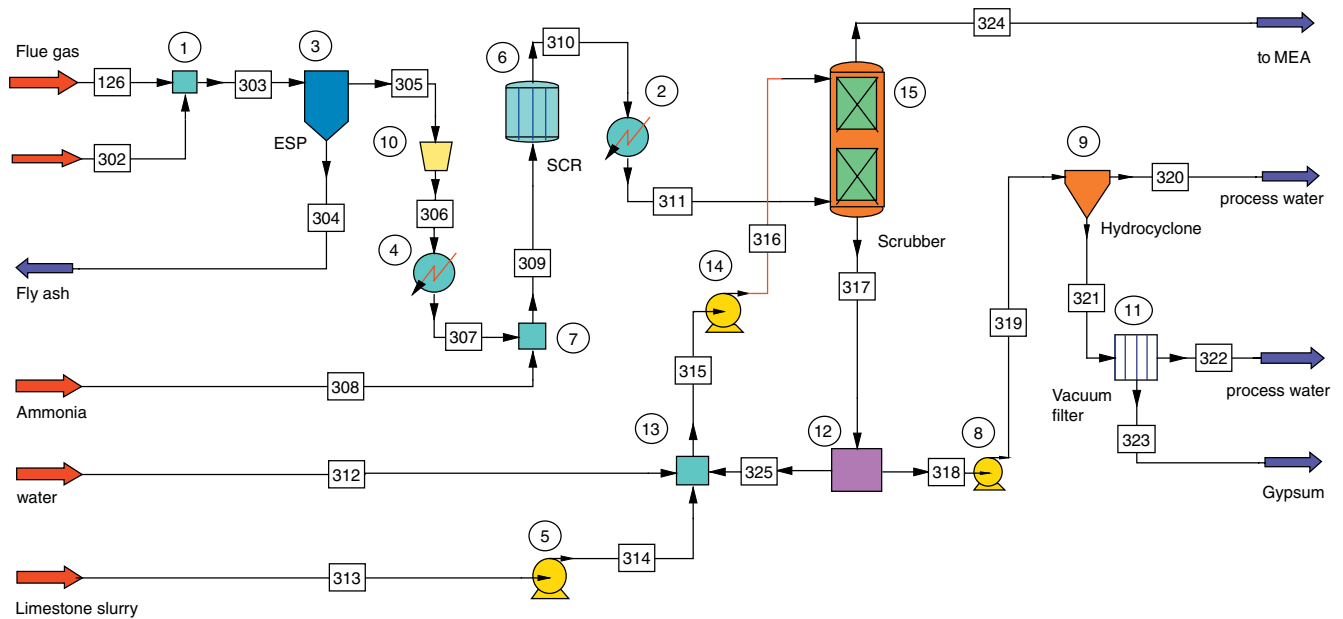


Table A1.4. Illinois coal

Stream no.	126	302	303	304
Temp., °F	295.0000	295.0000	295.0003	295.0003
Pres., psia	14.2000	14.2000	14.2000	14.1000
Enth., mm BTU/hr	-4,374.9	-54.992	-4,429.9	-54.440
Vapor, mass fraction	1.0000	0.00000	1.0000	0.00000
Total, lb/hr	4,319,700.00	25,675.20	4,345,375.00	25,417.41
Stream no.	305	306	307	308
Temp., °F	295.0003	374.6118	752.0000	70.0000
Pres., psia	14.1000	18.0000	18.0000	15.1000
Enth., mm BTU/hr	-4,375.3	-4,291.8	-3,863.5	-0.62266
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/h	4,319,958.00	4,319,958.00	4,319,958.00	535.74
Stream no.	309	310	311	312
Temp., °F	749.3875	752.0000	295.0000	70.0000
Pres., psia	15.1000	17.8000	17.8000	60.0000
Enth., mm BTU/hr	-3,864.1	-3,869.2	-4,385.2	-1,145.8
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	4,320,493.50	4,320,493.50	4,320,493.50	167,803.00
Stream no.	313	314	315	316
Temp., °F	70.0000	70.1574	129.1991	129.2440
Pres., psia	14.7000	60.0000	17.4000	30.0000
Enth., mm BTU/hr	-1,177.2	-1,177.2	-6.1073E+005	-6.1072E+005
Ionic strength, molal	0.0005	0.0005	0.0572	0.0572
Total, lb/h	179,427.23	179,427.25	96,026,952.00	96,026,952.00
Stream no.	317	318	319	320
Temp., °F	129.7292	129.7160	129.7508	129.7508
Pres., psia	17.4000	17.4000	30.0000	20.3720
Enth., mm BTU/hr	-6.0962E+005	-1,243.2	-1,243.2	-969.64
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	9,5874,696.00	195,514.00	195,514.00	144,110.03

Stream no.	321	322	323	324
Temp., °F	129.7508	129.7508	129.7508	129.2004
Pres., psia	20.3720	10.3720	10.3720	17.4000
Enth., mm BTU/hr	-273.53	-87.566	-185.96	-5,500.6
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	51,403.88	12,945.94	38,457.95	4,472,755.00
Stream no.	325			
Temp., °F	129.7160			
Pres., psia	17.4000			
Enth., mm BTU/hr	-6.0838E+005			
Vapor, mass fraction	0.00000			
Total, lb/hr	95,679,752.00			

Figure A1.4. Flue cleaning (PRB coal)

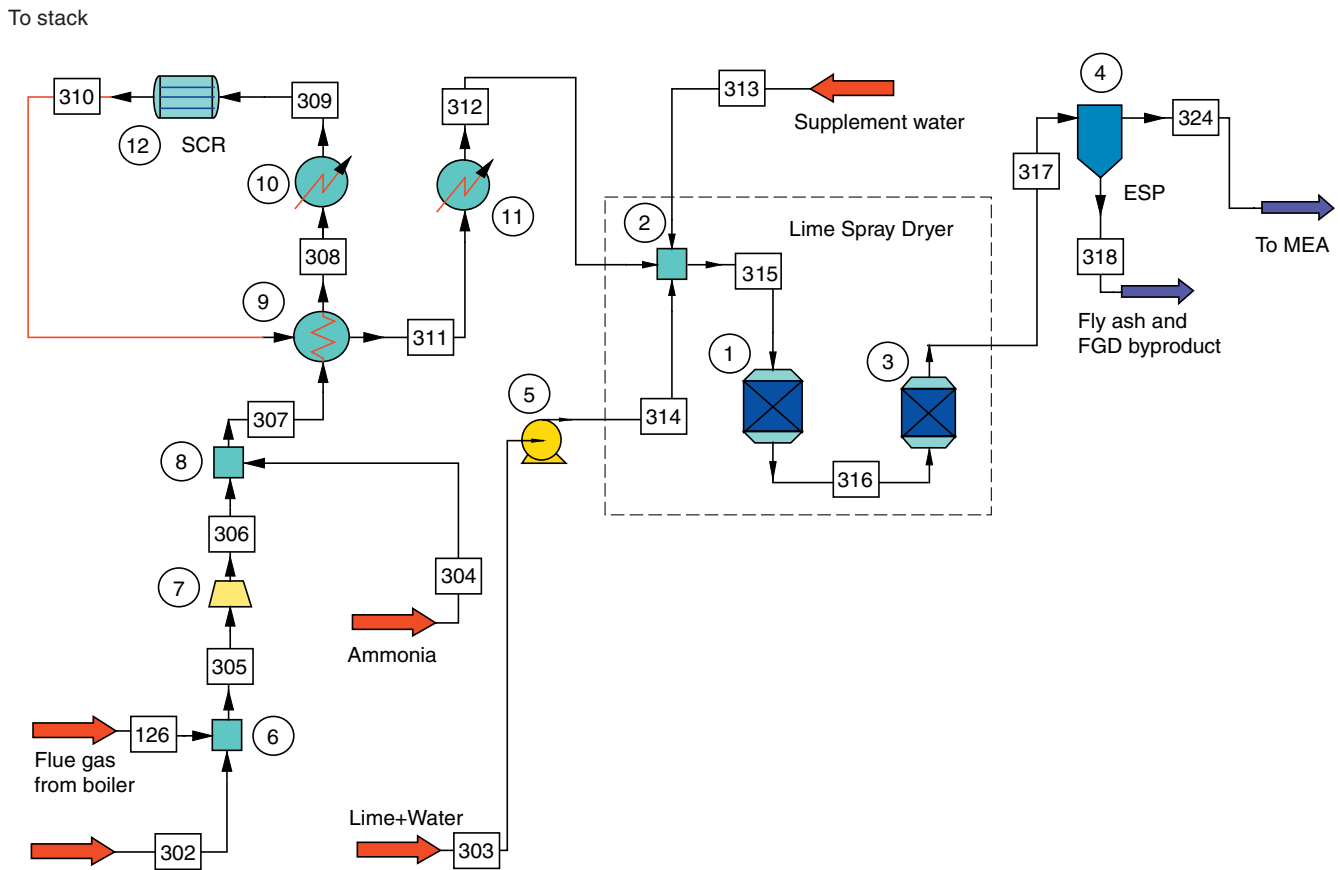


Table A1.5. Flue cleaning (PRB coal)

Stream no.	126	302	303	304
Temp., °F	295.0000	295.0000	63.0000	63.0000
Pres., psia	14.1000	14.1000	15.0000	18.2000
Enth., mm BTU/hr	-5,329.6	-47.225	-119.54	-0.90991
Vapor, mass fraction	1.0000	0.00000	0.00000	1.0000
Total, lb/hr	4,526,829.00	22,049.00	18,575.65	779.94

Stream no.	305	306	307	308
Temp., °F	295.0000	379.8514	379.7411	600.0000
Pres., psia	14.1000	18.2000	18.2000	18.2000
Enth., mm BTU/hr	-5,376.8	-5,281.0	-5,281.9	-5,015.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,548,878.00	4,548,878.00	4,549,658.00	4,549,658.00
Stream no.	309	310	31	312
Temp., °F	752.0000	752.0000	536.8289	295.0000
Pres., psia	18.2000	17.9000	17.9000	17.9000
Enth., mm BTU/hr	-4,826.2	-4,833.9	-5,100.4	-5,389.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,549,658.00	4,549,658.00	4,549,658.00	4,549,658.00
Stream no.	313	314	315	316
Temp., °F	68.0000	63.0000	151.0242	146.9291
Pres., psia	30.0000	30.0000	17.9000	17.6000
Enth., mm BTU/hr	-994.23	-119.54	-6,503.6	-6,503.6
Vapor, mass fraction	0.00000	0.00000	0.99624	0.99717
Total, lb/hr	145,560.00	18,575.65	4,713,792.50	4,713,791.00
Stream no.	317	318	324	
Temp., °F	156.8155	156.8155	156.8155	
Pres., psia	17.6000	17.4000	17.4000	
Enth., mm BTU/hr	-6,503.6	-82.409	-6,409.4	
Vapor, mass fraction	0.99518	0.00000	1.0000	
Total, lb/hr	4,713,985.50	29,743.08	4,684,241.50	

Appendix A2. Air-blown PC Power Plants with 533-MW (Gross) Output Installed with the MEA Process

Figure A2.1. Boiler

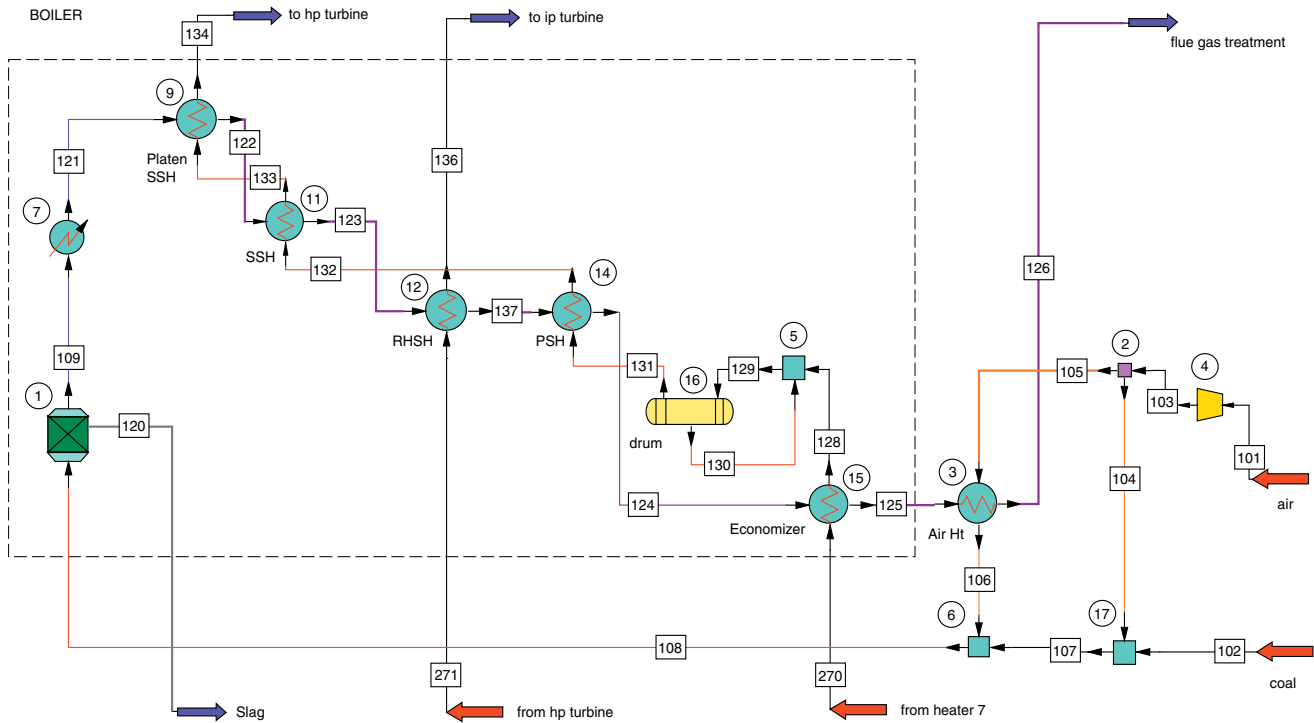


Table A2.1. Illinois coal

Stream no.	101	102	103	104
Temp., °F	63.0000	63.0000	81.6783	81.6783
Pres., psia	14.4000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	-13.910	-432.10	4.0910	0.20455
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/h	3,991,198.00	360,610.00	3,991,198.00	199,560.00
Stream no.	105	106	107	108
Temp., °F	81.6783	510.0580	52.9506	457.8348
Pres., psia	15.8000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	3.8865	401.70	-431.90	-30.193
Vapor, mass fraction	1.0000	1.0000	0.38092	0.92903
Total, lb/hr	3,791,638.00	3,791,638.00	560,170.00	4,351,798.00
Stream no.	109	120	121	122
Temp., °F	2,400.0000	2,400.0000	2,285.7006	1,900.0000
Pres., psia	15.3000	15.3000	15.3000	15.1000
Enth., mm BTU/hr	-1,748.3	-39.884	-1,904.3	-2,422.9
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	4,319,700.00	32,094.00	4,319,700.00	4,319,700.00

Stream no.	123	124	125	126
Temp., °F	1,700.0000	900.0000	650.0000	295.0000
Pres., psia	14.9000	14.5000	14.3000	14.1000
Enth., mm BTU/hr	-2,686.3	-3,689.5	-3,982.3	-4,380.1
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,319,700.00	4,319,700.00	4,319,700.00	4,319,700.00
Stream no.	128	129	130	131
Temp., °F	557.8544	557.8544	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-21,590	-21,590	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	0.00	3,422,824.00
Stream no.	132	133	134	136
Temp., °F	731.8905	802.0647	1,000.7155	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,298	-19,034	-18,516	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00
Stream no.	137	270	271	
Temp., °F	1,210.4062	488.9000	634.5002	
Pres., psia	14.7000	2800.0000	603.6000	
Enth., mm BTU/hr	-3,311.3	-21,883	-16,802	
Vapor, mass fraction	1.0000	0.00000	1.0000	
Total, lb/hr	4,319,700.00	3,422,824.00	3,022,124.00	
IL6# coal-new1	0.00	0.00	0.00	
Nitrogen dioxide	7.90	0.00	0.00	

Table A2.2. PRB coal

Stream no.	101	102	103	104
Temp., °F	63.0000	63.0000	81.6783	81.6783
Pres., psia	14.4000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	-14.043	-1,378.5	4.1302	0.20651
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	4,029,474.00	524,982.00	4,029,474.00	201,473.70
Stream no.	105	106	107	108
Temp., °F	81.6783	536.3796	57.3598	345.5448
Pres., psia	15.8000	15.8000	15.8000	15.8000
Enth., mm BTU/hr	3.9237	430.74	-1,378.3	-947.51
Vapor, mass fraction	1.0000	1.0000	0.29099	0.92109
Total, lb/hr	3,828,000.25	3,828,000.25	726,456.00	4,554,397.50
Stream no.	109	120	121	122
Temp., °F	2,400.0000	2,400.0000	2,191.6589	1,900.0000
Pres., psia	15.3000	15.3000	15.3000	15.1000
Enth., mm BTU/hr	-2,498.4	-34.252	-2,804.7	-3,226.5
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	4,526,829.50	27,562.00	4,526,829.50	4,526,829.50
Stream no.	123	124	125	126
Temp., °F	1,700.0000	900.0000	650.0000	295.0000
Pres., psia	14.9000	14.5000	14.3000	14.1000
Enth., mm BTU/hr	-3,510.3	-4,588.9	-4,903.2	-5,330.0
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,526,829.50	4,526,829.50	4,526,829.50	4,526,829.50
Stream no.	128	129	130	131
Temp., °F	562.6944	562.6944	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-2,156	-21,568	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	0.00	3,422,824.00

Stream no.	132	133	134	136
Temp., °F	749.9162	833.4616	1,000.2580	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,222	-18,938	-18,517	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00
Stream no.	137	270	271	
Temp., °F	1,245.7663	488.9000	634.5002	
Pres., psia	14.7000	2,800.0000	603.6000	
Enth., mm BTU/hr	-4,135.2	-21,883	-16,802	
Vapor, mass fraction	1.0000	0.00000	1.0000	
Total, lb/hr	4,526,829.50	3,422,824.00	3,022,124.00	

Figure A2.2. Steam cycle (same for Illinois coal and PRN coal)

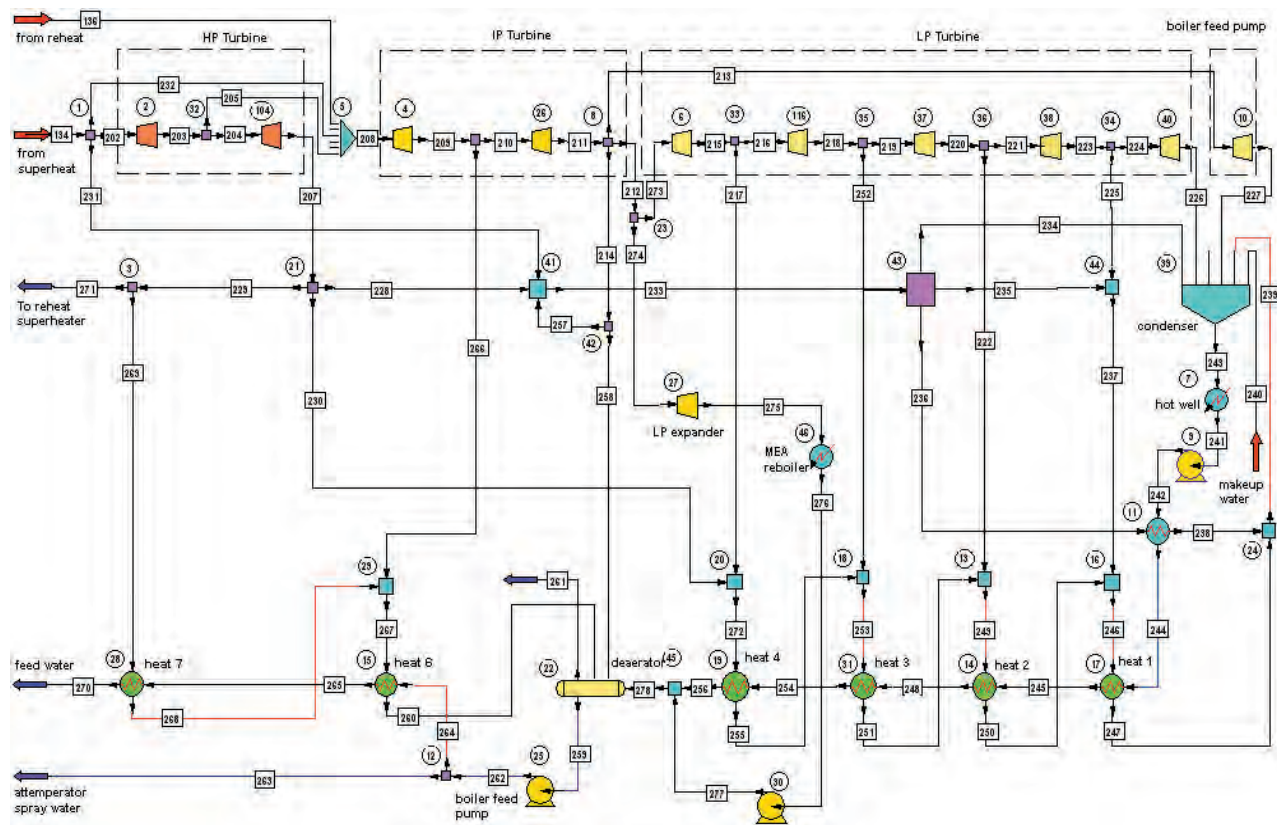


Table A2.3. Illinois coal

Stream no.	134	136	202	203
Temp., °F	1,000.0000	1,000.0000	1,000.0000	908.1930
Pres., psia	2,414.7000	545.4000	2,414.7000	1,775.0000
Enth., mm BTU/hr	5,000.4	4,587.5	4,991.5	4,863.3
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,022,125.00	3,416,724.50	3,416,724.50

Stream no.	204	205	207	208
Temp., °F	908.1930	908.1930	631.1807	997.5285
Pres., psia	1,775.0000	1,775.0000	603.6000	545.4000
Enth., mm BTU/hr	4,806.0	57.392	4,420.2	4,651.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,376,403.75	40,320.77	3,376,403.75	3,067,190.00
Stream no.	209	210	211	212
Temp., °F	817.2190	817.2190	702.8818	702.8818
Pres., psia	278.9000	278.9000	174.9000	174.9000
Enth., mm BTU/hr	4,386.6	4,240.6	4,080.4	3,626.8
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,067,190.00	2,965,172.00	2,965,172.00	2,635,575.50
Stream no.	213	214	215	216
Temp., °F	702.8818	702.8818	494.9298	494.9298
Pres., psia	174.9000	174.9000	66.5000	66.5000
Enth., mm BTU/hr	171.69	281.87	1,606.1	1,510.5
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	124,762.58	204,834.09	1,255,211.50	1,180,551.50
Stream, °F	494.9298	312.4632	312.4632	216.4570
Pres., psia	66.5000	24.0000	24.0000	12.8000
Enth., mm BTU/hr	95.529	1,412.4	1,364.0	1,314.5
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	74,660.00	1,180,551.50	1,140,068.13	1,140,068.13
Stream no.	221	222	223	224
Temp., °F	216.4570	216.4570	172.1188	172.1188
Pres., psia	12.8000	12.8000	6.3000	6.3000
Enth., mm BTU/hr	1,270.4	44.175	1,222.2	1,141.6
Vapor, mass fraction	1.0000	1.0000	0.97448	0.97448
Total, lb/hr	1,101,756.13	38,312.00	1,101,756.13	1,029,095.38
Stream no.	225	226	227	228
Temp., °F	172.1188	101.5784	104.7907	631.1807
Pres., psia	6.3000	1.0000	1.1000	603.6000
Enth., mm BTU/hr	80.602	1,039.5	128.88	16.235
Vapor, mass fraction	0.97448	0.90786	0.92852	1.0000
Total, lb/hr	72,660.82	1,029,095.38	124,762.58	12,401.53
Stream no.	229	230	231	232
Temp., °F	631.1807	631.1807	1,000.0000	1,000.0000
Pres., psia	603.6000	603.6000	2,414.7000	2,414.7000
Enth., mm BTU/hr	4,395.0	8.9243	1.9801	6.9305
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,357,185.25	6,816.96	1,355.44	4,744.03
Stream no.	233	234	235	236
Temp., °F	626.4604	626.4604	626.4604	626.4604
Pres., psia	174.9000	174.9000	174.9000	174.9000
Enth., mm BTU/hr	24.561	4.0125	15.866	4.6827
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	18,368.40	3,000.79	11,865.62	3,501.99
Stream no.	237	238	239	240
Temp., °F	186.0220	200.0000	122.4025	70.0000
Pres., psia	6.3000	174.9000	6.0000	14.7000
Enth., mm BTU/hr	96.468	0.58921	22.447	0.62795
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	84,526.44	3,501.99	248,301.00	16,527.00
Stream no.	241	242	243	244
Temp., °F	96.4000	97.5560	98.0755	100.4350
Pres., psia	0.9000	330.0000	0.9000	330.0000
Enth., mm BTU/hr	91.548	93.191	1195.4	97.285
Vapor, mass fraction	0.00000	0.00000	0.74644	0.00000
Total, lb/hr	1,421,686.50	1,421,686.50	1,421,686.50	1,421,686.50

Stream no.	245	246	247	248
Temp., °F	169.0000	169.9850	121.2895	198.7525
Pres., psia	300.0000	6.0000	6.0000	270.0000
Enth., mm BTU/hr	194.90	119.47	21.858	237.41
Vapor, mass fraction	0.00000	0.35145	0.00000	0.00000
Total, lb/hr	1,421,686.50	244,799.00	244,799.00	1,421,686.50
Stream no.	249	250	251	252
Temp., °F	201.5301	175.4000	206.7000	312.4632
Pres., psia	11.9000	11.9000	22.4000	24.0000
Enth., mm BTU/hr	65.519	23.001	21.343	48.435
Vapor, mass fraction	0.24480	0.00000	0.00000	1.0000
Total, lb/hr	160,272.41	160,272.41	121,960.42	40,483.48
Stream no.	253	254	255	256
Temp., °F	234.0796	229.4182	239.1000	289.7281
Pres., psia	22.4000	240.0000	62.4000	160.0000
Enth., mm BTU/hr	65.364	281.43	16.929	368.96
Vapor, mass fraction	0.34881	0.00000	0.00000	0.00000
Total, lb/hr	121,960.42	1,421,686.50	81,477.00	1,421,686.50
Stream no.	257	258	259	260
Temp., °F	702.8818	702.8818	366.0413	399.4454
Pres., psia	174.9000	174.9000	164.8000	263.8000
Enth., mm BTU/hr	6.3458	275.53	1,167.9	164.23
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	4,611.43	200,222.67	3,439,352.50	437,079.31
Stream no.	261	262	263	264
Temp., °F	366.0413	376.1441	376.1441	376.1441
Pres., psia	164.8000	2,903.3000	2,903.3000	2,903.3000
Enth., mm BTU/hr	0.00000	1,205.2	41.393	1,163.8
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	0.00	3,439,352.50	118,124.56	3,321,228.00
Stream no.	265	266	267	268
Temp., °F	407.5000	817.2190	410.8331	415.5000
Pres., psia	2,853.3000	278.9000	278.9000	588.5000
Enth., mm BTU/hr	1,277.3	145.90	277.73	131.83
Vapor, mass fraction	0.00000	1.0000	0.30374	0.00000
Total, lb/hr	3,321,228.00	102,017.80	437,079.31	335,061.50
Stream no.	269	270	271	272
Temp., °F	631.1807	488.3002	631.1807	499.1817
Pres., psia	603.6000	2,800.0000	603.6000	62.4000
Enth., mm BTU/hr	438.64	1,584.1	3,956.4	104.45
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	335,061.50	3,321,228.00	3,022,123.75	81,477.00
Stream no.	273	274	275	276
Temp., °F	702.8818	702.8818	475.1697	287.5000
Pres., psia	174.9000	174.9000	60.0000	60.0000
Enth., mm BTU/hr	1,727.3	1,899.5	1,753.7	355.07
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	1,255,211.50	1,380,364.00	1,380,364.00	1,380,364.00
Stream no.	277	278		
Temp., °F	288.4902	289.1184		
Pres., psia	330.0000	160.0000		
Enth., mm BTU/hr	356.47	725.43		
Vapor, mass fraction	0.00000	0.00000		
Total, lb/h	1,380,364.00	2,802,050.50		

Figure A2.3. Flue gas cleaning (Illinois coal)

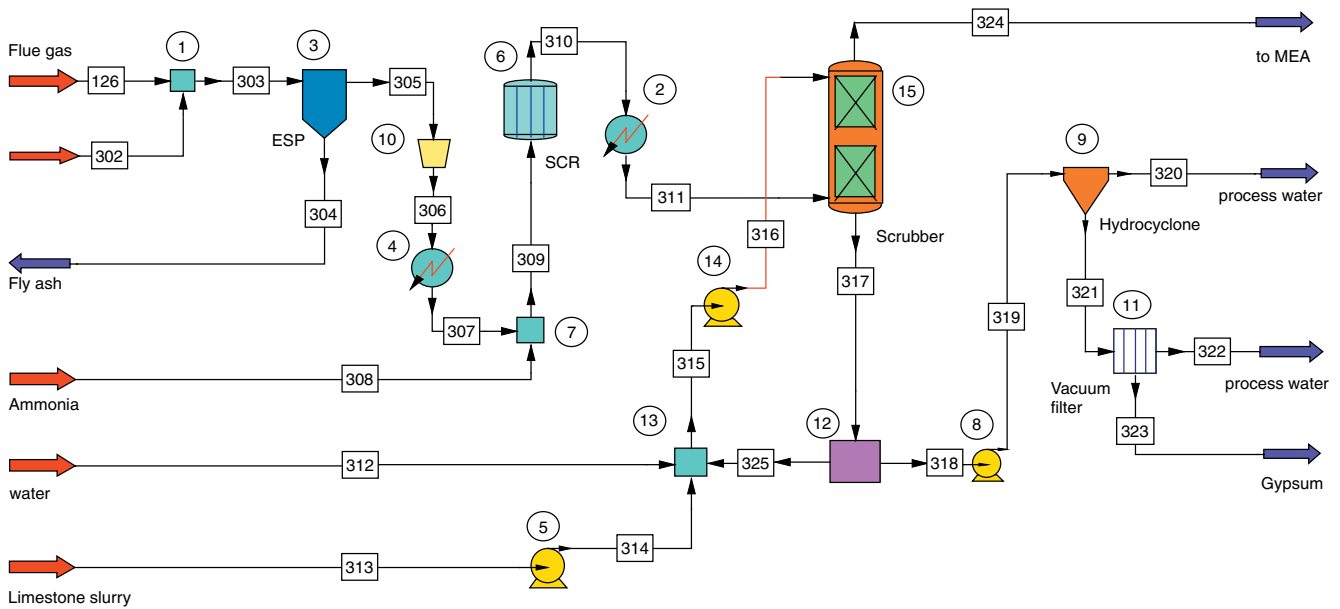


Table A2.4. Illinois coal

Stream no.	126	302	303	304
Temp., °F	295.0000	295.0000	295.0003	295.0003
Pres., psia	14.2000	14.2000	14.2000	14.1000
Enth., mm BTU/hr	-4,374.9	-54.992	-4,429.9	-54.440
Vapor, mass fraction	1.0000	0.00000	1.0000	0.00000
Total, lb/hr	4,319,700.00	25,675.20	4,345,375.00	25,417.41
Stream no.	305	306	307	308
Temp., °F	295.0003	374.6118	752.0000	70.0000
Pres., psia	14.1000	18.0000	18.0000	15.1000
Enth., mm BTU/hr	-4,375.3	-4,291.8	-3,863.5	-0.62266
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,319,958.00	4,319,958.00	4,319,958.00	535.74
Stream no.	309	310	311	312
Temp., °F	749.3875	752.0000	295.0000	70.0000
Pres., psia	15.1000	17.8000	17.8000	60.0000
Enth., mm BTU/hr	-3,864.1	-3,869.2	-4,385.2	-1,145.8
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	4,320,493.50	4,320,493.50	4,320,493.50	167803.00
Stream no.	313	314	315	316
Temp., °F	70.0000	70.1574	129.1991	129.2440
Pres., psia	14.7000	60.0000	17.4000	30.0000
Enth., mm BTU/hr	-1,177.2	-1,177.2	-6.1073E+005	-6.1072E+005
Ionic strength molal	0.0005	0.0005	0.0572	0.0572
Total, lb/hr	179,427.23	179,427.25	96,026,952.00	96,026,952.00
Stream no.	317	318	319	320
Temp., °F	129.7292	129.7160	129.7508	129.7508
Pres., psia	17.4000	17.4000	30.0000	20.3720
Enth., mm BTU/hr	-6.0962E+005	-1,243.2	-1,243.2	-969.64
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	95,874,696.00	195,514.00	195,514.00	144,110.03

Stream no.	321	322	323	324
Temp., °F	129.7508	129.7508	129.7508	129.2004
Pres., psia	20.3720	10.3720	10.3720	17.4000
Enth., mm BTU/hr	-273.53	-87.566	-185.96	-5,500.6
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	51,403.88	12,945.94	38,457.95	4,472,755.00
Stream no.	325			
Temp., °F	129.7160			
Pres., psia	17.4000			
Enth., mm BTU/hr	-6.0838E+005			
Vapor, mass fraction	0.00000			
Total, lb/hr	95,679,752.00			

Figure A2.4. Flue gas cleaning (PRB coal)

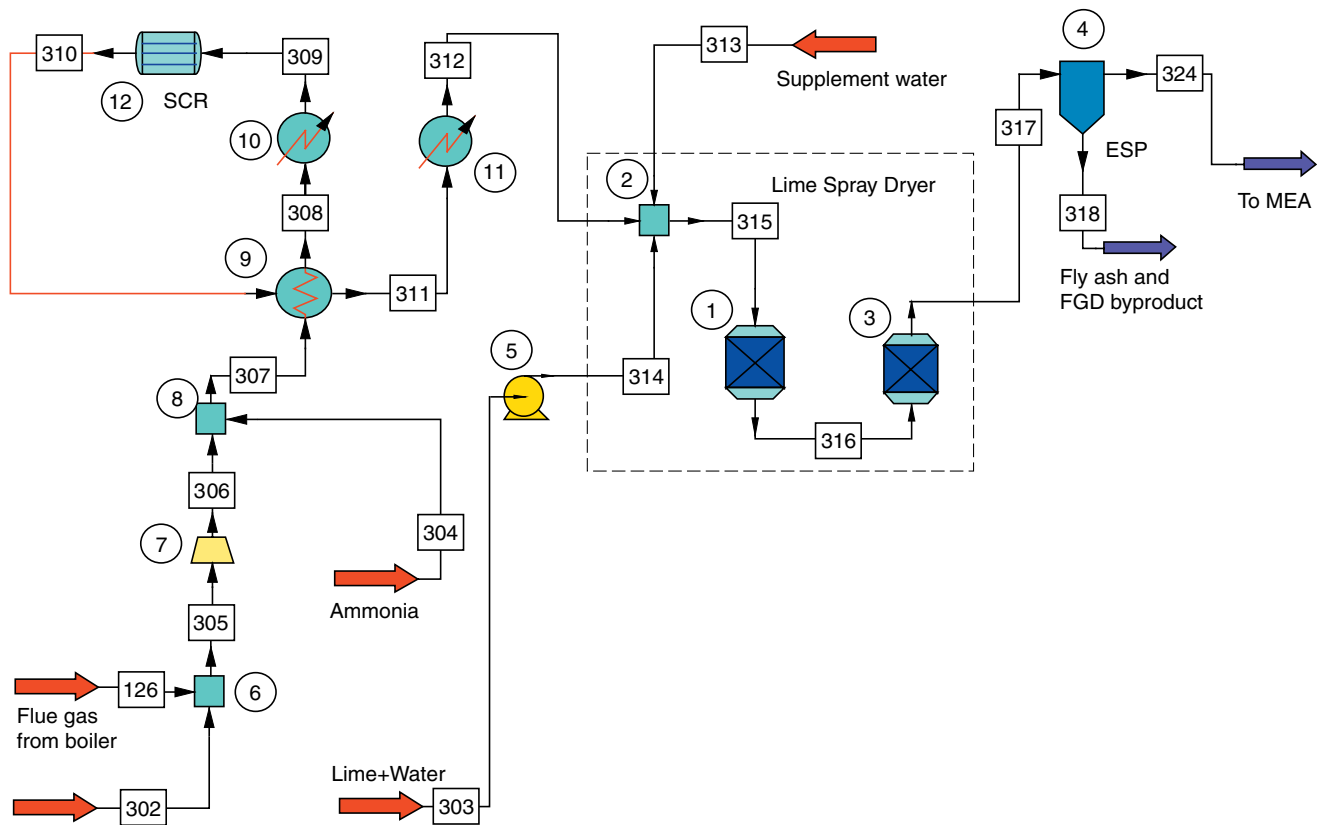


Table A2.5. Illinois coal and PRB coal

Stream no.	126	302	303	304
Temp., °F	295.0000	295.0000	63.0000	63.0000
Pres., psia	14.1000	14.1000	15.0000	18.2000
Enth., mm BTU/hr	-5,329.6	-47.225	-119.54	-0.90991
Vapor, mass fraction	1.0000	0.00000	0.00000	1.0000
Total, lb/hr	4,526,829.00	22,049.00	18,575.65	779.94

Stream no.	305	306	307	308
Temp., °F	295.0000	379.8514	379.7411	600.0000
Pres., psia	14.1000	18.2000	18.2000	18.2000
Enth., mm BTU/hr	-5,376.8	-5,281.0	-5,281.9	-5,015.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,548,878.00	4,548,878.00	4,549,658.00	4,549,658.00
Stream no.	309	310	311	312
Temp., °F	752.0000	752.0000	536.8289	295.0000
Pres., psia	18.2000	17.9000	17.9000	17.9000
Enth., mm BTU/hr	-4,826.2	-4,833.9	-5,100.4	-5,389.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,549,658.00	4,549,658.00	4,549,658.00	4,549,658.00
Stream no.	313	314	315	316
Temp., °F	68.0000	63.0000	151.0242	146.9291
Pres., psia	30.0000	30.0000	17.9000	17.6000
Enth., mm BTU/hr	-994.23	-119.54	-6,503.6	-6,503.6
Vapor, mass fraction	0.00000	0.00000	0.99624	0.99717
Total, lb/hr	145,560.00	18,575.65	4,713,792.50	4,713,791.00
Stream no.	317	318	324	
Temp., °F	156.8155	156.8155	156.8155	
Pres., psia	17.6000	17.4000	17.4000	
Enth., mm BTU/hr	-6,503.6	-82.409	-6,409.4	
Vapor, mass fraction	0.99518	0.00000	1.0000	
Total, lb/hr	4,713,985.50	29,743.08	4,684,241.50	

Figure A2.5. MEA process

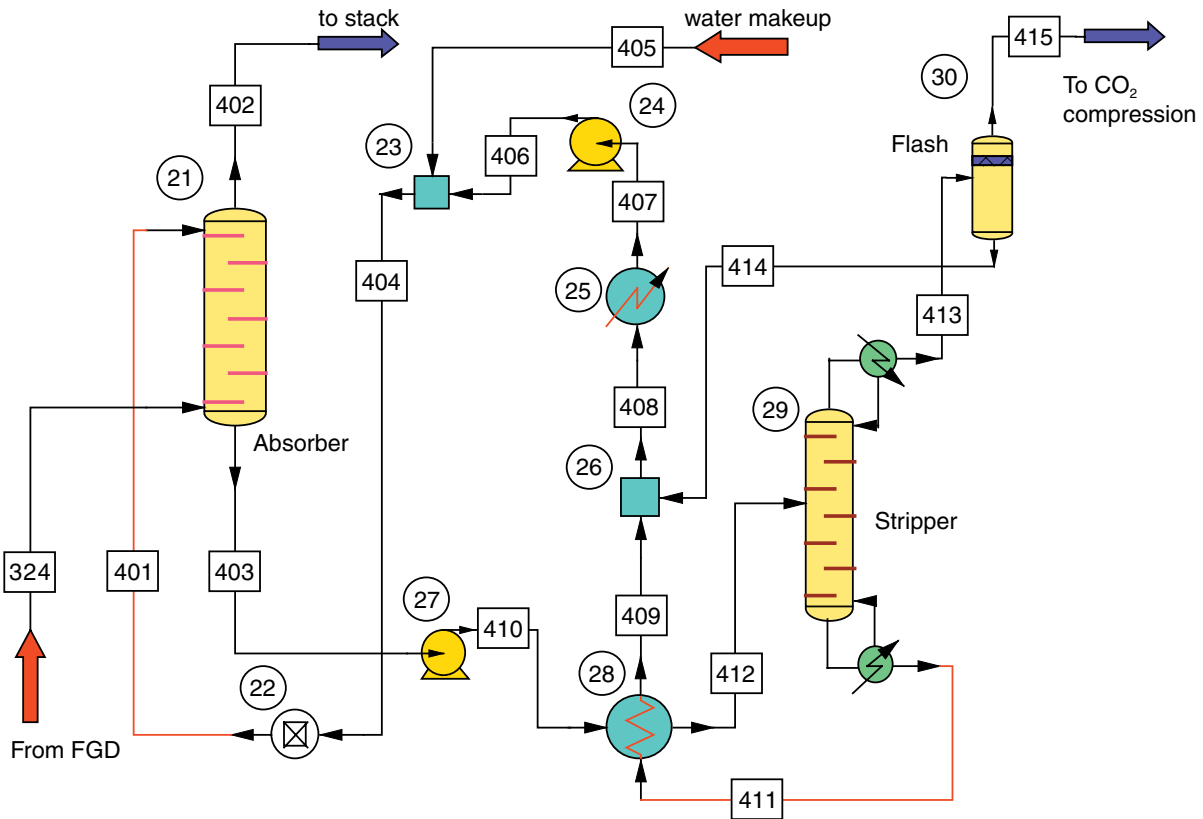


Table A2.6. Illinois coal

Stream no.	324	401	402	403
Temp., °F	129.2004	103.3656	126.7688	135.0667
Pres., psia	17.4000	25.0000	14.4000	15.0000
Enth., mm BTU/hr	-5,506.2	-91,894	-3,688.1	-93,673
Vapor, mass fraction	1.0000	0.00000	1.0000	0.00000
Total, lb/hr	4,472,743.00	17,251,364.00	3,879,624.75	17,840,666.00
Stream no.	404	405	406	407
Temp., °F	103.3656	68.0000	103.9998	104.0000
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-91,894	-1,781.3	-90,113	-90,113
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	17,251,364.00	260,625.22	16,990,738.00	16,990,738.00
Stream no.	408	409	410	411
Temp., °F	163.5854	164.4966	135.1040	240.9159
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-89,242	-87,705	-93,673	-86,584
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	16,990,738.00	16,763,741.00	17,840,666.00	16,763,468.00
Stream no.	412	413	414	415
Temp., °F	202.8000	202.8597	104.0000	104.0000
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-92,553	-4,569.0	-1,537.4	-3,293.2
Vapor, mass fraction	0.0057181	1.0000	0.00000	1.0000
Total, lb/hr	17,840,666.00	1,077,198.38	226,998.00	850,201.00

Table A2.7. PRB coal

Stream no.	324	401	402	403
Temp., °F	156.8155	103.6982	131.7120	143.0264
Pres., psia	17.4000	25.0000	14.4000	15.0000
Enth., mm BTU/hr	-6,415.1	-1.0319E+005	-3,777.0	-1.0589E+005
Vapor, mass fraction	1.0000	0.00000	1.0000	0.00000
Total, lb/hr	4,683,938.50	19,325,904.00	3,923,665.75	20,097,738.00
Stream no.	404	405	406	407
Temp., °F	103.6982	68.0000	103.9998	104.0000
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-1.0319E+005	-950.09	-1.0224E+005	-1.0224E+005
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	19,325,904.00	139,007.44	19,186,896.00	19,186,896.00
Stream no.	408	409	410	411
Temp., °F	171.0819	172.1472	143.0638	241.0265
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-1.0113E+005	-99,324	-1.0589E+005	-98,181
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	19,186,896.00	18,920,272.00	20,097,738.00	18,920,240.00
Stream no.	412	413	414	415
Temp., °F	205.0000	205.0469	104.0000	104.0000
Pres., psia	25.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-1.0475E+005	-5,027.7	-1,805.3	-3,528.2
Vapor, mass fraction	0.0042877	1.0000	0.00000	1.0000
Total, lb/hr	20,097,738.00	1,177,496.13	266,622.66	910,874.00

Figure A2.6. CO₂ compression

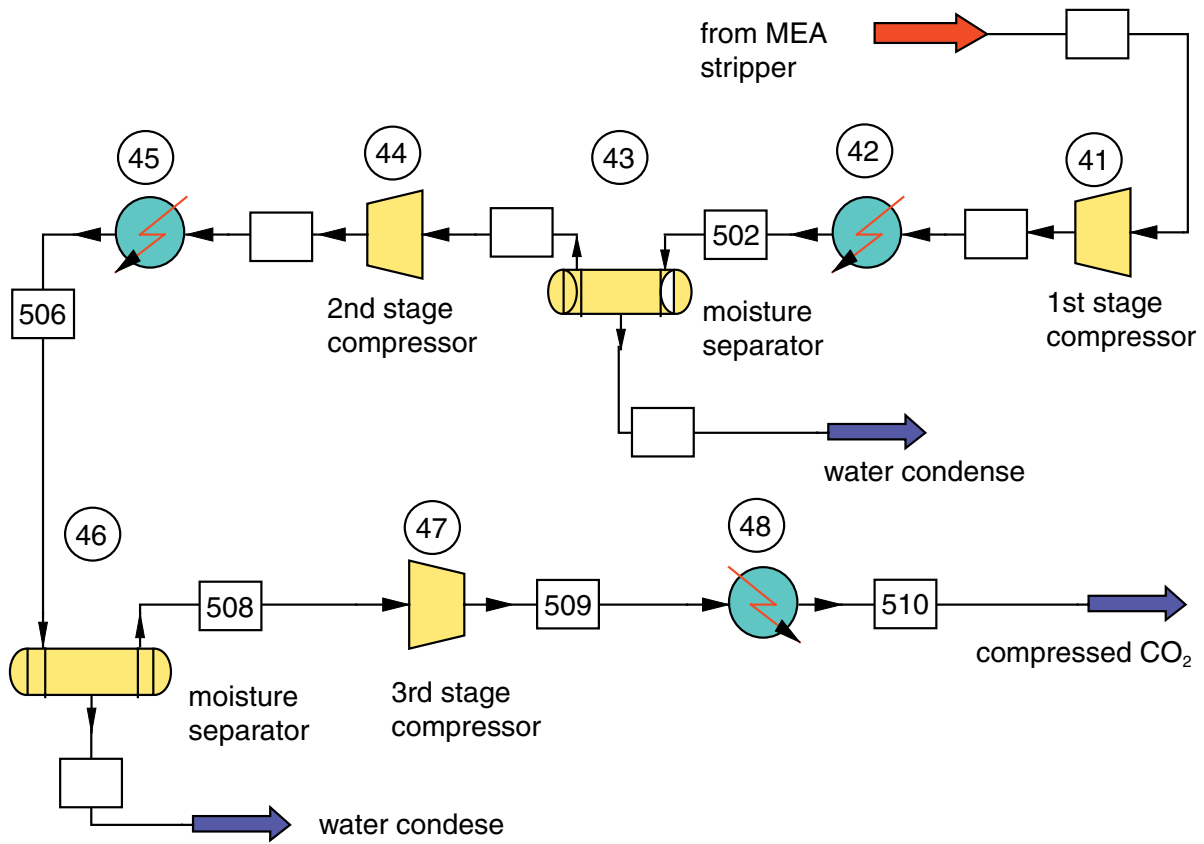


Table A2.8. Illinois coal

Stream no.	415	501	502	503
Temp., °C	40.0000	200.1252	40.0000	40.0000
Pres., bar	1.7237	10.0000	10.0000	10.0000
Enth., mm BTU/hr	-3,293.2	-3,238.1	-3,308.9	-87.230
Vapor, mass fraction	1.0000	1.0000	0.98486	0.00000
Total, lb/hr	850,201.00	850,201.00	850,201.00	12,875.92
Stream no.	504	505	506	507
Temp., °C	40.0000	225.7489	40.0000	40.0000
Pres., bar	10.0000	60.0000	60.0000	60.0000
Enth., mm BTU/hr	-3,221.7	-3,162.0	-3,242.4	-14.919
Vapor, mass fraction	1.0000	1.0000	0.99732	0.00000
Total, lb/hr	8,373,25.00	837,325.00	837,325.00	2,241.62
Stream no.	508	509	510	
Temp., °C	40.0000	67.8599	20.0000	
Pres., bar	60.0000	83.0000	83.0000	
Enth., mm BTU/hr	-3,227.4	-3,221.3	-3,260.7	
Vapor, mass fraction	1.0000	1.0000	0.00000	
Total, lb/hr	835,083.00	835,083.00	835,083.00	

Table A2.9. PRB coal

Stream no.	415	501	502	503
Temp., °C	40.0000	200.1241	40.0000	40.0000
Pres., bar	1.7237	10.0000	10.0000	10.0000
Enth., mm BTU/hr	-3,528.2	-3,469.2	-3,545.1	-93.438
Vapor, mass fraction	1.0000	1.0000	0.98486	0.00000
Total, lb/hr	910,874.00	910,874.00	910,874.00	13,792.23
Stream no.	504	505	506	507
Temp., °C	40.0000	225.7489	40.0000	40.0000
Pres., ba	10.0000	60.0000	60.0000	60.0000
Enth., mm BTU/hr	-3,451.7	-3,387.7	-3,473.8	-15.984
Vapor, mass fraction	1.0000	1.0000	0.99732	0.00000
Total, lb/hr	897,082.00	897,082.00	897,082.00	2,401.42
Stream no.	508	509	510	
Temp., °C	40.0000	67.8589	20.0000	
Pres., bar	60.0000	83.0000	83.0000	
Enth., mm BTU/hr	-3,457.8	-3,451.3	-3,493.4	
Vapor, mass fraction	1.0000	1.0000	0.00000	
Total, lb/hr	894,680.00	894,680.00	8,946.80.00	

Appendix A3. Oxy-combustion Power Plants with 533-MW (Gross) Output

Figure A3.1. Boiler

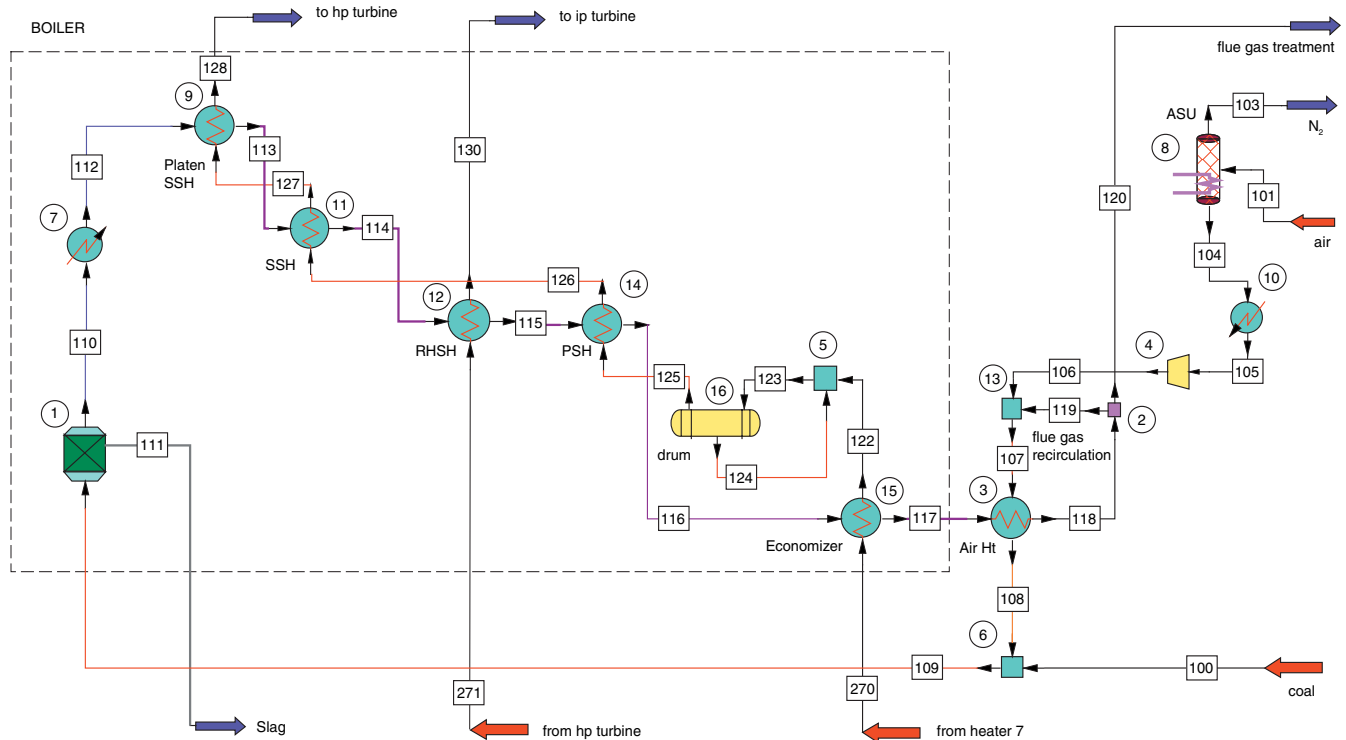


Table A3.1. Illinois coal

Stream no.	100	101	103	104
Temp., °F	63.0000	63.0000	-296.2000	-298.0684
Pres., psia	15.8000	14.4000	14.4000	14.4000
Enth., mm BTU/hr	-417.44	-11.988	-44.47	-145.34
Vapor, mass fraction	0.00000	1.0000	1.0000	0.00000
Total, lb/hr	348,374.00	3,461,228.00	2,617,629.00	843,599.00
Stream no.	105	106	107	108
Temp., °F	68.0000	86.9714	335.7514	512.3862
Pres., psia	14.4000	15.8000	14.1000	14.1000
Enth., mm BTU/hr	-1.7200	1.7064	-11,013	-10,841
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	843,599.00	843,599.00	3,770,798.50	3,770,824.00
Stream no.	109	110	111	112
Temp., °F	481.9835	2,400.0000	2,400.0000	2,222.8632
Pres., psia	15.8000	15.3000	15.3000	15.3000
Enth., mm BTU/hr	-11,258	-12,755	-38.530	-13,013
Vapor, mass fraction	0.92755	1.0000	0.00000	1.0000
Total, lb/hr	4,119,189.00	4,088,267.25	31,005.00	4,088,267.25
Stream no.	113	114	115	116
Temp., °F	1900.0000	1700.0000	1233.3990	900.0000
Pres., psia	15.1000	14.9000	14.7000	14.5000
Enth., mm BTU/hr	-13,473	-13,751	-14,376	-14,797
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,088,267.25	4,088,267.25	4,088,267.25	4,088,267.25

Stream no.	117	118	119	20
Temp., °F	550.0000	395.0000	395.0000	395.0000
Pres., psia	14.3000	14.1000	14.1000	14.1000
Enth., mm BTU/hr	-15,211	-15,384	-11,015	-4,369.1
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,088,267.25	4,088,268.25	2,927,199.50	1,161,067.88
Stream no.	122	123	124	125
Temp., °F	584.6858	584.6858	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-21,468	-21,468	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	0.00	3,422,824.00
Stream no.	126	127	28	130
Temp., °F	741.9480	820.6823	1,000.5983	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,255	-18,976	-18,516	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00
Stream no.	270	271		
Temp., °F	488.9000	634.5002		
Pres., psia	2,800.0000	603.6000		
Enth., mm BTU/hr	-21,883	-16,802		
Vapor, mass fraction	0.00000	1.0000		
Total, lb/hr	3,422,824.00	3,022,124.00		

Table A3.2. PRB coal

Stream no.	100	101	103	104
Temp., °F	63.0000	63.0000	-296.2000	-297.7483
Pres., psia	15.8000	14.4000	14.4000	14.4000
Enth., mm BTU/hr	-1,330.2	-12.029	-246.55	-142.66
Vapor, mass fraction	0.00000	1.0000	1.0000	0.00000
Total, lb/hr	506,615.00	3,457,391.00	2,639,851.00	817,540.00
Stream no.	105	106	107	108
Temp., °F	68.0000	86.7959	345.0483	527.6609
Pres., psia	14.4000	15.8000	14.1000	14.1000
Enth., mm BTU/hr	-1.6947	1.6513	-13,321	-13,111
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	817,540.00	817,540.00	4,089,010.50	4,089,067.25
Stream no.	109	110	111	112
Temp., °F	384.8558	2,400.0000	2,400.0000	2,002.2980
Pres., psia	15.8000	15.3000	15.3000	15.3000
Enth., mm BTU/hr	-14,441	-15,414	-33.052	-16,115
Vapor, mass fraction	0.92455	1.0000	0.00000	1.0000
Total, lb/hr	4,595,661.00	4,569,093.00	26,597.00	4,569,093.00
Stream no.	113	114	115	116
Temp., °F	1,900.0000	1,700.0000	1,317.3363	900.0000
Pres., psia	15.1000	14.9000	14.7000	14.5000
Enth., mm BTU/hr	-16,291	-16,629	-17,254	-17,896
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,569,093.00	4,569,093.00	4,569,093.00	4,569,093.00
Stream no.	117	118	119	120
Temp., °F	550.0000	395.0000	395.0000	395.0000
Pres., psia	14.3000	14.1000	14.1000	14.1000
Enth., mm BTU/hr	-18,397	-18,607	-13,322	-5,284.3
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	4,569,093.00	4,569,093.00	3,271,470.75	1,297,622.50

Stream no.	122	123	124	125
Temp., °F	603.2884	603.2884	665.1114	665.1114
Pres., psia	2,800.0000	2,450.0000	2,450.0000	2,450.0000
Enth., mm BTU/hr	-21,382	-21,382	0.00000	-19,676
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	0.00	3,422,824.00
Stream no.	126	127	128	130
Temp., °F	802.9302	925.1138	999.0877	1,000.0000
Pres., psia	2,440.0000	2,430.0000	2,414.7000	545.4000
Enth., mm BTU/hr	-19,034	-18,695	-18,519	-16,177
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,422,824.00	3,422,824.00	3,022,124.00
Stream no.	270	271		
Temp., °F	488.9000	634.5002		
Pres., psia	2,800.0000	603.6000		
Enth., mm BTU/hr	-21,883	-16,802		
Vapor, mass fraction	0.00000	1.0000		
Total, lb/hr	3,422,824.00	3,022,124.00		

Figure A3.2. Steam cycle (same for Illinois coal and PRN coal)

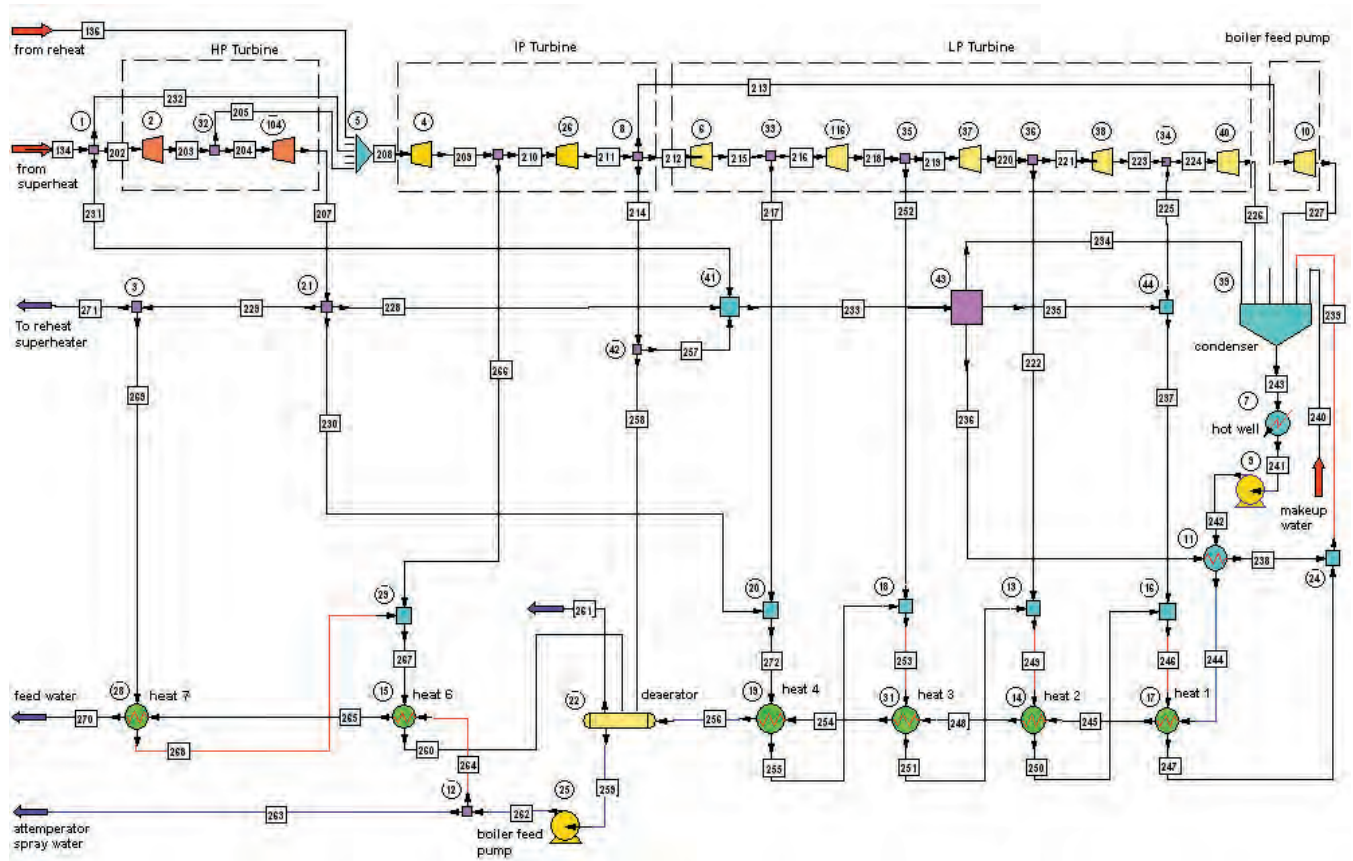


Table A3.3. Illinois coal and PRB coal

Stream no.	134	136	202	203
Temp., °F	1,000.0000	1,000.0000	1,000.0000	908.1930
Pres., psia	2,414.7000	545.4000	2,414.7000	1,775.0000
Enth., mm BTU/hr	5,000.4	4,587.5	4,991.5	4,863.3
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,422,824.00	3,022,125.00	3,416,724.50	3,416,724.50
Stream no.	204	205	207	208
Temp., °F	908.1930	908.1930	631.1807	997.5285
Pres., psia	1,775.0000	1,775.0000	603.6000	545.4000
Enth., mm BTU/hr	4,806.0	57.392	4,420.2	4,651.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,376,403.75	40,320.77	3,376,403.75	3,067,190.00
Stream no.	209	210	211	212
Temp., °F	817.2190	817.2190	702.8816	702.8816
Pres., psia	278.9000	278.9000	174.9000	174.9000
Enth., mm BTU/hr	4,386.6	4,240.6	4,080.4	3,626.8
Vapor, mass fraction	1.0000	0.0000	1.0000	1.0000
Total, lb/hr	3,067,190.00	2,965,172.00	2,965,172.00	2,635,575.50
Stream no.	213	214	215	216
Temp., °F	702.8816	702.8816	494.9297	494.9297
Pres., psia	174.9000	174.9000	66.5000	66.5000
Enth., mm BTU/hr	171.69	281.87	3,372.3	3,171.7
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	124,762.58	204,834.09	2,635,575.50	2,478,811.50
Stream no.	217	218	219	220
Temp., °F	494.9297	312.4631	312.4631	216.4566
Pres., psia	66.5000	24.0000	24.0000	12.8000
Enth., mm BTU/hr	200.58	2,965.7	2,864.0	2,760.2
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	156,764.03	2,478,811.50	2,393,808.00	2,393,808.00
Stream no.	221	222	223	224
Temp., °F	216.4566	216.4566	172.1188	172.1188
Pres., psia	12.8000	12.8000	6.3000	6.3000
Enth., mm BTU/hr	2,667.4	92.755	2,566.2	2,397.0
Vapor, mass fraction	1.0000	1.0000	0.97448	0.97448
Total, lb/hr	2,313,364.25	80,443.91	2,313,364.25	2,160,797.75
Stream no.	225	226	227	228
Temp., °F	172.1188	101.5784	104.7907	631.1807
Pres., psia	6.3000	1.0000	1.1000	603.6000
Enth., mm BTU/hr	169.24	2182.6	128.88	16.235
Vapor, mass fraction	0.97448	0.90786	0.92852	1.0000
Total, lb/hr	152,566.38	2,160,797.75	124,762.58	12,401.53
Stream no.	229	230	231	232
Temp., °F	631.1807	631.1807	1,000.0000	1,000.0000
Pres., psia	603.6000	603.6000	2,414.7000	2,414.7000
Enth., mm BTU/hr	4,395.0	8.9243	1.9801	6.9305
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	3,357,185.25	6,816.96	1,355.44	4,744.03
Stream no.	233	234	235	236
Temp., °F	626.4604	626.4604	626.4604	626.4604
Pres., psia	174.9000	174.9000	174.9000	174.9000
Enth., mm BTU/hr	24.561	4.0125	15.866	4.6827
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	18,368.40	3,000.79	11,865.62	3,501.99

Stream no.	237	238	239	240
Temp., °F	172.1188	200.0000	118.1270	70.0000
Pres., psia	6.3000	174.9000	6.0000	14.7000
Enth., mm BTU/hr	185.11	0.58921	42.801	0.62795
Vapor, mass fraction	0.99101	0.00000	0.00000	0.00000
Total, lb/hr	164,432.00	3,501.99	496,962.22	16,527.00
Stream no.	241	242	243	244
Temp., °F	96.4000	97.5560	98.0755	99.0167
Pres., psia	0.9000	330.0000	0.9000	330.0000
Enth., mm BTU/hr	180.43	183.67	2,358.9	187.77
Vapor, mass fraction	0.00000	0.00000	0.74740	0.00000
Total, lb/hr	2,802,050.50	2,802,050.50	2,802,050.50	2,802,050.50
Stream no.	245	246	247	248
Temp., °F	167.4000	169.9850	117.5445	198.7000
Pres., psia	300.0000	6.0000	6.0000	270.0000
Enth., mm BTU/hr	379.63	234.07	42.212	467.78
Vapor, mass fraction	0.00000	0.33771	0.00000	0.00000
Total, lb/hr	2,802,050.50	493,460.25	493,460.25	2,802,050.50
Stream no.	249	250	251	252
Temp., °F	201.5301	180.6844	210.1221	312.4631
Pres., psia	11.9000	11.9000	22.4000	24.0000
Enth., mm BTU/hr	137.12	48.966	44.361	101.70
Vapor, mass fraction	0.25293	0.00000	0.00000	1.0000
Total, lb/hr	329,028.28	329,028.28	248,584.39	85,003.41
Stream no.	253	254	255	256
Temp., °F	234.0796	231.1000	241.2455	292.3000
Pres., psia	22.4000	240.0000	62.4000	160.0000
Enth., mm BTU/hr	136.04	559.46	34.344	734.62
Vapor, mass fraction	0.36067	0.00000	0.00000	0.00000
Total, lb/hr	248,584.39	2,802,050.50	163,581.00	2,802,050.50
Stream no.	257	258	259	260
Temp., °F	702.8816	702.8816	366.0413	399.4454
Pres., psia	174.9000	174.9000	164.8000	263.8000
Enth., mm BTU/hr	6.3458	275.53	1,167.9	164.23
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	4,611.43	200,222.67	3,439,352.50	437,079.31
Stream no.	261	262	263	264
Temp., °F	366.0413	376.1441	376.1441	376.1441
Pres., psia	164.8000	2,903.3000	2,903.3000	2,903.3000
Enth., mm BTU/hr	0.00000	1,205.2	41.393	1,163.8
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	0.00	3,439,352.50	118,124.56	3,321,228.00
Stream no.	265	266	267	268
Temp., °F	407.5000	817.2190	410.8008	415.5000
Pres., psia	2,853.3000	278.9000	278.8000	588.5000
Enth., mm BTU/hr	1,277.3	145.90	277.73	131.83
Vapor, mass fraction	0.00000	1.0000	0.30377	0.00000
Total, lb/hr	3,321,228.00	102,017.80	437,079.31	335,061.50
Stream no.	269	270	271	272
Temp., °F	631.1807	488.3002	631.1807	496.6450
Pres., psia	603.6000	2800.0000	603.6000	62.4000
Enth., mm BTU/hr	438.64	,584.1	3,956.4	209.51
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	335,061.50	3,321,228.00	3,022,123.75	163,581.00

Figure A3.3. Flue gas cleaning (Illinois coal)

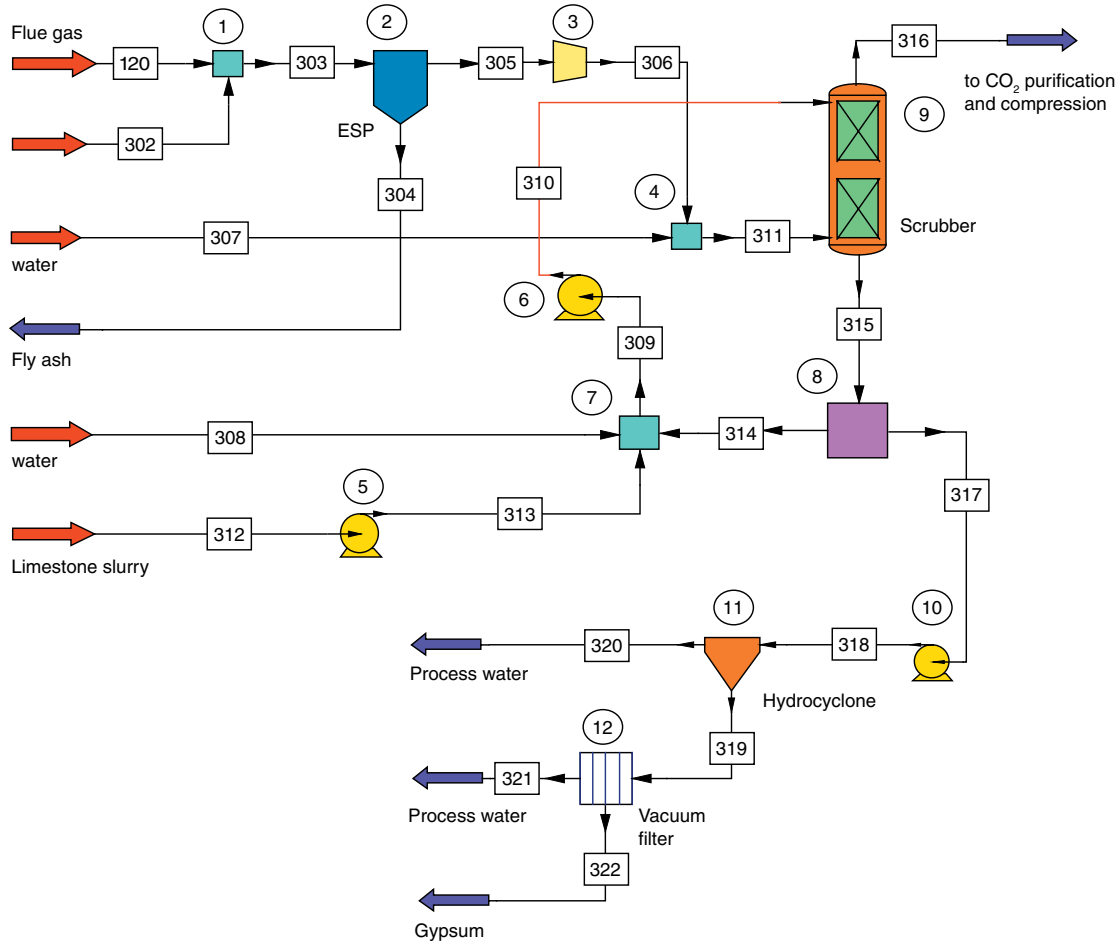


Table A3.4. Illinois coal

Stream no.	120	302	303	304
Temp., °F	395.0000	395.0000	394.9973	394.9973
Pres., psia	14.2000	14.2000	14.2000	14.1000
Enth., mm BTU/hr	-4,368.6	-52.566	-4,421.2	-52.007
Vapor, mass fraction	1.0000	0.00000	1.0000	0.00000
Total, lb/hr	1,161,067.88	24,804.28	1,185,872.13	24,540.49
Stream no.	305	306	307	308
Temp., °F	394.9973	408.3329	50.0000	50.0000
Pres., psia	14.1000	14.8000	14.8000	17.4000
Enth., mm BTU/hr	-4,369.2	-4,365.1	-203.16	-504.30
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	1,161,331.63	1,161,331.63	29,665.00	73,637.30
Stream no.	309	310	311	312
Temp., °F	168.2314	169.7365	295.0083	70.0000
Pres., psia	15.0000	435.1130	14.8000	15.0000
Enth., mm BTU/hr	-1.4107E+005	-1.4104E+005	-4,568.2	-1,137.4
Vapor, mass fraction	0.00000	0.00000	1.0000	0.00000
Total, lb/hr	22,412,292.00	22,412,288.00	1,190,996.63	173,353.00

Stream no.	313	314	315	316
Temp., °F	70.1575	169.4717	169.4717	169.6657
Pres., psia	60.0000	15.0000	15.0000	14.5000
Enth., mm BTU/hr	-1,137.3	-1.3942E+005	-1.4055E+005	-5,057.6
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	173,353.00	22,165,302.00	22,344,162.00	1,259,120.75
Stream no.	317	318	319	320
Temp., °F	169.4717	169.5176	169.5176	169.5176
Pres., psia	15.0000	30.0000	21.1405	21.1405
Enth., mm BTU/hr	-1,125.1	-1,125.1	-263.29	-861.76
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	178,861.58	178,861.56	49,990.19	128,871.36
Stream no.	321	322		
Temp., °F	169.5176	169.5176		
Pres., psia	11.1405	11.1405		
Enth., mm BTU/hr	-78.181	-185.11		
Vapor, mass fraction	0.00000	0.00000		
Total, lb/hr	11,624.74	38,365.45		

Figure A3.4. Flue gas cleaning (PRB coal)

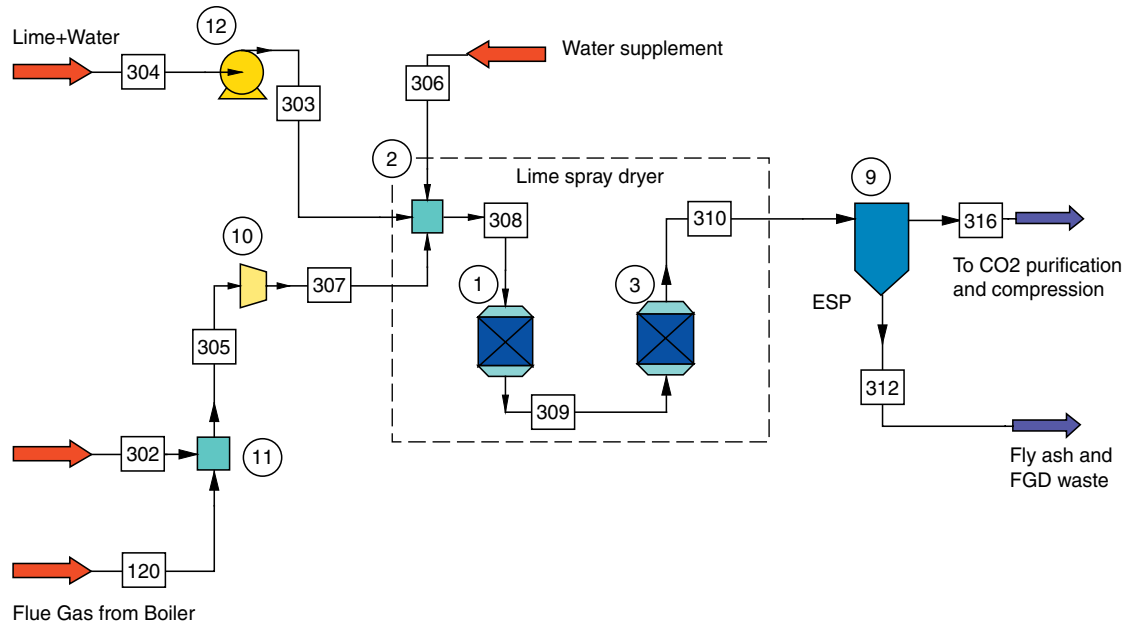


Table A3.5. PRB coal

Stream no.	120	302	303	304
Temp., °F	395.0000	395.0000	63.0577	63.0000
Pres., psia	14.1000	14.1000	30.0000	14.7000
Enth., mm BTU/hr	-5,283.7	-45.093	-115.15	-115.15
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	1,297,622.50	21,278.00	17,929.77	17,929.77
Stream no.	305	306	307	308
Temp., °F	395.0000	63.0000	412.0364	196.6996
Pres., psia	14.1000	15.0000	15.0000	15.0000
Enth., mm BTU/hr	-5,328.8	-407.07	-5,322.3	-5,844.5
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	1,318,900.50	59,515.00	1,318,900.50	1,396,345.38
Stream no.	309	310	312	316
Temp., °F	191.0855	201.0469	201.0469	201.0469
Pres., psia	14.7000	14.7000	14.5000	14.5000
Enth., mm BTU/hr	-5,844.5	-5,844.5	-79.371	-5,765.1
Vapor, mass fraction	1.0000	1.0000	0.00000	1.0000
Total, lb/hr	1,396,345.13	1,396,531.38	28,714.08	1,367,817.38

Figure A3.5. CO₂ purification and compression

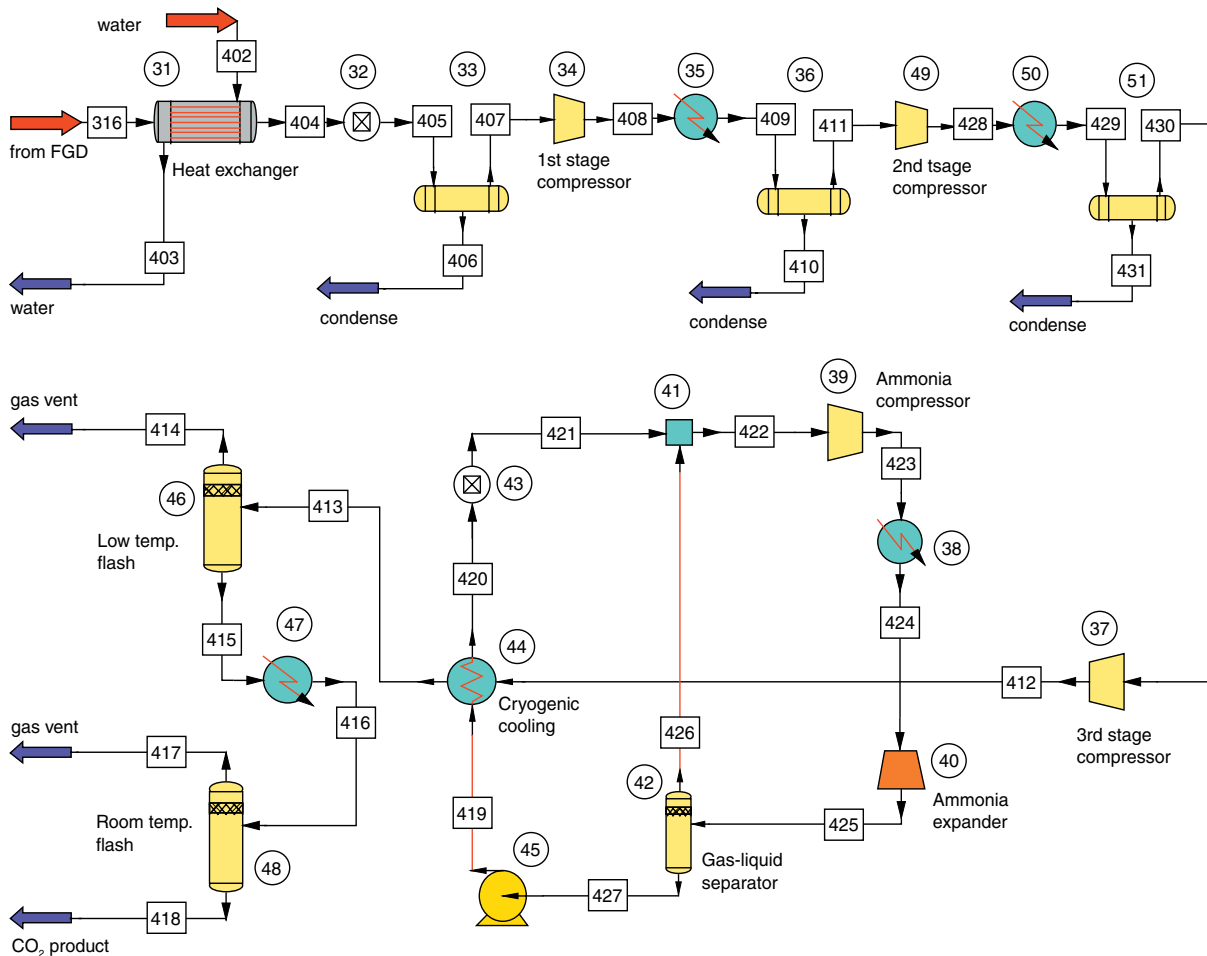


Table A3.6. Illinois coal

Stream no.	316	402	403	404
Temp., °C	76.4809	15.0000	70.0000	40.0000
Pres., bar	0.9997	2.0684	1.0132	0.9997
Enth., mm BTU/hr	-5,049.4	-18,985	-18,710	-5,324.0
Vapor, mass fraction	1.0000	0.00000	0.00000	0.80540
Total, lb/hr	1,259,107.50	2,777,197.25	2,777,197.25	1,259,107.50
Stream no.	405	406	407	408
Temp., °C	40.0000	40.0000	40.0000	294.8491
Pres., bar	0.9997	0.9997	0.9997	10.0000
Enth., mm BTU/hr	-5,324.0	-1,663.4	-3,660.5	-3,564.5
Vapor, mass fraction	0.80540	0.00000	1.0000	1.0000
Total, lb/hr	1,259,107.50	245,026.47	1,014,081.13	1,014,081.13
Stream no.	409	410	411	412
Temp., °C	40.0000	40.0000	40.0000	134.9481
Pres., bar	10.0000	10.0000	10.0000	83.0000
Enth., mm BTU/hr	-3,703.6	-202.40	-3,501.2	-3,512.7
Vapor, mass fraction	0.97051	0.00000	1.0000	1.0000
Total, lb/hr	1,014,081.13	29,909.95	984,172.00	981,498.00
Stream no.	413	414	415	416
Temp., °C	-33.0000	-33.0000	-33.0000	20.0000
Pres., bar	83.0000	83.0000	83.0000	83.0000
Enth., mm BTU/hr	-3,636.2	-63.003	-3,573.2	-3,521.3
Vapor, mass fraction	0.084346	1.0000	0.00000	0.027192
Total, lb/hr	981,498.00	82,785.49	898,713.00	898,713.00
Stream no.	417	418	419	420
Temp., °C	20.0000	20.0000	-33.4059	-33.0000
Pres., bar	83.0000	83.0000	1.5000	1.0000
Enth., mm BTU/hr	-70.105	-3,451.2	-377.19	-253.62
Vapor, mass fraction	1.0000	0.00000	0.00000	1.0000
Total, lb/hr	24,438.16	874,275.00	209,679.42	209,679.39
Stream no.	421	422	423	424
Temp., °C	-33.0000	-33.0809	180.7371	20.0000
Pres., bar	1.0000	1.0000	10.0000	10.000
Enth., mm BTU/hr	-253.62	-303.22	-258.65	-424.36
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	20,679.39	250,675.22	250,675.22	250,675.22
Stream no.	425	426	427	428
Temp., °C	-33.4252	-33.4252	-33.4252	283.5626
Pres., bar	1.0132	1.0132	1.0132	60.0000
Enth., mm BTU/hr	-426.80	-49.604	-377.19	-3,437.5
Vapor, mass fraction	0.16354	1.0000	0.00000	1.0000
Total, lb/hr	250,675.23	40,995.81	209,679.42	984,172.00
Stream no.	429	430	431	
Temp., °C	40.0000	40.0000	40.0000	
Pres., bar	60.0000	60.0000	60.0000	
Enth., mm BTU/hr	-3,537.8	-3,520.0	-17.774	
Vapor, mass fraction	0.99728	1.0000	0.00000	
Total, lb/hr	984,172.00	981,498.00	2,673.3	

Table A3.7. PRB coal

Stream no.	316	402	403	404
Temp., °C	93.9150	15.0000	70.0000	40.0000
Pres., bar	0.9997	2.0684	1.0132	0.9997
Enth., mm BTU/hr	-5,755.1	-26,707	-26,321	-6,141.4
Vapor, mass fraction	1.0000	0.00000	0.00000	0.75253
Total, lb/hr	1,367,817.38	3,906,867.50	3,906,867.50	1,367,817.38
Stream no.	405	406	407	08
Temp., °C	40.0000	40.0000	40.0000	290.3674
Pres., bar	0.9997	0.9997	0.9997	10.0000
Enth., mm BTU/hr	-6,141.4	-2,298.0	-3,843.4	-3,746.7
Vapor, mass fraction	0.75253	0.00000	1.0000	1.0000
Total, lb/hr	1,367,817.38	338,497.13	1,029,320.31	1,029,320.31
Stream no.	409	410	411	412
Temp., °C	40.0000	40.0000	40.0000	136.2390
Pres., bar	10.0000	10.0000	10.0000	83.0000
Enth., mm BTU/hr	-3,887.4	-204.77	-3,682.6	-3,694.5
Vapor, mass fraction	0.97060	0.00000	1.0000	1.0000
Total, lb/hr	1,029,320.31	30,259.94	999,061.00	996,355.00
Stream no.	413	414	415	416
Temp., °C	-33.0000	-33.0000	-33.0000	20.0000
Pres., bar	83.0000	83.0000	83.0000	83.0000
Enth., mm BTU/hr	-3,824.2	-36.507	-3,787.6	-3,732.5
Vapor, mass fraction	0.045073	1.0000	0.00000	0.025284
Total, lb/hr	996,355.00	44,908.40	951,447.00	951,447.00
Stream no.	417	418	419	420
Temp., °C	20.0000	20.0000	-33.4059	-33.0000
Pres., bar	83.0000	83.0000	1.5000	1.0000
Enth., mm BTU/hr	-70.468	-3,662.0	-395.83	-266.15
Vapor, mass fraction	1.0000	0.00000	0.00000	1.0000
Total, lb/hr	24,056.58	927,390.06	220,042.64	220,043.27
Stream no.	421	422	423	424
Temp., °C	-33.0000	-33.0805	180.7371	20.0000
Pres., bar	1.0000	1.0000	10.0000	10.0000
Enth., mm BTU/hr	-266.15	-318.21	-271.43	-445.33
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	220,043.27	263,064.63	263,064.63	263,064.63
Stream no.	425	426	427	428
Temp., °C	-33.4252	-33.4252	-33.4252	278.7653
Pres., bar	1.0132	1.0132	1.0132	60.0000
Enth., mm BTU/hr	-447.89	-52.056	-395.84	-3,618.5
Vapor, mass fraction	0.16354	1.0000	0.00000	1.0000
Total, lb/hr	263,064.63	43,022.01	220,042.64	999,061.00
Stream no.	429	430	431	
Temp., °C	40.0000	40.0000	40.0000	
Pres., bar	60.0000	60.0000	60.0000	
Enth., mm BTU/hr	-3,719.7	-3,701.8	-17.992	
Vapor, mass fraction	0.99729	1.0000	0.00000	
Total, lb/hr	999,061.00	996,355.00	2,705.51	

Appendix A4. IGCC Plants with 533-MW (Gross) Output Installed with Selexol Process

Figure A4.1. Gasifier, shift reactor, gas cleanup, and gas turbine

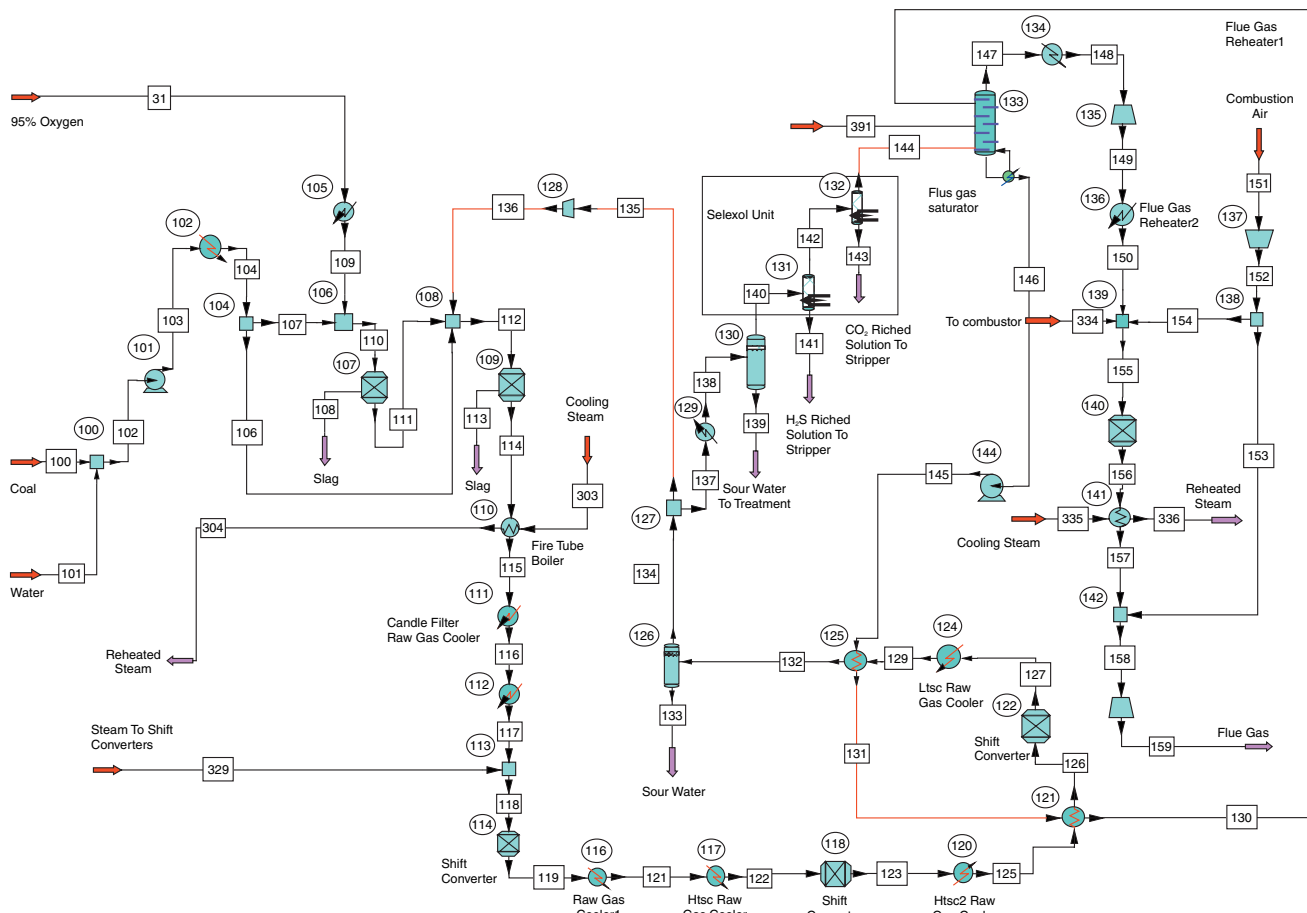


Table A4.1. Illinois coal

Stream no.	31	100	101	102
Temp., °F	239.8713	59.0000	59.0000	59.0001
Pres., psia	957.0000	14.7000	14.7000	14.7000
Enth., mm BTU/hr	8.5202	-243.90	-1,302.9	-1,546.8
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	268,910.69	324,152.00	190,375.00	514,527.00
Stream no.	103	104	106	107
Temp., °F	61.6427	300.0000	300.0000	300.0000
Pres., psia	860.0000	850.0000	850.0000	850.0000
Enth., mm BTU/hr	-1,546.2	-1,494.2	-313.79	-1,180.4
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	514,527.00	514,527.00	108,050.67	406,476.34

Stream no.	108	109	110	111
Temp., °F	2600.0000	305.0000	269.2364	2,600.0000
Pres., psia	823.0000	954.6000	840.0000	823.0000
Enth., mm BTU/hr	-23.449	12.580	-1,167.9	-1,247.1
Vapor, mass fraction	0.00000	1.0000	0.42366	1.0000
Total, lb/hr	22,791.12	268,910.69	675,388.00	652,590.00
Stream no.	112	113	114	115
Temp., °F	2221.1989	1900.0000	1900.0000	650.0000
Pres., psia	813.0000	800.0000	800.0000	797.0000
Enth., mm BTU/hr	-1,645.2	-9.7538	-1,532.9	-1,954.1
Vapor, mass fraction	0.92697	0.00000	1.0000	1.0000
Total, lb/hr	783,602.00	6,058.40	777,544.00	777,544.00
Stream no.	116	117	118	119
Temp., °F	550.0000	545.0000	562.1572	753.3545
Pres., psia	795.0000	792.0000	792.0000	783.0000
Enth., mm BTU/hr	-1,985.6	-1,987.2	-3,623.9	-3,623.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	777,544.00	777,544.00	1,071,480.38	1,071,485.00
Stream no.	121	122	123	125
Temp., °F	690.0000	550.0000	694.9540	612.0000
Pres., psia	774.0000	765.0000	759.0000	750.0000
Enth., mm BTU/hr	-3,654.5	-3,722.0	-3,722.0	-3,762.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	1,071,485.00	1,071,485.00	1,071,488.50	1,071,488.50
Stream no.	126	127	129	130
Temp., °F	369.8771	458.5451	370.0000	450.0000
Pres., psia	741.0000	741.0000	732.0000	751.0000
Enth., mm BTU/hr	-3,888.0	-3,888.0	-3,931.4	-5,975.3
Vapor, mass fraction	0.99184	1.0000	1.0000	0.00033324
Total, lb/hr	1,071,488.50	1,071,490.88	1,071,490.88	928,248.00
Stream °F	326.0000	303.3142	303.3023	303.3023
Pres., psia	761.0000	722.0000	722.0000	722.0000
Enth., mm BTU/hr	-6,100.6	-4,041.9	-585.92	-3,455.9
Vapor, mass fraction	0.00000	0.91622	0.00000	1.0000
Total, lb/hr	928,190.00	1,071,490.88	89,788.12	981,702.00
Stream no.	135	136	137	138
Temp., °F	303.3023	344.0381	303.3023	108.0000
Pres., psia	722.0000	850.0000	722.0000	714.0000
Enth., mm BTU/hr	-84.670	-84.257	-3,371.3	-3,537.4
Vapor, mass fraction	1.0000	1.0000	1.0000	0.91055
Total, lb/hr	24,051.69	24,052.37	957,650.00	957,650.00
Stream no.	139	140	141	142
Temp., °F	105.0000	105.0000	80.0000	90.0000
Pres., psia	704.0000	704.0000	700.0000	700.0000
Enth., mm BTU/hr	-576.54	-2,962.2	-12.125	-2,956.3
Vapor, mass fraction	0.00000	1.0000	0.98456	0.99961
Total, lb/hr	85,787.18	871,859.00	9,795.49	862,063.06
Stream no.	143	144	145	146
Temp., °F	90.0000	68.0000	209.8464	209.6072
Pres., psia	695.0000	695.0000	770.0000	695.0000
Enth., mm BTU/hr	-2,853.7	-115.00	-6,211.0	-6,211.2
Vapor, mass fraction	1.0000	0.99286	0.00000	0.00000
Total, lb/hr	738,801.00	123,262.51	928,190.00	928,190.00
Stream no.	147	148	149	150
Temp., °F	376.8052	520.0000	393.3941	535.0000
Pres., psia	690.0000	685.0000	385.0000	380.0000
Enth., mm BTU/hr	-1,092.5	-1,049.3	-1,084.8	-1,043.9
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	306,205.00	306,205.00	306,205.00	306,205.00

Stream no.	151	152	153	154
Temp., °F	68.0000	946.0071	946.0071	946.0071
Pres., psia	14.4000	380.0000	380.0000	380.0000
Enth., mm BTU/hr	-456.20	685.28	29.789	655.49
Vapor, mass fraction	0.99989	1.0000	1.0000	1.0000
Total, lb/hr	5,140,434.00	5,140,434.00	223,454.69	4,916,979.50
Stream no.	155	156	157	158
Temp., °F	861.7679	2,557.2514	2,449.7438	2,400.0109
Pres., psia	380.0000	353.0000	353.0000	353.0000
Enth., mm BTU/hr	-938.29	-938.30	-1,138.4	-1,108.6
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	5,322,013.00	5,322,005.50	5,322,005.50	5,545,460.50
Stream no.	159	303	304	329
Temp., °F	1095.6921	620.0002	631.9833	645.0002
Pres., psia	15.2000	2000.0000	1950.0000	800.0000
Enth., mm BTU/hr	-3,473.7	-6,402.5	-5,981.3	-1,636.7
Vapor, mass fraction	1.0000	0.00000	0.80997	1.0000
Total, lb/hr	5,545,461.50	1,028,788.00	1,028,788.00	293,937.00
Stream no.	334	335	336	391
Temp., °F	598.5389	598.5389	1,000.0000	267.0000
Pres., psia	385.0000	385.0000	347.0000	855.0000
Enth., mm BTU/hr	-549.87	-5,138.1	-4,938.0	-1,213.4
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	98,828.41	923,480.00	923,480.00	182,884.48

Table A4.2. PRB coal

Stream no.	31	100	101	102
Temp., °F	239.8713	59.0000	59.0000	58.9989
Pres., psia	957.0000	14.7000	14.7000	14.7000
Enth., mm BTU/hr	9.1419	-1,056.9	-1,216.6	-2,273.5
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	288,533.41	466,261.41	177,761.59	644,023.13
Stream no.	103	104	106	107
Temp., °F	61.5821	300.0000	300.0000	300.0000
Pres., psia	860.0000	850.0000	850.0000	850.0000
Enth., mm BTU/hr	-2,272.7	-2,198.8	-461.75	-1,737.1
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	644,023.13	644,023.13	135,244.84	508,778.28
Stream no.	108	109	110	111
Temp., °F	2,600.0000	305.0000	274.2680	2,600.0000
Pres., psia	823.0000	954.6000	840.0000	823.0000
Enth., mm BTU/hr	-19.890	13.498	-1,723.6	-1,806.8
Vapor, mass fraction	0.00000	1.0000	0.56388	1.0000
Total, lb/hr	19,331.82	288,533.41	797,312.06	777,974.00
Stream no.	112	113	114	115
Temp., °F	2,190.0837	1,900.0000	1,900.0000	650.0000
Pres., psia	813.0000	800.0000	800.0000	797.0000
Enth., mm BTU/hr	-2,367.0	-8.2734	-2,256.2	-2,772.9
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	940,136.00	5,138.84	934,997.00	934,997.00
Stream no.	116	117	118	119
Temp., °F	550.0000	545.0000	562.6477	718.0000
Pres., psia	795.0000	792.0000	792.0000	783.0000
Enth., mm BTU/hr	-2,811.7	-2,813	-4,450.4	-4,450.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	934,997.00	934,997.00	122,933.63	1,228,938.13

Stream no.	121	122	123	125
Temp., °F	665.0000	550.0000	668.0000	612.0000
Pres., psia	774.0000	765.0000	759.0000	750.0000
Enth., mm BTU/hr	-4,479.8	-4,544.1	-4,544.1	-4,575.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	1,228,938.13	1,228,938.13	1,228,941.38	1,228,941.38
Stream no.	126	127	129	130
Temp., °F	390.1741	473.6802	370.0000	450.0000
Pres., psia	741.0000	741.0000	732.0000	751.0000
Enth., mm BTU/hr	-4,703.6	-4,700.3	-4,777.1	-6,100.2
Vapor, mass fraction	0.99854	1.0000	0.98305	0.00035571
Total, lb/hr	1,228,941.25	1,228,943.50	1,228,941.00	947,713.00
Stream no.	131	132	133	134
Temp., °F	326.0000	335.2399	335.2399	335.2399
Pres., psia	761.0000	722.0000	722.0000	722.0000
Enth., mm BTU/hr	-6,228.5	-4,889.7	-851.71	-4,038.0
Vapor, mass fraction	0.00000	0.89407	0.00000	1.0000
Total, lb/hr	947,713.00	1,228,941.00	130,193.66	1,098,759.63
Stream no.	135	136	137	138
Temp., °F	335.2399	376.8267	335.2399	108.0000
Pres., psia	722.0000	850.0000	722.0000	714.0000
Enth., mm BTU/hr	-98.932	-98.441	-939.1	-4,192.5
Vapor, mass fraction	1.0000	1.0000	1.0000	0.85952
Total, lb/hr	26,919.61	26,917.07	1,071,840.00	1,071,840.00
Stream no.	139	140	141	142
Temp., °F	105.0000	105.0000	80.0000	90.0000
Pres., psia	704.0000	704.0000	700.0000	700.0000
Enth., mm BTU/hr	-1,015.7	-3,178.4	-10.903	-3,173.8
Vapor, mass fraction	0.00000	1.0000	0.96268	0.99962
Total, lb/hr	150,733.64	921,108.00	3,784.20	917,323.00
Stream no.	143	144	145	146
Temp., °F	90.0000	68.0000	209.9997	315.9250
Pres., psia	695.0000	695.0000	770.0000	695.0000
Enth., mm BTU/hr	-3,044.3	-142.39	-6,341	-6,833.2
Vapor, mass fraction	1.0000	0.99291	0.00000	0.00000
Total, lb/hr	788,137.00	129,186.65	947,713.00	1,038,595.06
Stream no.	147	148	149	150
Temp., °F	333.3868	520.0000	393.2608	535.0000
Pres., psia	690.0000	685.0000	385.0000	380.0000
Enth., mm BTU/hr	-610.92	-1,096.3	-1,132.5	-1,090.7
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	221,188.53	315,953.25	315,953.25	315,953.25
Stream no.	151	152	153	154
Temp., °F	68.0000	946.0071	946.0071	946.0071
Pres., psia	14.4000	380.0000	380.0000	380.0000
Enth., mm BTU/hr	-445.73	669.55	29.105	640.44
Vapor, mass fraction	0.99989	1.0000	1.0000	1.0000
Total, lb/hr	5,022,433.00	5,022,433.00	218,325.16	4,804,108.00
Stream no.	155	156	157	158
Temp., °F	859.0961	2,574.4999	2,465.4452	2,415.5973
Pres., psia	380.0000	353.0000	353.0000	353.0000
Enth., mm BTU/hr	-1,000.2	-994.20	-1,194.3	-1,165.2
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	5,218,890.00	5,218,882.00	5,218,882.00	5,437,207.50
Stream no.	159	303	304	329
Temp., °F	1,106.4225	620.0002	632.3465	645.0002
Pres., psia	15.2000	2,000.0000	1,950.0000	800.0000
Enth., mm BTU/hr	-3,503.9	-6,402.5	-5,885.9	-1,636.7
Vapor, mass fraction	1.0000	0.00000	1.0000	1.0000
Total, lb/hr	5,437,207.50	1,028,788.00	1,028,788.00	293,937.00

Stream no.	334	335	336	391
Temp., °F	598.5389	598.5389	1,000.0000	267.0000
Pres., psia	385.0000	385.0000	347.0000	855.0000
Enth., mm BTU/hr	-549.87	-5,138.1	-4,938.0	-1,213.4
Vapor, mass fraction	1.0000	1.0000	1.0000	0.00000
Total, lb/hr	98,828.41	923,480.00	923,480.00	182,884.48

Figure A4.2. Steam cycle

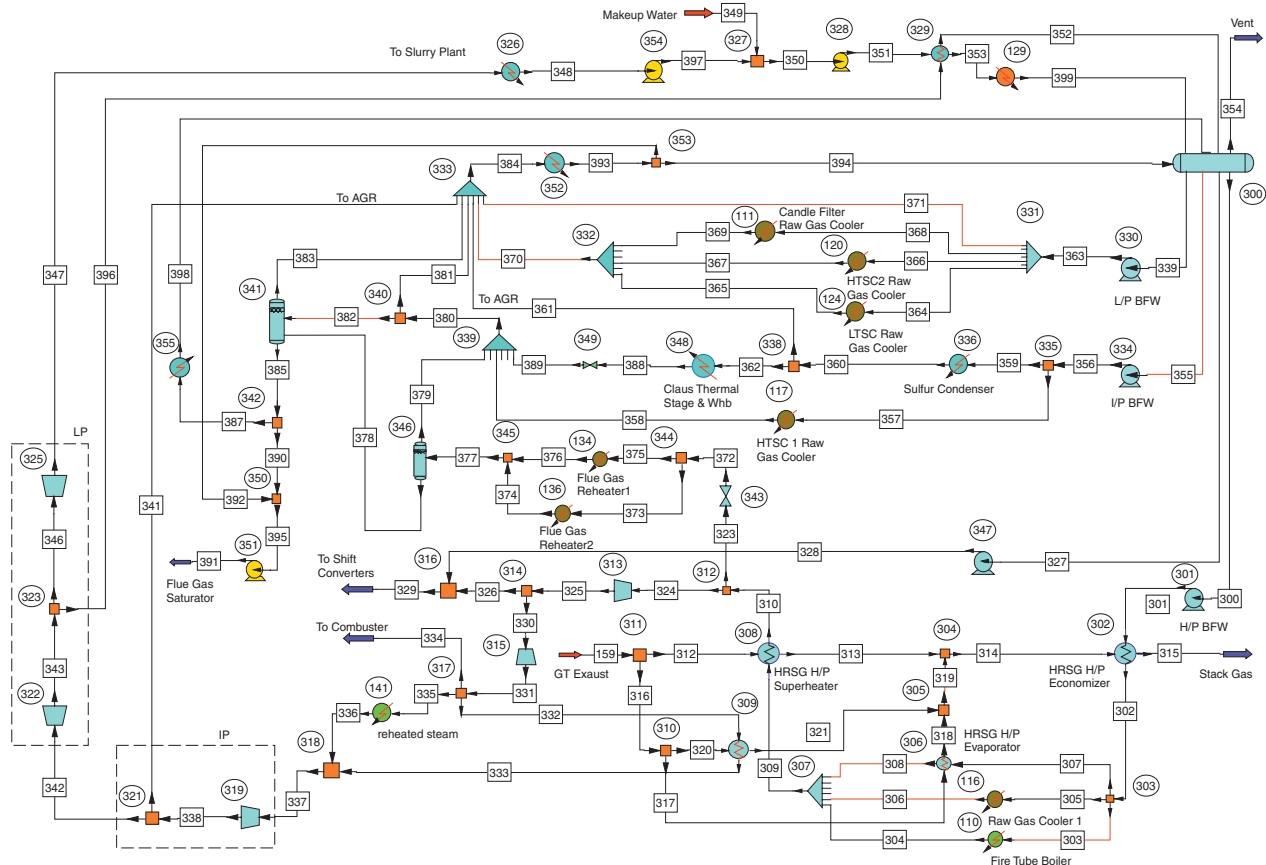


Table A4.3. Illinois coal

Stream no.	159	300	301	302
Temp., °F	1,095.6921	240.1082	247.5038	620.0000
Pres., psia	15.2000	25.0000	2,300.0000	2,000.0000
Enth., mm BTU/hr	-3,474.0	-9,714.1	-9,703.1	-9,074.5
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	5,545,462.00	1,458,127.00	1,458,127.00	1,458,127.00
Stream no.	303	304	305	306
Temp., °F	620.0000	632.2300	620.0000	632.1550
Pres., psia	2,000.0000	1,950.0000	2,000.0000	1,950.0000
Enth., mm BTU/hr	-6,402.5	-5,886.1	-378.99	-348.43
Vapor, mass fraction	0.00000	1.0000	0.00000	1.0000
Total, lb/hr	1,028,788.00	1,028,788.00	60,898.00	60,898.00

Stream no.	307	308	309	310
Temp., °F	620.0000	632.2000	631.9833	1,004.0000
Pres., psia	2,000.0000	2,000.0000	1,950.0000	1,840.0000
Enth., mm BTU/hr	-2,293.0	-2,286.5	-8,521.0	-7,858.0
Vapor, mass fraction	0.00000	0.00000	0.74815	1.0000
Total, lb/hr	368,441.00	368,441.00	1,458,127.00	1,458,127.00
Stream no.	312	313	314	315
Temp., °F	1095.6921	665.2483	680.4660	277.0513
Pres., psia	15.2000	15.0000	15.0000	14.8000
Enth., mm BTU/hr	-3,265.6	-3,928.7	-4,155.2	-4,783.8
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	5,212,733.50	5,212,733.50	5,545,462.00	5,545,462.00
Stream no.	316	317	318	319
Temp., °F	1,095.6921	1,095.6921	880.4981	915.0102
Pres., psia	15.2000	15.2000	15.2000	15.0000
Enth., mm BTU/hr	-208.44	-62.532	-68.970	-226.50
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	332,728.00	99,818.31	99,818.31	332,728.00
Stream no.	320	321	323	324
Temp., °F	1,095.6921	929.7526	1,004.0000	1,004.0000
Pres., psia	15.2000	15.0000	18,40.0000	1,840.0000
Enth., mm BTU/hr	-145.91	-157.53	-567.52	-7,290.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	232,909.38	232,909.38	105,308.85	1,352,818.25
Stream no.	325	326	327	328
Temp., °F	772.5801	772.5801	240.1082	242.1404
Pres., psia	800.0000	800.0000	25.0000	650.0000
Enth., mm BTU/hr	-7,425.0	-1,519.7	-113.65	-113.62
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	1,352,818.25	276,877.25	17,060.00	17,060.00
Stream no.	329	330	331	332
Temp., °F	645.0892	772.5801	598.5389	598.5389
Pres., psia	650.0000	800.0000	385.0000	385.0000
Enth., mm BTU/hr	-1,633.3	-5,905.4	-5,986.4	-298.41
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	293,937.25	1,075,941.00	1,075,941.00	53,633.00
Stream no.	333	334	335	336
Temp., °F	1,000.0000	598.5389	598.5389	1,000.0000
Pres., psia	347.0000	385.0000	385.0000	347.0000
Enth., mm BTU/hr	-286.79	-549.87	-5,138.1	-4,938.0
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	53,633.00	98,828.41	923,480.00	923,480.00
Stream no.	337	338	339	341
Temp., °F	1,000.0000	569.0683	240.1082	569.0683
Pres., psia	347.0000	58.0000	25.0000	58.0000
Enth., mm BTU/hr	-5,224.8	-5,427.2	-1,076.1	-1,799.7
Vapor, mass fraction	1.0000	1.0000	0.00000	1.0000
Total, lb/hr	977,113.00	977,113.00	161,529.19	324,028.13
Stream no.	342	343	346	347
Temp., °F	569.0683	467.1291	467.1291	101.5784
Pres., psia	58.0000	35.0000	35.0000	1.0000
Enth., mm BTU/hr	-3,627.4	-3,658.4	-3,621.8	-3,768.6
Vapor, mass fraction	1.0000	1.0000	1.0000	0.93869
Total, lb/hr	653,085.00	653,085.00	646,554.00	646,554.00
Stream no.	348	349	350	351
Temp., °F	80.0000	63.0000	71.9504	71.9816
Pres., psia	1.0000	14.4000	14.4000	25.0000
Enth., mm BTU/hr	-4,411.3	-3,996.8	-8,408.1	-8,408.1
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	646,554.00	584,349.19	1,230,902.88	1,230,902.88

Stream no.	352	353	354	355
Temp., °F	240.0000	77.6091	240.1082	240.1082
Pres., psia	27.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-43.509	-8,401.2	-49.681	-629.95
Vapor, mass fraction	0.00000	0.00000	1.0000	0.00000
Total, lb/hr	6,530.84	1,230,902.88	8,699.87	94,559.00
Stream no.	356	357	358	359
Temp., °F	242.7635	242.7635	481.7281	242.7635
Pres., psia	841.0000	841.0000	260.0000	841.0000
Enth., mm BTU/hr	-629.70	-432.63	-365.09	-197.07
Vapor, mass fraction	0.00000	0.00000	1.0000	0.00000
Total, lb/hr	94,559.00	64,966.57	64,966.57	29,592.43
Stream no.	360	361	362	363
Temp., °F	284.3000	284.3000	284.3000	241.3838
Pres., psia	741.0000	741.0000	741.0000	417.0000
Enth., mm BTU/hr	-195.81	-85.902	-109.91	-1,075.9
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	29,592.43	12,982.20	16,610.23	161,529.19
Stream no.	364	365	366	367
Temp., °F	241.3838	331.4878	241.3838	331.4878
Pres., psia	417.0000	105.0000	417.0000	105.0000
Enth., mm BTU/hr	-340.26	-296.87	-323.95	-283.55
Vapor, mass fraction	0.0000	0.85495	0.00000	0.83394
Total, lb/hr	51,084.00	51,084.00	48,636.50	48,636.50
Stream no.	368	369	370	371
Temp., °F	241.3838	331.4878	331.4878	241.3838
Pres., psia	417.0000	105.0000	105.0000	417.0000
Enth., mm BTU/hr	-319.24	-287.78	-868.20	-92.449
Vapor, mass fraction	0.00000	0.63684	0.77723	0.00000
Total, lb/hr	47,928.90	47,928.90	147,649.39	13,879.80
Stream no.	372	373	374	375
Temp., °F	951.8254	951.8254	407.9199	951.8254
Pres., psia	870.0000	870.0000	270.0000	870.0000
Enth., mm BTU/hr	-567.52	-283.76	-324.65	-283.76
Vapor, mass fraction	1.0000	1.0000	0.39199	1.0000
Total, lb/hr	105,308.85	52,654.43	52,654.43	52,654.43
Stream no.	376	377	378	379
Temp., °F	407.9199	406.2503	404.5561	404.5561
Pres., psia	270.0000	265.0000	260.0000	260.0000
Enth., mm BTU/hr	-326.88	-651.53	-431.68	-219.91
Vapor, mass fraction	0.34012	0.36757	0.00000	1.0000
Total, lb/hr	52,654.43	105,308.84	66,520.34	38,788.51
Stream °F	404.5561	404.5561	404.5561	300.0000
Pres., psia	260.0000	260.0000	260.0000	67.0000
Enth., mm BTU/hr	-691.02	-37.315	-653.71	0.00000
Vapor, mass fraction	0.91279	0.91279	0.91279	1.0000
Total, lb/hr	120,365.32	6,499.73	113,865.59	0.00
Stream no.	384	385	387	388
Temp., °F	300.0941	300.0000	300.0000	497.4000
Pres., psia	67.0000	67.0000	67.0000	665.0000
Enth., mm BTU/hr	-2,883.6	-1,190.7	-725.5	-106.02
Vapor, mass fraction	0.97986	0.00000	0.00000	0.00000
Total, lb/hr	505,039.22	180,386.00	109,913.30	16,610.23
Stream no.	389	390	391	392
Temp., °F	404.5561	300.0000	267.0836	242.0000
Pres., psia	260.0000	67.0000	855.0000	67.0000
Enth., mm BTU/hr	-106.02	-465.17	-1,213.4	-748.67
Vapor, mass fraction	0.12990	0.00000	0.00000	0.00000
Total, lb/hr	16,610.23	70,472.64	182,883.7	112,411.13

Stream no.	393	394	395	396
Temp., °F	242.0000	242.0000	264.4763	467.1291
Pres., psia	67.0000	67.0000	67.0000	35.0000
Enth., mm BTU/hr	-3,363.6	-2,614.9	-1,213.8	-36.584
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	505,039.22	392,628.09	182,883.77	6,530.84
Stream no.	397	398	399	
Temp., °F	80.0000	240.0000	240.1082	
Pres., psia	14.0000	35.0000	25.0000	
Enth., mm BTU/hr	-4,411.3	-732.26	-8,145.6	
Vapor, mass fraction	0.00000	0.00000	0.046730	
Total, lb/hr	646,554.00	109,913.30	1,230,902.88	

Table A4.4. PRB coal

Stream no.	159	300	301	302
Temp., °F	1,106.4220	240.1082	247.5038	620.0000
Pres., psia	15.2000	25.0000	2,300.0000	2,000.0000
Enth., mm BTU/hr	-3,504.2	-9,714.1	-9,703.1	-9,074.5
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	5,437,207.50	1,458,127.00	1,458,127.00	1,458,127.00
Stream no.	303	304	305	306
Temp., °F	620.0000	632.2300	620.0000	632.2850
Pres., psia	2,000.0000	1,950.0000	2,000.0000	1,950.0000
Enth., mm BTU/hr	-6,402.5	-5,886.1	-364.86	-335.43
Vapor, mass fraction	0.00000	1.0000	0.00000	1.0000
Total, lb/hr	1,028,788.00	1,028,788.00	58,628.00	58,628.00
Stream no.	307	308	309	310
Temp., °F	620.0000	632.2000	631.9833	1,004.0000
Pres., psia	2,000.0000	2,000.0000	1,950.0000	1,840.0000
Enth., mm BTU/hr	-2,307.1	-2,300.6	-8,522.1	-7,858.0
Vapor, mass fraction	0.00000	0.00000	0.74661	1.0000
Total, lb/hr	370,711.03	370,711.03	1,458,127.00	1,458,127.00
Stream no.	312	313	314	315
Temp., °F	1,106.4220	668.4714	683.9567	273.7841
Pres., psia	15.2000	15.0000	15.0000	14.8000
Enth., mm BTU/hr	-3,293.9	-3,958.1	-4,186.4	-4,815.1
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	5,110,975.00	5,110,975.00	5,437,207.50	5,437,207.50
Stream no.	316	317	318	319
Temp., °F	1,106.4220	1,106.4220	886.5415	922.5463
Pres., psia	15.2000	15.2000	15.2000	15.0000
Enth., mm BTU/hr	-210.25	-63.075	-69.552	-228.35
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	326,232.44	97,869.73	97,869.73	326,232.44
Stream no.	320	321	323	324
Temp., °F	1,106.4220	937.9244	1,004.0000	1,004.0000
Pres., psia	15.2000	15.0000	1,840.0000	1,840.0000
Enth., mm BTU/hr	-147.17	-158.80	-567.52	-7,290.4
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	228,362.69	228,362.69	105,308.85	1,352,818.25
Stream no.	325	326	327	328
Temp., °F	772.5801	772.5801	240.1082	242.1404
Pres., psia	800.0000	800.0000	25.0000	650.0000
Enth., mm BTU/hr	-7,425.0	-1,519.7	-113.65	-113.62
Vapor, mass fraction	1.0000	1.0000	0.00000	0.00000
Total, lb/hr	1,352,818.25	276,877.25	17,060.00	17,060.00

Stream no.	329	330	331	332
Temp., °F	645.0892	772.5801	598.5389	598.5389
Pres., psia	650.0000	800.0000	385.0000	385.0000
Enth., mm BTU/hr	-1,633.3	-5,905.4	-5,986.4	-298.41
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	293,937.25	1,075,941.00	1,075,941.00	53,633.00
Stream no.	333	334	335	336
Temp., °F	1,000.0000	598.5389	598.5389	1,000.0000
Pres., psia	347.0000	385.0000	385.0000	347.0000
Enth., mm BTU/hr	-286.79	-549.87	-5,138.1	-4,938.0
Vapor, mass fraction	1.0000	1.0000	1.0000	1.0000
Total, lb/hr	53,633.00	98,828.41	923,480.00	923,480.00
Stream no.	337	338	339	341
Temp., °F	1,000.0000	569.0683	240.1082	569.0683
Pres., psia	347.0000	58.0000	25.0000	58.0000
Enth., mm BTU/hr	-5,224.8	-5,427.2	-1,075.5	-1,799.7
Vapor, mass fraction	1.0000	1.0000	0.00000	1.0000
Total, lb/hr	977,113.00	977,113.00	161,444.00	324,028.13
Stream no.	342	343	346	347
Temp., °F	569.0683	467.1291	467.1291	101.5784
Pres., psia	58.0000	35.0000	35.0000	1.0000
Enth., mm BTU/hr	-3,627.4	-3,658.4	-3,621.8	-3,768.6
Vapor, mass fraction	1.0000	1.0000	1.0000	0.93869
Total, lb/hr	653,085.00	653,085.00	646,554.00	646,554.00
Stream no.	348	349	350	351
Temp., °F	80.0000	63.0000	71.9504	71.9816
Pres., psia	1.0000	14.4000	14.4000	25.0000
Enth., mm BTU/hr	-4,411.3	-3,996.8	-8,408.1	-8,408.1
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	646,554.00	584,349.19	1,230,902.88	1,230,902.88
Stream no.	352	353	354	355
Temp., °F	240.0000	77.6091	240.1082	240.1082
Pres., psia	27.0000	25.0000	25.0000	25.0000
Enth., mm BTU/hr	-43.509	-8,401.2	-49.679	-629.95
Vapor, mass fraction	0.00000	0.00000	1.0000	0.00000
Total, lb/hr	6,530.84	1,230,902.88	8,699.44	94,559.00
Stream no.	356	357	358	359
Temp., °F	242.7635	242.7635	404.5561	242.7635
Pres., psia	841.0000	841.0000	260.0000	841.0000
Enth., mm BTU/hr	-629.70	-432.63	-368.35	-197.07
Vapor, mass fraction	0.00000	0.00000	0.99974	0.00000
Total, lb/hr	94,559.00	64,966.57	64,966.57	29,592.43
Stream no.	360	361	362	363
Temp., °F	284.3000	284.3000	284.3000	241.3838
Pres., psia	741.0000	741.0000	741.0000	417.0000
Enth., mm BTU/hr	-195.81	-85.902	-109.91	-1,075.3
Vapor, mass fraction	0.00000	0.00000	0.00000	0.00000
Total, lb/hr	29,592.43	12,982.20	16,610.23	161,444.00
Stream no.	364	365	366	367
Temp., °F	241.3838	880.3931	241.3838	331.4878
Pres., psia	417.0000	105.0000	417.0000	105.0000
Enth., mm BTU/hr	-406.30	-329.50	-257.35	-226.02
Vapor, mass fraction	0.00000	1.0000	0.00000	0.81147
Total, lb/hr	60,998.75	60,998.75	38,636.50	38,636.50
Stream no.	368	369	370	371
Temp., °F	241.3838	331.4878	363.3692	241.3838
Pres., psia	417.0000	105.0000	105.0000	417.0000
Enth., mm BTU/hr	-319.24	-280.36	-835.88	-92.449
Vapor, mass fraction	0.00000	0.81194	1.0000	0.00000
Total, lb/hr	47,928.90	47,928.90	147,564.16	13,879.80

Stream no.	372	373	374	375
Temp., °F	951.8254	951.8254	407.9199	951.8254
Pres., psia	870.0000	870.0000	270.0000	870.0000
Enth., mm BTU/hr	-567.52	-283.76	-325.51	-283.76
Vapor, mass fraction	1.0000	1.0000	0.37199	1.0000
Total, lb/hr	105,308.85	52,654.43	52,654.43	52,654.43
Stream no.	376	377	378	379
Temp., °F	407.9199	406.2503	404.5561	404.5561
Pres., psia	270.0000	265.0000	260.0000	260.0000
Enth., mm BTU/hr	-327.78	-653.29	-445.59	-207.76
Vapor, mass fraction	0.31916	0.34713	0.00000	1.0000
Total, lb/hr	52,654.43	105,308.84	68,664.27	36,644.57
Stream no.	380	381	382	383
Temp., °F	404.5561	404.5561	404.5561	300.0000
Pres., psia	260.0000	260.0000	260.0000	67.0000
Enth., mm BTU/hr	-682.13	-36.835	-645.29	0.00000
Vapor, mass fraction	0.87761	0.87761	0.87761	1.0000
Total, lb/hr	118,221.38	6383.95	111,837.41	0.00
Stream no.	384	385	387	388
Temp., °F	383.4183	300.0000	300.0000	497.4000
Pres., psia	67.0000	67.0000	67.0000	665.0000
Enth., mm BTU/hr	-2,850.8	-1,191.4	-725.97	-106.02
Vapor, mass fraction	1.0000	0.00000	0.00000	0.00000
Total, lb/hr	504,838.19	180,501.69	109,983.84	16,610.23
Stream no.	389	390	391	392
Temp., °F	404.5561	300.0000	267.0836	242.0000
Pres., psia	260.0000	67.0000	855.0000	67.0000
Enth., mm BTU/hr	-106.02	-465.47	-1,213.4	-748.37
Vapor, mass fraction	0.12990	0.00000	0.00000	0.00000
Total, lb/hr	16,610.23	70,517.86	182,884.25	112,366.38
Stream no.	393	394	395	396
Temp., °F	242.0000	242.0000	264.4907	467.1291
Pres., psia	67.0000	67.0000	67.0000	35.0000
Enth., mm BTU/hr	-3,362.3	-2,613.9	-1,213.8	-36.584
Vapor, mass fraction	0.00000	0.00000	0.00000	1.0000
Total, lb/hr	504,838.19	392,472.00	182,884.25	6,530.84
Stream no.	397	398	399	
Temp., °F	80.0000	240.0000	240.1082	
Pres., psia	14.0000	35.0000	25.0000	
Enth., mm BTU/hr	-4,411.3	-732.73	-8,145.6	
Vapor, mass fraction	0.00000	0.00000	0.046730	
Total, lb/hr	646,554.00	109,983.84	1,230,902.88	

Appendix B1. Methodology of Cost Analysis for the PC-Based Power Plant

1. Capital Cost

In the capital cost analyses, a PC power plant was divided into the following process sections: (1) the basic plant, (2) the flue gas cleanup units including an FGD and an SCR, (3) the MEA unit, and (4) the auxiliaries in the oxy-combustion process.

1.1. Basic PC Plant

There are thirteen basic process areas involved in a sub-critical PC plant. These processes are listed in Table B1.1.

Table B1.1. Classification of process areas in the sub-critical power plant

	Process area	Operating parameter used for cost scaling
1	Coal handling	Coal feed rate
2	Coal preparation & feed	Coal feed rate
3	Feed water & miscellaneous	Water feed rate
4	PC boiler & accessories	Unit gross capacity
5	Electrostatic precipitator	Flue gas flow rate
6	HRSG, ¹ ducting, and stack	Flue gas flow rate
7	Steam turbine generator	Superheat and reheat steam flow rates
8	Cooling water system	Heat duty of cooling water tower
9	Ash/spent sorbent handling system	Ash in coal feed
10	Accessory electric plant	Unit gross capacity
11	Instrumentation & control	Unit gross capacity
12	Improvements to site	Unit gross capacity
13	Buildings and structures	Unit gross capacity

¹HRSG, heat recovery steam generator.

The capital cost of each listed process area is available for a 401-MWe (net) reference PC plant developed in a U.S. DOE-funded study (Parsons Infrastructure & Technology Group, Inc., 2000, 2002). The values reported in the U.S. DOE study were used to scale-up or scale-down the plant sizes investigated in this study. A power rule was used in the cost-scaling on the basis of operating parameters (see Table B1.1) specific to individual process areas. In this study, a uniform scaling exponent of 0.72 was employed for each process area (East Harbor Management Services Ltd., 2002; see also: <http://www.med.govt.nz/ers/electric/fossilfuel/fossilfuel.pdf>). The formula for cost-scaling is expressed as follows:

$$BEC_{i1} = BEC_{i0} \times (P_{i0} / P_{i1})^{0.72}$$

where

- BEC = bare erected cost;
- P = specific operating parameter;
- i = process area, 1 to 13; and

1 and 0 = plant under study and U.S. DOE reference plant, respectively.

The total plant cost (TPC) includes the following cost items: bare erected cost, engineering and home office, process contingency, and project contingency.

The calculation of the TPC can be expressed according to

$$TPC = \sum_i BEC_i \times (1 + A_i \% + B_i \%) \times (1 + C_i \%)$$

where

A = cost percentage of engineering and home office;

B = cost percentage of process contingency;

C = cost percentage of project contingency; and

i = type of process area.

For each process area of the basic plant, the engineering and home office fees and contingencies are available for the U.S. DOE reference plant.

1.2. Flue Gas Cleanup Units

1.2.1. FGD Unit

1.2.1.1. LSFO Process. The limestone slurry forced oxidation (LSFO) process without dibasic acid (DBA) addition was employed for the power plant burning Illinois high-sulfur coal with an SO₂ removal efficient of 95%. The LSFO consists of five process areas, and their bare erected costs are described as follows according to the EPA cost modeling approach (Srivastava, 2000).

- Reagent feed area

$$BM_F = -0.0034 \times (FR_L / 1,000)^4 + 2.1128 \times (FR_L / 1,000)^3 - 494.55 \times (FR_L / 1,000)^2 + (68,164.7 \times (FR_L / 1,000) + 7,118,470 + C_{B\&H})$$

BM_F = bare erected cost of reagent feed area, \$

FR_L = reagent feed rate, lb/hr;

C_{B&H} = cost of the ball mill and hydroclones, \$, estimated according to

$$C_{B\&H} = 32.9 \times (FR_L / 2,000)^2 + 22,412 \times (FR_L / 2,000) + 1,854,902$$

The CaCO₃ content of limestone was assumed at 95.3%, and the molar ratio of CaCO₃ to SO₂ was assumed as 1.05.

- SO₂ removal area

The bare erected cost is composed of the cost of absorbers, pumps, and auxiliary facilities.

$$BM_R = Absorbers + Pumps + Auxiliary$$

$$Absorbers = 173,978 \times (ACFM / 1,000 / N_a)^{0.5575} \times N_a$$

$$Pumps = 910.85 \times (F_{GPM} / N_p)^{0.5954} \times N_p$$

$$Auxiliary = 0.8701 \times (FR_{SO_2} / 1,000)^3 - 188.2 \times (FR_{SO_2} / 1,000)^2 + 34,809 \times (FR_{SO_2} / 1,000) + 1,905,302$$

where

BM_R = bare erected cost of SO₂ removal area, \$;

FR_{SO_2} = SO₂ feed rate, lb/hr;

F_{GPM} = slurry flow rate, gpm; based on L/G = 125 gal/1,000 ft³;

ACFM = flue gas flow rate into the absorber, acfm;

N_a = number of absorbers; maximum absorber size was limited to treat 700 MWe; larger size required multiple, equal size absorbers; and

N_p = number of pumps; a maximum single pump was limited to treat 43,000 gpm.

- Flue gas handling area

$$BM_G = ID \text{ Fans} + Auxiliary$$

$$ID \text{ Fans} = 91.24(ACFM / N_f)^{0.6842} \times N_f$$

$$Auxiliary = -0.1195 \times \left(\frac{ACFM}{1,000}\right)^2 + 777.76 \times \left(\frac{ACFM}{1,000}\right) + 238,203 + 0.000012 \times \left(\frac{ACFM}{1,000}\right)^3 - 0.1651 \times \left(\frac{ACFM}{1,000}\right)^2 \\ + 1,288.82 \times \left(\frac{ACFM}{1,000}\right) + 559,693 - 0.2009 \times \left(\frac{ACFM1}{1,000N_a}\right)^2 + 1,266.4 \times \left(\frac{ACFM1}{1,000N_a}\right) + 420,141$$

where

BM_G = bare erected cost of flue gas handling area, \$;

ACFM1 = flue gas flow rate out of absorber, acfm; and

N_a = number of ID fans (assumed to be in groups of 2,4, or 8 with a maximum individual fan capacity of 1.6 million cfm).

- Waste/by-product handling area

$$BM_w = Thickener + disposal$$

$$Thickener = 9,018.7 \times FR_{SO_2} \times 0.95 \times \frac{172}{64 \times 2,000} + 114,562$$

$$Disposal = 0.325 \times (FR_{SO_2} / 1,000)^3 - 168.77 \times (FR_{SO_2} / 1,000)^2 + 29,091 \times (FR_{SO_2} / 1,000) + 773,243$$

where

BM_w = bare erected cost of waste/by-product handling area, \$.

- Support equipment area

$$BM_E = \text{Chimney} + \text{auxiliary}$$

$$\text{Chimney} = 23,370 \times ACFM^{0.3339}$$

$$\text{Auxiliary} = 0.0003 \times MW_e^3 - 1.0677 \times MW_e^2 + 1,993.8 \times MW_e + 1,177,674$$

where

BM_E = bare erected cost of support equipment area, \$.

The cost of chimney was based on no flue gas reheat.

1.2.1.2. LSD Process The lime spray dryer (LSD) process was employed for the power plant burning the PRB low-sulfur coal with an SO_2 removal efficiency of 90%. The cost estimation was also referred to the EPA approach (Srivastava, 2000). The bare erected costs were based on five process areas and described as follows.

- Reagent feed area (BM_F)

$$BM_F = (170,023 \times \frac{FR_L}{1,000} + 376,411) + (72,338 \times GPM^{0.3195})$$

where

FR_L = reagent feed rate, lb/hr; lime purity was assumed as 90%; and molar ratio of CaO to SO_2 was assumed as 1.75; and

GPM = slurry flow rate, gal/min; lime content in slurry was assumed as 30%.

- SO_2 removal area (BM_R)

$$BM_R = \text{Spray Dryers} + \text{Auxiliary}$$

$$\text{Spray Dryers} = N_a \times \left[-3.57 \times \left(\frac{ACFM}{N_a \cdot 1,000} \right)^2 + 9,246 \times \left(\frac{ACFM}{N_a \cdot 1,000} \right) + 791,896 \right]$$

$$\text{Auxiliary} = N_a \times \left[\frac{581,877,809 \times Wt\%S^3 - 3,653,117 \times Wt\%S^2}{+ 693,335 \times Wt\%S + 214,198} \right] + 677,421 \times Wt\%S^{-0.0966}$$

where

N_a = number of absorbers; single absorber was limited to a maximum 300 MWe; larger unit used multiple, equal-sized absorbers;

ACFM = flue gas flow rate into the absorber, cfm; and

Wt%S = coal sulfur content.

- Flue gas handling area (BM_G)

$$BM_G = \text{Auxiliary} + \text{ID Fans}$$

$$\text{Auxiliary} = N_a \times \left[\begin{array}{l} 1,721.8 \times \left(\frac{ACFM}{1,000} \right)^{0.683} + \\ 1,326.2 \times \left(\frac{ACFM1}{1,000} \right)^{0.7131} \end{array} \right] + \left[\begin{array}{l} 15,338 \times \left(\frac{ACFM}{1,000} \right)^{0.5} + \\ 47,680 \times \left(\frac{ACFM1}{1,000} \right)^{0.5576} \end{array} \right] + \left[\begin{array}{l} 4,840.4 \times \left(\frac{ACFM2}{1,000} \right)^{0.5} + \\ 2,695.9 \times \left(\frac{ACFM3}{1,000} \right)^{0.5} \end{array} \right]$$

$$\text{ID Fans} = 91.24 \times \left(\frac{ACFM}{N_f} \right)^{0.6842} \times N_f$$

where

ACFM = flue gas rate at the absorber inlet, cfm;

ACFM1 = flue gas rate at the absorber exit, cfm;

ACFM2 = flue gas rate at the particulate control device inlet, cfm;

ACFM3 = flue gas rate at the ID fan exit, cfm; and

N_f = number of fans; the maximum flow rate of a single fan was assumed as 1.6 million cfm.

- Waste/by-product handling area (BM_w)

$$BM_w = 2,051,841,884 \times \text{Wt}\%S^2 - 1,443,163 \times \text{Wt}\%S + 1,026,479$$

- Support equipment area (BME)

$$BM_E = -1.211 \times MWe^2 + 2,704.2 \times MWe + 1,354,716.2 + \text{Chimney}$$

$$\text{Chimney} = 23,370 \times ACFM3^{0.3908}$$

According to the EPA approach, both for the LSFO process and the LSD process, 5% for general facilities, 10% for engineering and home office, 5% for process contingency, 15% for project contingency, and 3% for contractor's fee were applied to estimate the total plant cost.

$$TPC_{FGD} = \sum_i BM_i \times (1 + 5\% + 10\% + 5\%) \times (1 + 15\%) \times (1 + 3\%)$$

where

BM_i = bare erected cost of process area i.

1.2.2. SCR Unit

The cost model for SCR retrofit developed in an EPA-funded project was used in this study (Forter and Jozewicz, 2001). The model could be applied to coal-fired boilers with capacity of 100 MW to 850 MW and with NO_x inlet level of 0.15 to 2.5 lb/mm BTU. The cost model is expressed as follows:

$$D = 75 \times \left[\frac{300,000}{A} \left[\left(\frac{B}{1.5} \right)^{0.05} \left(\frac{C}{100} \right)^{0.4} \right] \right]^{0.35}$$

where

- D = total capital cost of SCR, \$/kW;
- A = plant size, kW;
- B = NO_x level at SCR inlet, lb/mm BTU;
- C = NO_x removal efficiency (assumed to be 90% in this study).

This cost accounts for the total capital requirement (TCR) except for interest and escalation during construction. The total plant cost (TPC) was assumed 10% less than TCR for the SCR unit.

The retrofit model could also be used for SCR installation in a new coal-fired boiler. A new SCR application was reported as 20 to 50% less than a retrofit, and 30% was adopted in this study.

1.3. MEA Unit

The capital cost of the MEA unit was estimated by a scaling approach. The reference is based on an MEA unit installed for a 400 MW (net) PC plant in a U.S. DOE study (Parsons Infrastructure & Technology Group, Inc., 2002).

Several important design parameters determine the economics of process scaling, including flue gas conditions, CO₂ removal efficiency, solvent flow conditions, and heat duty for solvent regeneration. Based on the design of the Fluor Daniel Econamine FG process, a CO₂ removal efficiency of 90% was assumed. In addition, typical lean and rich solvent conditions were chosen similar to the reference MEA unit.

Because flue gas conditions such as the CO₂ concentration and temperature are comparable for different PC plants burning either high-sulfur coal or PRB coal, the flow rate of the flue gas was chosen as the only basis for cost-scaling in this study. A power rule was assumed for cost-scaling with an exponent of 0.65. The cost-scaling was expressed as

$$TPC_{MEA} = TPC_{ref} \times \left(\frac{GF}{GF_{ref}} \right)^{0.65}$$

where

- TPC_{ref} = total plant cost of MEA unit in the reference plant, \$;
- GF = gas flow rate into MEA in the studied plant, lb/hr; and
- GF_{ref} = gas flow rate into MEA in the reference plant, lb/hr.

1.4. Oxy-Combustion Plant

In addition to the common components described in sections 1.1 and 1.2, additional process areas specific to the oxy-combustion process are described as follows. These include the ASU, flue gas cooling, water vapor condenser, CO₂ compression, cryogenic unit, and low temperature flash.

1.4.1. ASU

The capital cost for the ASU was provided by the American Air Liquide. The bare erected costs for different scale and O₂ purity are listed in Table B1.2. The unit cost in terms of \$1,000/(t/day) varies with the scale of oxygen production, but is almost comparable for 95% and 99% O₂ purity.

Table B1.2. Capital cost of oxygen generation

Oxygen production		95% O ₂ Purity		99 % O ₂ Purity	
lb/hr	tonnes/day	\$1,000	\$1,000/(tonnes/day)	\$1,000	\$1,000/(tonnes/day)
399,248	4,346	44,424	10.22	45,535	10.48
415,450	4,524	45,745	10.11	46,888	10.36
851,275	9,267	80,904	8.73	82,918	8.95
885,740	9,642	83,716	8.68	85,767	8.9
1,597,138	17,386	141,171	8.12	144,596	8.32
1,661,801	18,090	146,395	8.09	149,944	8.29

The total plant cost was estimated based on the assumptions of 5% engineering and home office fees and 10% project contingency:

$$TPC_{O_2} = BM_{O_2} \times (1 + 5\%) \times (1 + 10\%)$$

1.4.2. Flue Gas Cooling

A water spray cooling system is employed for flue gas cooling prior to the FGD process. The capital cost was estimated as follows (USEPA, 2002):

$$BM_{COOL} = 6,025 \times 1,000 \times \left(\frac{GPM}{215}\right)^{0.65}$$

$$TPC_{COOL} = 1.3725 \times BM_{COOL}$$

where

BM_{cool} = bare erected cost of the cooling system, \$;

TPC = total plant cost, \$; and

GPM = water consumption rate, gal/min.

1.4.3. Water Vapor Condenser

The capital cost of the flue gas condenser was based on that reported for an 865-MW plant (Anderson and Maksinen, 2002). The capital cost is scaled-up according to the following power rule.

$$TPC_{conds} = C_{ref} \times \left(\frac{FG}{FG_{ref}}\right)^{0.8} \left(\frac{m_w}{m_{wref}}\right)^{0.8}$$

where

C_{ref} = capital cost of the condenser in literature, \$;

FG = flue gas flow rate, cfm; and

m_w = cooling water consumption, lb/h.

1.4.4. Cryogenic Unit

The cryogenic unit cools the compressed CO₂ stream to -33°C, and the cooled stream is flashed to remove the gas components, such as oxygen, argon, and nitrogen. The final product is a liquefied CO₂ (>99% purity). The process consists of a compressor and an expander for the ammonia refrigeration cycle, heat exchangers, and a low-temperature flash.

Equipment costs were calculated using individual cost models built in CHEMCAD. An installation factor of 1.8 was assumed to cover the costs related to installation materials and labors. Engineering and home office was assumed at 5% of the bare erected cost. Project contingency was assumed at 10%; no process contingency was considered for these mature technologies. Total plant cost can be expressed as follows:

$$TPC_{cryogenic} = \sum_i \sum EC_i \times (1 + 80\%) \times (1 + 5\%) \times (1 + 10\%)$$

where

EC = equipment cost; and
i = type of equipment.

This cost estimation was conducted for the total plant cost (TPC), which consisted of bare erected cost, engineering and home office overheads and fee, and contingencies. Total plant investment (TPI) is calculated by adding the escalation of construction costs and interest during construction (Table 3) to the TPC:

$$TPI = TPC \cdot A \cdot \frac{[(1+i)/(1+ea)]^n - 1}{(1+i)/(1+ea)}$$

where

A = cost expended per year, 1/n;
n = construction years;
i = weighted cost of capital (discount rate); and
ea = inflation rate.

Table B1.3. Items of capital cost estimation

(a)	Bare erected cost
(b)	Engineering cost
(c)	Process contingency
(d)	Project contingency
	Total plant cost (TPC) = a + b + c + d
(e)	Total cash expended
(f)	AFDC (escalation and interest in construction period)
	Total plant investment (TPI) = TPC + e + f
(g)	Royal allowance
(h)	Pre-production costs
(i)	Inventory capital
(j)	Initial catalyst & chemicals
(k)	Land cost
	Total capital requirement (TCR) = TPI + g + h + i + j + k

The total capital requirement (TCR) covers all other expenditure to complete an entire plant. These include the pre-production, spare parts, inventory capital, initial chemicals, and land costs. The assumptions used for calculating the TCR are listed in Table B1.4.

Table B1.4. Assumptions for estimating the total capital requirement (TCR)

Prepaid royalties	0%
Pre-production	
O&M cost (except for fuel)	30 days
Fuel	7.5 days
Plant modifications	2% of total plant investment (TPI)
Inventory capital	
Coal	60 days
Consumables (excluding water)	60 days
Spare parts	0.5% of total plant cost (TPC)
Initial catalyst and chemical inventory	30 days
Land	\$6,500/acre

2. O&M Cost

2.1. Fixed O&M Cost

The fixed O&M cost includes the cost of operating labor, maintenance material and labor, and administrative and support labor (Table B1.5). The cost of operating labor (OL) was estimated based on the number of operating jobs (OJ) and the labor rate.

$$OL = \text{Labor rate} \times OJ \times 40 \text{ hrs/week} \times 52 \text{ weeks/yr}$$

Annual maintenance labor and material costs (ML&M) were estimated as a percentage of the total plant cost (TPC). The percentage varies with individual process areas. It was assumed that 40% of the ML&M is shared by the maintenance labor.

$$ML \ \& \ M = \sum_i F_i \cdot BM_i$$

where

- F = maintenance factor;
- BM = bare erected cost; and
- i = process area or equipment.

Administrative and support labor cost (A&S) was assumed to be 30% of the sum of operating labor cost (OL) and maintenance labor (ML&M) cost:

$$A \ \& \ S = 30\% \times (OL + 40\% \times ML \ \& \ M)$$

Table B1.5. Estimation of the fixed O&M cost¹

Fixed O&M cost	Assumptions
Operating labor	Labor rate: \$40/hr per person Operating jobs: 1. Basic plant: 25 persons/shift ³ 2. Flue gas cleanup: FGD ¹ and SCR ² 3. MEA unit: 2 persons/shift 4. Oxy-combustion: 2 persons/shift for ASU, 2 persons/shift for others
Maintenance	% of TPC: 1. Basic plant ³ 2. Flue gas cleanup: FGD ¹ and SCR ² 3. MEA unit: 2.5% 4. Oxy-combustion: 2.5% both for ASU and others
Administrative & support cost	30% of O&M labor

¹Srivastava, 2000.

²Foerter and Jozewicz, 2001.

³Gilbert/Commonwealth Inc., 1995.

2.2. Variable O&M Cost

The variable O&M cost includes the costs of consumables (chemicals, water, and waste disposal) and fuel. The unit price used in this study is listed in Table B1.6. A 70% loading factor of the power plant is assumed for variable O&M cost.

Table B1.6. Unit prices of consumables and coals

Category	Unit price
Coal	20 \$/t for PRB coal, 30 \$/t for Illinois coal
Water	0.06 \$/t
Waste water treatment chemicals	0.13 \$/lb
Ash disposal	10 \$/t
Limestone	15 \$/t
Lime	65 \$/t
Steam	7 \$/t
Ammonia	225 \$/t
SCR catalyst	Published models ¹
MEA	\$1250/tonne
MEA inhibitor	N/A (20% of the total MEA cost assumed)
Waste disposal from MEA unit	\$175/tonne
Caustic sodium	\$2,000/tonne
Activated carbon	\$2,000/tonne

¹Foerter and Jozewicz, 2001.

3. Cost of Electricity

The cost of electricity (COE) is the levelized (over the plant life) coal pile-to-busbar cost of power expressed in mills per kilowatt-hour.

The financial criteria used in this study (Table B1.7) are from the literature (Parsons Infrastructure & Technology Group Inc., 2002). Based on these assumptions, a levelized carrying charge (applied to TCR) is 0.138. No inflation was considered for categories in the O& M costs.

Table B1.7. Financial assumptions for the cost estimation

General characteristics		
Plant startup date (year)	2000	
Capital cost year dollars	2000	
Construction period	3 years	
Capacity factor	70%	
Financial assumptions		
Project book life	20 years	
Book salvage value	0%	
Project tax life	20 years	
Tax depreciation method	ACRS class	
Property tax rate	1% per year	
Insurance tax rate	1% per year	
Federal income tax rate	34%	
State income tax rate	4.2%	
Investment tax credit% eligible	0%	
Capital structure	% of total	Cost, %
Common equity	42	12
Preferred stock	10	8.5
Debt	45	9.0
Weighted cost of capital (after tax)	8.76%	
Escalation rates (apparent)		
General escalation	0%	
Primary/secondary fuel price escalation	0%	

A levelized busbar cost of electricity for the 70% design capacity factor is calculated using the following relationship:

$$COE = \frac{13.8\% \times TCR + 1.541 \times O \& M \text{ cost}}{MW_{net} \times 0.7 \times 8,760}$$

where

COE = cost of electricity, mills/kWh;

MW_{net} = new electricity output, MW;

TCR = total capital cost, \$; and

O&M cost = operating and maintenance cost, \$/yr.

4. Costs of CO₂ Avoidance and CO₂ Capture

CO₂ costs can be expressed in terms of either the cost per ton CO₂ removed or the cost per ton CO₂ avoided. The cost of CO₂ capture is defined as the increase in cost of electricity per captured CO₂ emissions due to installation of a CO₂ capture process. It can be expressed as follows

$$\text{Cost of CO}_2 \text{ capture (\$/ton)} = \frac{(\$ / kWh)_{\text{capture}} - (\$ / kWh)_{\text{reference}}}{(\text{ton CO}_2 / kWh)_{\text{capture}}}$$

where

- capture = the power plant with CO₂ capture facility;
- reference = air-blown PC plant without CO₂ capture;
- \$/kWh = levelized COE; and
- ton CO₂/kWh = CO₂ emissions per kWh generation.

Because a CO₂ capture unit consumes considerable electricity and thus reduces the plant output, the CO₂ emissions per net kilowatt-hour generation increase correspondingly. The actual avoided emissions are the difference between CO₂ emissions before and after the installation of the CO₂ capture unit. This relationship can be expressed as

$$\text{Cost of CO}_2 \text{ avoidance (\$/ton)} = \frac{(\$ / kWh)_{\text{capture}} - (\$ / kWh)_{\text{reference}}}{(\text{ton CO}_2 / kWh)_{\text{reference}} - (\text{ton CO}_2 / kWh)_{\text{capture}}}$$

Appendix B2. Methodology of Cost Analysis for the IGCC Plant with Selexol Unit

1. Capital Cost

The IGCC plant was categorized into sixteen process areas for the cost estimation (Table B2.1). The bare erected cost for each process area in this study was scaled from an IGCC case study developed in a U.S. DOE/EPRI project (Parsons Infrastructure & Technology Group Inc., 2002). The cost scaling was based on key parameters specific to individual process areas as listed in the last column of Table B2.1. A power law with an exponent of 0.72 was also assumed for the IGCC plant.

Table B2.1. Classification of process areas in the IGCC plant with the Selexol unit

	Process area	Operating parameter for cost scaling
1	Coal handling	Coal feed rate
2	Coal preparation & feed	Coal feed rate
3	Feed water & miscellaneous Bop systems	Water feed rate
4	Gasifier & accessories	Coal slurry feed rate
5	ASU and accessories	Oxygen feed rate
6	Gas cleanup and piping	Fuel gas flow rate
7	CO ₂ compression	CO ₂ captured
8	Gas turbine and accessories	Gross capacity
9	HRSG, ducting and stack	Flue gas flow rate
10	Steam turbine generator	Steam flow rates
11	Cooling water system	Heat duty of cooling water tower
12	Ash /spent sorbent handling system	Ash in coal feed
13	Accessory electric plant	Gross capacity
14	Instrumentation & control	Gross capacity
15	Improvements to site	Gross capacity
16	Buildings and structures	Gross capacity

Based on the bare erected costs of individual process areas, the total plant cost (TPC), the total plant investment (TPI), and the total capital requirement (TCR) are estimated according to the assumptions listed in Table B2.2.

The construction period adopted for the IGCC plant with Selexol unit is assumed to be 4 years. The royalty allowance is considered as 0.5% of the BEC, given the fact that the IGCC process is relatively less mature than the conventional PC plant.

Table B2.2. Estimation of TPC, TPI, and TCR

	Items	Assumptions
(a)	Bare erected cost (BEC)	$\sum BEC_i, i = 1, 2, \dots, 16$
(b)	Engineering cost	10% of BEC
(c)	Process contingency	5% of BEC for gasifier, gas cleanup and gas turbine; 0% for others
(d)	Project contingency:	15% of BEC
	Total plant cost (TPC)	= a + b + c + d
(e)	Total cash expended	$TPC/n * [1 + 1/(1+ea)^1 + 1/(1+ea)^2 + 1/(1+ea)^3]$
(f)	AFDC (escalation and interest in construction period)	$TPC/n * \{i/(1+ea) + [(1+i)^2 - 1]/(1+ea)^2 + [(1+i)^3 - 1]/(1+ea)^3\}$ (n: construction years; i: discount rate; ea: inflation rate.)
	Total Plant Investment (TPI)	= TPC + e + f
(g)	Prepaid royalties	0.5% of bare erected cost (BEC)
(h)	Initial catalyst & chemical inventory	30 days
(i)	Startup costs	
	Plant modifications	2% of TPI
	O&M costs	30 days
	Fuel costs	7.5 days
(j)	Working capital	
	Coal	60 days
	Consumables (excluding water)	60 days
	By-product inventory	30 days
	Spare parts	0.5% of TPC
(k)	Land	\$6,500/acre
	Total capital requirement (TCR)	= TPI + g + h + i + j + k

2. O&M Cost

An approach similar to that used in Appendix B1 was employed to estimate the fixed O&M costs for the IGCC plant. The total operating jobs are assumed as 17 persons per shift in this study; the maintenance cost is assumed 2.2% of the TPC (Table B2.3).

The variable O&M costs consist of the costs of consumables and fuel. Water and coal consumptions are obtained from simulation, and the others are linearly scaled from literature (EG&G, 2000; Akunuri, 2000). A loading factor of 70% is assumed for electricity generation. The unit purchase prices of consumables and fuels are listed in Table B2.3.

The credit of sulfur by-product from Claus/Scott process is included in the cost estimation. The price of sulfur product is assumed to be \$75/t. In addition, operating royalties are also incorporated in this study as 1% of the fuel cost.

Table B2.3. Assumptions used for estimating the O&M cost of the IGCC plant

Fixed O&M costs	
Operating labor	17 persons per shift, \$40/hr
Maintenance costs	2.2% of total plant cost (40% labor; 60% materials)
Administrative & support labor	30% of total labor (operating + maintenance)
Miscellaneous operating costs	10% of total labor
Variable O&M costs	
Coal	\$20/t for PRB coal, \$30.t for Illinois coal
Water	\$0.06/t
Selexol solvent	\$1.45/lb
Claus catalyst	\$470/t
SCOT activated alumina	\$0.067/lb
SCOT cobalt catalyst	\$6,000/t
SCOT Chemicals	\$275/t
By-product (sulfur) credits	\$75/t
Royalties	1% of fuel cost

3. Cost of Electricity

The financial criteria used for estimating the cost of electricity (Table B2.4) were referred to in the literature (Parsons Infrastructure & Technology Group Inc., 2002). Based on these assumptions, a levelized carrying charge (applied to TCR) is 0.138. No inflation is considered for categories involved in the O&M costs.

Table B2.4. Financial assumptions for the cost estimation

General characteristics		
Plant startup date (year)	2000	
Capital cost year dollars	2000	
Construction period, yr	4	
Capacity factor, %	70	
Financial assumptions		
Project book life, yr	20	
Book salvage value, %	0	
Project tax life, yr	20	
Tax depreciation method	ACRS class	
Property tax rate, %/yr	1	
Insurance tax rate, %/yr	1	
Federal income tax rate, %	34	
State income tax rate, %	4.2	
Investment tax credit% eligible, %	0	
Capital structure	% of total	Cost, %
Common equity	42	12
Preferred stock	10	8.5
Debt	45	9.0
Weighted cost of capital (after tax), %	8.76	
Escalation rates (apparent)		
General escalation, %	0	
Primary/secondary fuel price escalation, %	0	

A levelized busbar COE for the 70% design capacity factor is calculated according to the following relationship:

$$COE = \frac{13.8\% \times TCR + O \& M \text{ cost}}{MW_{net} \times 0.7 \times 8,760}$$

where

COE = cost of electricity, mills/kWh;

MW_{net} = new electricity output, MW;

TCR = total capital cost, \$; and

O&M cost = operating and maintenance cost, \$/year.

4. Costs of CO₂ Avoidance and CO₂ Capture

The cost of CO₂ avoidance and the cost of CO₂ capture are as described in Appendix B1. They are expressed as

$$\text{Cost of CO}_2 \text{ capture (\$/ton)} = \frac{(\$ / kWh)_{\text{capture}} - (\$ / kWh)_{\text{reference}}}{(\text{ton CO}_2 / kWh)_{\text{capture}}}$$

$$\text{Cost of CO}_2 \text{ avoidance (\$/ton)} = \frac{(\$ / kWh)_{\text{capture}} - (\$ / kWh)_{\text{reference}}}{(\text{ton CO}_2 / kWh)_{\text{reference}} - (\text{ton CO}_2 / kWh)_{\text{capture}}}$$

where

capture = the IGCC plant with Selexol unit;
reference = reference PC plant without CO₂ capture;
\$/kWh = levelized cost of electricity; and
ton CO₂/kWh = CO₂ emissions per kWh generation.

Note that the PC plant without CO₂ capture is used as the reference plant for CO₂ cost calculation.

Part 2 Truck and Rail Transportation Options

Rajani Varagani

1. Introduction

Sequestration of CO₂ consists of three independent steps: capture, transportation, and storage. For transport, the captured CO₂ must be suitable in terms of pressure, temperature, and composition because CO₂ is usually transported either in the supercritical/dense phase or in the liquid phase for maximum throughput and ease of loading and unloading. One of the main concerns for CO₂ transportation is inadvertent contact with water, which can cause problems such as hydrate formation and acidity increase. Hydrates are crystals that can plug pipes or valves or other equipment; acid formation is a corrosion issue.

2. Transportation Options

CO₂ can be transported by the following ways (Odenberger and Svensson, 2003):

1. Truck/motor carriers
2. Rail cars
3. Pipeline transportation
4. Water carriers (ships)

In order to understand the relative magnitude of the CO₂ transportation required for sequestration purposes, the total CO₂ emissions from coal burning power plants in the United States are approximately 4.9 million t/day (U.S. Department of Energy, 2000), but the nation's current CO₂ merchant market truck and rail infrastructure capacity is 30,000 t/day. Assuming mass is proportional to infrastructure, the current truck and rail infrastructure for handling CO₂ would have to increase 163 times to sequester and store 100% of the emitted CO₂. Hence, transportation by truck and rail is very likely not an option for permanent, long-term sequestration projects. However, it is very important to understand CO₂ transportation by truck and rail because that is the most probable scenario for transporting CO₂ to relatively short-term, sequestration test sites. Consequently, this report mainly discusses transportation of CO₂ intended for short-term demonstration tests of the second phase of the regional partnership program.

3. Truck Transportation

Motor carriers or trucks have been used for a long time for small-scale transportation because of their flexibility, adaptability, and reliability. CO₂ is transported at vapor pressure as a liquid with a pressure range of 275 to 300 psi and temperature of 0 to 10°F. A typical thermally insulated tank trailer (Figure 3.1) carries up to 22 t of liquid CO₂. A truck trailer costs about \$110,000, and a tractor that pulls the trailer costs about \$30,000. The cost of transportation by truck ranges from \$1.75 to \$2.00/mile per truck. These cost estimates assume that there is no wait to load or unload the truck and that roundtrip mileage is counted. This transportation technology is readily available but requires a logistic handling system that includes optimizing the number of trucks, scheduling loading and unloading, and choosing the route. Truck transportation is usually more expensive than rail or pipeline transportation.



Figure 3.1. Typical CO₂ truck trailer

4. Rail Transportation

Historically, railway is one of the main transportation options for bulk and less expensive materials. Railway can be very competitive to truck transportation because railways have large volume handling capacity over long distances. Railway infrastructure, however, plays a key role. The cost of transportation by rail depends mainly on the route from source to sink. If the route is direct, the transportation cost is less expensive, even for longer distances, than that for a shorter, indirect route with multiple transfers. For every rail-to-rail transfer, there is an additional fee that increases the transportation cost. Because the railway industry has high fixed costs and low operational costs, rail cars are often leased by companies rather than purchased.

A typical rail car (Figure 4.1) can hold up to 80 tons of liquid CO₂. The pressure inside the car is maintained at a constant 350 psi, the vapor pressure of the CO₂. If the temperature increases during transportation, the pressure is relieved by venting the CO₂ from the car. Hence, rail transportation is not recommended for long periods due to the associated loss of CO₂. The temperature inside the railcar is around 10°F. In the United States, it can take from 1 to 10 days for transportation between any two rail stations.



Figure 4.1. Typical CO₂ railcar

The typical cost of CO₂ transportation by rail is about \$25/t and up to \$5/t additional charges (e.g., transfer fees and yard usage fees). Distance traveled has minimal effect on transportation cost. Also, the cost to lease an 80-t rail car is approximately \$900/month for a minimum of 12 months and can be lower for longer lease durations. As railway tracks may not be present at the wellhead (the point of injection), trucks are likely coupled with rail transportation. Figure 4.2 shows the unloading of CO₂ from a railcar to a truck trailer.



Figure 4.2. Unloading CO₂ from railcar to truck

5. Secondary Storage Requirements

After the CO₂ is transported by rail and/or truck to the CO₂ injection site, secondary storage may be necessary for the following reasons:

- well's injection capacity is relatively low and requires that the truck or railcar remains at the injection well location for unreasonable (uneconomical) durations;
- intermittent injection is unacceptable; and
- higher injection pressure is required that necessitates the use of compressors and/or pumps

Different types of storage tanks are available in the market. Portable tanks are mounted on a truck carrier base and can be moved from one place to another very easily. Portable tanks have a maximum capacity of 60 tons, but availability is limited. Customer tanks are installed permanently on a concrete floor and are intended for long-term usage. Typical customer tanks can hold up to 50 t of CO₂ with a rent of \$1,500/month for at least 1 year. Storage tanks more than 50 t are available but are assembled at the site. Figure 5.1 shows customer storage tanks with capacities of 250 t (left) and 45 t (right two tanks). The number of storage tanks required depends on such things as injection rate and delivery intervals.



Figure 5.1. Secondary storage tanks

6. Unloading and Injection Equipment

Unloading CO₂ from railcars requires special equipment. Rail towers are built to unload CO₂ from rail cars because CO₂ is always unloaded from the top of the railcar (in contrast, CO₂ is unloaded from the bottom of truck trailers) (Figure 6.1). The number of towers required depends on the unloading rate or injection rate desired. Each tower can cost up to \$20,000.



Figure 6.1. Rail towers for unloading CO₂ from railcars

Compressors and/or pumps are needed for unloading and injecting CO₂. The unloading equipment package (includes compressor, pumps, valves, and piping) costs about \$20,000 to \$25,000, and injection equipment package costs about \$50,000 for 200 to 300 tons/day injection rates. Figure 6.2 shows a typical compressor that can be used for CO₂ unloading/injection, and Figure 6.3 shows a typical injection skid.

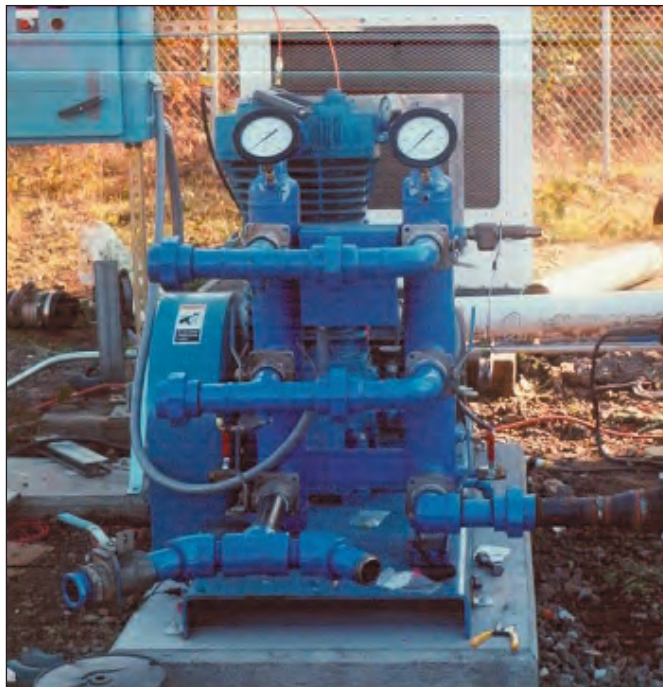


Figure 6.2. Typical CO₂ compressor



Figure 6.3. Typical CO₂ injection skid

7. Regulatory Information

In the United States, CO₂ transportation by rail, highway, air, and water is governed by federal authority under regulations promoted by the U.S. Department of Transportation (U.S. DOT) (www.access.gpo.gov). All of the equipment used must be in accord with the U.S. DOT standards. Additional information can be obtained from Compressed Gas Association, Inc. (2003).

8. References

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Part 3 Assessing CO₂ Pipeline Transportation Options in the Illinois Basin

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J. Steve Dracos

1. Introduction

1.1. Scope

The team of D. J. Nyman & Associates and Universal Enco, Inc. was commissioned to prepare this report on CO₂ pipeline transportation options in support of the Midwest Geological Sequestration Consortium's assessment of opportunities for geological carbon sequestration in the Illinois Basin. Our report is intended to provide a synopsis of the design and construction of a pipeline for the transportation of CO₂, including permitting and land acquisition at the front end as well as considerations for operation of the completed project. The synopsis is more than hypothetical; it has been prepared by a team that has designed pipelines and, more specifically, one that has designed CO₂ pipelines. Although in some respects the document takes the form of a tutorial, it is thought to be realistic with respect to the various activities that are paramount in designing a CO₂ pipeline.

Specifically, the team has addressed the following aspects of CO₂ pipeline design, construction, and operation:

1. Identify and describe the elements of a CO₂ pipeline transportation system, the general properties of CO₂, and the impact of these properties on pipeline design, operations, and related safety issues.
2. Describe the design, materials, and construction practices that are common to CO₂ pipelines including corrosion allowances, pipe and valve standards, type and spacing of mainline valves, common pumping and metering equipment, and comments based on practices specifically suitable to the Illinois Basin.
3. Identify right-of-way considerations and permitting requirements for pipelines in the basin, including co-location with existing pipelines and power lines, as well as agricultural mitigation (e.g., topsoil handling and drain tile avoidance).
4. Describe operating practices such as pipeline blow-down considerations, marking of the pipeline for third-party damage prevention, and community awareness programs necessary as part of sequestration outreach activities.
5. Prepare a cost matrix of approximate cost per mile based on pipeline diameter and construction settings (e.g., as urban and rural), including adjustment factors as appropriate for farmland, timber, terrain, and soil and rock conditions, which includes power costs based on pipeline diameter and transport volume.

The data presented in this report will be used to provide pipeline transmission cost information into a CO₂ capture and sequestration macro-economic model, which will be used to analyze numerous capture,

transport, and injection cases. The cost information provided in this report will be used to establish a primary or base transportation case with capture and sequestration locations for more detailed assessment. Detailed cost estimates for the final selected pipeline transportation case will be developed in a future project task (Task 9).

A preliminary conceptual route was selected to give the study a practical basis to facilitate the acquisition of meaningful data from industry sources. The selected conceptual route originates in the Peoria area, in the vicinity of several large coal-fired power plants, goes southward to a point slightly east of Springfield, and then extends south-southeast toward the Illinois, Indiana, and Kentucky border. The southern terminus is within a likely storage fairway emerging from the geological sink characterization studies. For planning purposes the pipeline was assumed to be approximately 200 miles in length (Figure 1.1). Data were gathered from the following sources:

- The authors' experience and accumulated body of knowledge
- Projects recently completed by Universal Enesco in Illinois
- A CO₂ pipeline recently completed by Universal Enesco
- Miscellaneous industry publications and industry Web sites
- Vendors (unit costs for material)
- Local union contractors (construction costs)
- County agencies along the route (land costs)

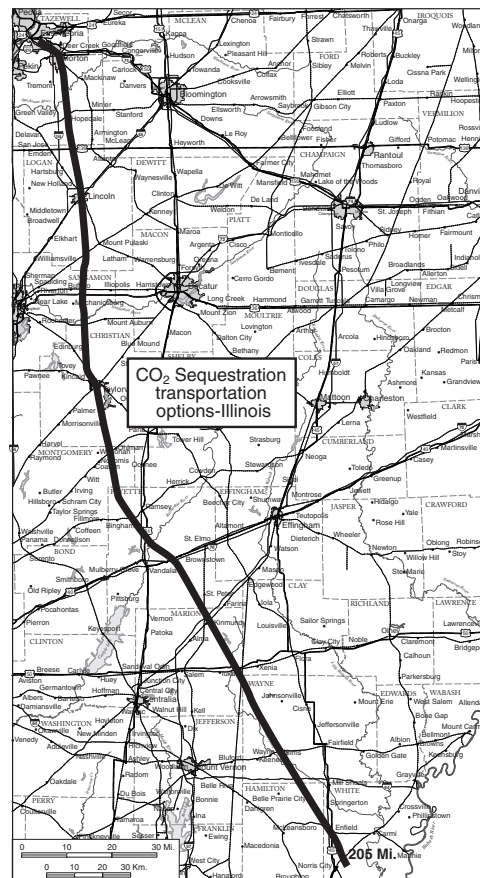


Figure 1.1. Conceptual route

1.2. Background

CO₂ is used extensively by the oil industry to enhance oil production. Currently, there are 70 active CO₂ projects of this type in the United States. Most of these involve a large CO₂ pipeline as part of the project operation, and almost all are supplied from natural underground sources of CO₂. There are currently about 2,400 km of large CO₂ pipelines in operation. A representative listing of some of the major CO₂ pipelines is given in Table 1.1.

Table 1.1. Major CO₂ pipelines in operation in the United States

Pipeline	Date	Diameter (inches)	Length (miles)	Location
Bravo	1984	20	218	Texas
Transpecto/Bravo	1996	12	120	Oklahoma
Cortez	1984	30	502	Colorado-Texas
Sheep Mountain	Approx. 1984	20/24	408	Colorado-Texas
Central Basin	Not available	26/16	26	Texas
Este	Not available	12/14	119	Texas
Trinity	Not available	12	180	W. Texas
Caprock	1972	16	140	Texas
Centerline	2003	16	120	Texas
Salt Creek	2003	16	125	Wyoming

CO₂ pipelines have compiled an excellent safety record during the 32 years that they have been used in the industry. The design, material, and construction issues related to the safe operation of CO₂ pipelines are regulated under the *2001 Code of Federal Regulations, Parts 190–199* (International Code Council, 2002). A point to note is that under federal regulations in the United States, CO₂ pipelines are classified as high volatile/low hazard and low risk (due to the product being nonflammable). As a matter of public record, during the period 1991 to 2001, there were no CO₂ pipeline-related injuries or deaths. A more detailed discussion of operations is included in Section 7.

Readers who are unfamiliar with pipelines should find it helpful to review Section 6, Construction, and the construction photo album (Appendix C1). A typical CO₂ pipeline consists of a receipt meter and pressure regulating facilities, receipt lateral pipelines, a main pipeline, a booster facility (if any), delivery lateral pipelines and delivery meter, and pressure/flow regulating facilities. These items are supported by auxiliary facilities such as a control center and operations and maintenance facilities.

2. Route Selection and Design

The selection of a good route is key to the success of any pipeline project. All pipeline projects of considerable length will encounter numerous objections by the stakeholders—landowners, tenants, environmental and other government agencies, and nongovernmental agencies. Although the stakeholders are motivated by a variety of issues and concerns, almost all of their objections will be focused on the route. During any proceedings related to condemnation, the proposed route requires strong justification.

In general, a properly selected, good route will withstand objections, and a poor route will not. As a minimum consequence, poor route selection results in rework and delays, but more serious ramifications are possible. Routes are selected in two stages: preliminary route selection and detailed route selection. The preliminary route is used as a basis for the planning and budgeting phases of the project. Once the project receives funding for permitting and right-of-way acquisition, detailed route selection and design are initiated. In all phases, the co-location of the pipeline route in an existing right-of-way corridor is a very important consideration.

2.1. Preliminary Route Selection

The objective of preliminary route selection is to identify several potential pipeline routes that minimize the impact to the public, landowners, and environment. This activity is typically undertaken by a relatively small group of specialists with local knowledge of right-of-way, environmental, construction, and operations. This selection process is essentially defined by the beginning, end, and key crossing points along the route, such as crossings of major rivers or other terrain features and areas of environmental impact, urban centers, parks, or environmental preserves that must be avoided. Available maps and published environmental data for the region to be traversed can be reviewed to determine the optimum route, which may include several route variations. By using GIS (Geographic Information System) resources, the route selection process can be expedited, and the quality of the final product can be markedly improved.

Often an existing corridor (e.g., electric transmission line or pipeline right-of-way) can be identified as a prospective routing for the pipeline under consideration. Even in the open agricultural land of Illinois it is generally best to follow a corridor if one is positioned in the general direction of the pipeline. However, if the corridor leads away from the next key pipeline point, thereby adding distance, the proposed route should move away from the corridor toward the next key point. It is important to recognize that increasing the length of pipeline will impact more landowners at higher overall cost. It is also important to recognize the age of the corridor because an older corridor that was established prior to contemporary environmental regulations might be located in areas that have an unacceptable impact under today's standards. Also, if the corridor has restricted construction room or other issues, the cost of working in the corridor could be higher than the cost associated with a longer route.

As a general guideline, the preliminary route selection for a 200-mile pipeline route in Illinois could be completed in approximately one to two months. Once selected, the preliminary route will be confirmed by ground and/or aerial reconnaissance in the field. Changes will be incorporated into the route as applicable.

2.2. Detailed Route Selection

After the preliminary route has been selected and approved, detailed route selection will commence. The key points and route variations in the preliminary route are analyzed, and a procedure for assessing route variations is established. The reasoning for the routing is documented so that consistency can be demonstrated during discussions with agencies and landowners as well as during potential eminent domain proceedings. The detailed route is scrutinized carefully through use of high-resolution, project-specific aerial photography and numerous field trips until a final preferred route is determined. Specific route information is entered into a GIS database.

Mainline and lateral valve sites will be located near roads to maximize ease of access; however, locations near populated areas will be avoided if possible due to the potential for vandalism or similar disruptions. Mainline and lateral valve settings will be located to avoid overhead obstructions, power lines, and floodplains.

Detailed cost estimates are normally prepared at the conclusion of selecting a final preferred route, although a limited number of route variations may remain under consideration pending land acquisition and permitting.

2.3. Detailed Route Design

Once a preferred route is identified, the pipeline company will contact landowners to discuss the project and seek permission to conduct civil and environmental surveys. These surveys are required for use in the detailed pipeline design and for preparing local, state, and federal permit applications. It is important to note that, even though pipeline officials may begin discussions with landowners at this point, the project is still being analyzed for feasibility, and neither the project nor the pipeline route is finalized at this time. Selecting a pipeline route generally involves discussing and evaluating options with landowners, environmental agencies, and regulatory officials. Once alternatives have been analyzed, field studies are initiated to confirm the environmental assumptions. These environmental studies generally follow procedures set out by federal and state law, sometimes resulting in environmental impact statements or environmental assessments that are published in draft form for public comment. During this process, landowner agreements must be obtained, and minor route variations are made to accommodate individual landowner's physical needs. The necessary permissions to locate within a corridor also must be obtained during this phase of the project. The process of obtaining this permission is discussed further in Section 5, Right-of-Way.

2.4. Corridors

During all phases of pipeline routing, the use of existing corridors for electric power transmission, other pipelines, or utilities is a major consideration. In urban or industrial areas, routing in existing corridors is required. Because the CO₂ needed for the sequestration will be coming from existing power plants that are probably located in urban areas, it is necessary to follow one of several corridors, such as power lines, utility lines, and railroads, that connect to the plant. Of these corridors, the power line corridor is probably the preferred pipeline route for two reasons. First, the power company or its affiliate generally owns it in fee, and, second, power line corridors generally have adequate workroom for installation of a pipeline without the use of adjacent property. Utilities generally do not own the corridor in fee, but rather have an easement, which makes it necessary to contact the underlying landowner to obtain a separate easement, which is already encumbered by the existing easement. Railroad rights-of-way are owned in fee but are so narrow that additional workspace from adjacent landowners is usually needed.

When a pipeline is routed in corridors containing high-voltage power lines, consideration must be given to areas where interference from electrical currents may occur. Interference can also occur in places where the pipeline crosses, is in close proximity to, or parallels high-voltage power lines. Special grounding procedures, such as installing zinc ribbon anodes along the pipeline and gradient ground mats at valves/test stations will ensure personal protection and allow for safe operation of the pipeline.

2.5. Geohazards

A CO₂ pipeline in central and southeastern Illinois may be subject to a several types of geohazards, including landslides in steeply sloped ground, seismic hazards such as liquefaction, seismic-induced landsliding, seismic wave propagation, ground shaking, and coal-mining subsidence. These potential geohazards can be avoided or mitigated through careful route selection and reconnaissance, state-of-the-art engineering methodology, and innovative design practice.

2.5.1. Landslides

Landslides are downslope movements of soil masses, most often triggered under static conditions by changes in moisture conditions and water table or by changes in slope geometry, such as undercutting of the toe of the slope. Such changes result in a redistribution of shear stresses along the slope, with a concurrent reduction in soil shear strength along the slide plane or a reduction in the resistance against sliding provided at the toe of the slope.

When a pipeline is contained within a sliding soil mass, it must deform to accommodate the differential displacement between the sliding mass and the adjacent ground outside the zone of sliding. Figure 2.1 is a schematic illustration of the effect of a landslide on a pipeline crossing a slide zone.

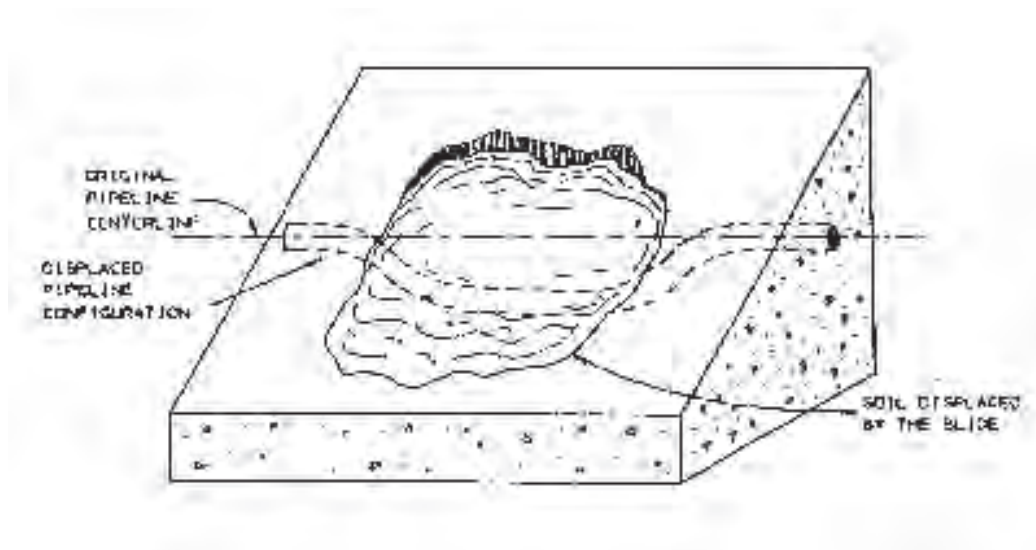


Figure 2.1. Buried pipeline subjected to landslide

The most significant landslide hazards that can affect buried pipelines are slumps, shallow slides, deep rotational slides, and translational slides. Slumps and shallow slides are caused primarily by inertial forces, but they are often assisted by densification of loose soil or liquefaction of underlying sediments. These movements occur mostly along the margins of embankments, cut-and-fill slopes, and slopes with relatively shallow cover in hilly or mountainous terrain. Deep slides involving significant components of translation and rotation of a soil mass can develop catastrophically and affect large areas. Translational slides are more likely to occur on natural slopes, whereas rotational slides often occur in homogenous materials such as highway fill embankments. A landslide frequently causes underthrusting in soils near the base of its slope so that substantial compression and bending may be transferred to pipelines located there.

The landslide threat to the proposed CO₂ pipeline in Illinois is thought to be minimal because most, if not all, of the route is through relatively flat or gently rolling terrain that is not particularly susceptible to landslides. In steeper areas where landslide risk may be present, the preferred approach is simply to avoid such hazards by careful routing away from them. Engineered solutions to stabilize slopes (e.g., drainage, buttresses, and tie-backs) are normally required only in mountainous terrain with limited routing options.

2.5.2. Seismic Hazards

Considerable attention has been focused in recent years on the potential consequences of future earthquakes in the central United States. The New Madrid Seismic Zone (NMSZ) in the central Mississippi River Valley is the primary seismic source for this area. The NMSZ is known mainly for the succession of four shocks, known collectively as the New Madrid earthquake sequence, which occurred on December 16, 1811 (two shocks), January 23, 1812, and February 7, 1812. The epicenter locations for these four earthquakes, which were felt over a major portion of the eastern United States, are shown on Figure 2.2 (Hopper, 1985). Street and Nuttli (1984) estimated that three of these four earthquakes would have measured between 8.4 and 8.7 surface wave magnitude, M_s . In addition to the four main shocks, there were numerous aftershocks.

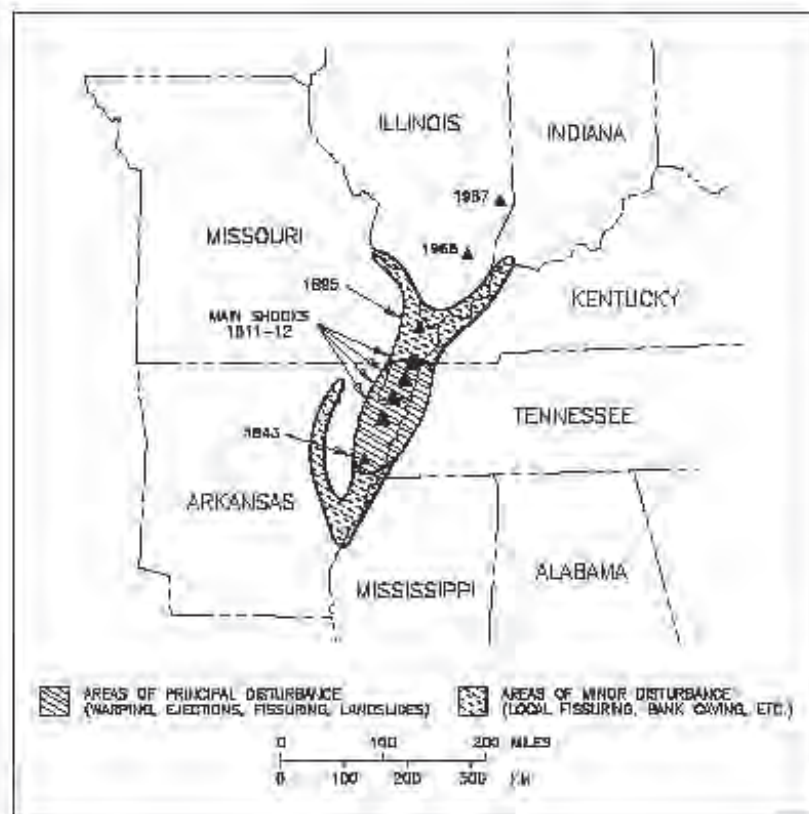


Figure 2.2. Epicenters of New Madrid earthquakes and areas of soil disturbance in 1811–1812 (Hopper, 1985; Fuller, 1912)

Based on a field study 100 years after the New Madrid earthquakes, Fuller (1912) characterized ground disturbance in the area affected by the earthquakes (Figure 2.2). Fuller noted numerous observations of ground fissuring, some of which were several hundred feet or more in length and 30 ft (9 m) wide. It is believed that much of the fissuring described by Fuller was lateral spreading or flow slides associated with liquefaction of a sand layer typically 6 to 15 ft (2 to 5 m) deep (Obermeier, 1985). Fuller also called attention to numerous landslides along river banks and in the high bluffs bordering the lowlands on the east side of the Mississippi River in southwestern Kentucky and western Tennessee and upstream along the Ohio River as far as Indiana. Owing to the general absence of documented accounts, it is believed that ground failure in Illinois was relatively insignificant, except, of course, for areas along the Mississippi and Ohio Rivers.

Since 1812, two significant shocks have occurred in the NMSZ, one in 1843 in northeastern Arkansas and the other in 1895 in southeast Missouri. These earthquakes were estimated to have had body wave magnitudes (m_b) of 6.0 and 6.2, respectively (Nuttli, 1974). Other large earthquakes in the region include two earthquakes in southern Illinois, a 5.5- m_b event near Broughton in 1968, and a 5.1- m_b event near Olney in 1987, and a magnitude 5.0 event near Evansville, Indiana, in 2002. The Evansville event occurred in the Wabash Valley Seismic Zone (WVSZ), which is located in southeastern Illinois and southwestern Indiana. The WVSZ is thought by some investigators to be capable of producing “New Madrid”-sized earthquake events. Field investigations of prehistoric earthquakes in the region indicate that an event of estimated magnitude 7.0 occurred in the WVSZ approximately 6,100 years ago (<http://www.cusec.org>). Thus, it would be prudent to consider this proximate seismic source in the design of a CO₂ pipeline route that passes into southeastern Illinois.

The principal earthquake hazards for pipeline systems in southern Illinois include ground failure due to liquefaction or landslides and ground shaking effects on aboveground facilities and equipment. Ground settlement and seismic wave propagation are less important, but could possibly affect buried pipelines in certain special circumstances. Surface fault rupture is also potentially hazardous to pipelines, in general, but there is no evidence of active faults in southern Illinois that might affect the planned route of the CO₂ pipeline. The potential effects of the various earthquake hazards on the CO₂ pipeline is described in this report.

Transmission pipelines are typically buried under a soil cover of 3 to 4 ft or deeper in agricultural areas. Burial tends to make a pipeline more susceptible to large permanent ground distortions such as landslide or liquefaction-induced ground displacement. The effects of seismic ground movement along a pipeline route are generally sporadic, depending on local soil, groundwater, and topographic conditions. The nature of the ground displacements are not well defined and generally can occur at any point within an area of potential movement. The amount of ground displacement depends largely on the intensity and duration of earthquake ground shaking.

2.5.2.1. Liquefaction. Soil liquefaction is defined as “the transformation of a granular soil from a solid state to liquefied state as a consequence of increased pore water pressure and reduced effective stress.” Liquefaction occurs as seismic waves propagate through saturated granular sediment layers, which induce cyclic shear deformation and collapse of loose particulate structures. As collapse occurs, contacts between grains are disrupted, and loads previously carried through those particle-to-particle contacts are transferred to the interstitial pore water. This load increases pore water pressure and concomitantly decreases intergranular or effective stress. As pore water pressures increase, the sediment layer softens,

allowing greater deformation and an accelerated rate of collapse of the particulate structures. When the pore pressure reaches a certain critical level, the effective stress approaches zero, and the granular sediment begins to behave as a viscous liquid rather than a solid. Liquefaction has occurred.

Liquefaction occurs in natural deposits in a rather narrow range of geologic and soil environments. Sediments that are most susceptible to liquefaction are granular soils that remain loose and uncemented after deposition during recent geologic time (modern or late Quaternary eras). Liquefaction occurs only in saturated sediments beneath a shallow groundwater table. Strong ground shaking can also trigger the transformation of deposits into a liquefied state, as could occur for a strong event occurring in the NMSZ or the WVSZ.

Liquefaction by itself poses little hazard to pipelines. Damage generally occurs when liquefaction leads to ground deformation or ground failure. Liquefaction may lead to flow failure, lateral spread, ground oscillation, buoyant rise of buried pipelines, or ground settlement. The type and extent of ground failure depends on site geometry and the depth, thickness, and extent of the liquefied layer.

1. Flow failure is the most catastrophic type of permanent ground deformation caused by liquefaction. Flow failure occurs on steeper slopes (greater than 6% or 3.5 degrees) underlain by loose liquefiable soils. Flow failures are characterized by large lateral displacements (several meters or more) and severe internal disruption of the failure mass. The preferred mitigation strategy is to avoid potential flow slide areas, as is done for potential landslide areas.
2. Lateral spread occurs on slopes that are too gentle to develop flow failure or in areas near a free face, such as an incised river channel. Lateral spreads involve sideways movement of surficial soil layers down the gentle slopes or toward the free face. Lateral spread displacements may be as large as several meters accompanied by shear failure zones as deep as several meters, depending on the depth of the liquefied soil and the geometry of the site. Displacements commonly occur as far as a few hundred meters from incised river channels. Displacement occurs in response to a combination of gravitational and earthquake-generated inertial forces acting on sediments within and above the liquefied zone. During displacement, the soil layers commonly break into large blocks, which transiently jostle back and forth and up and down in the form of ground waves (ground oscillation) as they migrate laterally. Displacements usually range up to 20 ft, but where ground conditions are particularly vulnerable and shaking is intense, larger displacements have occurred.

Lateral spreads create extension or tensional features such as open fissures at the head (upslope) of the failure, shear deformation along the margins, and compressional features such as buckling at the toe. These movements have pulled apart, sheared, and/or compressed pipelines during past earthquakes. For example, lateral spreads fractured water, gas, and oil pipelines during earthquakes in Niigata, Japan (1964), San Fernando, California (1971), Northridge, California (1994), and Kobe, Japan (1995), and elsewhere (O'Rourke and Tawfik, 1983; Oka, 1996; O'Rourke, 1995).

3. Ground oscillation occurs on flat terrain in response to inertial forces acting on decoupled soil materials above or within the liquefied zone. This decoupling allows large transient ground motions or ground waves to develop, but permanent displacements are usually small

and chaotic. Observers of ground oscillation commonly note slow-moving ground waves, up to a meter high, with wavelengths of tens of meters, accompanied by opening and closing of fissures. Generally, welded steel pipelines are capable of withstanding the flexural strains associated with ground oscillation.

4. Buoyant rise of pipelines may occur when the surrounding soil liquefies. For example, buried oil and gasoline tanks buoyantly rose during the 1993 Hokkaido Nansei Oki earthquake in Japan (Youd et al., 1995). Special measures to prevent buoyant rise are a design consideration for some pipelines in liquefiable areas. In most instances, well-fabricated steel pipelines can accommodate some rise, especially if distributed over a large length of the line, without exceeding the flexural strength of the pipe. Where mitigation is necessary, one effective measure is to surround the pipe with well-compacted backfill. Another measure is to embed the pipeline beneath the liquefiable layer to avoid the hazards associated with liquefaction. Often concrete coating, as used in standard floodplain and marsh construction, is sufficient to prevent buoyant rise. Buoyant rise is unlikely to be an issue for a small-to-medium diameter CO₂ pipeline, because the high operating pressure requires thick wall pipe, which, in combination with the weight of the liquid CO₂, results in a negatively buoyant pipeline system.
5. Ground settlement may occur due to the compaction of liquefiable deposits during earthquake shaking. Settlements may range from a few percent of the thickness of loose liquefiable layers to a fraction of a percent for denser sediments. Uniformly thick layers of homogeneous sediment usually compact and settle rather evenly with little consequent damage. Where granular layers vary in thickness, however, differential settlements may develop that could damage a buried pipeline. However, because of the generally ductile nature of steel pipelines and the generally small and widely distributed strains induced by all but very large and very concentrated ground settlements, very little damage has occurred to well-constructed steel pipelines from liquefaction-induced ground settlement.

Lateral spread is the most serious liquefaction-related hazard for the CO₂ pipeline system, because a pipeline crossing a zone of lateral spread displacement must deform longitudinally and in flexure to accommodate ground displacement. The areas most susceptible to lateral spread are at river and stream crossings at the southeastern end of the proposed pipeline route; these areas are closest to the NMSZ and WVSZ. In such areas, the design approach is to provide for a gently sloping (approximate 10%) transition from normal burial depth in the floodplain to the maximum depth beneath the channel and to use pipe and welds capable of mobilizing high strain without loss of pressure integrity. Some damage requiring repair may occur for large lateral spread displacement, but the overarching objective is to maintain pressure integrity in the deformed pipeline segment.

2.5.2.2. Earthquake-induced Landslides. As already described, most landslides occur under natural conditions related to increased moisture and/or changes in slope geometry. However, landslides can also be triggered by the inertial forces associated with seismic ground shaking, which increase the driving force for slope movement. Seismically induced landslides typically occur in slopes that have only marginal stability under static moisture, water table, and steepness conditions. Earthquakes exacerbate the climatic hazard of these marginally stable slopes (Transportation Research Board, 1996).

2.5.2.3. Seismic Wave Propagation. Body waves, including compression waves and shear waves, propagate radially from the source of earthquake energy release (hypocenter) into the surrounding rock and soil medium. Compression waves cause axial compressive and tensile strains in the ground in a radial direction away from the hypocenter. Shear waves cause shear strains in the ground perpendicular to these radial lines. When the compression waves and shear waves are reflected by interaction with the ground surface, surface waves (Love waves and Rayleigh waves) are generated. Except at very large distances from the epicenter, the magnitude of surface waves is much less than body waves.

A pipeline buried in soil that is subject to the passage of these ground waves will incur longitudinal and bending strains as it conforms to the associated ground strains. In most cases, these strains are relatively small, and welded pipelines in good condition typically do not incur damage. Propagating seismic waves also give rise to hoop membrane strains and shearing strains in buried pipelines, but these strains are small and may be neglected.

Well-constructed, buried oil and gas pipelines in good condition generally have not been affected by seismic wave propagation. There is no reported case of failure of a ductile, full penetration welded oil or gas pipeline attributable to wave propagation alone. Recent earthquake experience (Honegger, 1999) has indicated that wave propagation is a credible earthquake hazard for pipelines only in cases of extremely poor-quality girth welds or corrosion defects subjected to very high levels of seismic ground motion.

2.5.2.4. Ground Shaking. Earthquake ground shaking will cause seismic dynamic loading of above-ground pipeline facilities. Typical facilities include buildings, structures, vessels, liquid storage tanks, piping, mechanical and electrical equipment, control systems, instrumentation, and communications. The seismic design of pipeline facilities follows typical building code approaches, such as the the 2003 edition of the International Building Code (ICC, 2002) and ASCE Standard 7-02 (ASCE, 2002). Special attention should be given to ensuring the operational integrity of systems that provide essential monitoring, control, safety, and emergency functions. Examples of critical components include monitoring instrumentation, communications equipment, computer hardware, remote valve auxiliary equipment, emergency power systems, and uninterruptible power supplies.

2.5.3. Coal Mining Subsidence

According to the National Mining Association (www.nma.org), Illinois ranks seventh in the U.S. coal production and produces about 3% of the nation's coal. Illinois coal is mined by both underground and surface mining methods. The extraction of underground-mined coal causes displacement of the overlying strata that may reach the ground surface through subsidence. Underground mining in Illinois uses (1) room-and-pillar mining and (2) longwall mining methods. Each method is uniquely associated with subsidence of the ground surface.

Room-and-pillar mining drives entries, hallways, panels, and rooms in the coal seam, leaving 50 to 70% of the coal in place to prevent collapse of the cap rock into the mined cavities. The configuration of mined panels is intended to prevent or limit surface subsidence, and such may be the case for many years. However, slow deterioration of underground pillars long after mining has ceased may manifest itself as subsidence years or decades later.

Longwall mining provides for the full extraction of large panels of coal perhaps 500 to 1,200 ft in width and one to several miles long. Longwall mining is accomplished with a longwall mining machine that

extends the full width of panel and roof shields to prevent the collapse of the roof of the mined panel onto the equipment. As longwall mining progresses along the length of the panel, the roof collapses behind the advancing equipment and shields. Subsidence due to long wall mining operations occurs quite rapidly as mining progresses, usually within days and typically complete within about 4 to 6 weeks.

For room-and-pillar mining, surface subsidence may be “pit” or “sag.” Pit subsidence causes an abrupt drop in the surface and nearly vertical or belled outward walls (Bauer and Hunt, 1982). Pit subsidence is caused by collapse of a mine void and is most often associated with abandoned, shallow mines in areas with weak soil and rock overburden. Sag subsidence is usually associated with high extraction room-and-pillar mining or longwall mining. Sag depressions at the surface are typically several 100 ft wide with gentle slopes.

Regardless of the mining method used, the subsidence associated with underground mining can present a serious threat to the integrity of a buried pipeline. The pipeline must deform (bend, elongate, or shorten) to accommodate the vertical and horizontal displacement of the ground surface. Pit subsidence along a pipeline right-of-way could result in an abrupt loss of support for the pipeline while possibly leaving some of the overburden material on top of the pipeline as an external gravity load effect. Sag subsidence would cause the pipeline to deform in a sag-like shape to assume the new profile of the ground. Deformation at the margins of the sag depression could overstress the pipeline. If the pipeline bend exists within the subsidence depression, horizontal ground strains could possibly overstress the pipe bend as an applied thrust acts outward in the bend.

The prudent course of action for a pipeline project is simply to avoid routing the pipeline through areas of Illinois with potentially unstable abandoned mines or where high extraction mining could be reasonably anticipated. Nevertheless, if the CO₂ pipeline is located in a coal mining area, potential ground subsidence needs to be monitored over the course of its operating life. If high-extraction mining, particularly longwall mining, is to be conducted along the right-of-way, it is probably necessary to uncover (excavate) the pipeline prior to mining to allow the pipeline freedom of movement and to temporarily support the pipeline on sand bags or cribbing to restrict actual pipeline displacement to acceptable amounts. Additional safeguards in areas subjected to possible mining subsidence include the use of highly ductile pipe with overmatching girth welds (i.e., welds stronger than the pipe to mobilize ductile pipe behavior without weld fracture). This combination of ductile pipe and overmatching welds is often referred to as “high-strain” pipe.

3. Design Elements

3.1. CO₂ Properties

It is important to understand the properties of CO₂ in the range of usual pipeline operating temperatures and pressures. Depending on the temperature and pressure, CO₂ exists as a solid, liquid, or gas. The phase diagram shown in Figure 3.1 describes the relationship of these variables for CO₂ over a range of pressures and temperatures.

As noted on the phase diagram, the triple point (pressure, 5.1 atm/75.1 psia; temperature, 56.7°C/133°F) is the pressure and temperature at which the three phases (gas, liquid, and solid) exist simultaneously in thermodynamic equilibrium. The critical point (pressure, 72.8 atm/1,067 psia; temperature 31.1°C/88°F) is the point above which the liquid and gas phase become indistinguishable. This region of the phase

diagram—known as the dense, superfluid, or supercritical phase—is the region in which CO₂ pipelines operate.

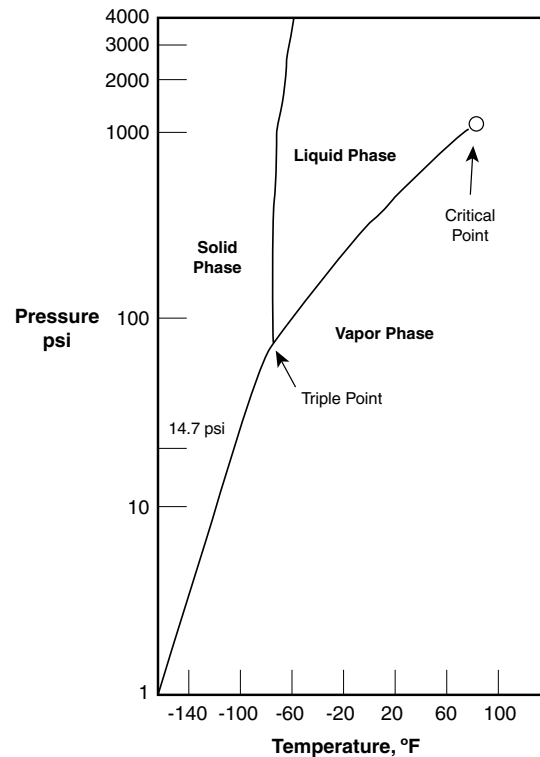


Figure 3.1. Properties of CO₂ over a range of pressures and temperatures

Another important property of CO₂ is the solid-gas phase boundary. Physically, this boundary implies that the gas and solid can coexist and transform back and forth without the presence of liquid as an intermediate phase. A solid evaporating or changing phase directly into the gas is called sublimation. Solid CO₂ is called dry ice because it does not go through a liquid state in its phase transition at ambient conditions.

It is not economical to operate a CO₂ pipeline in a gaseous region because of the larger-diameter pipeline needed to transport the product in its less dense, gaseous state. Instead, a CO₂ pipeline system normally operates in the superfluid region. Pressures are normally 2,500 to 2,700 psig at the inlet (nominal maximum operating pressure) and 1,400 to 1,600 psig at the outlet (nominal minimum operating pressure). These pressure ranges, although higher than most pipelines, are similar to those used on liquified petroleum gas (LPG) pipelines.

The ambient temperature for an underground pipeline in an Illinois agricultural area varies from 45°F in the winter to 70°F in the summer.

CO₂ is considered as a “natural refrigerant,” a category that includes ammonia and hydrocarbons such as ethane, propane, and butane. As with any refrigerant, when CO₂ is under high pressure and is flashed across an orifice to a lower pressure, it attempts to absorb heat from the surrounding environment. If heat cannot be absorbed in the process, the refrigerant will drop to a lower temperature. Materials for the

CO₂ pipeline need to be specified to withstand the refrigeration temperature that can be expected during a pressure reduction. This refrigeration temperature usually calculated from the expected maximum operating pressure to atmospheric pressure. If not specified properly, the pipeline materials could become brittle under certain conditions and fail in a catastrophic manner.

Natural gas lines that have combinations of contaminants, which include CO₂, H₂O, and H₂S, can experience major internal corrosion. In these contaminated natural gas pipelines, water reacts with CO₂ and/or H₂S to form carbonic or sulfuric acid, and corrosion of the pipe steel occurs. Similarly, corrosion problems will occur in a pure CO₂ pipeline if water is present as a contaminant. In all CO₂ pipelines, the process plant limits the water content of CO₂ before it is input into the pipeline meter and regulator facilities. A number of pipelines have operated successfully while requiring that water contact be limited to 30 lb of water per million standard cubic feet. An example of the composition of the CO₂ provided to the pipeline for a recent project is listed in Table 3.1. The water content in this example corresponds to approximately 8 lb/million standard cubic feet.

Table 3.1. CO₂ composition (example) showing a typical component supply limit

Component	mol%
Nitrogen	0.041670
Methane	1.116670
Hydrogen sulfide	0.000330
Carbonyl sulfide	0.026790
Ethane	0.014900
Water	0.016670
Carbon dioxide	98.782990
Total	100.000000

3.2. Flow Rate Design

Flow rate is the single most critical design input for a CO₂ pipeline. A set length, design flow rate, and a set of pressures and pipe diameters can be analyzed to reach the most economical and practical design. Most CO₂ pipelines operate with an upstream pressure of 2,500 psig or higher and have a delivery pressure near 1,500 psig. The meter and regulator stations at each end require a pressure drop of approximately 50 psi each, giving a pipeline differential of 1,000 psi to achieve the flow rate.

For preliminary sizing, the use of these inlet and outlet pressures and approximate physical properties allow a suitable hydraulic analysis to be performed. The physical properties used in the analysis are average specific gravity and viscosity calculated based on the average pipeline pressure and ground temperature. A brief narrative of the assumptions and methodology follows:

1. CO₂ = average pressure of 1,900 psig
2. CO₂ density = 48.49 lb/cu. ft. (calculated using FlashCalc for pure CO₂ at 1,900 psig and 80°F, assumed average temperature)
3. CO₂ viscosity = 0.06 centipoise (cP) for CO₂ at 80°F.
4. Pipe wall thickness (WT) is standard wall as defined by the manufacturing codes.

Liquid density = 48.49 lb/ft³ (water = 62.4) at 1,900 psig and 80°F

Vapor density at STP = 0.1152 lb/ft³ (air = 0.076)

5. Pressure drop was calculated using the following transmission factor (T):

$$T_{(oil)} = 3.6 \log (Re/8).$$

Smooth pipe function,

$$(F_{smooth}) = T_{oil} - \frac{4 \log \left(\frac{R_e}{T_{oil}} \right) - 0.6 - T_{oil}}{4 \log \left(\frac{4}{T_{oil} \ln(10)} \right) - 1} - 0.$$

Three iterations were used for this function.

Darcy-Weisbach friction factor:

$$f_{oil} = \frac{4}{T_{oil}^2}.$$

Darcy's formula for head loss (Crane Technical Paper #410):

$$h_L = \frac{0.1863 f L v^2}{D_o}.$$

These properties and hydraulic formula, when adjusted for fluid density, are used to estimate the pressure drops per mile for each of several different diameter pipelines (4 to 24 inches) under consideration as shown in Figure 3.2. For the initial analysis, it is assumed that CO₂ transport pipeline flows with only the inlet pressure provided by compression at the power plants and without intermediate pressure boosting. This assumption is a common assumption for CO₂ pipeline projects and allows for future expansion to an ultimate rate with the addition of a booster station.

With an assumed pipeline pressure drop of 1,000 psi, the average pressure drop per mile for the conceptual 200-mile Illinois pipeline under review is 5 psi/mile. Referring to the graph in Figure 3.2, the capacity of various pipeline diameters can be determined for a pressure drop of 5 psi/mile. The delivery flow rate can be determined by entering the graph on the pressure drop axis (ordinate) at 5 psi/mile. The intersection of the 5 psi/mile pressure drop value with the curve for a specific pipe diameter gives the flow rate on the flow rate axis (abscissa). Pipeline capacities for the 200-mile Illinois Basin pipeline (without boosting) are in Table 3.2 (column 2) for pipe diameters ranging from 12 to 24 inches.

Unit Pressure Drop vs Flow Rate as a Function of Pipe OD

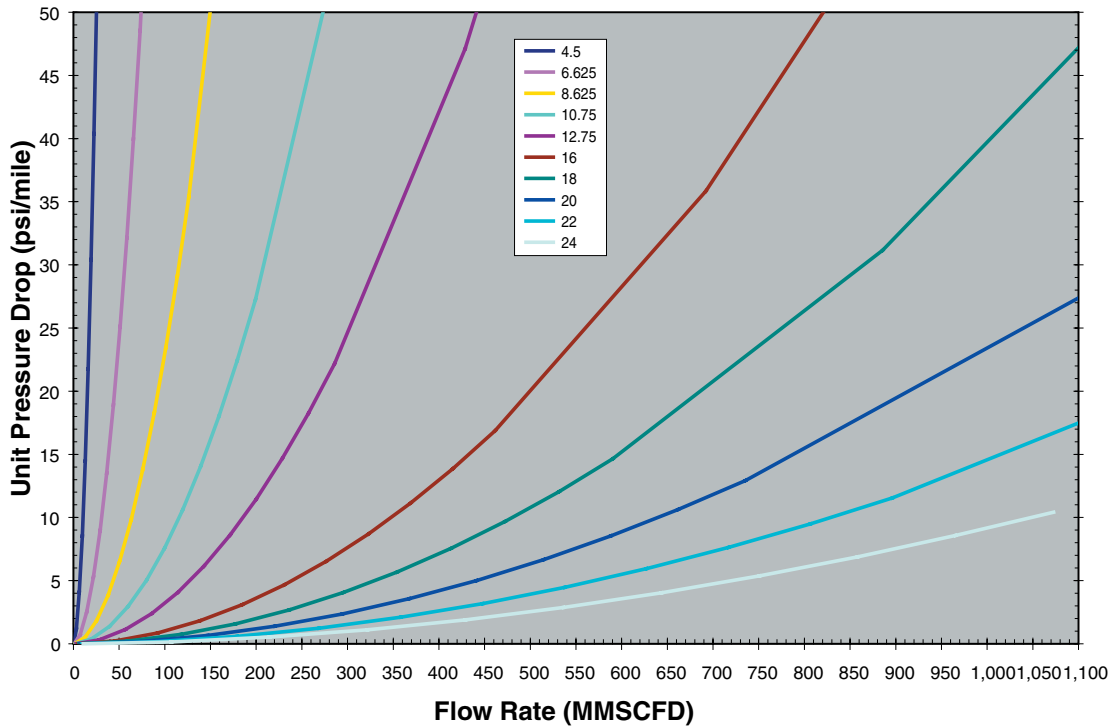


Figure 3.2. Pressure drop per mile for each diameter pipeline

Table 3.2. Flow capacity as a function of pipe diameter and pressure drop

Pipe diameter (inches)	Flow capacity with inlet pressure only, 1,000 psi pressure drop over 200 miles (MMSCFD) ¹	Flow capacity with 100% boosting at mid-point, 1,000-psi pressure drop over 100 miles		
		Flow capacity (MMSCFD)	Required BHP for 100% boosting at 100-mile mid-point	
			BHP/mile	BHP/100 miles
12	125	190		2,400
16	250	350		3,600
18	340	490		5,500
20	450	650		6,800
22	560	840		8,600
24	700	1,050		11,000

¹Million cubic feet per day.

If 100% boosting (1,000 psi) were applied at the pipeline midpoint, then the pressure loss would be an average of 10 psi/mile. Starting at the 10 psi/mile value on the ordinate axis, the following flow rate capacities would increase as given in column 3 of Table 3.2. The required brake horsepower (BHP) size for the booster station can be determined by using the graph shown in Figure 3.3. To use the graph, start at the ultimate flow rate for each diameter, read the horsepower per mile where it intersects the diameter,

and then multiply by the distance. For the case of a booster station at the midpoint of the hypothetical 200-mile Illinois Basin pipeline, the required BHP per mile and per 100 miles is given in columns 4 and 5, respectively, of Table 3.2 for the pipe diameters under consideration.

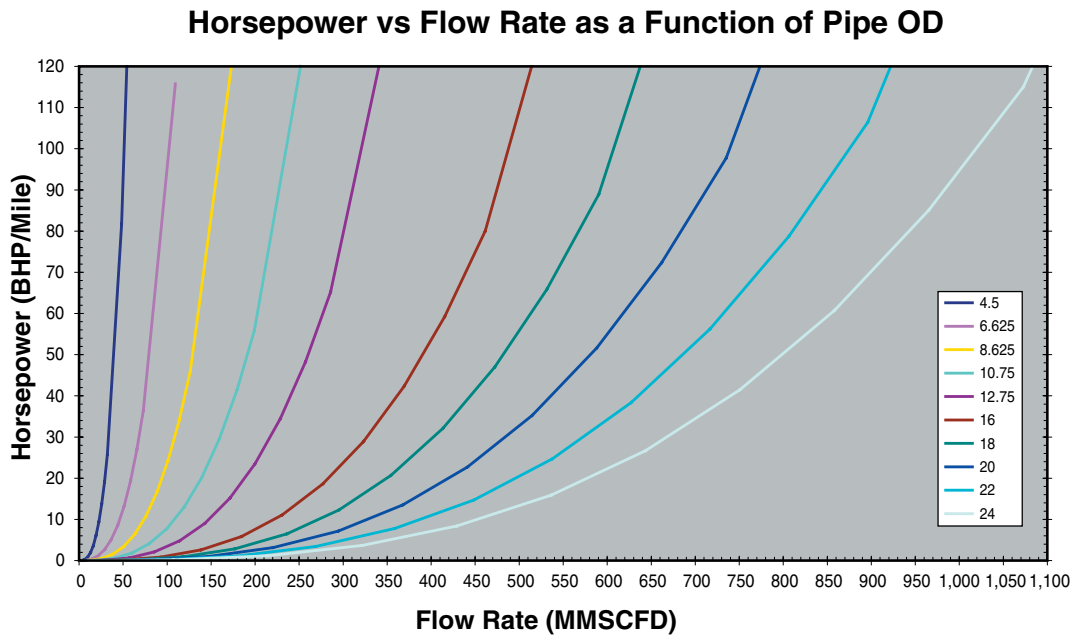


Figure 3.3. Required brake horsepower size for the booster station

3.3. Design

3.3.1. Codes – Federal, State, and Industry

The design of a CO₂ pipeline is very similar to the design of a high-pressure LPG pipeline. The minimum design for a CO₂ pipeline is covered by the U.S. Department of Transportation (U.S. DOT), Federal Code 49 CFR, Transportation, Part 195, Transportation of Hazardous Liquids by Pipeline, Section, 195.0, which prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or CO₂.

Illinois, with the exception of the Illinois Department of Agriculture, does not have regulations pertaining to CO₂ pipelines. The Illinois Commerce Commission (ICC) regulates the safety requirement of the gas pipelines in the state but defers the safety regulation of Part 195 liquid jurisdictional pipelines to the U.S. DOT.

The following design elements are presented with a reference to the specific U.S. DOT 195 regulation with a recommended method of applying the regulation to a CO₂ pipeline.

3.3.2. Pressure Design Formula

The design parameters for steel pipe are determined in accordance with the following equation (see U.S. DOT, Sec. 195.106, Internal Design Pressure):

$$P = (2St/D)EF$$

where

- P = design pressure (psig),
- S = specified minimum yield strength (psi),
- D = specified outside diameter of the pipe (inches),
- t = specified wall thickness of the pipe (inches),
- E = seam joint factor, and
- F = design factor.

In general, pipeline design pressure and other factors are known, and the wall thickness can be calculated.

3.3.2.1. *Design Factor “F.”* This design factor will be determined as a result of conditions or a combination of conditions such as crossings, fabrications, station yards, and special areas (Sec. 195.106, Internal Design Pressure). For the CO₂ pipeline under consideration, a design factor of 0.72 would be common for the mainline and lateral line in all areas where normal installation methods and cross-country conditions prevail. A design factor of 0.60 would be used for facilities piping at meter/regulator stations, and a design factor of 0.72 might be used for piping at pipeline launcher or receiver facilities. Section 195.106 allows for a design factor of 0.72 to be used in all cases; however, a more restrictive design factor is common practice for facilities, crossings, and congested areas. Also, the pipe installed at all highway, road, and open cut waterway crossings and in all fabricated assemblies needs to be of sufficient wall thickness and grade to be in compliance with a design factor of 0.60. Directionally drilled waterway crossings and railroad crossings shall be designed using a design factor of 0.50 or 0.60 depending on the length and depth of the crossing.

Based on the conceptual Illinois Basin route of 200 miles, the estimated number of road and river crossings for the pipeline will break down approximately as in Table 3.3.

Table 3.3. Mileage by design factor to accommodate road and river crossings

Route (miles)	Factor	Area
180	0.72	Open
15	0.60	Roads and mildly congested urban or commercial
5	0.50	Rivers and congested urban or commercial

3.3.2.2. *Yield Strength “S.”* The specified minimum yield strength for the pipe steel set forth in the manufacturing specifications is used in the design equation that determines the pressure rating of the pipe. The yield strengths measured during mill testing, which will be higher than the rated yield strength, are not used in the calculations. These actual higher yields provide another inherent safety factor in pipeline design. Examples of pipe grades are X42, X52, X60, X65, and X70. The numerical values are the rated yield strength of the pipe steel in pounds per square inch divided by 1,000.

A CO₂ pipeline would be constructed with X65 or X70 grade pipe if built in the next 5 years. Over the next several years, higher grade pipe will be introduced into the industry, which could have application in larger-diameter CO₂ pipelines.

The seam joint factor E (see Sec. 195.106, Internal Design Pressure) is 1.0 for butt-welding methods under consideration for CO₂ pipelines.

3.3.3. Pipe Wall Thickness

Design, yield, and seam joint factors, combined with expected pressure, indicate wall thickness for the diameters that are probable for the project. The wall thickness (inches) for a 2,800 psig, X65-grade pipeline is shown in Table 3.4 for the list of outside diameters under consideration and for the common safety factors (0.72, 0.60, and 0.50).

Table 3.4. CO₂ pipeline, 2,800 psig, grade X65 pipe

Wall thickness (inch)			
Diameter (inch)	Design factor (F)		
	F=0.72	F=0.6	F=0.5
4	0.135	0.162	0.194
6	0.198	0.238	0.285
8	0.269	0.317	0.380
10	0.322	0.386	0.463
12	0.381	0.458	0.549
16	0.479	0.579	0.689
18	0.538	0.696	0.775
20	0.598	0.718	0.862
22	0.658	0.790	0.948
24	0.718	0.862	1.034

3.3.4. Pipe Wall Thickness Transitions

End preparation for butt-welded sections of pipe having unequal wall thickness varying more than 3/32 inch (0.093 inch) will be taper bored or internally beveled.

3.3.5. Pipe Bending Design

The pipeline contractor will perform field bending during the construction of the pipeline system. The maximum allowable bend is up to 1.5 degrees in any length along the pipe axis equal to the diameter of the pipe (e.g., length of 24 inches in a 24-inch diameter pipe). To allow for pipe alignment during fit-up, the minimum straight tangent on a bend should be 4 to 5 ft on each end. For large areas requiring directional changes over a short distance, induction bends can be engineered and purchased in advance. The company will generally provide the contractor with induction bends for side bends greater than a set angle and for areas where major elevation changes are expected.

3.3.6. Depth of Cover

The minimum depth of cover required by U.S. DOT 195.24 would need supplementation to meet the the Illinois Department of Agriculture local land use requirements. The required depths will be as per the following:

- Industrial, commercial, and residential areas: 48 inches
- Agricultural and cultivated lands: 60 inches
- Public road surfaces and railroads: 60 inches (or permit requirements)

- Drainage ditches of public roads and railroad crossings: 48 inches (or permit requirements)
- River and major stream crossings: 60 inches (or permit requirements)
- Minor stream crossings, drainage canals, and ditches: 60 inches
- Freshwater supply: 60 inches (uncased)
- Irrigation canals: 60 inches (uncased)

3.3.7. Buoyancy Design

The pipe should be designed to be negatively buoyant both during and after construction. In general, in locations where the ditch cannot be dewatered during construction, a minimum negative buoyancy of 115% is normally used. Increased negative buoyancy may be required in areas where there is a potential for soil liquefaction or liquefied backfill that has higher than normal specific gravity. Acceptable methods to achieve the required negative buoyancy include ditch dewatering, concrete coating of pipe, or concrete weights (both set-on and bolt-on types).

3.3.8. Horizontal Directional Drill

A horizontal directional drill (HDD) is used to make river and other crossings where it is impractical or environmentally unacceptable to construct from the surface (see Appendix C1, Figures C1.11 to C1.15). The HDD has a minimum cover below the bottom of a river to prevent breakout of the drilling fluid. Also, the pipe handling equipment at the site limits the exit angle of the crossing, which is especially true for the larger-diameter pipes. For pipe handling, smaller angles are preferred, although a smaller angle increases the possibility of a drilling fluid breakout at the end of the HDD. In addition, the minimum radius of curvature for the pipe must be considered. Larger pipe has a proportionately larger minimum radius of curvature than a smaller pipe. These factors—minimum cover, angle of entry, angle of exit, and minimum radius—combine to give the minimum distance for a crossing. The design of the crossing must take into account geological conditions at the site.

3.4. Materials and Equipment

3.4.1. Summary

By developing a specification with input from the project metallurgist, the engineer, and the purchasing agent and by working only with pre-qualified suppliers, fully adequate equipment and materials can be readily obtained at a reasonable price.

3.4.2. Industry Code

The U.S DOT CFR Sec. 195 regulates CO₂ pipeline safety; this regulation requires that the pipe be provided in accordance with the American Petroleum Institute Code 5L or 5LX. The 5L code has two levels that a pipe can meet. The CO₂ pipe should be specified to meet the higher level PSL 2 requirements, as well as additional supplemental requirements, as determined by the engineer and metallurgist.

3.4.3. Line Pipe

The line pipe is the key material component for any pipeline. For a CO₂ pipeline, the line pipe must meet the U.S. DOT regulations just referenced. These regulations allow the pipe to be manufactured by a prescribed manufacturing method with varying grades of steel. In addition, the U.S. DOT regulation requires that the pipe have the proper chemistry and ductility to match the intended services.

3.4.4. Method of Manufacture

Three manufacturing methods are used for CO₂ pipelines: seamless, electric resistance welded (ERW), and double submerged arc welded (DSAW).

Each manufacturing method has advantages:

- Seamless pipe, as implied by its name, has no longitudinal seam weld. This pipe is used in plant facilities or fabrication that contains numerous connections. The lack of a seam, which should not align at a weld joint, simplifies the layout and welding process.
- ERW pipe is made from flat steel coils. The coils are uncoiled and formed into pipe, and the seam is welded by an electric resistance process. ERW pipe can be made in lengths up to 80 feet, which reduces field handling welding requirements. The maximum diameter of standard wall ERW pipe is 24 inches. The upper limits of wall thickness required for CO₂ pipelines are also at the upper limits in the 20- to 24-inch range. Recent 16-inch CO₂ pipelines successfully used ERW pipe.
- DSAW pipe can be made in larger diameters than the ERW. The steel is delivered in flat plates, which are then formed into the pipe shape using large hydraulic presses. The seam weld is then made using a submerged arc process. Thick-walled pipe of large diameter is manufactured using this process.

In the past, ERW pipe was not considered to be reliable enough for high-pressure CO₂ service because of seam failure issues with the higher grades of steel needed for CO₂ pipeline. However, ERW pipe from premium ERW mills has been used on recent CO₂ pipeline projects. For diameters in the 24-inch range, DSAW mills should be considered to ensure the best quality, because the price difference may not be significant.

3.4.5. Grade of Steel

Steel pipe can be made of various grades of steel as long as it meets the American Petroleum Institute (API) 5L or 5LX standard. API 5L is for low-grade steels, and APL 5LX is for the higher-grade steels that are now commonly used for CO₂ pipelines. The grade defines the tensile strength of the steel (e.g., grade X60 is 60,000 psi) used to form the pipe. The higher the grade, the more stress the steel can safely withstand before it yields. For a specific high pressure, the higher grade requires a thinner wall thickness and therefore has a reduced material, field handling, and welding costs. Over the years, the definition of “high” grade has gradually increased such that X65 or X70 is presently considered to be high grade. Tensile strength should be specified to limit the range of tensile strengths that are acceptable to less than 20,000 psi over the specified grade. In designated geohazard areas, it may be necessary to control the yield-to-tensile strength ratio to ensure ductile behavior.

3.4.6. Chemistry of Steel

Steel should be made using the basic oxygen or electric furnace process. The steel should be fully killed and made with a fine-grain, clean steel process and treated for inclusion shape control. If any H₂S exists in the CO₂, then the steel will need to be tested for hydrogen-induced cracking (HIC). This requirement limits the mill sources for the steel supply. Specifying certain maximums and minimums for carbon equivalent, sulfur, and other components is also standard operating procedure.

3.4.7. Toughness/Ductility of Steel

Based on the planned operating pressure, temperatures, and pipeline diameter, a specified toughness of the steel is needed to prevent brittle behavior of the pipeline system. This toughness specification level must take into account the refrigerating effects of the CO₂ during operational upsets and possible small leaks. The chemistry and the overall manufacturing process determine the toughness of the steel. Toughness is measured by use of a Charpy impact test and by a drop weight tear test. This latter test can be considered optional but should be conducted on a sampling of the pipes to determine the need for further testing.

3.4.8. Inspection and Mill Quality

The full ERW weld seam needs to be inspected by non-destructive testing that does not include radiographic techniques. All API 5L pipe is hydrotested in the mill. It is recommended that pipe be tested to 95% yield or greater. For large pipe, it is common to increase the hold time to 15 seconds and to require that the first pipes from a coil be measured for excessive deformation. The pipe should be inspected using longitudinal, long-wave transducers to identify pipe body laminations. A final test should be run to ensure that the pipe does not contain any residual magnetism.

3.4.9. Valves

Valves should be full-opening, ball-type, manufactured and tested in accordance with a detailed specification that is specially written for CO₂ service. In general, most CO₂ pipelines use ANSI 1500-rated valves. Valve trim should be suited for NACE MR-01-75 with elastomers that are suitable for the requirements for CO₂ service. Generally, the elastomers are a harder type, such as Viton or Nitrile, rather than the softer rubber type, such as Buna.

The valve used for the mainline service should be a through-conduit valve to ensure passage of inspection and cleaning pigs. The mainline valve should have weld-by-weld end connection. Side tap valves connected to the pipeline should be welded by a ring joint flange end connection, which results in a pipeline that is welded from one end to the other and decreases the chances for nuisance leaks that could result in an unnecessary shutdown.

Unless impractical, mainline and lateral valve sites are located near roads to maximize ease of access; however, locations near populated areas should be avoided if possible due to potential for vandalism. In areas of high population density, the valve spacing along the mainline should be decreased. The design factor in the hoop pressure equation for a valve setting is usually 0.5 or 0.6, but the internal diameter should be checked for passage of internal inspection pigs.

3.4.10. Meters

The metering for CO₂ custody transfer is usually by orifice metering set up in the same way as a natural gas or an LPG ethylene metering facility. The metering is based on orifice differential pressure. This differential pressure and temperature are inputs to an onsite computer that calculates the amount of CO₂ being delivered. The regulators are usually on the downstream side to protect the facility from over pressure and to ensure adequate backpressure in the pipeline. All of the electronic care is housed in an enclosed building. An example of the metering facility recently designed by Universal Ensco is shown in Figure 3.4.

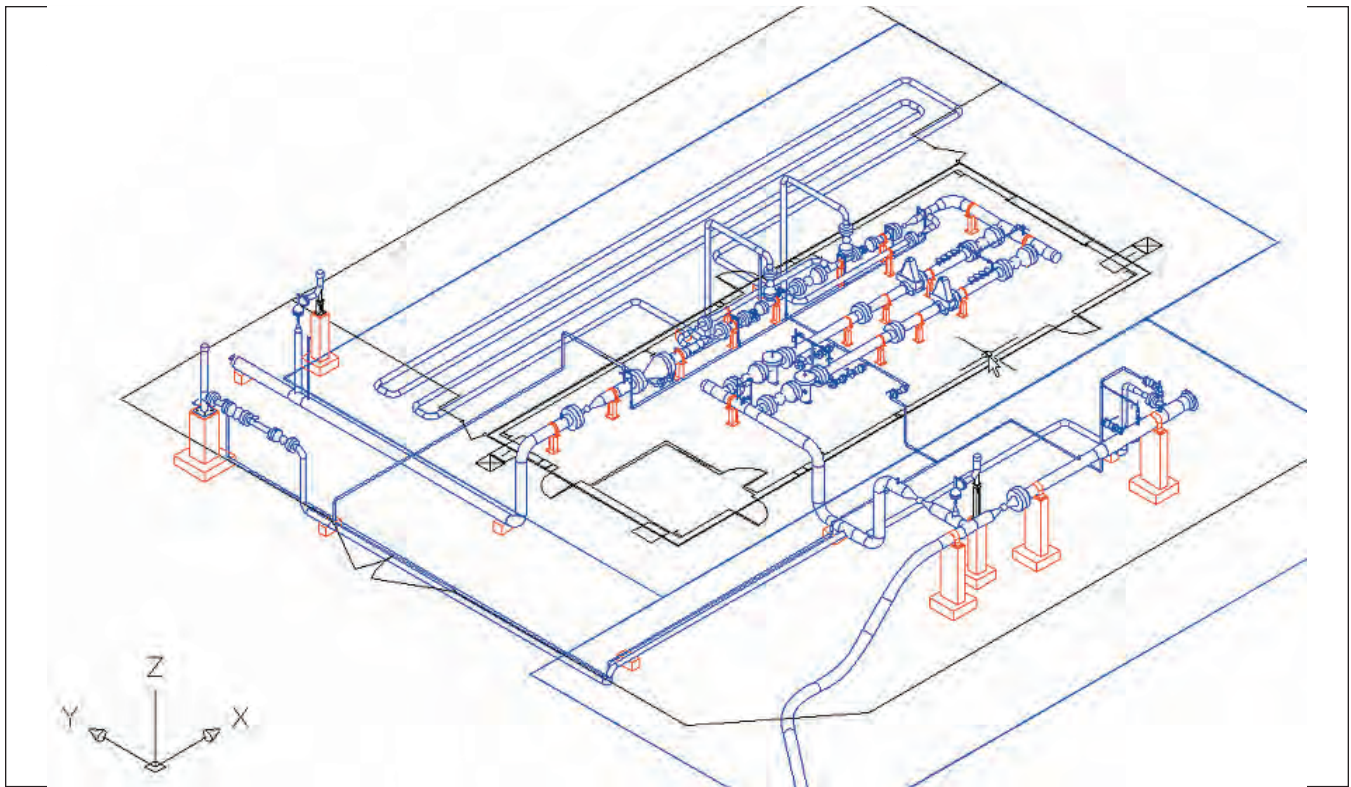


Figure 3.4. Anadarko CO₂ meter-regulator station

3.4.11. Pumps

If a flow rate is required that is in excess of that available, as free flow from the injection plant to the delivery points, an intermediate pump station can be installed. At the pump station, an electric drive, horizontal split-case multistage centrifugal pump can be installed. The pump can be controlled by a variable speed motor control system or by the installation of a pressure control valve. The pump seals need to be designed to account for the low lubrication provided by the CO₂.

4. Permits

As with any construction project, permits from a number of jurisdictional agencies are required for the CO₂ pipeline. The permits can be classified as business, environmental, and utility permits. It is vital that the permit process be started as early as possible. The process requires the involvement of environmental, right-of-way, and engineering specialists. An overview of the necessary permits and the planning required to obtain them follows. The discussion is based on recent experience in Illinois.

4.1. Business Permits

4.1.1. Illinois Commerce Commission

The Illinois Commerce Commission (ICC) is the prime permitting agency for pipelines in Illinois. Unless granted by the federal government, the ICC is the sole authority by which an intrastate pipeline can obtain eminent domain rights. The importance of the power of eminent domain is discussed in Section 5, Right-of-Way.

For a successful application, the ICC grants a “certification in good standing” that allows the pipeline to begin the eminent domain process. To obtain the certification, the ICC requires the application be completed based on Illinois statutes. The application must

1. be properly completed;
2. demonstrate that the applicant is fit, willing, and able to accomplish the project in accordance with Illinois statutes;
3. demonstrate that the project meets the standards for the public’s convenience; and
4. demonstrate that the project is a “public necessity.”

The ICC works in an independent manner and in the past has exercised its authority in a judicious manner. The application process is expected to take approximately 18 to 24 months.

4.2. Environmental Permits

Regardless of the exact route selected, a north-to-south sequestration pipeline in the Illinois Basin will inevitably traverse environmentally sensitive areas. Specifically, the route will cross a number of watercourses that are under the jurisdiction of the U.S. Army Corps of Engineers (U.S. ACOE). The U.S. ACOE will require a permit as part of its procedural review. During the review process, it will ask for comments from a number of other governmental agencies. Those agencies will be looking for specific items of compliance and mitigation in their area of special concern. The U.S. ACOE will review comments and, if reasonable, will include them as stipulations in the permit that it ultimately grants.

The USACOE permits are as follows:

1. Section 404, Dredge and Fill: Jurisdictional wetlands crossed along the route. This section is interpreted liberally by the U.S. ACOE and most applications are approved.
2. Section 404, Dredge and Fill, Section 10, Navigable Waters: Crossing Streams: Major streams are generally permitted as horizontal directional drilled crossings unless there are technical reasons that a crossing cannot be made in this manner. Generally the U.S. ACOE will seek input from the other agencies such as the Office of Fish and Wildlife, Illinois Department of Natural Resources.

The following environmental permits would be needed for the CO₂ pipeline project:

1. Illinois Department of Natural Resources: Rivers, Lakes and Streams Construction Permit
2. Illinois Department of Natural Resources: License to Cross
3. Illinois Environmental Protection Agency: NPDES (National Pollution Discharge Elimination System): Controls the discharge of silt into the surface water by imposing effluent limitations.
4. Illinois Environmental Protection Agency: NPDES Discharge Permit, discharge of liquids to streams during the construction of the pipeline.
5. Illinois Environmental Protection Agency: Construction Storm Water Permit, runoff from the right-of-way during construction of the pipeline.
6. Illinois Department of Agriculture: Agriculture Mitigation Agreement. Permit is not mandatory but is conventionally agreed upon. Note: The ICC looks upon this as a very important agreement to ensure public convenience.

7. County Land Use Department: Land Use Permit. In rural areas a pipeline does not impact normal usage; however, in an urban area, this could be an issue.
8. County Engineering Department: Site Development (Erosion Control) Permit

4.2.1. Plans for Pollution Prevention

The following pollution prevention plans must be submitted for the project:

1. Illinois EPA Pollution Prevention Plan Outline
2. Environmental Construction Mitigation Plan
3. Spill Prevention, Containment and Countermeasure Plan
4. Hazardous Waste/Contaminated Soil Plan
5. Inadvertent Release of Drilling Mud Plan
6. Plan for Unanticipated Historic Properties and Human Remains (Unanticipated Discoveries Plan)

4.3. State and County Highways and Railroad Crossing Permits

Highway and railroad crossing permits are generally routine and can be handled as a matter of course during the project. The large number of permits needed requires organization and on-site meetings with the agencies. Railroad companies require extra depth for crossing due to impact loading, and impact loading calculations must be submitted with the application.

5. Right-of-Way

5.1. Pipeline Right-of-Way/Easement Definition

A pipeline right-of-way is a strip of land over and around pipelines where some of the property owner's legal rights have been granted to a pipeline company. A right-of-way agreement between the pipeline company and the property owner is also called an easement and is usually filed in the public records with property deeds. Rights-of-way and easements provide a permanent, limited interest in the land that enables the pipeline company to operate, test, inspect, repair, maintain, replace, and protect one or more pipelines on property owned by others.

5.2. Negotiations

A company right-of-way representative will be the first contact between the pipeline company and the landowners. The objective of the first contact is for all landowners to understand all proposed features of the pipeline, including the alignment, underground depth, pipe size, temporary and permanent width of the easement, and aboveground equipment prior to construction. During these contacts, the representative will explain the project and the proposed process between the pipeline company and the landowners. If possible, the company representative will attempt to reach agreement with the landowner for negotiating an easement and will request permission to survey and stake the preliminary route for environmental, engineering, and construction evaluations.

The company will compensate each landowner for these rights:

1. The privilege of establishing a permanent easement across the landowner's property. Payment for the easement will be based on market value principles and the number of acres required. Although the company will obtain a permanent easement, the landowner will retain ownership and use of the land.
2. Damages to crops, grazing lands, timber, or any structures directly caused by the construction and maintenance of the pipeline. Construction damages will be paid on the area affected by the actual construction. The settlement for damages to crops either can be paid in advance, based on records of local yields, or can be paid after construction, based on the actual crop losses.

After the conditions and the amount of compensation for an easement are reached and the easement agreement is executed, payment will be issued to the landowner.

5.3. Eminent Domain

The company will negotiate with each landowner under a voluntary "willing buyer-willing seller" process. Should the process break down, the company could have the option of seeking help through the Illinois court system. This option is available only after the ICC has approved the project as one that is necessary and beneficial to the state. If the ICC approves the project and an agreement with the landowner cannot be reached, the easement for the property may be acquired using the state's eminent domain authority. A more complete discussion of this permit is covered in Section 4, Permits.

The procedures within the acquisition process leading up to the use of eminent domain are very structured. The pipeline company must demonstrate that it has negotiated in good faith on the alignment submitted to the court in a request for eminent domain. This demonstration would include being able to document that the route was varied to accommodate the special requirements of the landowner and that a fair offer was submitted. It is common practice to obtain an appraisal and an abstract for each property condemned. A registered surveyor prepares a certified plat detailing the route, and this plat is included in a letter to the landowner as part of the documentation in the final offer.

Filing a complaint in circuit court starts the condemnation process. The complaint must set forth authority, purpose, description, and names in regard to the pipeline and property being condemned. The property owner may raise a challenge as to the necessity of taking the property, whether the taking is for public use, whether the condemner made a bona fide attempt to offer fair compensation, or on any other basis relating to the right of the plaintiff to condemn.

These challenges are raised as a "traverse and motion to dismiss." The traverse denies the allegations of the complaint; the motion to dismiss points out certain specific objections that the property owner has to the condemnation. The judge rules on the issues raised in the traverse and motion to dismiss. There are no procedural rules that establish when a defendant must file a traverse and motion to dismiss or when a court must adjudicate the issues raised by such a pleading. As with other civil litigation in Illinois, both the condemner and the landowner in an eminent domain action are subject to discovery, including interrogatories, document requests, and depositions. Matters typically subject to discovery include the designation of expert witness, information related to witnesses, and the basis for the appraiser's opinions regarding value. Assuming the traverse and motion to dismiss is denied, the case proceeds to a trial to determine just and reasonable compensation. If either side so requests, a jury trial is held; otherwise, the trial is presented to the judge. A trial may take several days. The only issue is the amount of compensation. Upon the award, both the condemner and the landowner may appeal the determination.

Regardless of which party appeals the judgment, the condemner may enter the condemned property as long as a bond is posted in the amount of the compensation.

The estimated time for condemnation proceedings in Illinois varies by county and is influenced by the number of condemnations in the county. Because the proceedings are formal trials, there are multiple opportunities for the defendants to introduce delays through procedural maneuvering. A reasonable duration for planning purposes for the legal portion of the condemnation proceedings is 12 months.

5.4. Right-of-Way Widths

The right-of-way agreement or easement defines the width of the permanent easement and any temporary work space above the permanent easement to support the operations necessary to construct the pipeline. The easement will describe additional areas where extra temporary work space is required for construction at crossings and other special areas. The pipeline is not necessarily located in the center of the easement.

Any pipeline can be installed using a limited right-of-way, but the cost of construction and operation increases dramatically in such a case. Prior to starting any permitting and environmental activity, the width of the right-of-way should be designed to take into account such things as landowner operations, environmental conditions, anticipated weather conditions at the time of construction, and the diameter of the pipeline.

In the heavily farmed areas of Illinois, the width of the right-of-way needs to be increased to accommodate the handling of topsoil and the crossing of drain tiles. An approximation for permanent easement and temporary work space needed for a central Illinois pipeline project are shown in Table 5.1. These widths are based on knowledge of the existing land use, environmental requirements, and experience on recent projects in Illinois.

Table 5.1. Pipeline right-of-way easement and work space in southern Illinois

Pipeline Right Of Way Easement And Work Space Southern Illinois						
Dia (inches)	Permanent Easement (ft)	Subtotal			Allowance For Extra Temporary Workspace (%)	Total Acres / Mile
		Extra Temporary Work Space (ft)		Acre/mile		
4	25	25	50	6	10	6.6
6	25	25	50	6	10	6.6
8	30	30	60	7.3	10	8
10	30	30	60	7.3	10	8
12	30	40	70	8.5	10	9.3
16	40	50	90	10.9	10	12
18	40	50	90	10.9	10	12
20	40	50	90	10.9	10	12
22	40	50	90	10.9	10	12
24	40	50	90	10.9	10	12

6. Construction

6.1. General

Installing a long distance pipeline is accomplished in an assembly line process that moves along the pipeline route. The assembly line consists of equipment and personnel organized into what is termed in the industry as a pipeline spread. The spread is staffed and supplied based on the pipeline diameter length, schedule, terrain, permit and land requirements, and the anticipated weather and groundwater conditions. The spread begins at one end of the pipeline and works toward the other end with the specialty crews commencing work chronologically one after another. Once all of the crews are operating smoothly, the spread moves along the pipeline route at a rate of 1 to 2 miles per day. During a peak production period, a spread can install 3 miles per day.

Generally, the pipeline owner will contract with an engineering procurement and construction management company to supervise a pipeline construction contractor during the construction phase of the project. The construction contractor is responsible for organizing the construction spreads and the specialty crews performing work within each spread. The order in which the specialty crews perform work can vary due to terrain, weather considerations, groundwater conditions, and permit stipulations, but they generally follow this procedure:

1. Pre-construction activities and survey re-stake
2. Clearing and grading
3. Crossing, road and stream
4. Stringing and bending
5. Ditching
6. Pipe gang, facing and lineup
7. Firing line, welding and joint coating
8. Lower in and backfill
9. Cleanup
10. Tie-ins and fabrications
11. Testing and drying

These pipeline construction spread activities are illustrated in Appendix C1.

The construction spread will be staffed to support the desired rates of progress. Typically, the smaller-diameter pipelines (4 inches) will have a staff of about 150; a large-diameter pipeline (36 inches) will have about 500. A support staff monitoring the contractor for contract compliance, quality, landowner issues, and environmental will be staffed at about 20% of the construction staff.

After the ditch, pipe gang, firing line, and lower backfill crews reach the end of the spread, some portion of these crews and their equipment are rolled back to support the tie-in and cleanup operations.

6.2. CO₂ Welding and Refrigeration Issues

The properties and characteristics of CO₂ require the modification of standard pipeline construction practices in two areas: weld procedure development and the line fill process.

A welding procedure must be developed that provides adequate toughness to resist brittle failure in a leak event while maintaining the necessary field practicality. The project engineer, metallurgist, and a construction representative can work together to design a qualified procedure. A weld procedure is qualified by testing it on the pipe as shown in Figure 6.1.

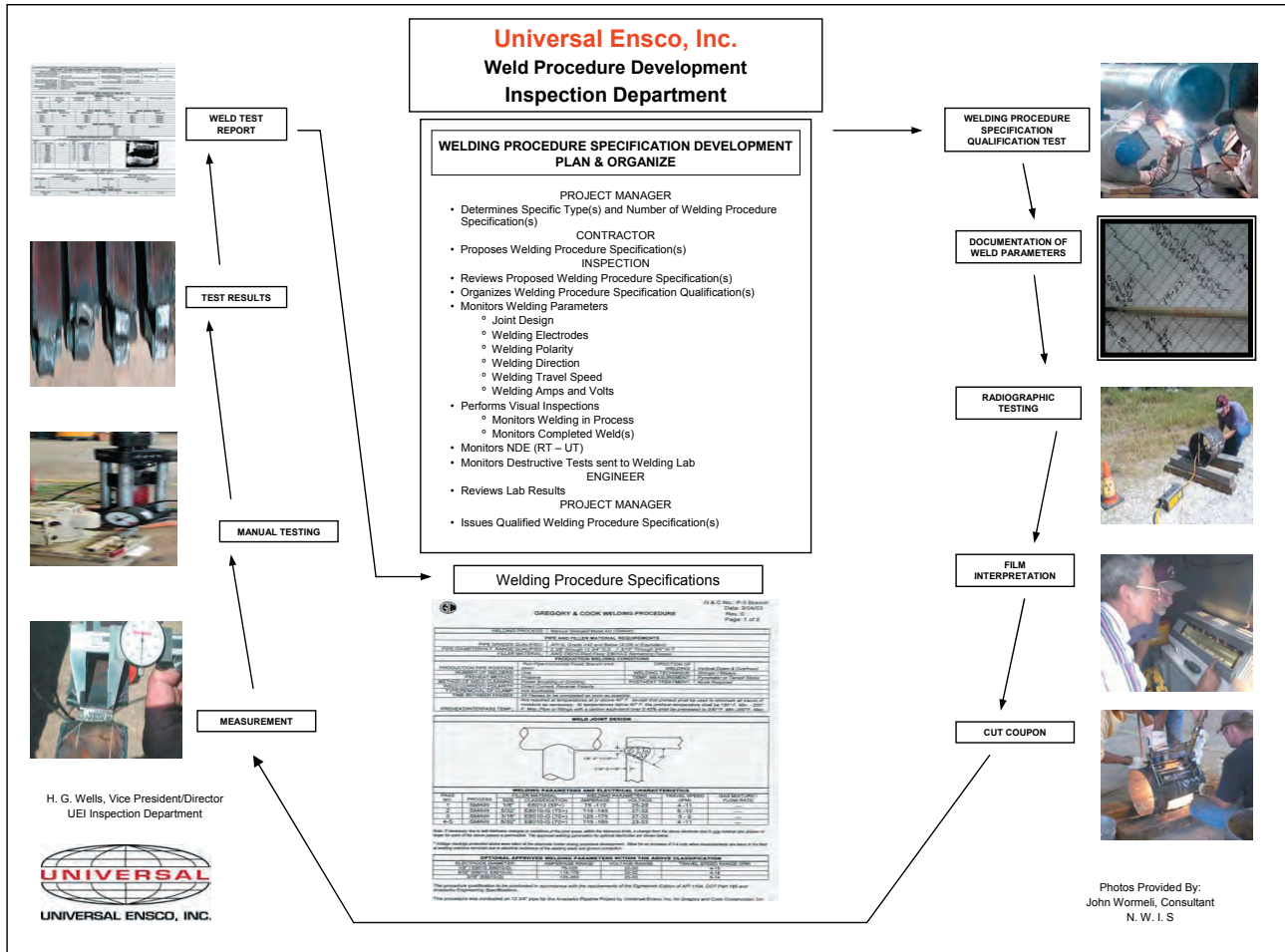


Figure 6.1. Process for testing the weld procedures

During the filling process, the refrigeration property of CO₂ must be considered to avoid dry ice. The filling process has two purposes. The first purpose is purging the pipeline of dry air by using CO₂, and the second is to pack the pipeline with CO₂ to the minimum operating pressure. The purging part of the filling process can also be handled in two ways. Either CO₂ can be delivered from the process as a gas at ambient temperature, or it can be throttled through a control valve into the pipeline. In the throttling method it is important that the refrigeration effect of CO₂ be considered (Figure 6.2).



Figure 6.2. CO₂ venting during pipeline purging

The refrigeration effect can be mitigated by using a line heater to raise the temperature of the CO₂. The alternative to the line heater is to maintain a backpressure above approximately 100 psig. The arrival of the CO₂ will be visible at the vent site as the vapor that condenses when the refrigerated CO₂ begins to discharge. CO₂ could form dry ice (i.e., solid CO₂), if the pressure is lowered too fast (Figures 6.3 and 6.4).

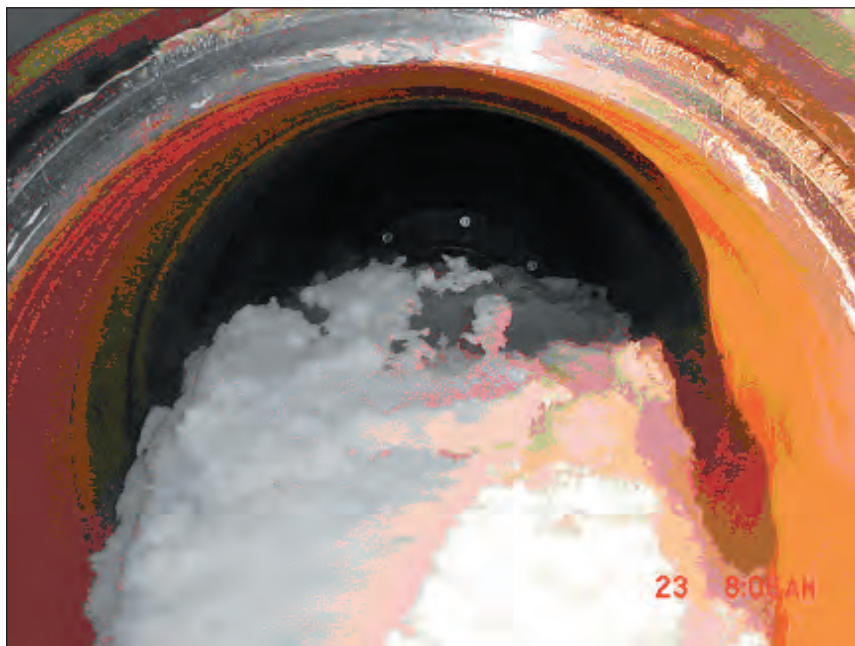


Figure 6.3. Dry ice formed by depressuring too rapidly



Figure 6.4. Pig damage from depressuring too rapidly

6.3. Agricultural Issues in Illinois

The terrain of central and southern Illinois is flat to rolling with a high percentage cleared for farming operations. Unfortunately, the subsurface and these farming operations can cause major difficulties in pipeline construction, including

1. unstable ditch conditions,
2. intermittent high groundwater in certain areas, and
3. drain tiles used for farming low areas.

A thorough investigation into the subsoil conditions should be made during the planning phase to determine the extent of ditch stability issues that may arise. If these ditch issues are expected to be consequential, then the right-of-way should be laid out to allow for the welding to proceed ahead of the ditching so that the ditch is open for the minimum amount of time and is closed up at the end of each day. If the conditions are isolated and dependent on weather conditions, then the contractor can slope the ditch and use a backhoe or crane to clam the ditch in advance of the lower-in (Figure 6.5).



Figure 6.5. Backhoe reaches over pipe to clam out ditch

Where the water table is high, water will accumulate in the trench during the weld operation. Prior to lowering, most of this water will be pumped out of the trench, but during lower-in and before backfill, the water will continue to accumulate. To isolate the water and prevent it from being carried forward by the backfill operation, the contractor will plug the pipe in intervals (Figure 6.6). This procedure will also stabilize the pipe during backfill operations.



Figure 6.6. Crane plugs pipe during backfill operations

Set-on weights provide a solution in areas that cannot be effectively dewatered (Figure 6.7). The weights are costly and require logistical consideration. First, they must be manufactured in advance and in sufficient quantity to be available when needed. Second, before the pipe is lowered in, an adequate quantity of weights must be delivered to the right-of-way at the necessary locations. Experienced supervisors must oversee the field situation to ensure that the team uses the minimum number of weights necessary to maintain the proper cover.



Figure 6.7. Set-on weights in a low areas where sand subsoil layer is on top of a deep layer of clay subsoil

The integrity of the existing drain tiles must be maintained across the full right-of-way and during the entire construction period. As shown in Figure 6.8, the string crew is working over the existing drain tiles at a location where temporary drain tile segments are in place behind the ditching operation. These temporary tiles will be removed during lower-in and replaced with permanent repairs after rough backfill is completed. If topsoil on the working side of the easement (Figure 6.8) is removed, the probability is increased that the heavy equipment will damage the drain tiles.



Figure 6.8. String crew working over existing drain tiles where temporary drain tiles (white segments) are in place

Areas with poor soil conditions at crossings can be determined in advance by interviews with county engineers, interviews with farmers, and by completing geotechnical studies. The severity of the poor soil situation will depend on the level of groundwater at the time of crossing. Contracts can be written by the engineer to risk-share the impact of the unknown groundwater situation with the contractor.



Figure 6.9. Road bore in a sandy area with high groundwater showing required sheet pile and ground dewatering systems

If possible, issues such as the ditch, high groundwater, and drain tile problems shown in Figure 6.5 through Figure 6.9 are best addressed, and difficulties minimized, by selecting a construction period beginning mid-summer and ending in the fall. During this period, rain patterns are favorable. In addition, the warm temperatures and the growing vegetation combine to minimize the impact of rainfall events. This time window of July through October does, however, present several minor issues that need to be considered:

1. The short summer construction season limits each spread length to 100 to 200 miles. Two contractors can mobilize in late June for kickoff after July 4, finish the mainline by September 15, and then test, tie-in, and cleanup by October 31.
2. A large-diameter pipeline requires that pipe be delivered to the pipe yard in April when frost-law road hauling restrictions could be in place. The yards need to be located along major roadways to limit the possibility of being subject to frost regulations and to mitigate exposure to the extra traffic safety issues related to poor visibility associated with the height of the corn along the roadways.

7. Operations

CO₂ pipelines have operated with very few incidents. Statistics on pipeline incidents for both natural gas and hazardous liquid pipelines, which include CO₂, are available from the Office of Pipeline Safety, U.S. DOT. Statistics for the period from 1986 to 2001 on pipeline incidents in the United States are summarized in Table 7.1. The reported safety record of CO₂ (zero fatalities and zero injuries) was excellent for this period.

Table 7.1. Pipeline incidents in the United States, 1986 to 2001

Pipeline	Natural gas transmission (1986–2001)	Hazardous liquids (1986–2001)	CO ₂ (1990–2001)
Incidents (no.)	1287	3035	10
Fatalities (no.)	58	36	0
Injuries (no.)	217	249	0
Property damage (US\$)	285,300,000	764,200,000	469,000
Incidents per 1,000-km pipeline (no./yr)	0.17	0.82	0.32
Property damage per 1,000-km pipeline (US\$/yr)	37,000	205,400	15,200

The envisioned CO₂ pipeline system will consist of receipt facility lateral pipelines, a main pipeline, booster facility if needed, and delivery lateral pipelines facilities. The operation of these facilities will be accomplished by a properly equipped staff of specialists based at a location removed from the pipeline and its facilities.

Personnel will make regular visits to all parts of the unattended facilities to ensure a safe operation. These unattended facilities are monitored 24 hours per day by a supervisory control system. The pipeline facilities are at one end of the system, and the supervisory control center is at the other end. The pipeline flow conditions and the facilities (valves and meters) are monitored and controlled from the control center. Trained pipeline operators staff the center 24 hours per day. The operators look for upset conditions and data inconsistencies, and they monitor pressure and flow conditions that could indicate leaking.

The public can contact the pipeline control center by telephone if they observe an emergency condition. The control center can shut down the pipeline if it is determined that leaking exists. The control center will be in contact with the receipt and delivery operations to ensure that the incoming and outgoing pipeline flows match those specified. The CO₂ line will have a considerable amount of leeway in “input versus output” due to the compressibility of the CO₂. This compressibility will allow the pipeline to be “packed” or “unpacked” to support both planned and unplanned operational changes.

To avoid the most common source of leaks—“third-party” damage—and to ensure prompt reporting of leaks, the pipeline will conduct a “public outreach” program. The pipeline emergency phone number is posted and maintained on signs at all pipeline, road, railroad, and water crossings. Public agencies such as fire, police, and civil defense are kept informed of the pipeline location, the telephone numbers of the control room, and the telephone numbers for the local pipeline operating personnel. Residents who live along the pipeline route will periodically be mailed a flyer that identifies the pipeline company; provides facts on the product characteristics; advises residents on how to determine the location of the pipeline; gives information describing the method of identifying a leak; describes procedures in case of a suspected leak; and provides the control room contact information in the event of an emergency. The flyer is also sent to local contractors who are likely to be excavating near the pipeline. A pipeline company Web site also provides all of this information.

In another effort to avoid damage by third parties, the operating company will be enrolled in a “call-before-you-dig” program. In general, these programs require all persons to call a “call-before-you-dig”

center at least two working days prior to the start of excavation. They require the pipeline companies to be members as well. The program in Illinois is called JULIE. JULIE (Joint Utility Locating Information for Excavators), also known as the “Illinois One-Call System,” is a not-for-profit corporation that provides professional and non-professional (i.e., homeowners) excavators with a toll-free number (1-800-892-0123) for locating and marking of underground facilities at no charge to the excavator. JULIE serves as a notification service for underground facility owners, taking information about planned excavations and distributing this information to its membership. Following this notification, it is the responsibility of each facility owner to mark the location of the relevant underground facilities at the excavation site. JULIE neither owns nor marks underground facilities.

Pipeline maintenance crews also work to ensure the integrity of pipeline infrastructure. Qualified personnel hired or contracted by the pipeline company ensure that welding operations, valve inspections, pipeline repairs, corrosion prevention system checks, and electronic equipment maintenance (among many other functions) are performed safely and according to pre-established procedures. These people work on the daily maintenance of the system and to assist with major pipeline repair and replacement projects. Pipeline employees are also trained in emergency response procedures and work with local emergency responders if a pipeline accident occurs. Venting of a CO₂ pipeline is required during filling and some depressuring operations (e.g., Figure 7.1). Prior to venting, local agencies and landowners should be notified.



Figure 7.1. CO₂ venting from mainline block valve site

A company or a team that is built from the ground up can accomplish the operation of the pipeline, or it can be subcontracted to a third party. The grassroots operations can be an independent, stand-alone operation, part of the CO₂ capture plants, or part of the CO₂ geological storage operation.

Because of the complexities of operating a pipeline in a heavily farmed area such as central and southern Illinois, a contractual arrangement for operation (and possibly ownership) with a relevant company is a better option than forming a new pipeline company. Relevant companies would be those companies that are currently operating CO₂ and/or LPG pipelines in the Midwest. A partial listing of companies operating CO₂ pipelines includes BP, Kinder Morgan, Transpectos, Exxon Mobil, Trinity LLC, and Anadarko. A partial listing of Midwest LPG pipeline operators includes Texas Eastern Products Pipeline, Marathon, Ashland, Exxon Mobil, Enterprise, Koch, and Buckeye. Clearly, a number of companies exist that could be considered as possible operation candidates for the operation of the CO₂ pipeline.

The LPG companies that operate in Illinois or nearby areas are the best candidates for this operation for the following reasons. First, companies are accustomed to operating in accordance with the previously discussed U.S. DOT 195 standard. Second, they understand the characteristics of high vapor pressure liquids similar to CO₂. The third and most important reason is that they have a base of operations in a heavily farmed area that can be expanded to accommodate the CO₂ pipeline operation much more economically than can be done by a newly formed pipeline company.

8. Cost Estimate

8.1. Introduction

The previous sections present the many elements that impact the cost for the CO₂ pipeline system under consideration. Once a proposed route has been selected and the distance for the pipeline lay has been determined, the primary cost consideration is the selection of the pipe diameter. Pipeline diameter is the key variable in establishing the flow capacity of the system. To clearly demonstrate the relationship between pipeline diameter and cost, a unit cost or per mile cost was developed for right-of-way, materials, and construction using varied pipeline diameters. These costs and the basis for their determination are discussed in the sections that follow. Using the total per-mile costs, a percentage factor, based on experience, was applied to account for the additional services necessary to install the pipeline. For pump stations, the cost per brake horsepower (BHP) was developed based on the costs for similar pump stations currently under construction in Pennsylvania. The pipeline operating cost projected for a range of diameters is based on a current estimate for a similar LPG pipeline project in Illinois. Maintenance cost for the pump stations was estimated using data provided by industry contacts, and power costs were calculated using an industry rule-of-thumb.

8.2. Pipeline Right-of-Way Cost

The cost to acquire right-of-way is directly related to the value of the property plus the costs associated with the interruption of business currently associated with the property. Although fair price can always be legitimately debated, experience has shown that a reasonable budget for right-of-way easements can be developed by using the actual value of the land that is impacted by the construction process. The cost associated with interruption of business in agricultural areas can be calculated based on an estimate of the years of crop loss. Combining these two cost elements gives a reliable subtotal that should be reviewed and factored for possible condemnation costs. Due diligence should be applied to this aspect of the process since the expense of condemnation proceedings can be considerable.

Based on the conceptual route, a limited analysis of recent land sales and crop production data was performed for the counties involved. The value of farmland is a function of the soils/productivity, demand, type of end user, the investment market, and the interest of the seller. Soil productivity is maintained in the county Supervisor of Assessments Office. Each parcel is evaluated, and a record of the productivity index is established. This step is key in the assessment of the land value and a major element in the appraisal process that is initiated prior to the sale of the property. The productivity index is reflected in the crop yield data shown in Table 8.1. That information shows that the relative quality of soils, production, and the land values are highest at the northern end of the conceptual route and tend to decrease toward the southern end of the route. There are, however, potential exceptions within each county.

Table 8.1. Land value and crop information, Illinois, as of July 23, 2004

County	Crop	Yield (bushel/acre)	Land value (\$1,000)
Tazewell	Corn	151	3-5
	Soybeans	52	
Logan	Corn	154	3-5
	Soybeans	52	
Sangamon	Corn	194	3-4.5
	Soybeans	48	
Christian	Corn	140	4.5+
	Soybeans	49	
Montgomery	Corn	127	3-4
	Soybeans	45	
Shelby	Corn	151	Best, 3.5; lower, 2.5-3
	Soybeans	52	
Fayette	Corn	86	East edge, 2.8-3.2; lesser quality, 2-2.5
	Soybeans	31	
Marion	Corn	133	1.5-2
	Soybeans	28	
Clay	Corn	69	1.2-1.8
	Soybeans	23	
Wayne	Corn	78	1.5; higher for bottomland
	Soybeans	25	

8.2.1. Land Values

For the 200-mile conceptual case, the application of the values in Table 8.1 results in the following estimate for land values: \$3,750/acre for the first 120 miles and \$2,850/acre for the final 80 miles. Overall, the cost for land is approximately \$3,150/acre.

8.2.2. Crop Loss Payments

In the area where construction occurs, the crop loss payments for the first year are for a 100% crop loss. There is considerable debate regarding the impact to crops in subsequent years. There is also a lack of unanimity on the issue of determining an appropriate price for the crop in subsequent years. It is safe to budget 100% for damage in Year 1, 75% for residual damage in Years 2 and 3, and 50% for residual

damage in Years 4 and 5. This budget results in a projected damage payment of 3.5 times the average crop yield of the acreage occupied during construction. This compensation is often disbursed at the initiation of construction to expedite the right-of-way acquisition process.

Corn is generally a more valuable commodity than soybeans. Therefore, the most conservative method of estimating crop loss values involves using the per-bushel price of corn. Per-bushel corn prices have fluctuated from \$1.99 in November 1994, to over \$5.00 in July 1996, to under \$2.00 in 2000. Prices are currently at \$2.50 per bushel. A reasonable budget value for corn is \$3.00 per bushel. Based on the data in Table 8.1, the average corn production for the route is about 125 bushels/acre. Applying these guidelines provides a crop loss payment of approximately \$1,300/acre.

The easement cost of \$3,150/acre and the crop loss payment of \$1,300/acre are combined with the acres per mile for the range of pipe diameters shown in Table 5.1. In addition, an experience factor is applied to capture the cost of the probable condemnation proceedings. The total right-of-way costs are shown for the range of diameters are shown in Table 8.2.

Table 8.2. Pipeline right-of-way cost

Diameter (inches)	(\$/mile)	(\$/diameter inch/mile)	(million \$/200 miles)
4	36,713	9,178	7.3
6	36,713	6,119	7.3
8	44,500	5,563	8.9
10	44,500	4,450	8.9
12	51,731	4,311	10.3
16	66,750	4,172	13.4
18	66,750	3,708	13.4
20	66,750	3,338	13.4
22	66,750	3,034	13.4
24	66,750	2,781	13.4

8.3. Pipeline Material Cost

Pipe is the primary material cost for the project. Pipe cost can be estimated by determining the weight of the pipe needed, estimating cost per unit weight of the pipe. For the conceptual CO₂ project, the proposed wall thickness for the pipe diameter was presented in Section 3 under pipe wall thickness. In that section, the wall thicknesses were calculated to allow for increased wall thickness in areas of congestion or areas of special construction technique. The estimated cost of pipe per ton is assumed to be \$950/t. Historically, this price would be considered to be high, since pipe sold for \$700 to \$750/t for an extended period of time. Over the past year, the price of pipe has rapidly escalated to \$1,050 to \$1,100/t. There are signs that this price will moderate over the next few years; however, it is unlikely that the cost will be below \$900/t in the foreseeable future. The unit price for pipe is adjusted by a 15% factor to allow for CO₂ metallurgy requirements, taxes, and delivery. Because the pipeline requires a number of mainline block valves and needs a minimum of two flow-rate meters (inlet and outlet), a cost allowance was determined for each pipe diameter. These costs were allocated into the unit cost per mile and ranged from \$5,750/mile for 4-inch pipe and \$18,400/mile for 24-inch pipe. The pipe cost and block valve cost are combined and shown in Table 8.3.

Table 8.3. Pipeline material cost

Diameter (inches)	(\$/mile)	(\$/diameter inch/mile)	(million \$/ 200 miles)
4	24,303	6,076	5
6	47,630	7,938	10
8	79,370	9,921	16
10	115,424	11,542	23
12	159,084	13,257	32
16	247,199	15,450	49
18	310,766	17,265	62
20	381,893	19,095	76
22	460,465	20, 930	92
24	546,136	22,756	109

8.4. Pipeline Construction Cost

The construction cost estimate for the pipeline is based on recent experience and discussions with union contractors who are familiar with the area. To obtain an approximate cost, several contractors were given a conceptual route map and were asked to provide an all-inclusive lay price. Discussions with the contractors indicated that it would be better to divide the unit pricing into three different types of construction: agricultural lay, congested lay, and special crossings for roads and rivers/streams. Unit costs were thus developed for these three types of construction. The vast majority of the route will be open agricultural lay. A rough estimate determined that only about 20,000 feet of congested lay and about 6,500 feet of special crossing techniques would be required. These variables were applied to each diameter. A 5% factor has been added to account for the cost associated with the non-destructive testing of the welds. The combined totals are shown in Table 8.4.

Table 8.4. Pipeline construction cost

Diameter (inches)	(\$/mile)	(\$/diameter inch/mile)	(million \$/ 200 miles)
4	85,071	21,268	17
6	115,915	19,319	23
8	141,753	17,719	28
10	173,476	17,348	35
12	210,730	17,561	42
16	275,533	17,221	55
18	306,206	17,011	61
20	336,354	16,818	67
22	365,978	16,635	73
24	395,601	16,483	79

8.5. Pipeline Services Cost

The pipeline will require professional services including but not limited to engineering, survey, mapping, right-of-way acquisition, legal, permitting acquisition, environmental consulting, geotechnical analysis, vendor inspection, and construction inspection. Based on extensive experience in project management,

it is recommended practice to base the estimate for these services on the subtotal of the cost for right-of-way, materials, and construction. For the smaller 4-inch line, the percentage required for professional services is approximately 20% and, for larger lines, is 12%. These costs are shown in Table 8.5.

8.6. Pipeline Total Cost

Combining the costs for right-of-way (Table 8.2), materials (Table 8.3), construction (Table 8.4), and services (Table 8.5) provides the total projected cost for the pipeline (Table 8.6). Table 8.7 is a cost summary that shows the cost per mile of right-of-way, material, construction, services, and total as they relate to the range of diameters.

Table 8.5. Support services cost

Diameter (inches)	(\$/mile)	(\$/diameter inch/mile)	(million \$/ 200 miles)	Factor (%)
4	29,217	7,304	6	20
6	38,049	6,341	8	19
8	47,812	5,977	10	18
10	56,678	5,668	11	17
12	67,447	5,621	13	16
16	88,422	5,526	18	15
18	95,721	5,318	19	14
20	102,050	5,102	20	13
22	107,183	4,872	21	12
24	121,018	5,042	24	12

Table 8.6. Total cost

Diameter (inches)	(\$/mile)	(\$/diameter inch/mile)	(million \$/ 200 miles)
4	175,304	43,826	35
6	238,307	39,718	48
8	313,435	39,179	63
10	390,078	39,008	78
12	488,992	40,749	98
16	677,905	42,369	136
18	779,444	43,302	156
20	887,047	44,352	177
22	1,000,375	45,472	200
24	1,129,505	47,063	226

Table 8.7. Summary cost

Diameter (inches)	Right-of-way (\$/mile)	Materials (\$/mile)	Construction (\$/mile)	Services (\$/mile)	Total cost(\$/mile)
4	36,713	24,303	85,071	29,217	175,304
6	36,713	47,630	115,915	38,049	238,307
8	44,500	79,370	141,753	47,812	313,435
10	44,500	115,424	173,476	56,678	390,078
12	51,731	159,084	210,730	67,447	488,992
16	66,750	247,199	275,533	88,422	677,905
18	66,750	310,766	306,206	95,721	779,444
20	66,750	381,893	336,354	102,050	887,047
22	66,750	460,465	365,978	107,183	1,000,375
24	66,750	546,136	395,601	121,018	1,129,505

8.7. Pump Station Cost

Under certain conditions, it may be preferable to use a smaller pipeline and install a pump station to increase capacity. In this case, the flow rate will require additional pressure boosting due to the increased pressure drop in the smaller pipeline. The cost savings of the smaller pipeline versus the larger pipeline (Table 8.6) will be partially offset by the cost of the pump station(s) and their additional power and operating costs.

The capital cost for a pump station is directly proportional to the installed BHP. Low-pressure stations for crude oil are around \$800 to \$900/BHP, whereas the stations used for CO₂ and refined products cost around \$1,000/BHP. This capital cost per BHP has been confirmed on a current, multi-station project in Pennsylvania.

The additional pressure drop (due to friction) of the smaller pipeline determines the additional BHP required. This friction drop and BHP for the additional pump station(s) can be determined by using Figures 3.3 and 3.4. For example, if a flow rate of 450 million cubic feet per day is required through 200 miles, a 16-inch pipeline with a pump station (total cost of \$134 million from Figure 3.4) can be used instead of a 20-inch pipeline (total cost \$176 million from Figure 3.4). The required BHP of the pump station is required to determine the cost of the station(s) and the true capital savings of the 16-inch pipeline compared with the 20-inch pipeline. Referring to Figure 3.2, for a flow rate of 450 million cubic feet per day, the pressure drop per mile for a 16-inch and 20-inch pipeline would increase to 16 psi/mile from 5 psi/mile. The BHP of the station could be determined by using Figure 3.3 at 450 million cubic feet per day and 16-inch pipe diameter to be 75 BHP/mile.

The receipt facility would still deliver the same flow and pressure to the pipeline. As discussed previously in Section 3, it is reasonable to assume a receipt pressure of 2,500 psig and a minimum pressure of 1,500 psig, resulting in 1,000 psig differential. The friction drop in the 20-inch line will deliver the CO₂ the total distance without additional pumping. However, the 16-inch pipeline would consume the 1,000 psig of available pressure at a point 62.5 miles downstream from the receipt point. At that point, pump station(s) must provide the remaining pressure to reach the delivery point, which is an additional 137.5 miles. At 75 BHP/mile, required pumping capacity is approximately 10,000 BHP. At

\$1,000/BHP, the pump stations will cost \$10 million. The true cost of the 16-inch pipeline will be (from Table 8.6) \$144 million versus \$176 million for a 20-inch pipeline.

8.8. Operating Cost

Pipeline operating costs will be nominal compared with installation cost. An operating company recently prepared an estimate for a 140-mile, 6-inch LPG pipeline expansion that incorporates into an existing operation. Adjusted for escalation and new regulations, this estimate was \$480,000/yr or about \$1,000/ mile for a 6-inch pipeline. Normalizing this value to unit diameter gives \$667/inch diameter/mile per year. Based on this information, operating costs have been summarized in Table 8.8 on a per-mile and a 200-mile basis for pipelines constructed of 4- to 24-inch diameter pipe.

Table 8.8. Annual pipeline operating costs

Diameter (inches)	(\$/mile)	(\$/200 miles)
4	2,667	533,333
6	4,000	800,000
8	5,333	1,066,667
10	6,667	1,333,333
12	8,000	1,600,000
16	10,667	2,133,333
18	12,000	2,400,000
20	13,333	2,666,667
22	14,667	2,933,333
24	16,000	3,200,000

The cost of operating a pump station includes the cost of the maintenance of the facilities and the cost of power to drive the facilities. The maintenance cost is a function of the cost of the initial installation, and the power cost is a function of the actual power consumed. Discussions with operating companies indicate that the yearly cost of personnel and maintenance for an electric station is approximately 5% of the installation cost. Because installation costs are about \$1,000/BHP, yearly maintenance costs will be approximately \$50/BHP. For the 200-mile, 16-inch pipeline with approximately 10,000 BHP, the yearly maintenance cost is projected to be approximately \$500,000/year.

Assuming that the installed stations operate continuously 24 hours per day, 365 days per year, then the power cost is also a function of the cost of the BHP installed and the unit cost for power. A rule of thumb for electric power costs is that 1 BHP operating for 1 yr will consume \$240/yr of electricity at a cost of \$0.03/kWh. If the cost of electricity is assumed to be \$0.045/kWh for a modern large load, then 1 BHP operating for 1 yr will cost \$360/yr. Therefore, the electric power cost for the example 16-inch pipeline with 10,000-installed BHP would be \$3.6 million/yr.

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Appendix C1. Construction Photo Gallery



Figure C1.1. Pipe yard

Pipe yards are stockpile locations near the pipeline route. Pipe yards are vital to the logistical support for a pipeline spread, and, ideally, all of the pipe is accumulated before construction begins. As a minimum, the yards must be supplied in a manner that supports construction.

The yards are located along the route at a spacing that is dependent on the diameter of the pipeline. The smaller the diameter is, the further apart the spacing needs to be. On a recent 120-mile, 16-inch pipeline, only two pipe yards were used. On an 880-mile, 36-inch pipeline, the yards were spaced 30 to 40 miles apart. Yards for smaller pipe diameter do not have to be adjacent to the route. Pipelines larger than 16 inches generally need to be close to the route to minimize hauling. If practical, the yard should be located near an existing railroad spur off a major roadway at a site developed for other industrial use.



Figure C1.2. Spread construction yard

To mobilize and operate a major spread requires a base of operation. The base is set up by the contractor to serve as a point for marshalling personnel and equipment, a location for delivery of miscellaneous materials, a site for fabrication and testing of welders, and a shop for equipment maintenance.

The yard also serves as the location for the construction managers, quality inspectors, surveyors, and environmental inspectors. The location of this yard is generally on the edge of a town or city near the route and is at the middle of the spread.



Figure C1.3. Survey re-stake

The pipeline company—through its engineering, construction management, and procurement company—will stake the pipeline centerline and right-of-way limits well in advance of construction. This preliminary staking permits the environmental inspectors to ensure that the route complies with the permit restrictions.

These re-stake crews proceed along the right-of-way supported by a right-of-way agent who is making advance contact with the tenants and landowners along the route. The right-of-way agents can also address any landowner issue of dispute. The crews use GPS survey equipment to navigate and stake the points based on georeferenced electronic drawings that were prepared in compliance with the permits and right-of-way agreements.



Figure C1.4. Topsoil stockpiling progress

The cleaning crew includes a small fence crew that constructs temporary gaps or gates where the pipeline crosses existing fences. These gates are kept closed at all times by crews following behind the fence crew.

The clearing crew removes obstructions from the right-of-way so that it is a suitable worksite for the work crews that follow. Generally, the area is completely cleared of timber, brush, and other vegetation. Timber, if marketable, is generally salvaged for the property owner. The remaining limbs, brush, and debris are burned or chipped and disposed of along the right-of-way in an approved manner. Bulldozers that have special blades are used to expedite the clearing process.



Figure C1.5. Completed grading. Note that the skids stringing, pipeline centerline stakes, and topsoil are stockpiled at the edge of the right-of-way

After clearing, the grading crew prepares the route for construction. In agricultural areas, topsoil separation is required in accordance with the easement and permits. In hilly terrain, preparations may require cutting down existing grades on high points and filling in low points.

The clearing and grading crews also install temporary bridges and culverts necessary to make the right-of-way useable as quickly as possible after rainfall events. They install ramps at roadways that allow equipment to approach and cross without impacting travel. These ramps provide access to the right-of-way from public roadways.



Figure C1.6. Stringing from the pipe yard

The contractor takes possession of the pipe at the pipe yard, which requires special trailers to distribute the pipe along the right-of-way. This work is generally subcontracted to a specialized hauling contractor who is familiar with the job and the government regulations. The pipe is handled with care to avoid damage to the coating and to the ends of the pipe.



Figure C1.7. Setting pipe from the string truck on skids

The pipe is placed along the right-of-way in a predetermined location and is positioned in a manner that facilitates the subsequent work processes. Spacing allowances are made for livestock movement or vehicles. Joints of special wall thickness or coating types must be placed in accordance with the engineering drawings.



Figure C1.8. Pipe bent to accommodate direction change

The pipe must conform to the horizontal and vertical changes in route direction by free stressing, bending, or the use of hot bends. For lines 8 inches and smaller, free stress of the pipe using its natural flexibility is practical. For larger pipelines, the pipe must be field bent to accommodate direction changes.



Figure C1.9. Pipe lifted into bending machine mandrel

After the optimum angle for a bend is determined, the total is divided into a series of smaller bends. The pipe is marked at the beginning and end points of the bends. The pipe is then inserted into the bending machine, and the series of smaller bends is completed. If field conditions do not permit field bends, hot bends made offsite are for bends of large deflection.

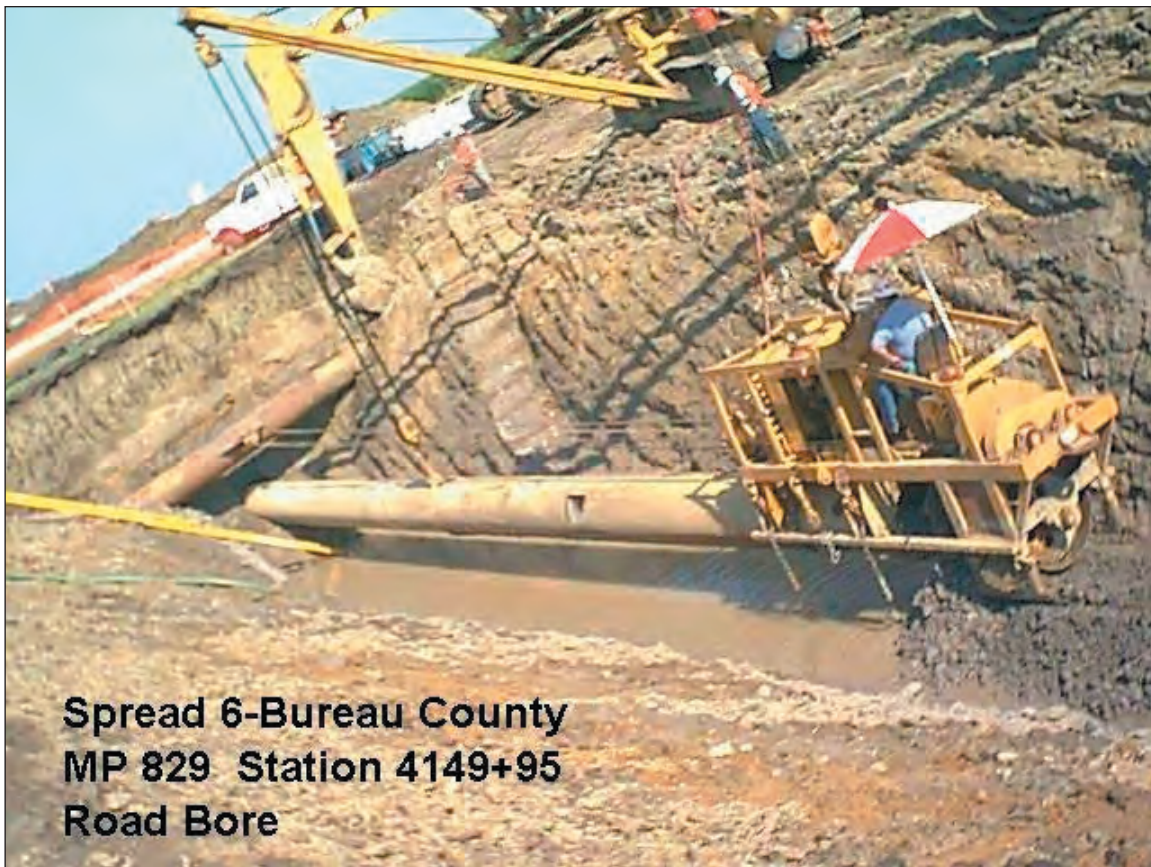


Figure C1.10. Road boring operation

At the start of the construction project, the road and stream crossing crews are generally in front of the main spread. During the project, they are sometimes caught and passed by the main spread. The road boring crews leapfrog along the route using public roadways. If the clear and grade crew passes them, they will often move down the right-of-way like a conventional crew.

Crossings of roads and streams generally require thicker pipe and extra depth. These are located by special permit drawings for each crossing. Roads are generally bored using a conventional boring machine that augers out a void under the roadway. Once boring is complete, a welded section of pipe is pulled into place and left to be tied into the mainline pipe to be installed later.

Streams or pipelines are usually crossed by open cutting the stream bed or excavating around the pipeline. Then a segment of pipe that has been built to the engineered profile of the crossing is installed. An example of this process is shown in the description of the tie-in crew.



Figure C1.11. Horizontal directional drill site

Horizontal directional drilling is generally done in the same manner as road crossing (drill and pull pre-welded pipe) but using an initial pilot hole that is directionally steered to match an engineered entry point, profile, and exit point. Small lines 8 inches and under can be economically installed for short distances and can even be used for lines over 5,000 ft.

This method of installation has geological limitations. It is not suitable for areas where soils are sandy and poorly graded, contain gravel or cobble, or are in highly faulted rock. The process is configured in a manner that allows the cuttings from the horizontal directional drilling operation to be returned to the drilling unit for handling and disposal.



Figure C1.12. Horizontal directional drilling pilot coming out

The horizontal directional drilling pilot is steered using a variable angle kicker tool similar to the techniques used in oil and gas directional drilling. The tool is steered using sensors at the tool and an electronic grid on entry and exit banks. The straightness of the pilot hole becomes critical for longer drills.



Figure C1.13. Horizontal directional drilling barrel reamer coming out

After the pilot hole has been properly established, a reamer is used to increase the size of the hole to accommodate the pipe.



Figure C1.14. Horizontal directional drilling—ready to pull the prewelded pipe

The pipe for the horizontal directional drilling is laid out, welded, inspected, and pre-hydrotested on the opposite bank from the HDD drill unit. After the hole has been completely reamed and debris removed using special tools, the pipe is ready to be pulled into the hole. The use of stabilizers and barrel reamers in front of the swivel is determined by the site conditions.



Figure C1.15. Pulling operations under way

The exit angle of the pilot hole determines the equipment considered necessary to assist in the pulling operation. The pipe needs to be lifted to the height where it “breaks over” and goes into the drilled hole at the proper angle to minimize resistance. The larger the exit angle is, the larger the equipment required to support the operation. The pipe is cradled on rollers to allow it to be pulled into the bore by the horizontal directional drilling unit.



Figure C1.16. Pipe going in under levee canal

The horizontal directional drilling unit is sized for the expected resistance during the pulling phase of the process. A wide range of unit sizes is available. Once the unit is pulled into place, a tie-in crew connects the pipe to the mainline. The pipe is then hydrotested with the rest of the pipeline.



Figure C1.17. Wheel trencher

The ditching operation excavates a stable trench so that the pipeline can be installed at the proper depth of cover. Prior to ditching, it is mandatory to call the appropriate agencies and notify the local utilities. It also is a common requirement for an electronic pipe locator to be used immediately in front of the ditching operation.

There is no one piece of equipment that will perform equally well under all conditions. The topography, geology, and weather on each project are unique. In general, a wheel trencher works well in stable soils because it is fast, makes a smooth trench, and stacks the spoil neatly in a pile. The hydraulic track backhoe is the alternate piece of equipment and is used when conditions are less than ideal or for smaller projects.



Figure C1.18. Pipe is ready for pipe gang—the pipe is strung on skids, the ditch is complete, and the ditch spoil is segregated from topsoil

Rock ditches can sometimes be accommodated by a wheel, saw trencher, or even backhoes. Some rock may require ripping by a bulldozer or blasting in advance of trenching. In an area of a rock ditch, the trench is padded with screened backfill before and after the pipe is lowered in. In all cases, the slope of the sides of the trench must be sufficient to prevent caving before the pipe can be welded and lowered.

In areas of high groundwater or for small pipelines, the ditch follows the welding. The trench is then dug to match the pipe. The pipe is lowered in the trench, and the trench is completely backfilled by the end of the day.



Figure C1.19. End facing to ensure the highest weld quality

The pipe is provided from the pipe mill with an end bevel for welding. For larger high-pressure lines that may have rigid welding requirements, end facing is sometimes required. End facing ensures that the bevels are correct and that the ends of the pipe are square for precise fit-up.



Figure C1.20. Lineup clamp shoes for pipe joint

Internal line clamps are not needed for small pipelines because their dimensional tolerances are within the tolerances allowed by the welding specifications. External lineup clamps are used to ensure proper welding set up for smaller pipelines. For larger lines (16 inches or greater), the internal line clamp is used as shown.



Figure C1.21. Pipe joint being stabbed over internal lineup

The pipe gang, working just ahead of the welding gang, sets the pipe in place so that welding can begin. The internal welding lineup clamp is moved forward to the end of the joint of pipe while welding is being completed. Once it is positioned on the end of the pipe being welded, the next joint is stabbed over the internal lineup clamp. That joint is positioned, spaced, and aligned with the previous joint, and the clamp is activated. The stringer pass (first pass) and some portions of the hot pass (second pass) are completed prior to release of the internal lineup clamp.



Figure C1.22. Manual welding from both sides (12 o'clock to 6 o'clock)

The firing line welders follow the pipe gang and complete the welding passes necessary for a complete weld. The number of passes depends on the thickness of the pipe. Generally, the welding operation is organized with a series of stations, each accomplishing a specific portion or pass of each weld. These stations start, finish, and move at the same time—like a wagon train.

Each weld is inspected visually, and a certain percentage of the welds are inspected by nondestructive testing. For manual welds, nondestructive testing is generally accomplished using external X-ray sources for small pipelines and internal X-ray machines for larger pipelines.



Figure C1.23. Mechanized welding, large-diameter high-pressure pipeline

Recent advances in the application of mechanized welding technology make it suitable for medium-diameter pipelines (20 to 24 inches) that operate at very high pressure and use high-grade (X80) steel pipe. Mechanized welding is best inspected by ultrasonic inspection because of its steep bevel angle.



Figure C1.24. Coating using fusion bond epoxy

There are many coating systems available to coat the weld joints, including conventional prime and tap, prime and heat shrink sleeves, fusion bond epoxy, and cold applied epoxy/urethane systems. Generally larger pipelines do not use tap or shrink sleeves. In all cases, cleaning the weld joint prior to application is critical.



Figure C1.25. Jeeping for pipe coating defects

When the pipe is welded and the joints are coated, the pipe is then ready to be lowered into the trench. To ensure that the coating has not been damaged, it is jeeped with a high-voltage coil. The voltage is set based on the coating thickness and properties so defects can be detected without damaging the coating. Just prior to lowering in, the pipe is lifted off the skids, and the coil is moved along the pipeline. Defects are marked and repaired.



Figure C1.26. Pipe welded, coated, and ready to be lowered in

The lower-in process is generally required to stay close to the welding process. In an area where wet subsoil conditions exist, it is common for the ditching and lower-in to be done on the same day so that no areas of the ditch are open at the end of the day.



Figure C1.27. Lower-in tractors in various boom positions

The lower-in operation uses side boom tractors, which are specially designed for this operation. The side booms have large counter weights on the side opposite the boom. These weights can be extended to give the tractors very stable lifting capacity. The number, size, and spacing of the side booms vary with pipe diameter, wall thickness, and soil conditions. The rollers that cradle the pipe are shown in a subsequent photo.



Figure C1.28. Lower-in crew making a road crossing

The lower-in crews, like the other crews, must take special precautions to prevent damage to roadways as they cross. Generally, traffic is stopped, and two rows of old tires are placed across the road. The side booms are guided to keep their tracks on the tires. Once the crew is across the roadway, the tires are removed, any debris is cleaned up, and traffic flow is restored. Note that the cradles on the end of the cables are roller types that allow the lower-in tractors to move in a continuous manner.



Figure C1.29. Surveying weld location and cover

As part of the as-built record, the locations of welds and pipe cover are recorded by survey or by inspection. An open ditch as-built is usually done for larger pipelines, and a closed ditch as-built is done for smaller pipelines.

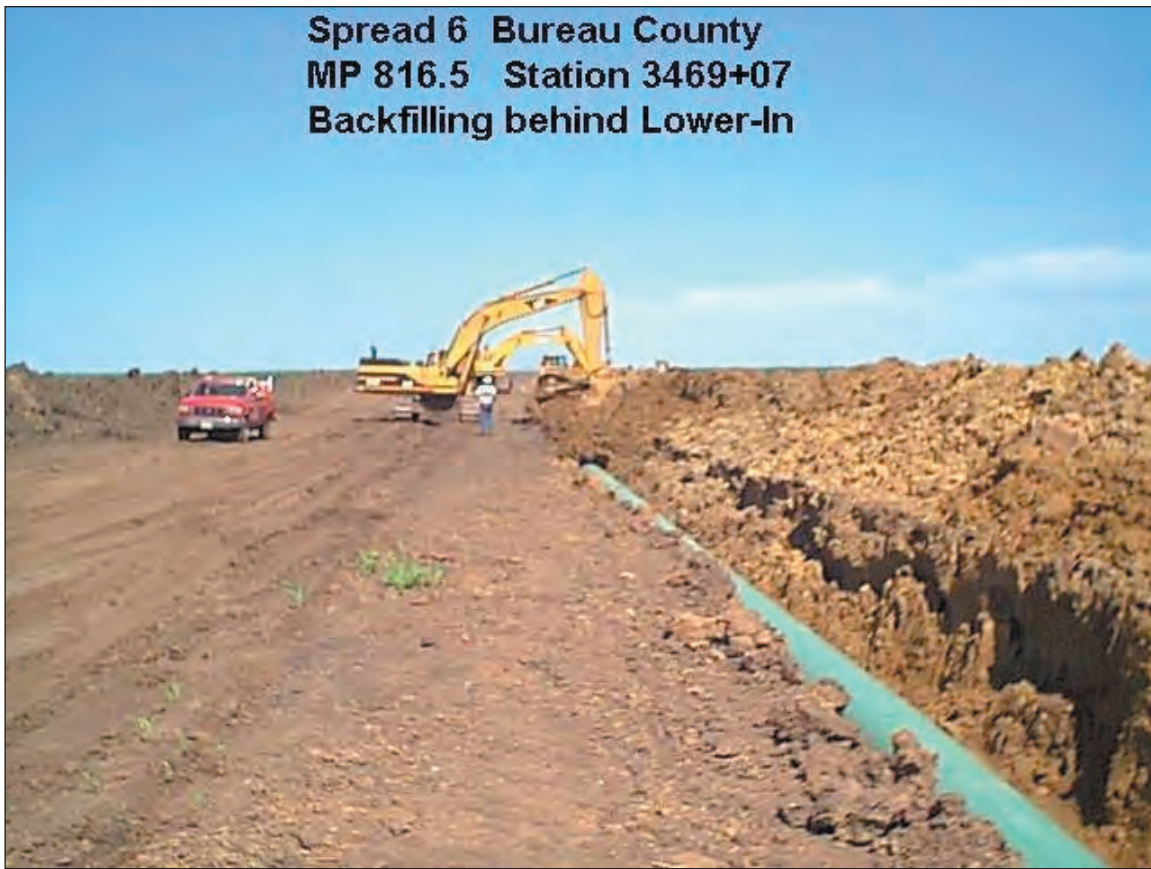


Figure C1.30. Lower-in backhoes (foreground) and dozer (background)

After pipe has been installed in the trench, the backfill operation can commence. Backfill is often required to be done on all pipe installed each day. For large-diameter pipe, backhoes generally plug the pipe by placing soil directly on the pipe to keep it stable for the subsequent backfilling operation. Then backhoes with a special wide buck pull the ditch spoil pile into the trench. A dozer follows along, providing further cleanup if necessary. On smaller pipelines, a dozer is often used to do rough backfill.



Figure C1.31. Cleanup (aerial view)

The cleanup operation is critical to comply with permit and landowner restrictions. Once the rough backfill operation has been completed, the cleanup operation can begin. Construction debris and surface rocks are removed to approved disposal locations. Subsoil is de-compacted as appropriate, and the surface is restored to the original profile. The topsoil is then returned to the original location.

This operation is very weather sensitive because the soil must be dry enough so that it can be worked without leaving ruts. Generally low ground pressure tractors are used for this operation.

Landowner releases are obtained, if possible, to provide documentation that the cleanup operation has been satisfactorily completed.



Figure C1.32. Prefabricated mainline valve being installed in rock ditch

Fabrication crews prepare and install valve sites, side taps, and scraper traps in the pipeline spread. The crews must ensure that foundations are at proper elevations, pipe is square, and that pipe is level. Generally, a tie-in crew will connect these to the mainline pipe.



Figure C1.33. Optimal welding conditions are essential

The pipe must be properly aligned and prepared so that optimal welding conditions are present, mitigating the need for repairs. Once the weld is made (as quickly as possible), it must be inspected, coated, and surveyed so that it can be backfilled.



Figure C1.34. Tie-ins: Sag and overbend section set in place

Tie-ins are made to connect areas of special construction to the mainline pipe. The tie-in crew is organized, with very experienced staff, and is equipped to handle multiple situations.



Figure C1.35. Hydrotest pressures provide accurate measurement using dead weight and testers

Once the pipeline has been completed for a minimum distance, that segment can be water filled and tested. The pipe segment is generally cleaned with air pigs or with a slug of water in front of a fill pig when the segment is being filled with hydrotest water. The fill is accomplished using a low-head, high-volume pump that takes water from an approved water source. After the segment is full of water, a high-pressure, low-volume pump is used to raise the pressure to the required test pressure. Pressure and temperature are then recorded. Pipelines are tested for a minimum time period (generally 8 hours) at a pressure that exceeds the maximum operating pressure by a specific safety factor (generally 25%).



Figure C1.36. Dewatering pigs

Dewatering and fill pigs are installed in the pipeline segments before the tests are started so that the water can be moved to the proper location at the end of the test.



Figure C1.37. Bank of air compressors set up for dewatering of the test segment

Air compressors are used to push test water to the next test segment or to a disposal point. Water for hydrotesting of a new pipeline can be discharged in most locations as long as it has been discharged through a hay bale structure.



Figure C1.38. Drying pig deflector being installed after test/dewater header has been removed

Once the test segment has been dewatered, several segments are connected into a larger segment for drying and cleaning. The air compressors used in dewatering are used to compress air through special dryers that remove the moisture from the air. This dry air then pushes a series of foam pigs and brush pigs through the cleaning segment. This process is repeated until the line is cleaned and the air being discharged has a dewpoint pressure less than in the specification.