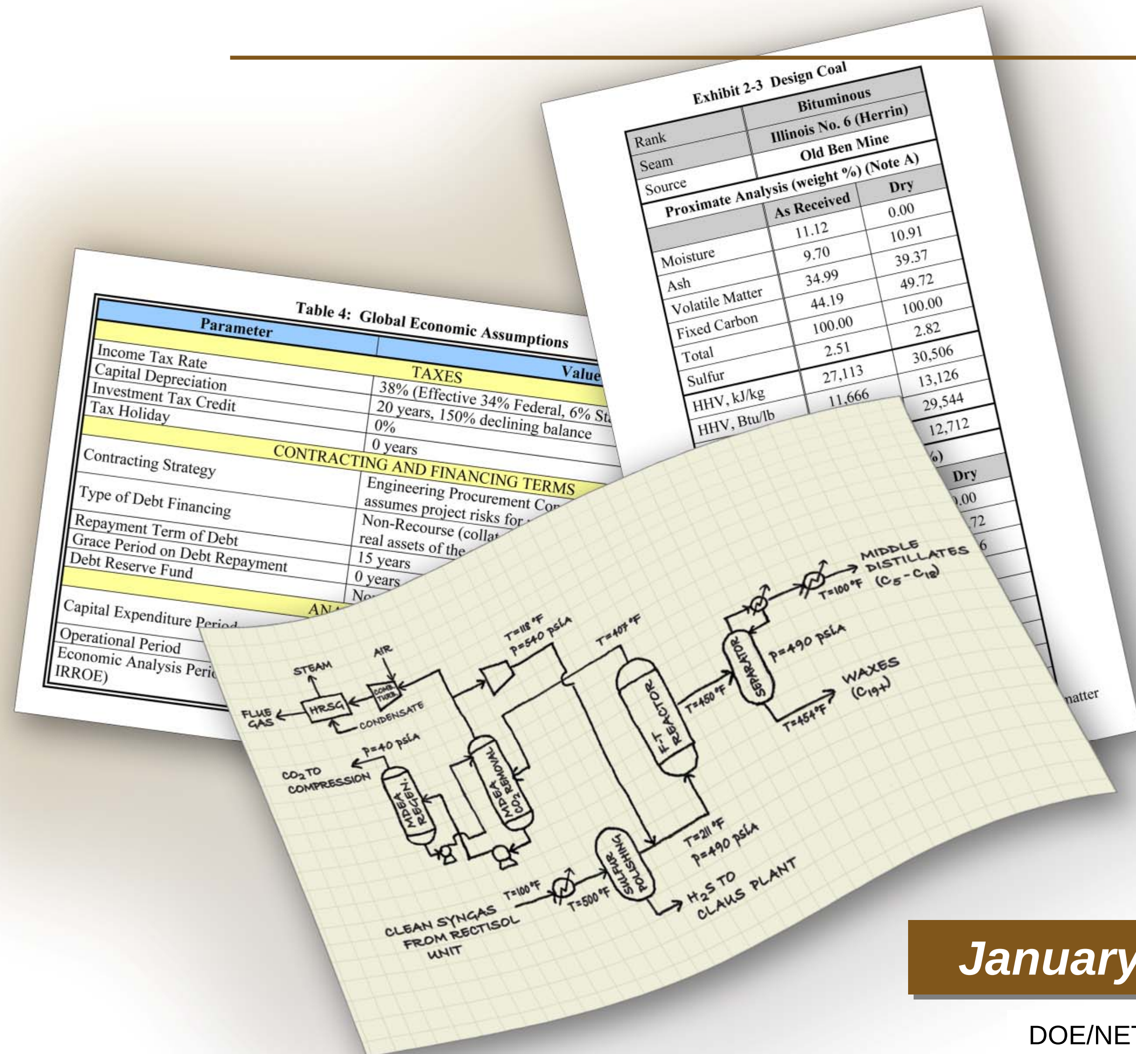
the ENERGY lab

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Process Modeling Design Parameters



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NATIONAL ENERGY TECHNOLOGY LABORATORY

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Disclaimer

1 Introduction

NETL conducts systems analysis studies that require a large number of inputs, from ambient conditions to parameters for Aspen Plus™ process blocks. The sheer number of assumptions required makes it impractical to document all of them in each report that is issued. The purpose of this section of the Quality Guidelines is to document the assumptions most commonly used in systems analysis studies and the basis for those assumptions.

2 Site Conditions and Characteristics

This section provides the conditions and characteristics of sites commonly used in NETL systems studies. The sites include locations in Montana, North Dakota, and Wyoming along with International Organization for Standardization (ISO) conditions, representative of a generic Midwest, U.S. location. Ambient conditions are required for estimating performance of the power plant configurations and to size the equipment so that an accurate cost estimate can be made. The ambient site conditions and characteristics of three locations plus a generic ISO site are presented in Exhibit 2-1 and Exhibit 2-2.

The method used to establish site conditions is provided in Exhibit 2-3 so that additional sites can be defined in a consistent manner. These guidelines should be used in the absence of any compelling market-, project- or site-specific requirements.

Exhibit 2-1 Site Characteristics

Site Characteristics	**Montana** (1)	**North Dakota** (1)	**Wyoming** (2)	**Midwest ISO** (3)
Topography	Level	Level	Level	Level
Size (Pulverized Coal or Integrated Gasification Combined Cycle), acres	300	300	300	300
Size (Natural Gas Combined Cycle)	100	100	100	100
Transportation	Rail or Highway	Rail or Highway	Rail or Highway	Rail or Highway
Ash/Slag Disposal	Offsite	Offsite	Offsite	Offsite
Water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water

Exhibit 2-2 Site Conditions

Site Conditions	Montana (1)	North Dakota(1)	Wyoming (2)	Midwest (ISO)
Elevation, m (ft)	1,036 (3,400)	579 (1,900)	2,042 (6,700)	0 (0)
Barometric Pressure, MPa (psia)	0.090 (13.0)	0.095 (13.8)	0.079 (11.4)	0.101 (14.7)
Design Ambient Dry Bulb Temperature, °C (°F)	5.6 (42)	4.4 (40)	5.6 (42)	15 (59)
Design Ambient Wet Bulb Temperature, °C (°F)	2.8 (37)	2.2 (36)	2.8 (37)	10.8 (51.5)
Design Ambient Relative Humidity, %	62	68	62	60
Cooling Water Temperature, °C (°F)	8.9 (48)	8.3 (47)	8.9 (48)	15.6 (60)
Air composition based on published psychrometric data, mass %				
H_2O	0.398	0.384	0.443	0.616
AR	1.283	1.283	1.282	1.280
CO_2	0.050	0.050	0.050	0.050
O_2	23.049	23.052	23.038	22.999
N_2	75.220	75.231	75.186	75.055
Total	100.00	100.00	100.00	100.00

The method to determine site conditions for new sites is given in Exhibit 2-3.

Exhibit 2-3 Method to Establish Site Conditions

Site Conditions	Method
Elevation	The site elevation is the average elevation in the state of interest. Average state elevations are available through numerous internet sources, including: http://en.wikipedia.org/wiki/List_of_U.S._states_by_elevation http://www.netstate.com/states/geography/

Site Conditions	Method
Barometric Pressure	The barometric pressure of atmospheric air varies with altitude as well as with local weather conditions. Only altitude effects are considered in the pressure calculation (4) as follows **P = 14.696 * (1 - (6.8753 x 10^$^{-6)}$ * Z)^5.2559** Z = Elevation (altitude) in ft P= barometric pressure in psia Barometric pressure, site elevations, and other climate data can also be obtained from the public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) and U.S. Geological Survey's National Elevation Dataset (http://ned.usgs.gov//) by searching for locations and specific parameters of interest.
Design Ambient Dry Bulb Temperature	The dry bulb temperature can be obtained for the site from public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) by searching for locations and specific parameters of interest. The yearly temperatures are averaged to obtain the ambient design dry bulb temperature of the particular site in consideration.
Design Ambient Wet Bulb Temperature	With known dry bulb temperature and relative humidity, wet bulb temperature for the site can be obtained from the psychrometric chart.
Design Ambient Relative Humidity	The relative humidity for the selected site is available from public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) by searching for locations and specific parameters of interest. The average annual relative humidity is considered as the design ambient relative humidity.
Cooling Water Temperature, °C (°F)(5)	Typical cooling tower approach temperatures are in the range of 4.4 to 11.1°C (8 – 20°F) for the power plant applications. Cold water temperatures for NETL systems studies assume an approach to wet bulb of 8.5°F for ISO condition locations and 11°F for the Montana, Wyoming and North Dakota locations. In all cases the cooling water range is assumed to be 11.1°C (20°F), which sets the cooling water hot water temperature.
Air Composition, mol%, dry (6)	Standard dry air is mainly composed of N_2 (78.08%), O_2 (20.95%), Argon (0.93%), and CO_2 (0.04%). Air temperature affects potential moisture content. As air temperature rises, its ability to hold water vapor increases significantly. The amount of water vapor in air at ground level can vary from almost zero to about 5 percent. Knowing the water vapor content, the remaining constituents can be calculated based on dry air composition. Obtain water vapor content from psychometric chart or other relevant method.

3 Property Methods

A summary of the property methods used for modeling various sections of energy systems is given in Exhibit 3-1.

Exhibit 3-1 Property Methods

Section	Property Method
Gasification and Coal Boiler	Peng-Robinson (PENG-ROB)
Compressor and Gas Turbine	PENG-ROB
HRSG and Steam Turbine	Steam tables (STEAM-TA)
Sour Water System	PENG-ROB and Non-Random Two Liquid (NRTL)
Sulfur Recovery Unit	PENG-ROB
CO_2 Capture	PENG-ROB
CO_2 Compression	PENG-ROB

The gas side modeling for the gasification and boiler systems uses the Peng-Robinson equation of state based on the Aspen User Manual (7) recommendations and an evaluation of high-temperature syngas quench systems conducted by the National Institute of Standards and Technology (NIST) for the Electric Power Research Institute (EPRI) (8).

Steam turbines and heat recovery steam generators (HRSG) are modeled using steam table property values. The steam table is the standard for water-based systems, and uses an enthalpy reference state of the triple point of water at 32.02°F and 0.089 psia. Aspen recommends the STEAM-TA property method for pure water and steam, and it is the default property method for the free-water phase, when present. Because the steam tables are a common source of enthalpy data, all enthalpy values in NETL systems studies are adjusted to the steam table reference conditions as described in Section 4 of the Guidelines.

In IGCC plants, the sour water system uses the Peng-Robinson equation of state with the exception of the chloride removal process, which uses the Non-Random Two Liquid (NRTL) property method. The NRTL method more accurately predicts the solubility of chlorides in water.

The sulfur recovery unit, CO_2 capture process, and CO_2 compression system use the Peng-Robinson equation of state. According to Aspen, "This property method is particularly suitable in the high temperature and high pressure regions, such as in hydrocarbon processing applications or supercritical extractions" (7).

The property methods of smaller process subsystems in each model should be specified based on the surrounding model blocks and streams to insure consistency in the balance calculations unless there are compelling reasons to do otherwise.

4 Steam Cycle Conditions

Steam cycle conditions for combustion-based subcritical and supercritical coal units in NETL systems studies are based on a market survey that was conducted in 2005 (9). The conditions chosen, at the steam turbine throttle valve are representative of currently available commercial offerings and are shown in Exhibit 4-1. There is no consensus regarding the boundary between supercritical and ultra-supercritical steam conditions. A literature review conducted in 2007 did not provide definitive USC steam conditions, but based on the review the conditions shown in Exhibit 4-1 were chosen (10). Study specific requirements can override the baseline steam conditions, and a range of conditions used in past systems studies is also shown in Exhibit 4-1.

Similarly, a vendor survey was used to establish the steam conditions for the bottoming cycle of natural gas combined cycle systems (9). Steam conditions for the bottoming cycle of integrated gasification combined cycle plants were established based on typical vendor offerings. The conditions and ranges are documented in Exhibit 4-2.

The steam turbine leakage constants are given in Exhibit 4-3. These constants are used in the formula:

$$Q = C \rho \sqrt{P}$$

where C = steam seal leakage constant from Exhibit 4-3
Q = leakage flow rate [lb/hr] and
P = pressure of inlet stream of the leakage section [psia]
ρ = density of inlet stream of the leakage section [lb/ft^3]

The leakage stream sources and destinations are defined in another QGESS document, Model Structure and Documentation (11).

Exhibit 4-1 Steam Conditions for Coal Combustion Technologies

	Subcritical	Range	Supercritical	Range	Ultra-supercritical	Range
Main Steam Pressure, MPa (psig)	16.5 (2,400)	--	24.1 (3,500)	--	27.6 (4,000)	27.6 – 34.5 (4,000 – 5,000)
Main Steam Temperature, °C (°F)	566 (1,050)	538 – 566 (1,000 – 1,050)	593 (1,100)	593 – 599 (1,100 – 1,110)	649 (1,200)	649 – 732 (1,200 – 1,350)
Reheat Steam Temperature, °C (°F)	566 (1,050)	538 – 566 (1,000 – 1,050)	593 (1,100)	593 – 621 (1,100 – 1,150)	649 (1,200)	649 – 760 (1,200 – 1,400)

Exhibit 4-2 Steam Conditions for NGCC and IGCC Technologies

	NGCC	NGCC Range	IGCC[1]	IGCC Range
Main Steam Pressure, MPa (psig)	16.5 (2,400)	--	12.4 (1,800)	--
Main Steam Temperature, °C (°F)	566 (1,050)	--	538 or 566 (1,000 or 1,050)	510 – 579 (950 – 1,075)
Reheat Steam Temperature, °C (°F)	566 (1,050)	510 – 566 (950 – 1,050)	538 or 566 (1,000 or 1,050)	510 – 579 (950 – 1,075)

[1] The low temperature (1000°F) is typical of capture plants and the high temperature (1050°F) of non-capture plants

Exhibit 4-3 Steam Seal Leakage Constants

Steam Seal Leakage Constants for PC, NGCC and IGCC Steam Turbine Types (3)	**SUB PC**	**SC PC**	**USC PC**	**NGCC**	**IGCC**
VSL1[a]	56	N/A	20	56	56
VSL2[a]	44	N/A	N/A	44	44
GOV1[b]	430	500	590	340	340
GOV2[b]	N/A	355	N/A	N/A	N/A
GOV3[b]	N/A	110	N/A	N/A	N/A
HP1[c]	450	550	950	450	450
HP2[c]	255	410	760	N/A	N/A
IP[d]	525	1,115	10,300	390	490

[a]VSL – Valve stem leakage prior to entering HP turbine
[b]GOV – governing stage leakages
[c]HP – high pressure turbine leakage at HP exit
[d]IP – intermediate pressure turbine leakage at IP exit

5 Process Parameters for Modeling

The process parameters used for Aspen modeling and spreadsheet modeling are documented in the following tables. For each parameter associated with a unit operation a single value is provided along with a typical range of values associated with that parameter. When no entry appears on the range column, it simply means that all NETL systems analyses to date have consistently used the parameter value. It does not imply that a range of values is not possible. When available, a reference source is provided for the design parameter and range. In many cases, the source is engineering judgment. Additional explanation is provided in the "Notes" column as warranted.

5.1 MOTOR EFFICIENCIES

Electric motors are used to drive pumps and compressors in many applications. The motor efficiency is a function of motor size as documented in Exhibit 5-1.

Exhibit 5-1 Electric Motor Efficiencies

Equipment and Parameter	Parameter Value	Range	Source	Notes
Electric Motors				
Efficiency, %	<1,000 kW: 95 <10,000 kW: 96.5 >10,000 kW: 97		Engineering Judgment	

5.2 COAL COMBUSTION SYSTEMS

The process parameters listed in this section are for pulverized coal and circulating fluidized bed combustion systems. Technology-specific and fuel-specific distinctions are identified where applicable.

Exhibit 5-2 Process Parameters for Coal Combustion Systems

Equipment and Parameter	Parameter Value	Range	Source	Notes
Boiler				
Efficiency, %	88	83.5 - 88	(12 p. 5)	Depends on coal type (sulfur content) and boiler type (PC versus CFB); parameter value is based on bituminous coal in a PC boiler

Equipment and Parameter	Parameter Value	Range	Source	Notes
Heat Loss, %	1		(13) (14 p. 11) (15 pp. 23-7)	Heat loss percentage is based on fuel heat input
Air Infiltration, %	2		(15 pp. 10-16)	Infiltration air percentage is based on theoretical (stoichiometric) air
Excess Air Based on Flue Gas O_2 Content, vol%	2.7		(15 pp. 10-15)	Design parameter is on a dry basis downstream of the air heater leakage
Combustion Air Preheater				
Air Leakage, %	5.5		(15 pp. 20-13)	Air leakage is 5.5% of total combustion air flow and divided between primary and secondary air based on a ratio of pressure drops between the fan outlet and the air heater
Flue Gas Exit Temperature, °C (°F)	High S coal: 177°C (350°F) Low S coal: 149°C (300°F) CFB: 132°C (270°F)		Engineering Judgment	CFB case assumes in-bed limestone injection
Primary Air Fan				
Polytropic Efficiency, %	75		Engineering Judgment	
Pressure Rise, kPa (psi)	PC: 10.0 (1.44) CFB: 10.5 (1.517)		(15 pp. 25-12)	
Portion of Total Combustion Air, %	Bituminous coal (PC): 23.5 Low rank coal (PC): 40.0 Bituminous coal (CFB): 60 Low rank coal (CFB): 60		Engineering Judgment	
Forced Draft Fan				
Polytropic Efficiency, %	75		Engineering Judgment	
Pressure Rise, kPa (psi)	PC: 3.8 (0.556) CFB: 4.2 (0.614)		(15 pp. 25-12)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Portion of Total Combustion Air, %	Bituminous coal (PC): 76.5 Low rank coal (PC): 60.0 Bituminous coal (CFB): 40 Low rank coal (CFB): 40		Engineering Judgment	
Induced Draft Fan				
Polytropic Efficiency, %	75		Engineering Judgment	
Pressure Rise, kPa (psi)	8.4 (1.224)	6.2 – 8.4 (0.90 – 1.224)	(15 pp. 25-12)	Pressure ratio is adjusted to provide 2 inches H_2O above ambient pressure at the stack base
Oxidation Air Blowers				
Isentropic efficiency, %	65	65-75	Engineering Judgment	
Discharge Pressure, kPa (psia)	310.3 (45)		(15 pp. 25-12)	

Exhibit 5-3 Process Parameters for Steam Turbines and Feedwater Systems

Equipment and Parameter	Parameter Value	Range	Source	Notes
Subcritical Single Reheat Steam Cycle (2,415 psia/1050°F/1050°F)				
Inlet Pressure, MPa (psia)	16.6 (2,415)		(15 pp. 26-2)	
Max Steam Temperature, °C (°F)	565.5 (1,050)		(16 pp. 1-14)	
HP Exhaust Pressure, MPa (psia)	4.2 (620)		(15 pp. 2-8)	
IP Inlet Pressure, MPa (psia)	3.9 (565)		(17)	
IP Exhaust Pressure, MPa (psia)	0.52 (75)		(17)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
LP Inlet Pressure, MPa (psia)	0.51 (73.5)		(17)	
Governing Stage Isentropic Efficiency, %	80		(17)	
HP Isentropic Efficiency, %	86.39		(17)	
IP Isentropic Efficiency, %	86.26		(17)	
LP Isentropic Efficiency, %	89.71		(17)	
Generator Efficiency, %	98.5	98.5-99	(17)	
Blowdown,% of main steam flow	1		(17)	
Supercritical Single Reheat Steam Cycle (3,515 psia/1100°F/1100°F)				
Inlet Pressure, MPa (psia)	24.2 (3,515)		(15 pp. 26-7)	
Max Steam Temperature, °C (°F)	593 (1,100)	593-599 (1,100-1,110)	(17)	
Exhaust Pressure, MPa (psia)	4.9 (711)		(15 pp. 2-16)	
HP Exhaust Pressure, MPa (psia)	4.9 (711)		(17)	
IP Inlet Pressure, MPa (psia)	4.5 (656)		(17)	
IP Exhaust Pressure, MPa (psia)	0.52 (75)	0.52-0.95 (75-138)	(17)	
LP Inlet Pressure, MPa (psia)	0.51 (73.5)	0.51-0.93 (73.5-135)	(17)	
Governing Stage Isentropic Efficiency, %	80		(17)	
HP Isentropic Efficiency, %	83.72		(17)	
IP Isentropic Efficiency, %	88.76		(17)	
LP Isentropic Efficiency, %	92.56		(17)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Generator Efficiency, %	98.5	98.5-99	(17)	
Ultrasupercritical Single Reheat Steam Cycle (4,015 psia/1200°F/1200°F)				
Inlet Pressure, MPa (psia)	27.7 (4,015)	27.7-34.6 (4,015-5,015)	(15 pp. 2-18)	
Max Steam Temperature, °C (°F)	649 (1,200)	649-760 (1,200-1,400)	(17)	
HP Exhaust Pressure, MPa (psia)	8.3 (1,200)	8.3-10.3 (1,200-1,500)	(17)	
IP Inlet Pressure, MPa (psia)	7.8 (1,128)	7.8-9.8 (1,128-1,420)	(17)	
IP Exhaust Pressure, MPa (psia)	0.52 (75)	0.52-0.67 (75-97.5)	(17)	
LP Inlet Pressure, MPa (psia)	0.51 (73.5)		(17)	
Governing Stage Isentropic Efficiency, %	80		(17)	
HP Isentropic Efficiency, %	83.72		(17)	
IP Isentropic Efficiency, %	88.76		(17)	
LP Isentropic Efficiency, %	92.56		(17)	
Generator Efficiency, %	98.5	98.5-99	(17)	
Surface Condenser				
Operating Pressure, MPa (psia)	0.0068 (0.982)	0.43 - 5.8 (0.002-0.04)	(15 pp. 2-16)	Operating pressure depends on cooling water temperature. Design parameter is for ISO condition cooling water.
Terminal Temperature Difference, °C (°F)	11.7 (21)	11.7 – 12.8 (21 - 23)	(18)	Terminal temperature difference is higher than typical to account for lack of a summer design condition

Equipment and Parameter	Parameter Value	Range	Source	Notes
Condensate Pumps				
Discharge Pressure, MPa (psia)	1.7 (250)	0.86-1.7 (125-250)	(15 pp. 2-18)	
Efficiency,%	80		Engineering Judgment	
Deaerator				
Operating Pressure, MPa (psia)	0.12 (17.4)		(19)	
Operating Temperature, °C (°F)	176 (349)	212-350 (100-177)	(19)	
Boiler Feed Water Pump Turbine				
Inlet Pressure, MPa (psia)	0.50 (73.5)		(15 pp. 2-16)	
Exhaust Pressure, Pa (psia)	0.013 (2)		(15 pp. 2-16)	
Isentropic Efficiency,%	80		Calculated Value	
Boiler Feed Water Pump – Subcritical Steam Cycle (2,415 psia/1050°F/1050°F)				
Discharge Pressure, MPa (psia)	21.4 (3,110)		(15 pp. 2-18)	
Efficiency,%	80		Engineering Judgment	
Boiler Feed Water Pump – Supercritical Steam Cycle (3,515 psia/1100°F/1100°F)				
Discharge Pressure, MPa (psia)	28.9 (4,200)		(15 pp. 2-16)	
Efficiency,%	80		Engineering Judgment	
Boiler Feed Water Pump – Ultrasupercritical Steam Cycle (4,015 psia/1200°F/1200°F)				
Discharge Pressure, MPa (psia)	32.4 (4,700)			
Efficiency,%	80			

Equipment and Parameter	Parameter Value	Range	Source	Notes
LP Feed Water Heaters				
Cold Side Temperature Approach, °C (°F)	5.56 (10)		(15 pp. 2-16)	
Pressure Drop, MPa (psi)	0.03 (5)		Engineering Judgment	
IP Feed Water Heater				
Cold side temperature approach, °C (°F)	5.56 (10)		(15 pp. 2-16)	
Pressure drop, MPa (psia)	0.03 (5)		Engineering Judgment	
HP Feed Water Heater				
Cold Side Temperature Approach, °C (°F)	5.56 (10)		(15 pp. 2-16)	
Pressure Drop, MPa (psi)	0.03 (5)		Engineering Judgment	

Exhibit 5-4 Process Parameters for Environmental Systems Associated with Coal Combustion

Equipment and Parameter	Parameter Value	Range	Source	Notes
SCR				
Operating Temperature, °C (°F)	371 (700)	343 – 399 (650 – 750)	(15 pp. 34-4)	SCR is used in PC cases
Catalyst	Titanium/ Vanadium Oxide		(15 pp. 34-5)	
NOx Reduction, %	Bituminous coal: 90 Low rank coal: 65		(15 pp. 29-3)	NOx production and removal are estimated
Ammonia Slip, ppmv	2	1 – 5	(20)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
SNCR				
Operating Temperature, °C (°F)		760 – 1,093 (1,400 – 2,000)	(15 pp. 32-9)	SNCR is used in CFB cases but not modeled in Aspen, hence no parameter value is listed
NOx Reduction, %	46		(15 pp. 29-23)	Assumed NOx inlet concentration of 0.13 lb/MMBtu
Ammonia Slip, ppmv	2	1 - 5	(21 p. 2)	
Baghouse				
Pressure Drop, kPa (psi)	1.4 (0.20)		(15 pp. 33-10)	
Particulate Removal Efficiency, %	99.8	99.5 – 99.98	(15 pp. 32-10)	Range depends on inlet solids loading (including solids from dry FGD applications)
Activated Carbon Injection				
Carbon Feed Rate, kg/MMacm (lb/MMacf)	PRB: 16 (1.0) Lignite: 24 (1.5)		(15 pp. 32-11)	No ACI is used in bituminous coal cases because of assumed 90% co-benefit capture with SCR, wet FGD and a baghouse
Hg Removal Efficiency, %	PRB: 91.5 Lignite: 90		(15 pp. 32-11)	Combined co-benefit capture and ACI for PRB coal
Dry FGD Absorber Module				
SO_2 Removal Efficiency,%	93		(15 pp. 35-12)	Used with low sulfur PRB and lignite coals
Exit Temperature, °C (°F)	82 (180)	13.8 - 19.4 (25 - 35	(15 pp. 32-9)	Range is degrees above adiabatic saturation temperature
Pressure Drop, MPa (psi)	0.40 (0.002)		Engineering Judgment	
Wet FGD Absorber Module				
SO_2 Removal Efficiency,%	98		(15 pp. 32-9)	Used with high sulfur bituminous coal
Exit Temperature, °C (°F)	57 (135)		(15 pp. 35-3)	
Pressure Drop, MPa (psi)	0.002 (0.40)		(15 pp. 35-3)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Limestone Slurry Feed Pumps				
Discharge Pressure, MPa (psia)	0.10 (15)		(15 pp. 35-10)	
Efficiency,%	65		Engineering Judgment	

5.3 COMBINED CYCLE SYSTEMS

The heat recovery steam generator (HRSG) system unit operation data is given in Exhibit 5-5. Where values differ for natural gas applications and syngas applications, the natural gas values are given first.

Exhibit 5-5 HRSG System Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
HRSG – (Natural Gas / Syngas)				
Combustion Turbine Exhaust Gas/ HP Steam Approach Temperature, °C (°F)	63 (113) / 28 (50)		(15 pp. 27-16)	
Gas side pressure drop through HRSG, MPa (psia)	0.003 (0.5)	0.003-0.004 (0.5-0.61)	(15 pp. 27-16)	
LP, IP, and HP pinch point temperature, °C (°F) (22)	13.9 (25)	5.5-16.6 (10-30)	(15 pp. 27-16)	
LP, IP, and HP economizer approach temperature, °C (°F)	16.7 (30) / 19.4 (35)	13.9-22.2 (25-40) / 18.3-23.9 (33-43)	(15 pp. 27-16)	
LP Economizer + Valve+ Pipe Pressure Drop, MPa (psi)	0.07 (10)	0.07-0.10 (10-15)	(15 pp. 27-16)	
IP Economizer + Valve + Pipe Pressure Drop, MPa (psi)	0.14 (20)	0.034-0.14 (5-20)	(15 pp. 27-16)	
HP Economizer + Valve + Pipe Pressure Drop, MPa (psi)	0.21 (30)	0.17-0.21 (25-30)	(15 pp. 27-16)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
LP Superheater + Valve + Pipe Pressure Drop, MPa (psi)	0.03 (5)		(15 pp. 27-16)	
IP Superheater + Valve + Pipe Pressure Drop, MPa (psi)	0.14 (20)	0.14-0.20 (20-30)	(15 pp. 27-16)	
HP Superheater + Valve + Pipe Pressure Drop, MPa (psi)	0.41 (60)	0.41-0.69 (60-100)	(15 pp. 27-16)	
Re-heater Pressure Drop, MPa (psi)	0.21 (30)	0.2-0.27 (30-40)	(15 pp. 27-16)	

The gas turbine system unit operation data is given in Exhibit 5-6. Where values differ for natural gas applications and syngas applications, the natural gas values are given first.

Exhibit 5-6 Gas Turbine System Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
Gas Turbine Compressor (Natural Gas / Syngas)				
Inlet Silencer Pressure Drop, cm H_2O (in H_2O)	7.6 (3.0)	7.6 – 10.2 (3.0 - 4.0)	(17)	
Inlet Pressure, MPa (psia)	0.10 (14.6)	0.08 – 0.10 (11.3 – 14.6)	(17)	Ambient pressure less the inlet silencer pressure drop
Inlet Temperature, °C (°F)	15 (59)	4.4 - 15 (40 – 59)	(17)	Site ambient temperature
Pressure Ratio	18.4 / 16.1		(23)	
Isentropic Efficiency, %	85 / 81		(17)	
Gas Turbine Combustor (Natural Gas / Syngas)				
Inlet Fuel Pressure, MPa (psia)	3.1 (450) / 3.2 (464)		(17)	
Combustor Pressure Drop, % of air inlet pressure	5 /10		(17)	
Gas Turbine Expander (Natural Gas / Syngas)				
Expander Cooling Air, % of compressor output	9.2 / 20		(17)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Turbine Isentropic Efficiency, %	87.5 / 93.9		(17)	
Turbine Mechanical Efficiency, %	100		(17)	
Turbine Exhaust Temperature, °F(°C)	1,163 (628)	1,070 - 1,124 (576-606)	(23)	
Power Output, MW	181 / 232	168 -181/ 207 -232	(24)	Parameter value is at ISO conditions, and range reflects de-rate at various elevations modeled

The steam turbine system unit operation data is given in Exhibit 5-7.

Exhibit 5-7 Steam Turbine System Unit Operation Data

Unit Operation	Design Parameter	Range	Source	Notes
Single Reheat Subcritical Steam Turbine (NGCC: 2415 psia/1050°F/1050°F / IGCC: 1800 psia/ 1050°F/1050°F)				
Max Steam Temperature, °C (°F)	565.5 (1,050)		(16 pp. 1-14)	
HP Inlet Pressure, MPa (psia)	16.7 (2,415) / 12.5 (1,815)		(16 pp. 1-14)	
HP Exhaust Pressure, MPa (psia)	2.7 (390) / 3.5 (501)		(17)	Includes HP governing and HP turbine stages
IP Inlet Pressure, MPa (psia)	2.5 (360) / 3.2 (458)		(17)	
IP Exhaust Pressure, MPa (psia)	0.52 (75) / 0.45 (65)		(17)	
LP Inlet Pressure, MPa (psia)	0.52 (75) / 0.45 (65)		(17)	
Governing Stage Isentropic Efficiency, %	85 / 80		(17)	
HP Isentropic Efficiency, %	85 / 88.2		(17)	
IP Isentropic Efficiency, %	91.1 / 90.2		(17)	
LP Isentropic Efficiency, %	92.7 / 91.8		(17)	

Unit Operation	Design Parameter	Range	Source	Notes
Generator Efficiency, %	98.5	98.5-99	(17)	
Blowdown,% of feedwater flow	1 / 0.5		(17)	

5.4 GASIFICATION AND ASSOCIATED SYNGAS SYSTEMS

The gasifier system unit operation data is given in Exhibit 5-8.

Exhibit 5-8 Gasifier Systems Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
Gasifier – Dry feed				
Operating Temperature, °C (°F)	1,426 (2,600)	982 - 1,454 (1,800 - 2,650)	(25 p. 4)	Parameter value is for a specific gasifier using bituminous coal, and the range represents all dry feed gasifiers modeled to date
Gasifier/Quench Operating Pressure, MPa (psia)	4.2 (615)		(15 pp. 18-11)	Other operating pressures are possible but haven't been considered to date
Syngas Cooler (SGC) Operating Pressure, MPa (psia)	Gas side:4.2 (615) Steam side: 13.8 (2,000)		(26)(25)	
SGC Exit Temperature, °C (°F)	232 (450)	191 – 260 (375 – 500)	(26)(25)	Syngas cooler exit temperature is case dependent
Cyclone and Ceramic Candle Filters (in dry feed operation)				
Operating Temperature, °C (°F)	363 (685)	231 - 363 (448 - 685)	(26)(27)	
Operating Pressure, MPa (psia)	4.1 (600)		(26)(27)	
Gasifier – Slurry Feed				
Gasifier/Quench Operating Pressure, MPa (psia)	4.2 (615)	3.4 - 4.2 (500 – 615)	(26)(28)(27)	
Gasifier /SGC) Operating Pressure, MPa (psia)	4.2 (615)	3.2 - 5.6 (475 – 815)	(26)(28)(27)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Radiant Syngas Cooler (RSC) Exit Temperature, °C (°F)	537 (1,000)	537 – 815 (1,000 – 1,500)	(26)(28)(27)	
Cyclone and Ceramic Candle Filters (in slurry feed operation)				
Operating Temperature, °C (°F)	232 (450)	222 – 235 (431 – 455)	(26)(27)	
Operating Pressure, MPa (psia)	4.1 (595)		(26)(27)	

The syngas processing, sour water and mercury removal systems unit operation data is given in Exhibit 5-9.

Exhibit 5-9 Syngas Processing Systems Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
Single-Stage Syngas Recycle Compressor				
Discharge Pressure, MPa (psia)	4.2 (615)		(26)	
Isentropic Efficiency, %	75		(26)	
Syngas Scrubbing Tower				
Syngas Exit Temperature, °C (°F)	202 (396)	110 - 202 (230 - 396)	(26)(27)	
Pressure Drop, MPa (psi)	0.06 (10)	0.03-0.06 (5 – 10)	(26)(27)	
Sour CO-Shift				
High Temperature Shift (HTS) Catalyst			(29)(30)	Chromium or copper promoted iron based catalysts Copper-zinc aluminum catalysts
Low Temperature Shift (LTS) Catalyst			(29)(30)	Chromium or copper promoted iron based catalysts Copper-zinc aluminum catalysts
HTS Conversion, %	2.5% CO at the reactor outlet		(29)(30)	
LTS Conversion, %	0.2% CO at the reactor outlet		(29)(30)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
HTS temperature, °C (°F)	413 (776)	300-450 (572-842)	(29)(30)	The scrubber syngas feed is normally re-heated to 30°F to 50°F above saturation before entering the shift reactor to avoid catalyst damage by liquid water.
LTS temperature, °C (°F)	(239) (463)	180-250 (356-482)	(29)(30)	The scrubber syngas feed is normally re-heated to 30°F to 50°F above saturation before entering the shift reactor to avoid catalyst damage by liquid water.
HTS / LTS Pressure Drop, MPa (psi)	0.07 (10)	0.07-0.14 (10-20)	(29)(30)	
COS/HCN Hydrolysis Reactor				
Catalyst			(29) (31)	Activated alumina based catalysts
Pressure Drop, MPa (psi)	0.03 (5)		(29) (31)	
Conversion, %	99		(29) (31)	
Operating Temperature, °C (°F)	232 (450)	177-232 (350-450)	(29) (31)	The scrubber syngas feed is normally re-heated to 30°F to 50°F above saturation before entering the reactor to avoid catalyst damage by liquid water
Low Temperature Gas Cooling Heat Exchangers				
Pressure Drop, MPa (psi)	0.06 (10)	0.02-0.06 (3-10)	(26)	
Syngas Exit Temperature, °C (°F)	35 (95)		(26)	
Sour Water Stripper (SWS) Pumps				
Discharge Pressure, MPa (psia)	0.79 (115)	0.34-0.55 (50-80)	(31)	
Efficiency, %	80		(31)	
Knockout Drums				
Pressure Drop, MPa (psi)	0.03 (5)	0.02-0.03 (3-5)	(26)	
SWS Regenerator				
Operating Temperature, °C (°F)	115 (239)	116-135 (240-275)	(31)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Condenser Pressure Drop, MPa (psi)	0.03 (5)		(31)	
Column Operating Pressure, MPa (psia)	0.45 (65)	0.34-0.51 (50-75)	(31)	
pH of Stripped Water	8		(31)	
SWS Reboiler				
Steam Pressure, MPa (psia)	0.45 (65)	0.45-0.75 (65-110)	(31)	
SWS Exchangers				
Gas Side Pressure Drop, MPa (psi)	0.03 (5)		(31)	
Trim Cooler				
Pressure Drop, MPa (psi)	0.03 (5)		(31)	
Mercury Removal Bed Preheater				
Operating Temperature, °C (°F)	2.8 (5)		(32)	Degrees above the saturated syngas dew point temperature
Pressure Drop, MPa (psi)	0.03 (5)	0-0.03 (0-5)	(32)	
Mercury Removal Bed				
Adsorbent Type			(33)	Sulfur-impregnated activated carbon
Operating Temperature, °C (°F)	35 (95)	30-41 (86-103)	(33)	
Pressure Drop, MPa (psi)	0.06 (10)		(33)	
Removal Efficiency,%	95	90-95	(33)	
Space Velocity, hr^{-1}	4,000		(33)	

The sulfur processing system unit operation data is given in Exhibit 5-10.

Exhibit 5-10 Sulfur Processing Systems Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
Claus Reaction Furnace				
Furnace Temperature, °C (°F)	1,316 (2,400)	1,094-1,649 (2,000-3,000)	(34)	Parameter value is minimum required for ammonia destruction
Pressure Drop, MPa (psi)	0.003 (0.5)	0.003-0.01 (0.5-2)	(34)	
Residence Time, sec	0.8		(34)	When the H_2S concentration is 50% or higher, the straight-through version of the modified Claus process where all of the acid gas is routed to the acid gas burner) is generally used. Below this concentration, it is usually necessary to use the split-flow version of the process (where only a portion of the acid gas is combusted in the burner) in order to maintain a stable flame in the burner. Below an H_2S concentration of about 15%, a stable flame usually cannot be maintained in the burner, but special design techniques (such as supplemental fuel gas firing) can be employed to extend the range of the process to very lean acid gas streams.
Claus Waste Heat Boiler				
Outlet Temperature, °C (°F)	343 (650)	316-427 (600-800)	(35)	
Steam Pressure, MPa (psia)	3.0 (430)		(35)	Steam Generated
Claus Condenser				
Outlet Temperature, °C (°F)	185 (365)	340-375 (171-191)	(35)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Steam Pressure, MPa (psia)	0.45 (65)	0.38-0.55 (55-80)	(35)	Steam Generated
Pressure Drop, MPa (psi)	0.003 (0.5)	0.003-0.01 (0.5-2)	(35)	
Claus Reheat Exchanger				
Outlet Temperature, °C (°F)	232 (450)	216-232 (420-450)	(35)	
Steam Pressure, MPa (psia)	3.0 (430)	2.6-3.7 (380-545)	(35)	Required Heat Source
Pressure Drop, MPa (psi)	0.003 (0.5)	0.003-0.006 (0.5-1)	(35)	
Claus Reactor				
Catalyst			(35)	Alumina based with promoting agents
Exit Temperature, °C (°F)	278 (532)	278-344 (532-650)	(35)	
Steam Pressure, MPa (psia)	0.45 (65)	0.38-0.55 (55-80)	(35)	Steam Generated
Pressure Drop, MPa (psi)	0.003 (0.5)	0.003-0.006 (0.5-1)	(35)	
Claus Final Condenser				
Exit Temperature, °C (°F)	138 (280)	121-149 (250-300)	(35)	
Generated Steam Pressure, MPa (psia)	0.45 (65)	0.20-0.45 (30-65)	(35)	Steam Generated
Pressure Drop, MPa (psi)	0.003 (0.5)	0.003-0.01 (0.5-2)	(35)	
Sulfur recovery, %	99.9	97.5-99.9	(35)	

The tail gas treatment system unit operation data is given in Exhibit 5-11.

Exhibit 5-11 Tail Gas Treatment Systems Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
TGTU Hydrogenation Reactor				
Catalyst			(36)	Cobalt molybdate on alumina
Operating Temperature, °C (°F)	290 (550)	204-293 (400-560)	(36)	
TGTU Waste Heat Boiler				
LP Steam, MPa (psia)	0.45 (65)	0.3-0.5 (43.5-72.5)	(37)	Steam Generated

5.5 CARBON DIOXIDE CAPTURE AND COMPRESSION SYSTEMS

The CO_2 capture system unit operation data is given in Exhibit 5-12.

Exhibit 5-12 CO_2 Capture System Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
CO_2 Capture Specifications – Post-Combustion Amine				
CO_2 Capture Efficiency, (%)	90		(38)(39)	
Absorber Pressure Drop, MPa (psi)	0.005 (0.72)		(38)(39)	
Absorber Temperature, °C (°F)	32 (89)	29-49 (85-120)	(38)(39)	
Reboiler Steam Requirement, kJ/kg CO_2 (Btu/lb CO_2)	3,556 (1,530)	2,952-3,556 (1,270-1,530)	(38)(39)	
CO_2 Regenerator Outlet Pressure, MPa (psia)	0.16 (23.5)	0.16-0.18 (23.5-26.5)	(38)(39)	
Reboiler Steam Pressure, MPa (psia)	0.44 (73.5)		(38)(39)	Steam Required
Reboiler Steam Temperature, °C (°F)	149 (300)		(38)(39)	Steam Required

The CO_2 compression system unit operation data is given in Exhibit 5-13.

Exhibit 5-13 CO_2 Compression System Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
CO_2 Compression System				
Intercooler Approach Temperature, °C (°F)	5.6 (10)	5.6 – 11.1 (10 – 20)	Engineering Judgment	
CO_2 Compressor Stage Pressure Ratio	2.2	1.6 - 2.5	Engineering Judgment	
CO_2 Compressor Outlet Pressure, MPa (psia)	15.3 (2,215)		Engineering Judgment	
CO_2 Compressor Intercooler Pressure Drop, MPa (psi)	0.003 (0.5)		Engineering Judgment	
Polytropic Stage Efficiency, %	86		Engineering Judgment	
Mechanical Stage Efficiency, %	98		Engineering Judgment	
Triethylene Glycol (TEG) Unit Pressure Drop, MPa (psi)	0.002 (0.3)	0.002 - 0.03 (0.3-5)	Engineering Judgment	

5.6 ANCILLARY SYSTEMS

The section contains specifications for ancillary process systems common to many types of cycles.

Exhibit 5-14 Process Parameters for Cooling Water Systems

Equipment and Parameter	Parameter Value	Range	Source	Notes
Wet Cooling Tower				
Cooling Water Temperature Approach to Ambient Wet Bulb Temperature, °C (°F)	5 (8.5)		(40 pp. 9-95)	
Cooling Water Range, °C (°F)	11 (20)		(40 pp. 9-95)	

Equipment and Parameter	Parameter Value	Range	Source	Notes
Evaporative Losses, % of Circulating Water Flow	0.8		(40 pp. 9-95)	
Drift Losses, % of Circulating Water Flow	0.001		(40 pp. 9-95)	
Blowdown Losses [Evaporative Losses/(Cycles of Concentration-1)]			(40 pp. 9-95)	Note - The cycles of concentration is a measure of water quality, and a mid- range value of 4 was assumed.
Dry Cooling Tower				
Fan Power Ratio	3.5	3 - 4	(41 pp. 3-23)	Ratio of dry cooling tower power requirement relative to a wet cooling tower design of the same heat duty

The air separation system unit operation data is given in Exhibit 5-15.

Exhibit 5-15 Air Separation System Unit Operation Data

Equipment and Parameter	Parameter Value	Range	Source	Notes
Main Air Compressor with Intercooling				
Type	Centrifugal Multistage		(42)	
Discharge Pressure, MPa (psia)	1.3 (190)	0.6-1.3 (87-190)	(42)	Parameter value assumes elevated pressure ASU for gasification applications; low end of range is for oxycombustion applications
Isentropic Stage Efficiency, %	84	84-90	Engineering Judgment	
Oxygen Compressor				
Discharge Pressure, psia (MPa)	5.1 (740)	4.2-6.5 (615-940)	(42)	Discharge pressure depends on gasifier type
Isentropic Stage Efficiency	84		Engineering Judgment	
Nitrogen Compressors				
Discharge Pressure, MPa (psia)	3.2 (469)	2.7-5.6 (389-815)	(32)	Range reflects variety of N_2 applications from combustion turbine diluent to gasifier transport gas

Equipment and Parameter	Parameter Value	Range	Source	Notes
Isentropic Stage Efficiency, %	84		(32)	

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